niagara peninsula energy

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December 23, 2014

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
PO Box 2319
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

RE: Niagara Peninsula Energy Inc.
2015 Cost of Service Rate Application (EB-2014-0096) – Interrogatory Responses

Dear Ms. Walli:

In accordance with Procedural Order No. 1, issued November 18, 2014, Niagara Peninsula Energy Inc. ("NPEI") hereby submits responses to Interrogatories received from Board Staff, Energy Probe Research Foundation ("Energy Probe"), the Vulnerable Energy Consumers Coalition ("VECC") and School Energy Coalition ("SEC").

An electronic copy of the Interrogatory Responses and the accompanying Excel files have been submitted through the RESS system, and two hard copies and one CD will be delivered to the OEB office.

This document is being filed pursuant to the Board's e-Filing Services.

Yours truly,
Niagara Peninsula Energy Inc.

SWilson

Suzanne Wilson, CPA, CA
Vice-President, Finance

Contents

Niagara Peninsula Energy Inc.
2015 Cost of Service Application
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Exhibit 1 Administration

1. 1 Staff 1.Updates

Upon completing all interrogatories from Board 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 previous version of the RRWF included in the middle column. Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or an explanatory note.

Also upon completing all interrogatories from Board staff and intervenors please provide any updates to the following Microsoft Excel documents in working format: PILS, 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 reflecting the revised revenue requirement in the updated RRWF.

Response

The updated RRWF in working Microsoft Excel format has been uploaded to NPEI's 2015 COS web drawer. Changes arising from interrogatories have been noted in the middle column. The following is a list of the adjustments made as a result of the interrogatory process:

1. Regulatory Costs have been updated to be amortized over 5 years versus 4 years as per interrogatory 1-EP-2. The impact is a decrease to the revenue requirement in the amount of (**$20,070)**.

2. The RTSR model was updated as per interrogatory 8-VECC-48. The impact on the Working Capital allowance is an increase of $11,309. Using the originally filed weighted average cost of capital of 6.23% the total return on rate base increases by $705. The impact of PILS is an increase of $144 for a total net increase in revenue requirement of **$849**.

3. Cost of Power has been adjusted to correct pricing as identified in interrogatory per 2 EP 12. The impact on working capital allowance is an increase of $589,368. Using the originally filed weighted average cost of capital of 6.23% the total return on rate base increases by

$36,689. The impact of PILS is $7,487 increase for a total net increase in revenue requirement of **$44,177**.

4. SSS Admin Revenue has been updated as identified in interrogatory per 3.0-VECC-24 and 3-EP-20. SSS Admin Revenue increased by $6,047 due to the incorrect calculation of SSS Admin Revenue for the Residential and GS<50 rate classes. The impact on Revenue requirement results in a decrease of **($6,047)** before the change in cost of capital parameters.

5. Distribution Revenue at Current Rates and Proposed Rates have changes as a result of changing the load forecast due to the following:

   - Impact of the 2015 CDM adjustment of 74.4 GW as per interrogatory 3 Staff 33 and 3.0-VECC-17.
   - Update for 2013 final verified OPA CDM results as per interrogatory VECC #16
   - Update load forecast for double counting of CDM adjustments for 2014 and 2015 as per VECC #18

   The impact on the Revenue Requirement was an increase of $25,758, offset by a decrease in the Distribution Revenue at Existing Rates of ($294,112) for a net decrease in the Revenue Deficiency of **($268,354).**

6. The Cost of Capital parameters have been updated as per interrogatory 5-EP-34 and the calculation of weighted average cost of capital has been updated as per interrogatory 5-Staff-42. The revenue requirement has decreased by **($157,081)** before the change in the Small Business Deduction for PILS. The loan RFP actual interest rate has also been updated as per interrogatory 5-Staff-42.

7. PILS model was updated to remove the 7% reduction related to the Small Business Deduction and for the other impacts noted above for a total impact of $51,254 as per interrogatory 4-Staff-41.

Please see the RRWF tracking form below:

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2015 Filers

Tracking Form

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.)

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	$ 8,949,680	6.23%	$ 143,761,898	$ 153,984,823	$ 20,018,027	$ 4,936,879	$ 43,189	$ 16,754,348	$ 30,971,328	$ 1,596,475	$ 29,374,853	$ 1,003,773
1	1-EP-2	Correct amortization period of regulatory costs to 5 years	$ 8,949,306	6.23%	$ 143,759,342	$ 153,965,160	$ 20,015,471	$ 4,936,879	$ 43,156	$ 16,734,685	$ 30,951,258	$ 1,596,475	$ 29,354,783	$ 983,703
		Change	-$ 374	0.00%	-$ 2,556	-$ 19,663	-$ 2,556	$ -	-$ 33	-$ 19,663	-$ 20,070	$ -	-$ 20,070	-$ 20,070
2	8-VECC-48	Update RTSR Model for proposed 2015 UTRs	$ 8,950,011	6.23%	$ 143,770,651	$ 154,052,148	$ 20,026,779	$ 4,936,879	$ 43,300	$ 16,734,685	$ 30,952,107	$ 1,596,475	$ 29,355,632	$ 984,552
		Change	$ 705	$ -	$ 11,309	$ 86,988	$ 11,308	$ -	$ 144	$ -	$ 849	$ -	$ 849	$ 849
3	3-EP-12	Update COP for Oct 2014 RPP Report	$ 8,986,700	6.23%	$ 144,360,019	$ 158,585,748	$ 20,616,147	$ 4,936,879	$ 50,787	$ 16,734,685	$ 30,996,285	$ 1,596,475	$ 29,399,809	$ 1,028,729
		Change	$ 36,689	$ -	$ 589,368	$ 4,533,600	$ 589,368	$ -	$ 7,487	$ -	$ 44,178	$ -	$ 44,177	$ 44,177
4	3-EP-20, 3-VECC-24	Update SSS Admin Revenue	$ 8,986,700	6.23%	$ 144,360,019	$ 158,585,748	$ 20,616,147	$ 4,936,879	$ 50,787	$ 16,734,685	$ 30,996,285	$ 1,602,522	$ 29,393,762	$ 1,022,682
		Change	-$ 0	$ -	$ 0	$ -	$ -	$ -	-$ 0	$ -	$ -	$ 6,047	-$ 6,047	-$ 6,047
5	3-VECC-16, 3-VECC-17, 3-VECC-18	Update CDM for 2013 final verified. Update 2015 CDM target. Correct double counting of CDM variable in regression model	$ 9,008,080	6.23%	$ 144,703,471	$ 161,227,692	$ 20,959,600	$ 4,936,879	$ 55,165	$ 16,734,685	$ 31,022,042	$ 1,602,522	$ 29,419,520	$ 754,328
		Change	$ 21,380	$ -	$ 343,452	$ 2,641,944	$ 343,453	$ -	$ 4,378	$ -	$ 25,757	$ -	$ 25,758	-$ 268,354
6	5-EP-34	Update 2015 Cost of Capital Parameters	$ 8,862,798	6.12%	$ 144,703,471	$ 161,227,692	$ 20,959,600	$ 4,936,879	$ 43,366	$ 16,734,685	$ 30,864,961	$ 1,602,522	$ 29,262,439	$ 597,247
		Change	-$ 145,282	-$ 0	$ -	$ -	$ -	$ -	-$ 11,799	$ -	-$ 157,081	$ -	-$ 157,081	-$ 157,081
7	4-Staff-41	Update 2015 PILs to reflect elimination of Small Business Deduction	$ 8,862,798	6.12%	$ 144,703,471	$ 161,227,692	$ 20,959,600	$ 4,936,879	$ 94,620	$ 16,734,685	$ 30,916,215	$ 1,602,522	$ 29,313,693	$ 648,501
		Change	-$ 0	$ -	$ 0	-$ 0	-$ 0	$ -	$ 51,254	$ -	$ 51,254	-$ 0	$ 51,254	$ 51,254

8. The Cost Allocation model was updated for the services weighting factors used for the streetlight, sentinel and unmetered scattered load rate classes as per interrogatory 7-VECC-41. The number of meters for the residential and GS<50 rate classes were updated on I.7.1 and the corresponding increase in meter reading was also updated on I.7.2 as per interrogatories 7-VECC-43 and 7-VECC-44 respectively.

9. EDDVAR model has been updated as per interrogatory 9-Staff-53 for the correction to the change in number of customers versus connections.

As a result of the changes above a number of other models have been updated which includes:

1.Weather normalization model
2.PILS model
3.RRWF model
4.Cost Allocation model
5.RTSR model
6.EDVARR model
7.Chapter 2 Appendices- Yellow highlighted tabs.

Please see Attachment #1 for a complete updated RRWF.

2. 1 Staff 2.Benchmarking

Reference

1.Scorecard
http://www.ontarioenergyboard.ca/documents/scorecard/2013/Scorecard%20-%20Niagara%20Peninsula%20Energy%20Inc..pdf

Preamble

On August 14, 2014, the Board established the stretch factor assignments for 2015 rates in the Report of the Board: Rate Setting Parameters and Benchmarking under the renewed Regulatory Framework for Ontario's Electricity Distributors. The applicant was assigned to Group III out of five groups; unchanged from the prior assignment.

a)Please provide details on any initiatives undertaken to improve the applicant's assignment in future years

NPEI's Total Cost per Customer may be trending down, for in 2011 it was $690, and has consistently dropped to $672 in 2013.

b)What is NPEI's target for 2015?

c)What is NPEI's five year target?

For CDM, Distributor Targets are stated as demand levels, while the actuals are stated as percentages.

d) Please state what the 2009 – 2013 percentages are in terms of demand.

e) Are the target demands based on projects that were not completed in the historical years? If not please explain the trends.

Response

a) Through attrition NPEI anticipates the impact of the water reverting back to the City of Niagara Falls will improve its cohort assignment in future years. With the exception of the System Analyst that has been included in the 2015 COS rate application and assuming the status quo, NPEI does not anticipate hiring any back of the house employees within the next five years. NPEI does not anticipate any significant capital additions related to its administration facilities in the next five years. NPEI is committed to improve customer engagement and improve its scorecard results. NPEI anticipates an upward trend in the new residential/small business services connected on time statistic beginning in 2014 with the engagement of a third party contractor. NPEI also anticipates an improvement in the system reliability statistics in 2014 and future years with continued investments in its tree trimming program.

b) NPEI would note that the cost per customer went down from $690 to $672, in part, as a result of a reduction in the weighted average cost of capital from 7.08% to 5.96% and this trend has reversed from 2013 to 2015 thereby placing upward pressure on costs per customer. NPEI has not targeted a specific dollar per customer cost for 2015 and beyond.

c) Excluding the impact of any changes in the weighted average cost of capital and smart meters and through attrition of water related labour NPEI anticipates its total cost per customer will be comparable to 2013 in five years assuming the status quo.

d) The table below shows NPEI's CDM demand results for 2011-2013 in MW. As per the comment on the 2013 Scorecards, the CDM net annual peak demand target savings do not include any persisting peak demand savings from the previous years.

2011 - 2013 Peak Demand CDM Results	2011	2012	2013	OPA 2014 Target
Net Annual Peak Demand Savings (MW)	1.4	1.5	2.0	15.5
Net Annual Peak Demand Savings (% of target achieved)	9.0%	9.6%	12.9%	100.0%

e) The target Annual Peak Demand savings of 15.49MW on the Scorecard is the target set by the OPA, not NPEI.

3. 1 Staff 3.Customer Engagement

Reference

- Appendix 2-AC

Preamble

NPEI states that for "1. Definition and Schedule of Customer Engagement Plan":

> "Identification that in order to document and respond to customer needs and preferences, plan needed to be in place. Within the plan, define principles of customer engagement, the documentation and process to be followed to track customer needs and preferences. Schedule quarterly meetings. Follow through on lessons learned."

a) Please provide a progress report and target dates for any item of the plan that has not been implemented.

b) Is NPEI maintaining quarterly meetings? If so please provide any agendas and presentations for the meetings.

c) What lessons were learned and what were the follow-ups from the meetings?

NPEI states in "2. Identify customer needs, preferences, priorities: use of data analytics from customer surveys, customer call activity, outages. Take a long term perspective by applying principles of customer engagement over a 5 year period of distribution system plan:"

> "Customer needs and preferences identified: utility response time, communication and education to customers on how to save on their monthly bill. Integration of customer needs/preferences/priorities in DS planning and plan."

d) Please state the integration with the DSPlan, stating changes that were made.

e) What forms of outreach were employed to explain how the current application serves the needs and expectations of customers? If none were employed, please explain why.

For conservation, "5. Conservation program access and Site Visits", NPEI stated:

> "NPEI completed data collection and consultation to determine key market characters within service area. NPEI completed market character interviews and site visits. NPEI will integrate tracking consultation topics into CDM engagement activities."

f) What topics is NPEI tracking?

g) What has NPEI learned from this?

NPEI engages directly with its customers in "6. Educate and inform customers" and "7. Customer Consultations"

h) What feedback did NPEI receive from its customers, and what actions as a result did NPEI undertake or is planning?

Response

a) Please see the attached Niagara Peninsula Energy Inc. Plan document Attachment #2. This sets out high level tasks to complete and the target month of completion. Niagara Peninsula Energy Inc. has completed the Engagement Plan, Baseline Report, Documented how education and information to customers will be conducted and documented, completed customer data collection and consultation including market characterization data collection, market characterization interviews and site visits, reviewed the current process of tracking customer's inquiries, complaints and feedback, completed the annual customer satisfaction survey, and conducted one transactional survey and began meetings with staff to review the engagement plan.

b) Yes, NPEI did maintain quarterly meetings. Please see attached agendas in Attachment #3 and presentations for the meetings.

c) The lessons learned included that we were engaging our customers; however, we needed to better document how we were engaging the customers whether it was the completion of a call, letter dropped off to residence, or discussions held at community events, or school presentations. Further, the Steering Committee discussed that customer engagement was not only found in customer service and billing, conservation and our website. Customer Engagement includes all interaction with the customer across the utility.

   We learnt that our customers were very and fairly satisfied.

   The types of problems faced by our customers were high bills. This provided us with information of more local conservation programs were needed. NPEI determined that it would apply for a local conservation program plan from the OPA Conservation Fund. More emphasis within the call with the customer regarding high bills was needed on education and review of the customer's usage as a method to decrease the high bill.

Dependent on the stage of development of the engagement plan outlined the follow ups from the meetings. Initial meetings reviewed and set out the plan of what we needed to accomplish and how to complete and set plan dates. Dependent on the meeting, follow ups included completing data collection of all accounts, review of data, review of engagement plan templates provided by ICF, discussion of how to conduct customer survey, definition of survey, including questions to include, planning of survey, discussion of progress of DSP, review of current customer calls, complaints and feedback, and NPEI staff completion of the engagement plan and baseline report. Within the upcoming December meeting, we will review progress and discuss plan for 2015.

d) The Distribution System Plan was developed in conjunction with the Customer Engagement Plan. Customer feedback is used to validate and maintain NPEI's strategic objectives. Refer to the response to 2-staff-5, a) for a description of how Customer Satisfaction is one of the 5 key performance indicators that provides feedback for NPEI's planning cycles.

Customer feedback is also used to adjust weighting of the 4 key evaluation criteria used to justify and prioritize capital expenditures. Refer to 2-staff-5, b) below for details on existing weighting factors.

e) Customer outreach occurs when a customer calls into the utility during an outage and a two way dialogue occurs between the representative and the customer. Feedback from the customer is documented within the account. Dependent on the information, this information is also included within the outage management system to be used by Operations. Further dependent on stage of outage feedback is provided directly to the Control Room to assist with addressing the customer needs, preferences and priorities.

Customer outreach occurs when scheduling for capital work or maintenance to be completed causing interruption to our customer and a letter is hand delivered to the customer. This provides opportunity for the customer to provide feedback directly to individual delivering the notice or to call into our Customer Centre. Feedback from the customer is provided to the Operations staff scheduling the work to be completed.

Several of the identified capital expenditures involved customer consultation to identify needs and priorities. For example, the development of project reference #SR-28 (Rolling Acres OH to UG Conversion, Ph1) included public consultation to present the current state of distribution facilities, the alternatives and costs associated with risk mitigation efforts, and impacts to municipal and private property. The Public Information Centre was held on September 24, 2014 at a local Cultural Centre in the vicinity of the construction area.

Another example is the Grid Modernization Project (Wi-Max). NPEI facilitated meetings with each of the 5 municipal stakeholders to identify the proposed plan, impacts on the public, properties, and facilities. NPEI also participated in public consultation to identify the proposed implementation plan and construction of communication facilities. The meeting dates are summarized as follows:

- Town of Lincoln - February 7, 2013
- Township of West Lincoln - February 14th, 2013
- Town of Pelham - Wednesday March 13, 2013
- Niagara Region - April 16, 2013
- City of Niagara Falls - April 22, 2013

f) In review of the data collection, key market groups included hotels, motels, and agriculture (including wineries.) Usage, conservation measures and programs to offer were topics being tracked.

g) NPEI has learned that customers are primarily concerned with the billed amount and high consumption. They want to learn about their bill and learn what can be done to decrease the bill. Commercial customers want to learn about efficiencies gained from conservation initiatives for their business that can assist with decreasing their bill.

Key market groups including hotels, motels, and agriculture are interested in province wide, as well as, local conservation programs.

NPEI engages directly with its customers in “6. Educate and inform customers” and “7. Customer Consultations”

h) NPEI learned that the customer wants to learn and be informed. The most preferential form of communication is the phone according to our customers. NPEI reviewed with call centre staff how high bills were addressed. Representatives take time either via the phone, in person with the customer in the office to review usage trends, present how the customer can track their own usage from their home using our website, My Account, and reviewed the bill and how it is calculated. Representatives work with the customer to make payment arrangements to assist with a high bill.

From a conservation planning perspective, NPEI learned that customers are interested in province wide conservation programs and that local conservation programs would be beneficial.

NPEI CDM Program Advisor meets with customers to review applicable programs that are available to the customer.

NPEI is working with OPA to define and create local conservation programs. NPEI will be applying to the OPA Conservation Fund to achieve the local conservation programs.

NPEI is planning to have a staff member on the OPA agriculture committee with the Ministry of Agriculture.

ENERGY PROBE

4. 1-Energy Probe-1

Ref: Exhibit 1, Tab 2, Schedule 5

How many months of actual data are included in the bridge year forecasts for each of the revenue forecasts, OM&A forecasts and capital forecasts?

Response

The rate application was prepared between March and July of 2014. The capital forecasts and OM&A forecasts are based on the 2014 Budget with the assumption that both of these budgets will be met by the end of 2014. The weather normalization load forecast and customer data are based on actuals up to December 31, 2013. Therefore, there are zero months of 2014 actual data included in the bridge year forecasts for revenue, OM&A and capital.

5. 1-Energy Probe-2

Ref: Exhibit 1, Tab 2, Schedule 5 &
Exhibit 1, Tab 6, Schedule 24

a) The regulatory costs shown appear to have been amortized over a 4 year period (i.e. $98,313 out of $$393,250). Please explain why these costs have not been amortized over a 5 year period representing the cost of service rebasing year, followed by 4 years under IRM as required under 4th Generation IRM from the RRFE?

b) Please reconcile the figure of $98,313 with the statement in Exhibit 1, Tab 6, Schedule 24 that indicates a 5 year normalization of regulatory costs.

Response

a) Exhibit 1, Tab 2 Schedule 5 is incorrect. The regulatory costs should be amortized over a 5 year period as noted on Exhibit 1, Tab 6, Schedule 24. Sheet APP2-M Regulatory Costs included in the 2015 Filing Requirements Chapter 2 Appendices is also incorrect and has been updated below.

Appendix 2-M
Regulatory Cost Schedule

On-Going
One-Time

	Regulatory Cost Category	USoA Account	USoA Account Balance	Ongoing or One-time Cost? [2]	Last Rebasing Year (2011 Board Approved)	Most Current Actuals Year 2013	2014 Bridge Year	Annual % Change	2015 Test Year	Annual % Change
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H) = [(G)-(F)]/(F)	(I)	(J) = [(I)-(G)]/(G)
1	OEB Annual Assessment	5655		On-Going	$ 187,429	$ 166,367	$ 170,000	2.18%	$ 172,000	1.18%
2	OEB Section 30 Costs (Applicant-originated)									
3	OEB Section 30 Costs (OEB-initiated)	5655		On-Going	$ 3,500	$ -	$ 12,868		$ 10,000	-22.29%
4	Expert Witness costs for regulatory matters									
5	Legal costs for regulatory matters	5655		One-Time	$ 50,000	$ 6,306	$ 6,306	0.00%	$ 45,000	613.61%
6	Consultants' costs for regulatory matters	5655		One-Time	$ 20,000	$ 28,324	$ 28,324	0.00%	$ 23,050	-18.62%
7	Operating expenses associated with staff resources allocated to regulatory matters									
8	Operating expenses associated with other resources allocated to regulatory matters [1]									
9	Other regulatory agency fees or assessments									
10	Any other costs for regulatory matters (please define)									
11	Intervenor costs	5655		One-Time	$ 7,500	$ 12,501	$ 12,501	0.00%	$ 10,600	-15.21%
12	Sub-total - Ongoing Costs [3]		$ -		$ 190,929	$ 166,367	$ 182,868	9.92%	$ 182,000	-0.47%
13	Sub-total - One-time Costs [4]		$ -		$ 77,500	$ 47,131	$ 47,131	0.00%	$ 78,650	66.88%
14	Total		$ -		$ 268,429	$ 213,498	$ 229,999	7.73%	$ 260,650	13.33%

Please fill out the following table for all one-time costs related to this cost of service application to be amortized over the test year plus the IRM period.

		Historical Year(s)	2014 Bridge Year	2015 Test Year	Amortize 5 years
4	Expert Witness costs				
5	Legal costs	25,224	6,306	225,000	45,000
6	Consultants' costs	113,298	28,324	115,250	23,050
7	Incremental operating expenses associated with staff resources allocated to this application.				-
8	Incremental operating expenses associated with other resources allocated to this application. [1]				-
11	Intervenor costs	50,004	12,501	53,000	10,600
		188,526	47,132	393,250	78,650

b) The correct regulatory costs amortized over a 5 year period should be $78,650 as noted below. This results in a decrease to OM&A of $19,663 and has been included as a tracked item on the RRWF tracking form.

6. 1-Energy Probe-3

Ref: Exhibit 1, Tab 6, Schedule 19

a) Please confirm that there are no Board of Director costs shown in any of the historical years, bridge year or test year for NPEI related to any of the entities shown in Chart 1-1 (other than NPEI itself) in Exhibit 1, Tab 6, Schedule 19. If this cannot be confirmed, please provide the amounts included.

b) Please provide the costs associated with the NPEI Board of Directors for each of 2011 through 2013 on an actual basis, along with the forecasts for 2014 and 2015.

Response

a) NPEI confirms there are no Board of Director costs shown in any of the historical years, bridge year or test year for NPEI related to any of the entities shown in Chart 1-1 (other than NPEI itself) in EX1Tab6Sch19.

b) Please see the table below that provides the costs associated with the NPEI Board of Directors from 2011 to 2013 actual, projected 2014 based on actuals up to October 31, 2014 and budgeted 2015.

				Actuals up to 10/31/2014 included in the Forecast	
	Actual	Actual	Actual	Forecast	Budgeted
Board Expenses	2011	2012	2013	2014	2015
Wages	64,330	70,160	54,832	54,500	55,000
Seminars/Conferences	33,581	33,146	59,756	35,273	37,000
Total	97,911	103,306	114,588	89,773	92,000

VECC

7. 1.0 – VECC - 1

Reference: 1/T3/S1/Attachment 2/ Attachment 4

a)Please provide the cost of the NPEI Customer Engagement Plan.
b)Please provide the cost of the 2014 Customer Survey.

Response

a) The cost of the NPEI Customer Engagement Plan was $22,500. These costs are included in account 4380 as part of the OPA expenses and are not a part of NPEI's distribution expenses in 2014.
b) The cost of the 2014 Customer Survey was $21,500 and is included in the Billing and collecting expenses in NPEI's distribution expenses.

8. 1.0-VECC - 2

Reference:1/T3/S1/Attachment 2/section 2.1/section 2.3/section 3.2

a)Please provide the annual summary of call centre calls for each of 2011 through 2014. Specifically, please show the number of "high bill calls" (see pg.12) that NPEI receives annually.
b)Please provide the list of 2014 capital projects currently posted on NPEI website.

c) Please provide the summary results of the transactional survey's described in section 2.3 (pg.19) for each year 2011 through 2014.

Response

a) Please see Attachment # 4 detailing the annual summary of Call Centre Calls for 2011 to 2014.

Customer Service calls include new services, moves, change of account information, requests for information, payment arrangements, arrears management program inquiry, CDM measures/programs available, general inquiry, and high bill.

Collections calls include arrears inquiry, payment arrangements, arrears management program inquiry, disconnect/reconnect.

Billing calls include high bill, questions/explanation of bill, usage and demand inquiry, CDM measures/programs available, payment methods.

Outage calls are taken by all representatives based on first queue available to ensure priority response.

b) NPEI has updated its website for the 2014 capital projects.

c) Transactional surveys were defined in 2014 and will be deployed beginning in 2015. Call center scripts were revised in 2014; however, quantitative values were not being captured in survey format. Feedback from customers was included within the notes on the account. This exercise in 2014 enhanced the direction to be taken in 2015, along with define the qualitative and quantitative data to be recorded within the transactional surveys beginning in 2015. A trial transactional survey was used to identify those customers giving permission for electronic communications. This transactional survey was well received providing 100% reconfirmation from e-billing customers.

9. 1.0–VECC- 3

Reference:1/T3/S1/Attachment 2/pg.13

a) Please provide the number of customers currently enrolled in NPEI's e-billing option?
b) Please explain the financial benefits, if any, that e-billing provides to NPEI as compared to regular post or in-person bill payment.
c) At page 13 of the NPEI Customer Engagement Baseline Report it states that: *"NPEI provides links on its website regarding its rate filing and opportunities to participate in the*

rate proceedings." Upon review of the Web site we were unable to find any such link. Does NPEI post information on its request for a rate increase on its web site? If not please explain why not.

Response

a) NPEI currently has as at December 11, 2014 8,037 customers currently enrolled in NPEI's e-billing option. E-billing provides for quick access to billing information to provide convenience to the customer. The e-billing option is available to the customer with the following options: customer can choose not to receive a hardcopy in addition to e-bill; customer can choose to receive both e-bill notification and hardcopy bill; or customer can choose to access the bill via the web portal without notification of bill being produced and receive the hardcopy the bill.

b) The financial benefits that e-billing provides to NPEI is minimal as compared to regular post or in-person bill payment due to currently a customer receives a paper bill in addition to e-billing upon request of specified option at time of enrolment. 39% of the customers enrolled with the e-bill option opted not to receive the hardcopy in addition to the e-bill notification. This represents less than 1% of the total accounts; therefore, there is minimal savings to postage. With respect to in-person bill payments the savings would come from the elimination of a debit machine and the service charges associated with debit card transactions. For NPEI this is approximately $275 per month or $3,300 annually. The cashiering tasks are required to post payments from all sources to customers account and the Brinks pick up fees are still required regardless of whether a customer mails a cheque or pays by cheque in person.

c) NPEI's rate application and OEB notice are included under the Regulatory section on its website. Please see the home page, Regulatory section on www.npei.ca.

10. 1.0-VECC- 4

Reference:E1/

a)How many in-person payment offices does NPEI operate (i.e. where you can pay your bill in cash)?

b)What is the cost of these operations?

Response

a) There is one in-person payment office located at the Niagara Falls office building.

b) There is no additional cost for this operation due to the building is NPEI's administration building. A cashiering function is required to process all customer payments regardless of the payment method chosen by the customer. The additional cost would be the debit card transaction service fees noted above.

SEC

11. SEC #1 [Ex. 1/2/1] With respect to the merger:

a. Please provide all documents prepared prior to 2008 dealing in whole or in part with the expected, planned, or forecast benefits from the merger.

b. For each of the years of data provided in the Application (2011 through 2015), please identify all savings arising as a result of the merger.

c. In the attached (Appendix A) excerpt from the evidence in EB-2010-0138, the Applicant sets out the benefits to ratepayers of the merger. For each of the benefits forecast, please provide details on the actual benefits achieved, and provide information, including quantitative information, on the persistence of those benefits into the period 2015 and beyond.

Response

a) NPEI submitted all of the documents related to the merger with NPEI's _IRR_SEC_20110223.pdf filing during the 2011 rate application Board file number EB-2010-0138 Responses to interrogatories-SEC dated February 23, 2011.

b) Section 2.2 of the letter dated September 24, 2007 from NPEI to the Ontario Energy Board contained the following net savings:

Wage Parity and benefit Burden costs = ($211,542)
Back of the house operations, consulting, legal, rate filing, administration facility, specialized resources = $561,900
Net savings = $350,358

The table below illustrates the same components included in section 2.2 of the letter noted above as savings and costs in each of the years from 2011 to 2015. The costs related to the administration building were underestimated at the time the savings/costs of the merger was prepared. Property taxes and facility operations were underestimated. The former PWU rented their office space and owned a warehouse which housed its operations and stores functions. The condition of both facilities was not sustainable for future years and would have resulted in PWU incurring administration facility costs regardless of the merger. PWU had plans to build an administration building prior to the merger.

	2011	2012	2013	2014	2015
Audit	39,600	39,600	40,800	40,800	40,800
Legal and consulting	60,000	75,000	55,000	40,000	40,000
Rate application	47,131	47,131	47,131	47,131	78,650
Administration buildings	(161,905)	(161,905)	(161,905)	(161,905)	(161,905)
Computer Mtce	223,000	223,000	223,000	223,000	223,000
Bank Service Charges	25,000	25,000	25,000	25,000	25,000
Other back of the house savings	39,100	47,200	54,500	56,800	49,000
	271,926	295,026	283,526	270,826	294,545
Wage Parity	(262,362)	(262,362)	(262,362)	(262,362)	(262,362)
	9,565	32,665	21,165	8,465	32,184

The following table outlines the back of the house positions from 2007 to 2015. Efficiencies and economies of scale have resulted in a reduction of 5 employees. These employees retired between 2008 and 2014 and were not replaced.

# of employees	2007	2007	2007	2015	
	NF	PW	Total	Total	Change
Billing	8	4	12	11	-1
Customer Service	7	4	11	10	-1
Cashier	2	1	3	2	-1
Receptionist	1	0	1	1	0
Accounting	2	3	5	3	-2
	20	12	32	27	-5

c) Examples of functions that are not duplicated due to the merger are regulatory filings, IFRS componentization, GIS mapping, smart meter and CDM initiatives, micro-fit initiatives and programming changes related to deposit policy, e-care, and e-billing. In addition to the financially quantifiable benefits, there are more Operations crews readily available to respond to outages and improve customer service and response times. In the last three major storms, economies of scale were realized as NPEI deployed crews from Niagara Falls to the peninsula west service territory as needed and on a priority basis. Prior to the merger the former Peninsula West Utilities (PWU) would have had to contract out storm restoration services provided these services were available. Equipment sharing is also a benefit to the former utility as PWU contracted these services out as well. Employee expertise and best practices exist for IFRS componentization, rate application preparation, outage management, smart meter and

CDM activities. Economies of scale have also been realized as noted in the table above. The former PWU did not have any in house IT resources prior to the merger. These costs were contracted out. Subsequent to the merger IT resources are readily available to ensure productivity in engineering, operations, billing, customer service and accounting is not hindered.

12. SEC #2 [Ex. 1/2/2]

Attached as Appendix B is the Applicant's response to SEC IR#4 in EB-2010-0138. On this table, please retain the existing columns for 2006 through 2009, and:

(a) Replace the columns for 2010 and 2011 with actuals.

(b) Add actuals for 2012 and 2013, and

(c) Add forecast for 2014, and budget for 2015 as applied for,

If there are any major trends, patterns or anomalies in the data, any additional explanation the Applicant can provide would also be of assistance.

Response

The updated table is provided below.

Description	2006	2007	2008	2009
Revenue				
Revenue Deficiency				
Distribution Revenue	24,283,344	25,802,563	25,731,545	25,714,295
Other Operating Revenue (Net)	2,260,825	2,503,646	1,960,023	2,300,073
Total Revenue	**26,544,169**	**28,306,209**	**27,691,568**	**28,014,368**
Costs and Expenses				
Administrative & General, Billing & Collecting	6,996,933	7,271,213	7,272,731	7,528,149
Operation & Maintenance	5,555,764	5,950,110	5,519,882	5,542,515
Depreciation & Amortization	6,667,024	6,896,734	7,732,755	7,754,076
Property Taxes	194,863	201,207	231,271	215,254
Capital Taxes	219,248	193,300	207,218	250,731
Deemed Interest	3,357,626	3,470,003	3,874,940	4,375,681
Regulatory Debit				
Total Costs and Expenses	**22,991,458**	**23,982,567**	**24,838,797**	**25,666,406**
Less OCT Included Above	(219,248)	(193,300)	(207,218)	(250,731)
Total Costs and Expenses Net of OCT	**22,772,210**	**23,789,267**	**24,631,579**	**25,415,675**
Utility Income Before Income Taxes	**3,771,959**	**4,516,942**	**3,059,989**	**2,598,693**
Income Taxes:				
Corporate Income Taxes	1,987,152	1,520,059	918,023	763,489
Total Income Taxes	**1,987,152**	**1,520,059**	**918,023**	**763,489**
Utility Net Income	**1,784,806**	**2,996,883**	**2,141,966**	**1,835,204**
Capital Tax Expense Calculation:				
Total Rate Base	94,183,053	97,335,286	101,964,324	108,236,325
Exemption	10,000,000	12,500,000	15,000,000	15,000,000
Deemed Taxable Capital	**84,183,053**	**84,835,286**	**86,964,324**	**93,236,325**
Ontario Capital Tax	219,248	193,300	207,218	250,731
Income Tax Expense Calculation:				
Accounting Income	3,771,959	4,516,942	3,059,989	2,598,693
Tax Adjustments to Accounting Income	1,870,700	(167,454)	(167,454)	(167,454)
Taxable Income	**5,642,659**	**4,349,488**	**2,892,535**	**2,431,239**
Income Tax Expense	1,987,152	1,520,059	918,023	763,489
Tax Rate Refecting Tax Credits	35.22%	34.95%	31.74%	31.40%
Actual Return on Rate Base:				
Rate Base	94,183,053	97,335,286	101,964,324	108,236,325
Interest Expense	3,357,626	3,470,003	3,874,940	4,375,681
Net Income	1,784,806	2,996,883	2,141,966	1,835,204
Total Actual Return on Rate Base	**5,142,432**	**6,466,886**	**6,016,906**	**6,210,885**
Actual Return on Rate Base	5.46%	6.64%	5.90%	5.74%
Required Return on Rate Base:				
Rate Base	94,183,053	97,335,286	101,964,324	108,236,325
Return Rates:				
Return on Debt (Weighted)	6.64%	6.62%	6.85%	6.09%
Return on Equity	9.00%	9.00%	9.00%	9.00%
Deemed Interest Expense	3,357,626	3,470,003	3,874,940	4,375,681
Return On Equity	4,238,237	4,380,088	4,285,561	4,217,970
Total Return	**7,595,863**	**7,850,091**	**8,160,501**	**8,593,650**
Expected Return on Rate Base	8.07%	8.07%	8.00%	7.94%
Revenue Deficiency After Tax	**2,453,431**	**1,383,205**	**2,143,595**	**2,382,766**
Revenue Deficiency Before Tax	**3,787,129**	**2,126,306**	**3,140,231**	**3,473,586**

Description	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Projected	2014 Projected excluding smart meter entry related to prior years	2015 Budget
Revenue							
Revenue Deficiency							
Distribution Revenue	25,745,718	26,969,849	27,756,246	27,893,149	30,852,103	30,852,103	29,313,693
Other Operating Revenue (Net)	2,268,793	1,903,780	1,993,175	1,741,204	1,678,147	1,678,147	1,602,522
Total Revenue	**28,014,512**	**28,873,629**	**29,749,420**	**29,634,353**	**32,530,250**	**32,530,250**	**30,916,215**
Costs and Expenses							
Administrative & General, Billing & Collecting	7,824,398	7,970,219	7,988,439	7,950,095	10,100,221	8,958,435	9,888,612
Operation & Maintenance	5,690,750	6,281,768	6,708,104	6,280,725	6,650,913	6,569,538	6,846,074
Depreciation & Amortization	7,014,282	7,230,525	7,421,270	5,321,041	5,645,351	5,372,205	4,936,879
Property Taxes	207,321	185,288	406,629	258,673	272,520	272,520	287,232
Capital Taxes	75,343	0	0	0	0	0	0
Deemed Interest	4,134,965	3,583,104	3,673,912	3,868,109	4,161,005	4,161,005	3,479,829
Regulatory Debit				3,054,566	3,115,329	3,115,329	0
Total Costs and Expenses	**24,947,058**	**25,250,903**	**26,198,354**	**26,733,208**	**29,945,340**	**28,449,033**	**25,438,626**
Less OCT Included Above	(75,343)	0	0	0	0	0	0
Total Costs and Expenses Net of OCT	**24,871,715**	**25,250,903**	**26,198,354**	**26,733,208**	**29,945,340**	**28,449,033**	**25,438,626**
Utility Income Before Income Taxes	**3,142,797**	**3,622,726**	**3,551,066**	**2,901,145**	**2,584,909**	**4,081,216**	**5,477,589**
Income Taxes:							
Corporate Income Taxes	950,836	133,068	828,451	52,334	0	0	94,620
Total Income Taxes	**950,836**	**133,068**	**828,451**	**52,334**	**0**	**0**	**94,620**
Utility Net Income	**2,191,960**	**3,489,658**	**2,722,615**	**2,848,811**	**2,584,909**	**4,081,216**	**5,382,969**
Capital Tax Expense Calculation:							
Total Rate Base	115,457,440	119,916,459	122,955,566	129,454,802	139,257,184	139,073,710	144,703,471
Exemption	15,000,000						
Deemed Taxable Capital	**100,457,440**	**119,916,459**	**122,955,566**	**129,454,802**	**139,257,184**	**139,073,710**	**144,703,471**
Ontario Capital Tax	75,343						
Income Tax Expense Calculation:							
Accounting Income	3,142,797	3,622,726	3,551,066	2,901,145	2,584,909	4,081,216	5,477,589
Tax Adjustments to Accounting Income	0	(3,035,763)	58,840	(2,315,745)	(3,975,577)	(3,975,577)	(4,814,861)
Taxable Income	**3,142,797**	**586,963**	**3,609,906**	**585,400**	**(1,390,668)**	**105,639**	**662,728**
Income Tax Expense	950,836	133,068	828,451	52,334	0	0	94,620
Tax Rate Refecting Tax Credits	30.25%	22.67%	22.95%	8.94%	0.00%	0.00%	14.28%
Actual Return on Rate Base:							
Rate Base	115,457,440	119,916,459	122,955,566	129,454,802	139,257,184	139,257,184	144,703,471
Interest Expense	4,134,965	3,583,104	3,673,912	3,868,109	4,161,005	4,161,005	3,479,829
Net Income	2,191,960	3,489,658	2,722,615	2,848,811	2,584,909	4,081,216	5,382,969
Total Actual Return on Rate Base	**6,326,925**	**7,072,761**	**6,396,527**	**6,716,921**	**6,745,914**	**8,242,221**	**8,862,798**
Actual Return on Rate Base	5.48%	5.90%	5.20%	5.19%	4.84%	5.92%	6.12%
Required Return on Rate Base:							
Rate Base	115,457,440	119,916,459	122,955,566	129,454,802	139,257,184	139,257,184	144,703,471
Return Rates:							
Return on Debt (Weighted)	5.97%	4.98%	4.98%	4.98%	4.98%	4.98%	4.01%
Return on Equity	9.00%	9.58%	9.58%	9.58%	9.58%	9.58%	9.30%
Deemed Interest Expense	4,134,965	3,583,104	3,673,912	3,868,109	4,161,005	4,155,522	3,479,829
Return On Equity	4,156,468	4,595,199	4,711,657	4,960,708	5,336,335	5,329,305	5,382,969
Total Return	**8,291,433**	**8,178,302**	**8,385,570**	**8,828,817**	**9,497,340**	**9,484,827**	**8,862,798**
Expected Return on Rate Base	7.18%	6.82%	6.82%	6.82%	6.82%	6.81%	6.12%
Revenue Deficiency After Tax	**1,964,508**	**1,105,541**	**1,989,042**	**2,111,897**	**2,751,426**	**1,242,606**	**0**
Revenue Deficiency Before Tax	**2,816,679**	**1,429,653**	**2,581,474**	**2,319,232**	**2,751,426**	**1,242,606**	**0**

13. SEC #3 [Ex. 1/2/4, p. 2, and Ex. 6/1/1, Attach 1.]

Please confirm that, before taking into account the change in useful lives of assets, the deficiency is $4,337,636, representing an overall rate increase of 15.3% from revenue at existing rates.

Response

NPEI confirms that before taking into account the change in useful lives of assets, the deficiency is $4,337,636 (3,333,862 + 1,003,773) excluding the impact of PILS, representing an overall rate increase of 15.3% from revenue at existing rates. NPEI omitted filing Appendix 2-Y in the original rate filing. NPEI has included an updated Appendix 2-Y including the impact of PILS as per below. Note the PILS under “2015 CGAAP without policy changes” excludes the impact of the 7% small business deduction.

Appendix 2-Y
Summary of Impacts to Revenue Requirement from Transition to MIFRS

Revenue Requirement Component	2015 MIFRS	2015 CGAAP without policy changes	Difference	Reasons why the revenue requirement component is different under
Closing NBV 2014	$ 120,619,682	$ 114,231,253	$ 6,388,429	
Closing NBV 2015	$ 126,868,071	$ 117,145,780	$ 9,722,291	
Average NBV	$ 123,743,877	$ 115,688,517	$ 8,055,360	
Working Capital	$ 20,018,027	$ 20,018,027	$ -	
Rate Base	$ 143,761,904	$ 135,706,544	$ 8,055,360	
Return on Rate Base	$ 8,949,680	$ 8,448,205	$ 501,475	
			$ -	
OM&A	$ 17,041,580	$ 17,041,580	$ -	
Depreciation	$ 4,936,879	$ 8,270,741	-$ 3,333,862	
PILs or Income Taxes	$ 43,189	$ 1,125,195	-$ 1,082,006	
			$ -	
Less: Revenue Offsets			$ -	
			$ -	
			$ -	
			$ -	
Insert description of additional item(s)			$ -	
Total Base Revenue Requirement	$ 30,971,328	$ 34,885,721	-$ 3,914,393	

14. SEC #4 [Ex. 1/2/4]

Attached as Appendix C is a table comparing the most recent (2013) results of the 22 Ontario distributors that have more than 25,000, and less than 100,000, customers, including the Applicant. With respect to this comparison table:

a) Please identify any distributors on the list that the Applicant feels are not appropriate comparators, and provide reasons for that conclusion.

b) The OM&A per customer of the Applicant is the 6th highest, at about 105% of the average of the comparators. Please explain how the Applicant plans to improve its position on this metric relative to the comparators, and how those plans are consistent with the requested increase in OM&A per customer in this Application.

c) The Distribution Revenue per customer of the Applicant is 8th highest, at 112% of the average of the comparators. Please provide any information available to the Applicant that explains its relatively high distribution revenue per customer relative to the comparators.

d) Gross PP&E per customer (i.e. original cost of assets) is 3rd highest, at 128% of the average. Please provide any specifics of the asset mix of the Applicant that affect the validity and usefulness of this comparison.

e) The "aging ratio" (i.e. ratio of net book value to original cost of assets) is the 6th lowest of the comparators, suggesting that the Applicant's assets have a greater average age relative to most of its peers. Please provide any data available to the Applicant (other than information already included in the Distribution System Plan) that will assist the Board and the parties in understanding the relative age of the Applicant's assets, compared to other distributors.

f) The three year average efficiency rating of the Applicant is the 7th worst of the comparator group. What is the Applicant's current plan to improve its efficiency rating relative to comparator utilities? Please provide any documents planning or forecasting improvements in efficiency rating, or any of the components of the calculation, in the period 2015-2019.

Response

NPEI is able to benchmark OM&A per customer, distribution revenue/customer, gross PP&E/customer, net PP&E/customer, aging ratios, efficiency assessments, total cost/customer and total cost/km of line only to itself.

The details provided in the 2015 cost of service rate application explain NPEI's capital expenditures, distribution revenue, other revenue, depreciation expense and OM&A costs from

2011 through to the 2015 test year. Variances on a year over year basis as well as on a project and program basis have also been provided and support NPEI's rate application.

The table below illustrates that NPEI's OM&A costs/customer are lower than the average of all LDC's from 2010 to 2013. Also, NPEI's OM&A cost/customer have trended down from 2012 to 2013 while the average of all LDC's in the province have trended up during this time period.

	2010 Yearbook Overall	2010 Yearbook NPEI	2011 Yearbook Overall	2011 Yearbook NPEI	2012 Yearbook Overall	2012 Yearbook NPEI	2013 Yearbook Overall	2013 Yearbook NPEI
OM&A per customer	$ 282.00	$ 262.02	$ 292.00	$ 274.98	$ 309.00	$ 289.67	$ 325.00	$ 276.36
% NPEI is lower than average of all LDC's		-7.09%		-5.83%		-6.26%		-14.97%
% change year over year Average of all LDC's			3.55%		5.82%		5.18%	
% change year over year for NPEI				4.95%		5.34%		-4.59%
Net Fixed asset/customer	$2,551.00	$2,315.00	$2,713.00	$1,976.00	$2,917.00	$2,038.52	$3,080.00	$2,176.45
% NPEI is lower than average of all LDC's		-9.25%		-27.17%		-30.12%		-29.34%
% change year over year Average of all LDC's			6.35%		7.52%		5.59%	
% change year over year for NPEI				-14.64%		3.16%		6.77%

In order to compare to other distributors on an individual distributor basis NPEI would require additional detailed data. For example, how the LDC's on Appendix C treated capitalized administration costs, stores and vehicle expenses prior to 2013, and when the LDC's smart meters were finally disposed. Detailed information regarding capital programs, OM&A programs, wages, benefits etc. are not on Appendix C for a comparisons to be made. Customer growth, customer rate class mix, and density variables contribute to differences in OM&A per customer, distribution revenue per customer, fixed asset costs per customer. Wages and benefit information for each LDC on Appendix C also will contribute to the differences in the comparators listed above.

15. SEC #5 [Ex. 1/2/7]

Please provide a list of all capital projects that are included in the forecast for 2015-2019, but were also included in the capital plans for 2011-2014. Please provide the reasons why each of those projects was not completed prior to 2015.

Response

The following list summarizes the projects that are carried over from 2014 to 2015:

- Project 2014-0001 (SR #24) - Crawford Street Rebuild:

This design and initial phases of construction were completed in 2014. The balance of work will be completed in 2015. Construction was delayed due to the availability of internal resources. Resource constraints were related to an increased demand for new connections and road relocation work. The projected cost to be carried forward to 2015 is $455,367.

- Project 2014-0008 (SR #28) - Rolling Acres Phase 1:
  The design was completed and civil work commenced in 2014. The balance of civil work will be completed in the 2nd quarter of 2015. Civil work did not commence until December 2014 due to the availability of the selected civil contractor on the project. The projected cost to be carried forward to 2015 is $490,577.

- Project 2014-0018 (SS#53) - King Street 27.6kV Extension:
  The King Street 27.6kV Extension project was designed in 2014 and will carry over into 2015. Construction will not commence until 2015 due to internal resource availability. The projected cost to be carried forward to 2015 is $102,554.

In light of these identified carryovers, a portion of the scope of project 2015-0011 (SR #56) Frederica Street Rebuild will be deferred in the amount of $455,367. Project 2015-2010 (SR#31) Pole Replacements will be reduced in scope in the amount of $102,554. In order to complete the balance of the identified 2015 capital projects, an additional $490,577 of expenditure is required relating to Rolling Acres Phase 1.

The table below shows NPEI's proposed 2015 capital expenditure as adjusted for the 2014 carry overs as discussed above.

Appendix 2-AA
Capital Projects Table

Project #	Ref #	Projects	2014 Bridge Year	2015 Test Year	2015 Update for Carryforwards	Total	Actuals at Oct 31	Nov to Dec	2014 Total Projected	Projected vs Bridge Year
		Reporting Basis	**CGAAP**	**MIFRS**	**MIFRS**					
		System Access								
		Subdivisions	400,000	587,004	587,004	3,181,561	813,642	152,480	966,122	566,122
	42	Customer Connection/Extension				999,318				-
	42	New Upgrade Services				1,071,284				-
	43	Line Relocation due to Municipal Requirements < Materiality	539,910	500,000	500,000	2,400,394	578,763	149,767	728,530	188,620
	42	Demand based system reinforcements	1,410,778	1,007,500	1,007,500	5,150,664	1,753,963	393,135	2,147,098	736,320
	55	Niagara Parks Commission		818,905	818,905	818,905				-
2013-0100	**38**	City of Niagara Falls Kalar @ Rideau				169,530				-
2010-0016	**39**	Dorchester NS&T to Morrison				180,976				-
2011-0072	**40**	Drummond & Lundy's Lane Conflicts				267,123				-
2010-0009	**41**	Kalar to Catalina relocation				647,406				-
2010-0053		Oakwood Drive relocation				159,399				-
2010-0026	**49**	South Pelham Street				816,593				-
		Capital contributions	-900,000	-827,800	-827,800	-6,924,015	- 792,373	- 175,469	- 967,842	- 67,842
										-
		Sub-Total System Access	**1,450,689**	**2,085,609**	**2,085,609**	**8,939,139**	**2,353,995**	**519,913**	**2,873,908**	**1,423,219**
		Miscellaneous System Access	280,000	343,500	343,500	1,803,603	89,485	9,101	98,586	- 181,414
		Total System Access	**1,730,689**	**2,429,109**	**2,429,109**	**10,742,741**	**2,443,480**	**529,014**	**2,972,494**	**1,241,805**
		System Renewal								-
		MS/DS Rehabilitations								-
2010-0025	4	Pelham MS				226,046				-
2010-0017	10	Campden DS Feeder Egress				207,208				-
2011-0017	12	Campden DS Oil Containment				214,586				-
2011-0013	5	Smithville				636,049				-
2011-0022 2	6	Station Street				279,250				-
	7	Station #22 North of Pew		507,139	507,139	507,139				-
	8	Station #22 South of Pew		143,724	143,724	143,724				-
2012-0012	6	Greenlane				472,805				-
2013-0017	9	Station #8	252,037			443,150	291,747	5,752	297,499	45,462
2011-0011	11	4 Sectionalizing West Area				156,718				-
2011-0004	13	Lundy's Lane Pole Line -Montrose				156,213				-
2011-0007	14	Murray/Culp/Dunn/Main Rebuilds				395,970				-
2011-0005 &	15	Riall St Rebuild				501,064				-
2012-0002	16	Lundy's Lane/Ker St UG replacement				356,580				-
2012-0001	17	Montrose Kinsmen to Lundys				608,128				-
2012-0007	18	Murray/Dixon Rebuild				633,981				-
2012-0014 &	19	Victoria Ave Voltage Conversion				343,346				-
2013-0005	1	12-M-6 Replacement	372,631			911,378	265,264	10,343	275,607	- 97,024
2013-0011	2	Dorchester-Garden St to McMillan	362,018			560,825	518,962	15,043	534,005	171,987
2013-0008	3	High Street - Dorchester Stn 10 O/H				633,880				-
2013-0007	20	Murray/Culp				712,700				-
2013-0021	21	OH to UG Beacon Inn Jordan				259,593				-
2013-0003	22	UG Primary Weightman Bridge	701,810			814,811	761,764	43,395	805,159	103,349
2014-0009	23	3-M-28, 3-M-26, 3-M-29	417,731			417,731	21,288	421,538	442,826	25,095
2014-0001	24	Crawford Street Rebuild	516,557	282,324	737,691	798,880	9,124	52,066	61,190	- 455,367

Appendix 2-AA
Capital Projects Table

Project #	Ref #	Projects	2014 Bridge Year	2015 Test Year	2015 Update for Carryforwards	Total	Actuals at Oct 31	Nov to Dec	2014 Total Projected	Projected vs Bridge Year
		Reporting Basis	**CGAAP**	**MIFRS**	**MIFRS**					
	56	Frederica Street Rebuild		676,144	220,777	676,144				-
2014-0004	25	Fallsview Blvd -Ferry/Robinson	332,173			332,173		-	-	- 332,173
2014-0015	26	Jordan Rd-Red Maple to QEW	397,516			397,516	9,763	305,000	314,763	- 82,753
	26	Jordan Phase II		449,324	449,324	449,324				-
2014-1006	27	Wholesale Meter Replacement	300,000			300,000	278,372	84,608	362,980	62,980
2014-0008	28	OH to UG Rolling Acres Phase I	768,694	570,500	1,061,077	1,339,194	36,317	241,800	278,117	- 490,577
2014-0007	29	OH line rebuilds - 6 streets	516,513			516,513	464,497	96,128	560,625	44,112
1007 & 2007	30	System Sustainment/Minor Betterments	400,000	680,000	680,000	3,736,480	953,977	21,603	975,580	575,580
1010 & 2010	31	Replace poles identified with limited structural integrity	778,702	431,729	329,175	4,547,032	344,285	81,656	425,941	- 352,761
0020's	32	Replacement of Submersibles & Kiosks with EFD switches and posi-tects	624,457	647,029	647,029	3,629,528	246,317	43,206	289,523	- 334,934
2013-2011	33	Replacement of Transformers with >50PPM PCB Content	566,479	495,104	495,104	1,186,758	346,844	15,226	362,070	- 204,409
	57	NWTC Metering		289,605	289,605	289,605				-
	60	Willodell Rebuild		310,710	310,710	310,710				-
	59	Willoughby Dr. Extension		383,293	383,293	383,293				-
	58	Willoughby Drive		372,191	372,191	372,191				-
		Sub-Total System Renewal	**7,307,316**	**6,238,817**	**6,626,840**	**29,858,218**	**4,548,521**	**1,437,364**	**5,985,885**	**- 1,321,431**
		Miscellaneous System Renewal		144,237	144,237	1,819,953	-	-	-	-
		Total System Renewal	**7,307,316**	**6,383,054**	**6,771,077**	**31,678,171**	**4,548,521**	**1,437,364**	**5,985,885**	**- 1,321,431**
		System Service								-
		Smart meters	1,903,089			6,105,227	1,724,874	-	1,724,874	- 178,215
		MIST Meters		143,150	143,150	143,150				-
0006's	**34**	Switchgear replacement program	110,057	250,002	250,002	1,591,405	119,261	217	119,478	9,421
2010-0024	**35**	Cherry Avenue				179,386				-
2010-0023	**36**	Durham Voltage Conversion				364,430				-
2010-0002	**37**	High Street Area				255,782				-
2010-0008	**47**	Oakwood Drive				198,387				-
2011-0003	**50**	KM2 & KM6 Montrose-McLeod				347,760				-
2012-0003	**51**	Kalar MTS K-M-1				169,041				-
2014-0018	**53**	King Street 27.6 kV	112,554	114,460	217,014	227,014		10,000	10,000	- 102,554
2010-0007	**54**	Robinson St Primary Extension				1,039,940				-
	62	Culp St-Drummond to Main								-
	48	Kalar Extend NS&T ROW-Beaverdams				768,438				-
		Mobile Substation				214,555				-
		Wi-Max Project	227,500	215,000	215,000	1,123,209	88,443	169,699	258,142	30,642
		Sub-Total System Service	**2,353,200**	**722,612**	**825,166**	**12,939,426**	**1,932,578**	**179,916**	**2,112,494**	**- 240,706**
		Miscellaneous	130,000	203,000	203,000	1,172,176	82,250	47,777	130,027	27
		Total System Service	**2,483,200**	**925,612**	**1,028,166**	**14,111,602**	**2,014,828**	**227,693**	**2,242,521**	**- 240,679**
		General Plant								-
		Building	1,500,485	44,000	44,000	4,276,958	1,460,370	179,373	1,639,743	139,258
		Computer Hardware	297,040	240,248	240,248	1,688,673	215,322	59,831	275,153	- 21,887
		Computer Software	498,710	368,740	368,740	1,639,150	409,891	272,577	682,468	183,758
		Vehicles	672,000	698,878	698,878	5,271,903	53,265	161,660	214,925	- 457,075
		General Equipment	299,000	95,627	95,627	1,257,029	204,989	68,167	273,156	- 25,844
		Sub-Total General Plant	**3,267,235**	**1,447,492**	**1,447,492**	**14,133,713**	**2,343,837**	**741,608**	**3,085,445**	**-181,790**
		Miscellaneous-General Plant	0	0	0	-				-
		Total General Plant	**3,267,235**	**1,447,492**	**1,447,492**	**14,133,713**	**2,343,837**	**741,608**	**3,085,445**	**-181,790**
		Less Renewable Generation Facility Assets and Other Non Rate-Regulated Utility Assets (input as negative)	0	0	0	-				
		Total	**14,788,440**	**11,185,268**	**11,675,845**	**70,666,228**	**11,350,666**	**2,935,679**	**14,286,345**	**-502,095**
Increase due to carryforwards					490,577					

16. SEC #6 [Ex. 1/2/10 p. 5]

Please confirm that the columns on Table 1-9 should be labelled 2016-2018, rather than 2015-2017. If not confirmed, please reconcile the revenue to cost ratios listed in Tables 1-8 and 1-9 as proposed for 2015.

Response

Table 1-9 label is correct as to what NPEI was proposing in the original rate application filing. Table 1-8 the column that reads "Proposed Revenue to Cost Ratio" should "Impact of adjusting Cost Ratios from 2015 Cost Allocation Model to Board Minimums" Table 1-8 illustrates the Revenue to Cost Ratios for 2015 by adjusting the Residential, Sentinel Lights, and USL rate classes to the Board minimum targets with the difference impacting the GS>50 rate class at 145.63%. Table 1-9 is NPEI's actual proposal to move the Residential rate class from the Board minimum target of 85% to 87% with the difference impacting the GS>50 rate class at 138.36%.

An updated Table 1-8 is shown below which incorporates all of the changes noted in IRR #1 (1-Staff-1) above.

Cost Allocation Based Calculations

Class	Revenue Cost Ratio	Check Revenue Cost Ratios from 2015 Cost Allocation Model	Revenue to Cost Ratio	Current Service Revenue	Miscellaneous Revenue	Current Base Revenue	2015 Board Target Low	2015 Board Target High	Final 2011
Residential	80.8%	80.8%	85.000%	18,140,754	1,261,305	16,879,449	85%	115%	85.0%
GS < 50 kW	118.4%	118.36%	118.36%	3,931,042	189,247	3,741,794	80%	120%	109.1%
GS >50	161.9%	161.93%	146.00%	8,349,440	138,636	8,210,805	80%	120%	145.8294%
Sentinel Lights	69.9%	69.93%	80.00%	74,011	5,263	68,748	80%	120%	70.0%
Street Lighting	87.0%	86.95%	86.95%	285,969	5,919	280,050	70%	120%	70.0%
USL	119.3%	119.30%	120.00%	134,999	2,151	132,848	80%	120%	101.5%
TOTAL	100.0%	100.0%		30,916,215	1,602,522	29,313,693			

An updated Table 1-9 is shown below which also incorporates the changes noted in IRR#1 (1-Staff-1) above. Table 1-9 is NPEI's proposed Revenue to Cost Ratios for 2015 where the GS>50 rate class will achieve the Board's maximum target by 2017.

Class	Proposed Revenue-to-Cost Ratios			Policy Range
	2015	2016	2017	
	%	%	%	%
Residential	87.00%	89.00%	91.97%	85 - 115
GS < 50 kW	118.36	118.36%	118.36%	80 - 120
GS > 50 kW	138.53%	131.07%	120.00%	80 - 120
Street Lighting	86.95	86.95%	86.95%	70 - 120
Sentinel Lighting	80.00	80.00%	80.00%	80 - 120
Unmetered Scattered Load (USL)	120.00	120.00%	120.00%	80 - 120

17. SEC #7 [Ex. 1/2/10 p. 7]

Please explain the figure for GS>50 in the column "Cost Allocation Model Ceiling" in light of page O2 of the Cost Allocation Model, which shows the ceiling – Minimum System plus PLCC adjustment – at $110.61. Please calculate the volumetric charge for GS>50 on the assumption that the monthly fixed charge is $110.61.

Response

The figure of $179.58 for GS>50 in the column "Cost Allocation Model Ceiling" is NPEI's 2014 Board-approved monthly service charge for the GS>50 kW class. This column represents the greater of the current monthly service charge and the Minimum System plus PLCC adjustment from the Cost Allocation Model, based on Section 2.11.1 of the Filing Requirements which states: *"If a distributor's current fixed charge is higher than the calculated ceiling, there is no requirement to lower the fixed charge to the ceiling, nor are distributors expected to raise the fixed charge further above the ceiling."*

The table below shows the fixed and volumetric charges, as proposed, and using the monthly fixed charge based on the Minimum System plus PLCC. Note: the figures in the table reflect the changes to NPEI's proposed revenue requirement and cost allocation as follows:

- NPEI's revenue requirement has been updated as detailed in the response to 1-Staff-1
- The service weighting factors in the Cost Allocation model have been revised as per the response to 7-VECC-41
- The number of meters for the Residential and GS<50 kW classes has been corrected, on Sheet I-7.1 Meter Capital of the Cost Allocation Model, as well as the corresponding meter reading costs on Sheet I.7.2 Meter Reading Costs, as per the response to 7-VECC-43.

The rates in the table below reflect NPEI's proposed plan to move the revenue-to-cost ratio for the GS>50 kW class to 120% over a 3 year period.

General Service > 50 kW	2015 as Proposed		2015 Using Minimum System plus PLCC	
	Fixed/Variabe Proportion	Rate	Fixed/Variabe Proportion	Rate
Fixed - Monthly Service Charge	20.82%	$156.61	14.66%	$110.28
Volumetric Charge	79.18%	$3.7301	85.34%	$4.0060

18. SEC #8 [Ex. 1/3/1, Attach 2]

With respect to the Customer Engagement Plan and related activities:

a) Please provide information, including lists of references, CVs of report authors and key investigators, and other such evidence, to demonstrate that ICF International, who are energy efficiency and environmental consultants, have expertise in customer engagement planning for electricity distributors.

b) Please confirm that the Applicant does not intend to call ICF International as expert witnesses in this proceeding.

c) Please provide details of the selection process or processes used to retain ICF International to carry out the Customer Engagement Plan, the Baseline Study, and any other work done by that firm for the Applicant in the period from January 1, 2012 to date. If any of the projects were tendered or selected through RFP, please provide the tender or RFP document, and the full bid by ICF International.

d) For each project carried out by ICF for the Applicant in 2012 through 2014, please provide a copy of the agreement between ICF and the Applicant, including any schedules, and any amendments, and provide details of all costs incurred with respect to that project. In any case in which some or all of the costs of the project were allocated to CDM activities, rather than regulated distribution activities, please provide details of the allocations including the amounts, and the basis on which the allocation was done.

e) For each project carried out by ICF for the Applicant in 2012 through 2014, please provide details of any costs associated with the project that are included in regulatory costs, or any other costs, to be recovered in rates in 2015 or beyond.

Response

a) Please see Attachment #5 ICF International.

b) Judy Simon from ICF International was the consultant engaged by NPEI. We are undecided at this time whether Miss Simon will be called as a witness expert or not.

c) ICF International was the selected vendor for the consultation of the Customer Engagement Plan, the Baseline Study as a sole source vendor as defined within the NPEI Purchasing Policy (NPE-F-200.) Per the Purchasing Policy, ICF International was already on site on existing projects and it was not practical to engage another contractor. ICF International has been working on CDM initiatives with NPEI.

Please see Attachment #5 CDM-2014 Rate Filing Opportunity

d) In review of Attachment #5 CDM-2014 Rate Filing Opportunity and Attachment #5 Customer Engagement Baseline Report the costs are outlined. The Customer Engagement Plan and Baseline Report were allocated as distribution activities based on requirements towards an improved scorecard.

e) See Attachment #5 CDM-2014 Rate Filing Opportunity and Attachment #5 Customer Engagement Baseline Report.

19. SEC #9 [Ex. 1/3/1]

Please provide a breakdown of all costs incurred, or to be incurred, by the Applicant for customer engagement activities (including planning, implementation, regulatory compliance, and supervision) in each of 2014 and 2015, including but not limited to external costs such as ICF consulting fees, and internal costs such as staff assigned to planning or implementation activities.

Response

See Attachment #5 CDM-2014 Rate Filing Opportunity and Attachment #5 Customer Engagement Baseline Report

20. SEC #10 [Ex. 1/3/1, Attach 2, p. 6]

Please provide minutes of the last three meetings of the Steering Committee, and provide:

a. All reports and other formal communications issued by the Steering Committee; and

b. All presentations and formal reports given to the Steering Committee by either internal staff or external consultants.

Response

Please see attachments as presented in IRR #3 1- Staff-3 above.

21. SEC #11 [Ex. 1/3/1, Attach 2, p. 8]

Please confirm that the Customer Engagement Plan and Baseline Plan, as well as the new initiatives contained within them, are driven by the Board's requirements in the Renewed Regulatory Framework to expand customer engagement. Please identify and describe any of the new initiatives that were planned by the Applicant prior to the Renewed Regulatory Framework. For any that were so planned, please provide the planning documents (such as strategic plans, presentations, etc.) that described those initiatives prior to the Renewed Regulatory Framework.

Response

The Customer Engagement Plan and Baseline Plan, as well as, the new initiatives contained within them, are driven by the Board's requirements in the Renewed Regulatory Framework to expand customer engagement.

22. SEC #12 [Ex. 1/3/1, Attach 2, p. 9]

Please provide a list of the "certain topic areas of importance" referred to.

Response

Certain topic areas of importance include local conservation programs funded through OPA Conservation Fund, Education of customer bill, efficiencies that a business could achieve through conservation in hotels and agriculture.

23. SEC #13 [Ex. 1/3/1, Attach 2, p. 11]

Please provide details of the "market characterization site visits" carried out earlier this year. Please confirm that the costs associated with these site visits have been included in the CDM budget funded by the OPA.

Response

See Attachment #5.

24. SEC #14 [Ex. 1/3/1, Attach 2, App. B and C]

Please identify which of the strategic steps and specific tasks itemized have been carried out, and the results of each according to the metrics described.

Response

See Attachment #5.

25. SEC #15 [Ex. 1/3/1, Attach 3, p. 8]

The Applicant says: *"NPEI has decided to improve its distribution system planning to include customer solicitation as to what projects or initiatives are important to our customers."* Please describe how this activity will be carried out, how the customer feedback will be factored into capital planning, and the ultimate goals of, and benefits sought to be achieved from, the new process.

Response

NPEI initiated a formal process for customer engagement in 2014. The objective is to be able to identify negative trends in customer satisfaction through analysis of resulting data from customer feedback. In review of cyclical trends, NPEI identifies needs that will mitigate negative trends and maintain alignment with business values. For example, outage response time has been identified as an area of concern for NPEI customers. NPEI's grid modernization program is an example of one of the initiatives in place to improve overall response times during system disturbances.

Where applicable, customer feedback as solicited through customer forums and communications received is provided to Operations so that it can be used within the planning process.

26. SEC #16 [Ex. 1/3/1, Attach 3, p. 10]

Please provide details of the relationship between NPEI and the external vendor in the provision of account and energy data to customers, including:

a. The roles of both the Applicant and the vendor;

b. Any additional contacts between customers and the vendor that are outside the scope of the relationship; and

c. A copy of the agreement(s) between the Applicant and the vendor.

Response

a) Niagara Peninsula Energy Inc. purchased the software from the vendor, Harris Computers Inc. The software is utilized via the Niagara Peninsula Energy Inc. website to provide customer account and energy data. In addition to Harris software, Niagara Peninsula Energy Inc. uses the web portal provided by Utilismart Inc. to provide energy data to its General Service greater than 50kW interval metered customers.

b) There is no contact between the customer and the vendors. The provision of account and energy data to customers is branded to Niagara Peninsula Energy Inc.

c) See Attachment #6 – Agreement between Niagara Peninsula Energy Inc. and Harris Computers Inc.; and Agreement between Niagara Peninsula Energy Inc. and Utilismart Inc. Both agreements have auto renewal to maintenance.

27. SEC #17 [Ex. 1/3/1, Attach 4, p. 4]

Please describe in detail the Applicant's strategy to deal with the decline from 62% (2010) to 50% (2014) in satisfaction with the cost of the Applicant's service relative to other utilities.

Response

NPEI only has the ability to focus on the customers in which it services. The decline referred to above relates to province wide survey results.

NPEI performed its first customer survey in 2014 and does not have any prior year's survey results to compare to. NPEI customers may not have been dissatisfied with NPEI's cost of service in 2010 and therefore would not be a part of the same trend being experienced in the province with respect to cost of service. On page four of the customer survey results "reasonable costs" in 2014, NPEI scored 80% satisfied versus the provincial results of 77%. As noted above in IRR #14 SEC-4, the table illustrates that NPEI has trended downward in its OM&A cost per customer.

28. SEC #18 [Ex. 1/4/2]

Please advise the date the budget was first approved by senior management. If there were any changes between the budget approved on that date, and the budget included in this Application, please identify those changes and advise the date of each such change.

Response

The 2015 capital and operating budgets included in this Application were developed by senior management as a collaborative effort. There have been no changes between the budget and the application to date other than the 3 projects identified in SEC #5 above.

29. SEC #19 [Ex. 1/6/20, Attach 1.8, p. 3]

Please confirm that the role of the Applicant's Board of Directors does not include protecting the interests of the ratepayers, except to the extent that those interests are consistent with the interests of the shareholders.

Response

Not confirmed. The question appears to assume a unity of interest on the part of customers and shareholders. As such, NPEI does not agree that there is such a unity of interest. Further, the role of the Board of Directors is founded in multiple sources including statute, common law and NPEI's documents.

30. SEC #20 [Ex. 1/6/20, Attach 1.9]

Please provide a copy of the current, signed agreement including all amendments.

Response

Please see Attachment #7.

31. SEC #21[Ex. 1/6/20, Attach 1.9, p. 7, s. 2.2(b)(i)]

Please provide the most recent report or other documentation in the possession of the Applicant that shows that the Applicant's rates are "consistent with similar utilities in comparable growth areas". Please provide a list of all utilities the Applicant considers to be similar and comparable for this purpose.

Response

The tables below show the 2014 Board-approved distribution rates for the Residential, General Service < 50 kW and General Service > 50 kW rate classes for NPEI and all of the LDC's which border NPEI's licensed service territory. The tables also include total distribution charges based on NPEI's typical monthly billing determinants.

	Residential	800	kWh		
Application #	LDC	Rate Class	Monthly Service Charge ($)	Distribution Volumetric Rate ($/kWh)	Total Monthly Distribution Charges
EB-2013-0132	Grimsby Power Inc.	Residential	15.47	0.0119	24.99
EB-2013-0137	Horizon Utilities Corporation	Residential	14.92	0.0147	26.68
EB-2013-0177	Welland Hydro-Electric System Corp.	Residential	15.9	0.0135	26.70
EB-2013-0155	Niagara-on-the-Lake Hydro Inc.	Residential	17.94	0.0126	28.02
EB-2013-0154	Niagara Peninsula Energy Inc.	Residential	16.06	0.0161	28.94
EB-2013-0117	Canadian Niagara Power Inc. Fort Erie	Residential	18.94	0.0201	35.02
EB-2013-0141	Hydro One Networks Inc.	Residential Year Round Medium Density - R1	20.15	0.0339	47.27

	General Service < 50 kW	2000	kWh		
Application #	LDC	Rate Class	Monthly Service Charge ($)	Distribution Volumetric Rate ($/kWh)	Monthly Distribution Charges
EB-2013-0177	Welland Hydro-Electric System Corp.	GS < 50 kW	28.26	0.0083	44.86
EB-2013-0137	Horizon Utilities Corporation	GS < 50 kW	33.21	0.0086	50.41
EB-2013-0132	Grimsby Power Inc.	GS < 50 kW	26.29	0.0129	52.09
EB-2013-0155	Niagara-on-the-Lake Hydro Inc.	GS < 50 kW	37.28	0.0112	59.68
EB-2013-0154	Niagara Peninsula Energy Inc.	GS < 50 kW	37.79	0.0138	65.39
EB-2013-0117	Canadian Niagara Power Inc. Fort Erie	GS < 50 kW	24.36	0.024	72.36
EB-2013-0141	Hydro One Networks Inc.	General Service GSe	36.26	0.04025	116.76

	General Service > 50 kW	180	kW		
Application #	LDC	Rate Class	Monthly Service Charge ($)	Distribution Volumetric Rate ($/kW)	Monthly Distribution Charges
EB-2013-0132	Grimsby Power Inc.	GS 50 to 4,999 kW	169.78	1.7419	483.32
EB-2013-0155	Niagara-on-the-Lake Hydro Inc.	GS 50 to 4,999 kW	266.42	2.1025	644.87
EB-2013-0137	Horizon Utilities Corporation	GS 50 to 4,999 kW	302.77	2.1001	680.79
EB-2013-0177	Welland Hydro-Electric System Corp.	GS 50 to 4,999 kW	272.09	2.3798	700.45
EB-2013-0154	Niagara Peninsula Energy Inc.	GS 50 to 4,999 kW	179.58	4.24	942.78
EB-2013-0117	Canadian Niagara Power Inc. Fort Erie	GS 50 to 4,999 kW	143.56	6.9224	1,389.59
EB-2013-0141	Hydro One Networks Inc.	General Service Demand Billed GSd	52.27	11.495	2,121.37

32. SEC #22 [Ex. 1/6/20, Attach 1.9, p. 14, s. 5.2 (i) and (k)]

Please provide the last three Special Resolutions approving each of capital projects over $5 million, and financing over $5 million. For each such Special Resolution, please provide the presentations, reports and other materials provided to the shareholders to explain the request for approval.

Response

Please see Attachment #8.

Exhibit 2 Rate Base

33. 2 Staff 4.Capitalization Policy

References

1. Exhibit 1 Tab 6 Schedule 22

- Chapter 2 Cost of Service Rate Application based on a Forward Test Year
- Exhibit 2, Tab 2, Schedule 3, p. 2

Preamble

NPEI last rebased in 2011. In Reference 1, NPEI indicated that it changed its capitalization policies effective January 1, 2011 and therefore, Appendix 2-Y is not applicable. However, NPEI did change its depreciation policy effective January 1, 2013.

In Reference 2 it states that revenue requirement impacts of any changes in accounting policies must be separately quantified in Appendix 2-Y.

a) Please quantify the impact of depreciation changes to revenue requirement in Appendix 2-Y.

b) Please confirm that the capitalization policy changes were already captured in NPEI's last cost of service rate application EB-2010-0138.

In Reference 3, under labour burden, NPEI indicated since January 1, 2011, it no longer capitalized any portion of stores, garage or training expenses. However, NPEI subsequently indicated that there will be an impact relating to general and admin burden under IFRS.

c) Please clarify whether there has been a change in capitalization policy since NPEI's last rebasing application for the period of June 1, 2011 to April 30, 2014. If there has been a change, please quantify the impact of the change.

Response

a) The impact of depreciation changes to the revenue requirement including the impact of PILS is $3,914,393. See Appendix 2-Y shown in IR#13 SEC #3 above.

b) NPEI confirms that the capitalization policy changes regarding the capitalization of the stores and vehicle departments and training costs were made effective January 1, 2011 and were therefore already captured in NPEI's last Cost of service rate application EB-2010-0138.

c) NPEI has not changed the capitalization policy since its last rebasing application for the period of June 1, 2011 to April 30, 2014.

34. 2-staff-5. Performance Measurement for Continuous Improvement – Key Performance Indicators; Asset Management Process

Reference

1. Distribution System Plan, p. 8
2. Distribution System Plan, pages 22-25

Preamble

At Reference 1, NPEI provides key performance metrics that provide input to its asset management plan and capital expenditure planning process: reliability performance, safety performance, customer satisfaction, regulatory compliance, and asset health indices. NPEI provides little commentary on how these performance metrics are weighted in the evaluation of various “strategic objectives and “technical alternatives” in its asset management planning process. .

At page 22 of Reference 2 an asset management decision and process chart is included. NPEI discusses “strategic investments” and “technical alternatives”. At page 24 NPEI discusses how it develops business cases that are evaluated based on evaluation criteria. At page 25 of Reference 2 NPEI discusses supporting inputs and outputs related to capital expenditure planning.

a) NPEI provides little commentary on how performance metrics are tracked, measured, or otherwise used to provide useful feedback for NPEI’s planning cycles for the asset management plan and the capital planning process (and DS Plan.) Please elaborate for both the asset management plan and the capital planning process.

The use of a table or matrix may supplement the following interrogatory responses:

b) Please elaborate on the evaluation criteria and how these are quantitatively used to develop a score to rank projects to propose for implementation, and conversely which projects should be deferred.

c) How are the supporting inputs and outputs quantitatively applied to the capital expenditure planning process? It is not clear why one project would be preferred over another.

d) Please describe how NPEI quantify and compare the benefits from projects, and how these benefits flow to customers?

Response

a) Section 5.2.3 of the Distribution System Plan, includes a summary description of each of the 5 key performance metrics. An explanation of how NPEI uses the 5 key performance metrics to provide useful feedback for NPEI's planning cycles is summarized as follows:

Reliability Performance:

NPEI monitors reliability indices on a monthly basis. The month to month reliability reports are analyzed to identify negative trends in system performance at the feeder level. In some cases, a localized negative trend in reliability can be mitigated through a minor betterment or operational improvement such as tree clearing. Annually, negative trends that have been identified throughout the course of a year are summarized and needs for corrective actions are identified. Any available technical alternatives for mitigation of the negative trend in performance are documented and evaluated.

Safety Performance:

NPEI uses Ontario Regulation 22/04 compliance metrics as one of the key indicators of NPEI's safety performance. Compliance audits and due diligence inspections are conducted by independent auditors throughout the course of a year. NPEI identifies negative trends in non-compliance, needs improvement, or safety related findings. Negative trends are summarized on an annual basis and expenditure needs for corrective action are identified. As an example, the switchgear replacement program was initiated in 2009 as a result of non-compliance findings related to NPEI's process for inspection and maintenance of underground distribution equipment.

Customer Satisfaction:

NPEI initiated a formal process for customer engagement in 2014. The objective is to be able to identify negative trends in customer satisfaction through analysis of resulting data from customer feedback. In review of cyclical trends, NPEI identifies needs that will mitigate negative trends and maintain alignment with business values. For example, outage response time has been identified as an area of concern for

NPEI customers. NPEI's grid modernization program is an example of one of the initiatives in place to improve overall response times during system disturbances.

Regulatory Compliance:

NPEI holistically inspects overhead, underground and substation equipment based in the requirements of the Distribution System Code. The completeness in the inspection data provides the foundation for the prioritization of asset replacements. While the Asset Condition Assessment provides an overall condition of a given asset class, a high level risk assessment is performed on a per asset basis to determine replacement needs. High priority assets are replaced first under programs that levelize capital expenditures over time. The results of asset inspection programs are analyzed annually to prioritize necessary replacements.

Asset Health Indices:

NPEI's asset health indices provide a snapshot into the overall capability of distribution assets. The asset condition assessment identifies asset classes for which programmatic replacement is required. It also provides a levelized plan for replacement to maintain a satisfactory condition of assets. The levelized plan identifies the level of non-discretionary expenditure required to maintain asset performance at current levels and to mitigate risk associated with asset failure. The pole replacement program is an example of an expenditure designed to maintain asset class health and to mitigate worker and public safety risk.

b) NPEI uses each of the evaluation criteria to assess the risk (consequence vs. likelihood) of maintaining the existing system condition vs. the risk following project completion (differential risk). For example, for the evaluation criteria of reliability performance, NPEI will quantify a risk score based on impact on SAIDI and SAIFI for the existing condition. The risk score following project completion is also quantified. A differential risk score is then determined for the evaluation criteria of reliability performance.

The differential risk score is determined for each of the 4 evaluation criteria. Each score is then weighted based on the following table:

Evaluation Criteria	Weight
Reliability/Performance	25%
Efficiency	25%
Safety	30%
Community Relations / Regulatory	20%

The weighting values were determined by NPEI based on the impact of the particular evaluation criteria against strategic objectives. The weighted scores from each evaluation criteria are aggregated. This cost of execution of a project is assessed against the aggregate weighted score. Projects are ranked according to the resulting cost vs. differential risk value.

Projects with a lower cost vs. differential risk value are typically prioritized for execution. In some cases there are project dependencies which may cause deviation of project selection from this ranking. For example, NPEI may choose to defer a project on a given municipal right of way in order to coordinate construction efforts with the road authority.

c) NPEI's supporting inputs and outputs contain underlying asset data that is analyzed to identify trends in performance and asset degradation. Negative trends such as cyclical deterioration of SAIDI and SAIFI are identified through such analysis. Projects are proposed in such cases to mitigate the negative trend.

The magnitude of the expected mitigation is reflected in the resultant risk differential score as described above. The aggregate of differential scores from the 4 key evaluation criteria related to project execution cost is used to rank projects for execution.

d) NPEI quantifies the benefits from projects through the differential risk assessment process. The risk assessment for each of the 4 evaluation criteria encompasses the magnitude of benefit. The project execution cost over the differential risk represents the overall benefit to customers in terms of the quantity of expenditure. Each of the evaluation criteria relates directly to NPEI's strategic objectives which have been architected to maintain an acceptable level of service to our customers.

35. 2-staff-6.Asset Management Process – Values & Strategy

Reference

1.Distribution System Plan, page 24

Preamble

Business cases are developed for projects identified at the highest priority levels. NPEI states that business cases are in-line with corporate business values and strategic objectives.

Please explain how these corporate values & strategic objectives align with goals of providing customer value, price, and reliability.

Response

NPEI's strategic objectives focus on customer satisfaction, sustainability, safety, and regulatory compliance. From these strategic objectives, NPEI has defined 4 key evaluation criteria to ensure the provision of customer value, price and reliability through capital expenditure.

Reliability Performance is a component of 3 out of 5 of NPEI's strategic objectives. Customer feedback received by NPEI to date indicates that reliability and response time are fundamental to customer satisfaction.

NPEI recognizes that efficiency is a key component of Customer Satisfaction. Our strategic objectives focus on Customer Satisfaction by balancing service quality and reliability with reasonable rates.

Sustainability is a key component in each of the strategic objectives. NPEI facilitates the delivery of Conservation Initiatives, Green Energy Technologies, and Smart Grid initiatives to accommodate both the present and future needs of our Customers. Sustainability also requires investment that promotes the Safety of our Customers and Employees.

NPEI will continue to monitor the applicability of our strategic objectives as we trend customer feedback over time. NPEI will continue to adapt our strategic objectives to meet the needs of our customers.

36. 2-staff-7.Capital Plan Variance Analysis – General

References

1.Exhibit 2 Tab 2 Schedule 1

2.Appendix 2-AA

Preamble

At reference 2, NPEI provides commentary with respect to its Consolidated Distribution System Plan and includes a comparison of plan versus actual capital expenditures by Category for 2010-2014. NPEI did not provide a table indicating year-to-year variances between plan and actual expenditures.

a)Please provide a variance analysis for each year, starting in 2010, between plan and actual expenditures. Please present this information in tabular form.

b)Please provide the table at page 1 of the first reference with the smart meter variance (328.1%) removed, so as to show variances without the impact of smart meter recovery approval. Provide the same variance table as in part a) of this interrogatory except with the table adjusted to remove smart meter recovery approval.

c)With reference to the table to be provided in part a) above, please explain in detail why NPEI's actual expenditures for 2011, 2012, and 2013 were significantly below planned expenditures.

d)Revenues for the planned expenditures were in the rates NPEI was charging. Please explain how NPEI re-allocated the funds. Did this increase net income?

e)With reference to the table to be provided in part a), please explain in detail why NPEI's actual expenditures for 2014, the bridge year, were approximately 15% higher than 2013.

f)Please explain to what extent deferred investments have resulted in any backlog of work, into the 2015 test year or otherwise.

g)Please explain if and how NPEI's lower actual capital expenditures impacts system reliability at its current levels, given that the customer survey shows that reliability is a major concern for customers. With respect to 2013, please explain why general plan purchases original budgeted for 2013 were deferred until 2014.

Response

a)The Table below shows the variance between plan and actual for each year from 2010 to 2014.

CATEGORY	Historical Period											
	2010				2011				2012			
	Plan	Actual	Var	Var	Plan	Actual	Var	Var	Plan	Actual	Var	Var
	$ '000			%	$ '000			%	$ '000			%
System Access	2,130	2,558	427	20.1%	2,199	942	- 1,257	-57.2%	1,630	1,086	- 544	-33.4%
System Renewal	2,998	2,769	- 228	-7.6%	4,768	4,162	- 607	-12.7%	7,870	5,150	- 2,720	-34.6%
System Service	6,699	6,465	- 234	-3.5%	1,512	1,966	454	30.0%	2,362	1,424	- 938	-39.7%
General Plant	1,820	1,621	- 199	-10.9%	1,123	1,280	157	14.0%	2,769	2,621	- 148	-5.4%
TOTAL EXPENDITURE	13,647	13,413	- 234	-1.7%	9,603	8,350	- 1,252	-13.0%	14,631	10,280	- 4,351	-29.7%
System O&M	$ 5,731	$ 5,691	-$ 40	-0.7%	$ 6,142	$ 6,282	$ 140	2.3%	$ 6,764	$ 6,708	-$ 55	-0.8%

CATEGORY	Historical Period							
	2013				2014 Bridge Year			
	Plan	Actual	Var	Var	Plan	Actual	Var	Var
	$ '000			%	$ '000			%
System Access	2,031	1,997	- 33	-1.6%	1,731	1,731	- 0	0.0%
System Renewal	5,838	5,907	69	1.2%	7,307	7,307	0	0.0%
System Service	1,100	847	- 253	-23.0%	580	2,483	1,903	328.1%
General Plant	6,028	3,897	- 2,131	-35.3%	3,267	3,267	0	0.0%
TOTAL EXPENDITURE	14,997	12,649	- 2,348	-15.7%	12,885	14,788	1,903	14.8%
System O&M	$ 6,880	$ 6,281	-$ 600	-8.7%	$ 6,636	$ 6,636	$ -	0.0%

b) The table below shows the variance between plan and actual for each year from 2010 to 2014, where the impact of smart meter costs has been removed as follows:

- Under System Service, $1,114K of smart meter costs have been removed from the 2012 planned amount.
- Under System Service, $1,903K of smart meter costs has been removed from the 2014 actual amount.

CATEGORY	Historical Period											
	2010				2011				2012			
	Plan	Actual	Var	Var	Plan	Actual	Var	Var	Plan	Actual	Var	Var
	$ '000			%	$ '000			%	$ '000			%
System Access	2,130	2,558	427	20.1%	2,199	942	- 1,257	-57.2%	1,630	1,086	- 544	-33.4%
System Renewal	2,998	2,769	- 228	-7.6%	4,768	4,162	- 607	-12.7%	7,870	5,150	- 2,720	-34.6%
System Service	6,699	6,465	- 234	-3.5%	1,512	1,966	454	30.0%	1,248	1,424	176	14.1%
General Plant	1,820	1,621	- 199	-10.9%	1,123	1,280	157	14.0%	2,769	2,621	- 148	-5.4%
TOTAL EXPENDITURE	13,647	13,413	- 234	-1.7%	9,603	8,350	- 1,252	-13.0%	13,517	10,280	- 3,237	-23.9%
System O&M	$ 5,731	$ 5,691	-$ 40	-0.7%	$ 6,142	$ 6,282	$ 140	2.3%	$ 6,764	$ 6,708	-$ 55	-0.8%

CATEGORY	Historical Period							
	2013				2014 Bridge Year			
	Plan	Actual	Var	Var	Plan	Actual	Var	Var
	$ '000			%	$ '000			%
System Access	2,031	1,997	- 33	-1.6%	1,731	1,731	- 0	0.0%
System Renewal	5,838	5,907	69	1.2%	7,307	7,307	0	0.0%
System Service	1,100	847	- 253	-23.0%	580	580	0	0.0%
General Plant	6,028	3,897	- 2,131	-35.3%	3,267	3,267	0	0.0%
TOTAL EXPENDITURE	14,997	12,649	- 2,348	-15.7%	12,885	12,885	0	0.0%
System O&M	$ 6,880	$ 6,281	-$ 600	-8.7%	$ 6,636	$ 6,636	$ -	0.0%

c) In 2011, gross capital additions were $1,252K or 13% lower than planned. As explained in Exhibit 2, Tab 2, Schedule 1 of the originally filed evidence, this variance is largely due to subdivision costs being lower than planned ($360K) and capital contribution received being higher than planned ($722K.) The specific level and timing of subdivision costs each year are driven by the subdivision developers' schedules, and are largely outside of NPEI's control. Similarly, capital contributions are mostly recovered from subdivisions and line relocations due to road works, which are driven by the municipalities or region.

In 2012, excluding smart meter costs, gross capital additions were $3,327K or 23.9% lower than planned. This variance is largely due an asset which NPEI had planned to purchase from Hydro One which did not occur ($2,360K). Also, 2012 capital contribution received were $627K greater than planned. Further details on the budgeted purchase from Hydro One which did not occur are given below in response to 2-Staff-8.

In 2013, gross capital additions were $2,348K or 15.7% lower than planned. This variance is largely due to deferred general plant expenditures: building ($1,532K), hardware ($318K) and software ($168K).

Due to the weather in the spring of 2013, the yard excavation project was delayed, which in turn delayed the completion of the new wire building and high mast lighting. Therefore, the building workspace optimization phase of the project was not completed in 2013. Also, NPEI was notified by its supplier in December 2013 that the high mast lighting would not be delivered by year end.

Hardware and software capital expenditures are made throughout each year based on the availability of NPEI's internal technical staff to install, configure and deploy the hardware/software. Each technology project follows a project methodology including information gathering, requirements, design, construct, test, implement, followed by implementation support. Within specific projects, within the requirements review, it was found that several projects needed to be completed prior to beginning one that formed a latter requirement in the enterprise solution. More attention was required within the design and build in order to address what was required in the enterprise solution. This resulted in several projects being deferred, as it no longer fit the design of the solution to be completed in conjunction. A software example of this is the design and implementation of the interface between Outage Management System and the Customer Information System (CIS). The CIS was undergoing an update of the customer web portal; through design, we found that the interface which we initially thought would be a new build could be an integrated process between the sub-systems decreasing the level of development needed. This resulted in the interface being deferred until the web portal and integrated customer forms were implemented. Where such efficiencies were learnt within earlier phases of the project, latter projects were deferred. In addition to efficiencies learnt within the software project cycle, NPEI's internal technical staff review hardware requirements; in 2013, NPEI worked towards movement to a virtual farm of servers; this resulted in decrease in physical hardware required. In addition, any software projects that were deferred, any corresponding hardware requirements were also deferred.

d) The level of gross capital additions that was approved in NPEI's 2011 COS Application (EB-2010-0138) is $9,344,633. With the exception of 2011, NPEI's capital additions have exceeded this amount in each year. Further, as shown in Exhibit 3, Tab 1, Schedule 1, Table 3-1, NPEI's actual service revenue in each of 2011, 2012 and 2013 was lower than the 2011 Board approved level of $31,780,612. Therefore, net income was not increased due to plan versus actual capital variances.

Table 3-1: Summary of Operating Revenue

Revenue Item	2011 Board Approved ($)	2011 Actual ($)	2012 Actual ($)	2013 Actual ($)	2014 Bridge ($)	2015 Test ($)
Distribution Revenue (Fixed and Volumetric)	29,818,865	26,969,849	27,756,275	27,893,149	28,284,395	29,374,853
Total Throughput Revenue	29,818,865	26,969,849	27,756,275	27,893,149	28,284,395	29,374,853
MicroFIT Monthly Service Charge	-	4,486	11,087	16,187	20,542	21,060
SSS Administration Charges	126,094	132,759	138,403	142,218	141,294	140,656
Miscellaneous Service Revenues	924,416	874,868	794,766	810,536	805,434	803,285
Late Payment Charge	381,550	419,155	372,203	353,574	357,661	361,000
Retailer Revenues	83,718	70,048	50,446	45,077	45,342	45,471
Other Utility Operating Income	82,416	43,664	42,683	48,359	43,100	44,000
Gain/Loss on Disposition/Retirements	-	16,397	359	(56,879)	-	-
Revenues/Expenses of Non-Utility Operations	240,885	198,278	343,909	147,195	26,072	-
Miscellaneous Non-Operating Income	40,000	58,882	118,923	118,062	111,027	81,003
Interest Dividend Income	127,863	140,673	174,715	180,173	307,684	157,000
Total Other Revenue	2,006,942	1,959,211	2,047,495	1,804,503	1,858,155	1,653,475
Less Carrying Charges	(45,195)	(55,431)	(54,350)	(63,298)	(187,684)	(57,000)
Total Other Revenue excluding carrying charges	**1,961,747**	**1,903,780**	**1,993,145**	**1,741,205**	**1,670,471**	**1,596,475**
Total Service Revenue including carrying charges	31,825,806	28,929,059	29,803,770	29,697,652	30,142,550	31,028,327
Total Service Revenue excluding carrying charges	**31,780,612**	**28,873,629**	**29,749,420**	**29,634,354**	**29,954,866**	**30,971,328**

e) The actual 2014 capital expenditures as shown in part a) of $14,788K includes $1,903K of smart meter costs that were transferred from the smart meter variance accounts into rate base, as approved in NPEI's Smart Meter Application (EB-2013-0359). Excluding these costs, as per part b), NPEI's 2014 capital budget of $12,885 is $236K or 1.8% higher than the 2013 actual capital additions of $12,649K.

f) Please refer to the response to SEC #5 above.

g) As stated in part d) above, NPEI has consistently maintained greater levels of capital expenditures than are included in NPEI's last Board approved rate base. In cases where the completion of non-discretionary projects requires that a discretionary project be deferred, NPEI's Engineering and Operations department consider system reliability when rescheduling capital projects.

With respect to General Plant purchases originally budgeted for 2013 and deferred to 2014, please see the response to part c) above.

37. 2-staff-8. Capital Plan Variance Analysis – Cancellation of $2.4M System Renewal Asset Purchase

Reference

1.Exhibit 2 Tab 2 Schedule 1 p. 2

NPEI has indicated that a system renewal project involving a 2012 planned purchase of a $2.4M asset from Hydro One did not occur.

a)Please explain what was the asset to be purchased, referring to previously filed evidence in other proceedings before the Board where necessary, and state why it was not purchased, what alternative courses of action were contemplated, and how NPEI arrived at that decision.

b)Given this was a system renewal project, what effect did the decision not to purchase this investment have on subsequent system renewal decisions, and on service reliability? Were costs incurred on other projects that would achieved the same goals that the asset purchase would have achieved?

c)What contingency plans were made in lieu of the purchase?

d)Does NPEI still have future plans to purchase the $2.4M asset? If so, when, and at what cost?

Response

a) The assets to be purchased are comprised of a 27.6 kV distribution circuit of approximately 23 kilometres in length of predominantly single three phase circuit configuration. One voltage regulator station of 10 MVA capacity, configured in a ground mounted orientation with related property, fenced containment and supporting switching and control apparatus. One 5 MVA, 27.6 / 8.32 kV step down station (MS) including property and fenced containment and 17 kilometres of 8.32 kV distribution circuits of predominantly single three phase circuit configuration. The assets traverse the NPEI distribution territory providing electricity to NPEI customers along the circuit route, and terminate in an adjacent Hydro One distribution territory providing electricity to a small number of customers there. Approximately 95% of the energy distributed by the circuit is utilized within the NPEI distribution territory. Furthermore, the circuit is supplied from a transformer station distant to the points of consumption. A closer transformer station exists to the points of consumption which should be utilized to supply energy along this circuit route, which would result in a significant reduction in energy losses. The asset was not purchased as a result of the owner, Hydro One deciding to terminate ongoing collaborative purchasing activities mid-stream. Based upon the system configuration and geographic locations of the supply stations, NPEI determined no other economically feasible alternatives were available. No alternatives were provided by Hydro One.

b) Since no other economically feasible alternatives are available, NPEI is forced to work within the circuit configuration and operating constraints that the current assets present. Configuration changes promoting higher reliability and loss reduction optimization are currently restricted. Some investment has been made in system switches to provide configuration changes and increased operational flexibility.

c) Please see b) above.

d) NPEI would choose to purchase the assets based upon the determination of current market value and a re-examined cost benefit analysis.

38. 2-staff-9. – Capital Plan Variance Analysis – Yard works

References

1. Exhibit 2 Tab 2 Schedule 1 p. 2
2. Exhibit 2 Tab 2 Schedule 1 p. 8
3. Exhibit 2 Tab 2 Schedule 2 p. 71

Preamble

In Reference 2, NPEI State:

"In 2013, NPEI engaged a third party consultant to review the purchasing, receiving, and issuance of inventory processes and procedures. In 2014, the consultant was engaged to implement various changes to processes and procedures related to NPEI's supply chain management. The current Niagara Falls small stores area is over 30 years old in its design, layout and shelving. NPEI constructed a new wire building which received occupancy at the end of 2013."

a) Please provide a copy of the consultant's report discussed in the passage above, and a copy of the original NPEI business case study justifying the project investment and any updates to that study that includes further justification for the project. Please include options and alternatives that were considered and a ranking of these options, and how this expenditure provides value for customers, or generates efficiencies at NPEI.

b) Please explain whether or not the work associated with yard projects (totalling $1.875M) was contemplated in NPEI's previous asset management planning cycle.

c) Is any of the space in these new facilities being shared with NPEI 's unregulated affiliates? If yes, please indicate how NPEI intends to assign or recover shared costs.

d) At the third reference, High Mast lighting is included at a cost of $435,000. What are the benefits of this expenditure? Did this lighting replace an existing end-of-life yard lighting solution?

Response

a) A copy of the consultant's report is attached as Attachment #9. The project involving the review and modification of material management processes within the utility resulted from the physical building modifications that were occurring. Space constraints required NPEI to construct additional office and administrative areas which were most economically provided via the utilization of material storage space within the existing building envelope. The resulting reduction in storage space lead to the construction of a stand-alone storage building and modifications to the layout of the remaining storage space within the existing building. These additions and changes to the storage spaces provided the opportunity to review and optimize many material handling and tracking processes. Details of these process changes and the resulting benefits are contained in the attached report.

b) This work was not contemplated in the previous asset management cycle. Details of the determinants for these expenditures are contained in exhibit 2 tab1 schedule 2 General Plant Description of the current application.

c) The facilities are not shared with unregulated affiliates.

d) The lighting both replaced an existing system which was over 30 years old and provides illumination for the expanded storage yard area. (Approximately 23,000 square meters). The new lighting system provides efficient yard illumination for security and work requirements via dimmable LED technology.

39. 2-staff-10. – Service Reliability Raw Data

Reference

1. Distribution System Plan 5.2.3.1, p.10-18

Preamble

Graphs have been provided in Reference 1, but not discrete values, except for a few of these at Appendix 2-G.

a) Please provide the underlying data-points associated with the following figures in excel format: Figures 5.4, 5.5, 5.7, 5.10, 5.11, 5.12, 5.15, 5.16, and 5.17

b) Please provide the historical three-year average for the period 2010-2012 and the figures for 2013 in both raw form, and adjusted to remove severe weather events (such as those in 2011 and 2013) as well as loss of supply (e.g. upstream stations).

Response

a) Refer to Attachment #10 Excel spreadsheet with filename: NPEI_2-staff-10_raw_data.xls.

b) Historical Data Unadjusted:

	2010	2011	2012	3 Year Average	2013
SAIDI	2.11173	2.58060	2.75332	2.48188	5.55830
SAIFI	1.23480	1.54147	1.70148	1.49258	2.20777
CAIDI	1.71018	1.67412	1.61819	1.66750	2.51760

Historical Data Adjusted to Exclude Major Events and Loss of Supply:

	2010	2011	2012	3 Year Average	2013
SAIDI	1.77286	2.58014	2.30820	2.22040	2.54739
SAIFI	1.06102	1.05098	1.22942	1.27408	1.15578
CAIDI	1.67090	1.68440	1.87746	1.74425	2.20405

40. 2-staff-11. Service Quality and Reliability Performance (Appendix 2-G)

References

a)Distribution System Plan 5.2.3.1, Figure 5-10

b)Exhibit 2, Tab 3

NPEI has provided graphs of the reliability indicators, but has provided limited commentary on adverse deviations from trend or targets, as stipulated in 2.5.2.5 of the Chapter 2 Filing Requirements.

a)Please provide a brief explanation, particularly with respect to the degradation in annual SAIFI statistics from 2010 to 2013.

b) Please provide an indication if any of the figures fall outside the three-year average for SAIDI, SAIFI, and CAIDI.

c)Please also state how the information has been incorporated into the DS Plan and has been used to continuously improve the asset management and capital expenditure planning process. Please point to projects that have been planned.

d)Please state what NPEI is doing to improve the service quality measures. In the response please point to specific DSP projects, the year it will be built and the cost.

Response

a) The raw data provided above indicates an annual degradation of SAIFI from 2010 to 2013.

In 2011, a significant contributor to SAIFI was a wind storm in which wind gusts in excess of 100km/h were experienced over the course of several hours. This event alone contributed 0.4808 to the 2011 value for SAIFI.

In 2012, SAIFI was impacted by multiple losses of Hydro One supply events. The contribution to SAIFI from these events alone was 0.4721. The majority of the contribution was related to multiple occurrences of loss of supply to an outdoor bus at Stanley TS.

In 2013, SAIFI was impacted by two separate related weather events as described in the Distribution System Plan. These combined events contributed 1.0520 to SAIFI.

The adjusted data provided above depicts the trend in SAIFI with these influencing events removed. As evident in the adjusted data, the 2013 value for SAIFI is below the 3 year historical average.

b) Based on the adjusted data provided above which removes the influence of events outside of NPEI's control, the following table indicates figures that fall outside of the 3 year average:

Year	Indices	Amount Over Average
2011	SAIFI	0.3597
2012	SAIDI	0.0878
2012	CAIDI	0.1332
2013	SAIDI	0.3270
2013	CAIDI	0.4598

c) NPEI reviews the indices monthly to identify negative trends in feeder performance related to a re-occurring outage cause. For example, in 2012 and 2013 the Murray TS 3M30 feeder was a significant contributor to both SAIDI and SAIFI. Project 2013-0002 (less than materiality) was executed to correct this deficiency by reducing feeder exposure and introducing redundant supply to the area.

Another example is project 2014-0018 (SS-34) which was selected for execution based on cost/risk-differential analysis in order to mitigate reliability issues on the Vineland DS 4501F1 feeder. This circuit was a significant contributor to SAIDI and SAIFI in 2014. Implementation of this project will reduce feeder exposure by an additional point of supply to the area.

d) NPEI will continue to trend feeder performance and evaluate technical alternatives to correct deficiencies. Project 2016-0005 is a multi-year project designed to provide a second source of supply to the Jordan area. This area is serviced by a radial supply from the Vineland 4501F1 feeder which has experienced degradation in SAIDI and SAIFI due to lack of redundancy. The total cost of the multi-year implementation is $1.1M.

NPEI also has re-occurring programs directed at reliability improvements. For example, Project Reference #SS-34 is a multi-year project that targets air insulated switchgear in areas susceptible to contamination. These units contribute to SAIDI, SAIFI and momentary outages and are prioritized for replacement based on risk analysis. NPEI has a re-occurring capital expenditure of $250K to replace these suspect units.

41. 2-staff-12.Outage Management System

Reference

1. Distribution System Plan, p.18 and Figure 5-17

NPEI indicates at the reference that:

> "Prior to 2012, NPEI manually reviewed outage statistics to identify poor performing feeders. With the implementation of an outage management system that leverages AMI data for outage and restoration notification messages, NPEI is able to provide an accurate depiction of feeder performance."

When in 2012 was the Outage Management System rolled-out and fully operational?

Response

The Outage Management System was rolled out in February of 2011 and was fully functional with trouble analysis and work force management capabilities. The AMI system was integrated with the OMS by internal resources in January 2012.

42. 2-staff-13. Missing Station and Feeder Information

References

1. Distribution System Plan, Appendix C (NPEI Feeder Reliability)
2. Distribution System Plan, page 27

It appears that many feeders on the system are missing from the table provided at Appendix C for both 2012 and 2013, particularly those stations which are "DS" stations. A list of feeders is provided in the DS Plan at page 27, and many of these feeders are missing.

a) Information for the following stations and feeders, and possibly others, are omitted: Compden DS, Greenlane DS, Smithville DS, Jordan DS, Murray TS (Feeder

3M28). Why are certain stations and feeders missing from this table, or why were they not filed?

b)Please provide a complete table showing all feeder information. If requested information is not available, please explain why.

The table at Appendix C is sorted by "SAIDI Average Hours of Interruption / Customer".

c)Please provide additional versions of these tables sorted by what NPEI has termed "SAIFI Average # of Interruptions / Customer".

d)Please provide commentary on the worst performing feeders as measured by SAIFI as well.

e)Please indicate any capital projects associated directed with these worst performing circuits.

Response

a) The tables provided in Appendix C of the Distribution System Plan cover all main supply feeders that supply the Niagara Peninsula Energy distribution system. All downstream connected Distribution Station (DS) are supplied by feeder at Transformer Stations (TS) that are listed in Appendix C. The feeder reliability data for the upstream TS feeder incorporates outage data from the downstream connected DS feeder(s).

   The tables also do not include an entry for the feeder if an outage event was not experienced in a given year. The 3M28 did not experience an outage event in 2012 but did in 2013

b) The following table indicates which upstream feeder normally supplies a particular downstream DS. As mentioned above, the indices for a given upstream feeder include outage events that occurred on the downstream DS feeders.

MS/DS	Upstream TS	Upstream Feeder
Bismark DS	Beamsville TS	18M2
Campden DS	Niagara West TS	M5
Greenlane DS	Vineland DS	F2
Jordan DS	Vineland DS	F1
Smithville DS	Beamsville TS	18M2
Allendale MS (#8)	Murray TS	3M52
Armoury MS (#1)	Stanley TS	12M6
Dorchester MS (#23)	Stanley TS	12M33
Drummond MS (#10)	Murray TS	3M51
Lewis MS (#7)	Murray TS	3M26
Margaret MS (#14)	Murray TS	3M17
Ontario MS (#3)	Stanley TS	12M6
Park MS (#6)	Stanley TS	12M41
Swayze MS (#18)	Stanley TS	12M43
Virginia MS (#17)	Stanley TS	12M5
Pelham DS	Allanburg TS	45M7
Station DS	Allanburg TS	45M7

c) See Attachment # 11, Feeder_Performance_Summary_by_SAIFI.

d) Analysis of feeder performance in terms of SAIFI indicates a year to year occurrence of the following feeders as repeated poor performers: 3M17, 3M30, 2508M4, and the 2508M5.

A major contributor to SAIFI on the Murray TS 3M17 circuit is related to outages on the connected Margaret MS (Station #14). There is a lack of redundant supply for 4.16kV loads connected to this station. As a result, planned maintenance activities require service interruption for connected customers. The downstream overhead infrastructure is also at or approaching end of life. Pole degradation has led to structural failure causing outages during weather events.

The Murray 3M30 was also a poor performer as measured by SAIDI in 2012 and 2013. Projects have been implemented to mitigated poor performance on this feeder.

The Niagara West 2508M4 feeder services a small portion of NPEI load. Most of the downstream connected circuit supplies Grimsby Power Load. The majority of outages on this circuit have been attributed to faults downstream of NPEI's point of connection.

The Niagara West 2508M5 was reconfigured in 2014 to reduce exposure on the circuit. A portion of the circuit including the supply to Campden DS was permanently transferred to Vineland DS to mitigate poor performance.

e) In 2017, Project #2017-0007 (Reference #SR-72) will commence to convert Margaret Station #14 loads to 13.8kV. This is part of a multi-year project directed at elimination Station #14. Connected loads will be converted to a 13.8kV supply with redundancy. This project not only replaces structures at end of life, it will also contribute to the improvement of reliability on the 3M17 circuit.

As indicated above, Project 2013-0002 (less than materiality) was executed to improve SAIDI and SAIFI performance on the 3M30 feeder by reducing exposure and introducing redundant supply to the area.

43. 2-staff-14.Lightning Protection

References

a)ICF International NPEI Customer Engagement Baseline Report, DS Plan, Appendix G.

b)Distribution System Plan, Appendix E, Kinectrics Distribution Asset Condition Report

Preamble

At page 6 of Reference 1, ICF International states that:

> “From the Lincoln/West Lincoln area, review of information has determined a requirement to fortify lightning mitigation equipment within the system, as highlighted by a large number of failed transformer/step-down units during large lightning event.”

There appear to be no specific projects in the DS Plan or asset management plan addressing lightning mitigation through the active use of lightning arrestors, surge suppressors, or through advance means such as lightning detectors.

a)Were lightning strikes experienced in 2013 and in prior years a contributor to degradation of any assets, particularly poles, power transformers, large-pad mounted transformers, and pole-top transformers?

b)Given that lightning mitigation was cited as a critical prong of system planning in the ICF Report, why has NPEI not responded to these consultant recommendations in the customer engagement report? Given the number of power transformers recommended for replacement, in Ref 2, would it not be prudent for NPEI to install lightning protection systems, especially to protect these new assets, and/or critical infrastructure?

Response

a) A particularly strong weather event was experienced in July 2013 which had an unusually large amount of lightning, during which 2-pole mounted 250KVA step-down transformers and 6-distribution transformers were damaged requiring replacement. Power Transformers have not been affected as recent upgrades to the Distribution Stations in the Lincoln and West Lincoln areas included the installation of Station Class Arrestor Equipment and improvement in Station Grounding Grid installations.

b) The cost of the equipment for lightning mitigation is under the materiality threshold, but has been included in NPEI's Standard Yearly Sustainment Program as outlined within the 2015-2019 Budget Project descriptions. A large amount of data was compiled during the recently completed PCB sampling of approximately 3000 units within this service territory, and deficiencies were dispatched to Service Crews as they were reported, with costs charged to the Work Order.

44. 2-staff-15.Kinectrics Asset Condition recommendations

Reference

Distribution System Plan, Appendix E, Kinectrics Report, page 28

The Kinectrics report stated that:

“It is recommended that information gathered from visual inspections and ultrasonic and infrared scans [of underground cables] be incorporated into the Health Index.”

a)Please indicate how NPEI has implemented this recommendation in its DS Plan and capital expenditures planning. If the recommendation has not been implemented, please explain why.

b)Has this recommendation placed upward pressure on the budget allocated for underground cable inspection in the future?

Response

a) NPEI has existing inspection programs for underground equipment and civil structures. Visual, infrared, and ultrasonic inspections are already conducted within equipment enclosures but there is minimal data captured on cable condition. NPEI has begun the process of augmenting its underground inspection database to incorporate attribution for cable condition. Inspections conducted from 2015 forward will include this attribution and the resulting data will be an additional input to the health index of underground cables for future asset condition assessments.

b) The recommendation places negligible upward pressure on the budget allocation for underground cable inspections going forward. Underground equipment inspections already include ultrasonic and infrared scanning. Data acquisition and analysis will be conducted via existing process and systems.

45. 2-staff-16. Wi-max Project

References

1. Exhibit 2 Tab 1 Schedule 2 pages 66-68

2. Exhibit 1 Tab 2 Schedule 7 p. 4

Preamble

NPEI has included significant capital expenditures in the prior period, as well as in the DS Plan period.

a) Has the Wi-max project been fully deployed? If not, when will it be in service?

b) What is the total projected cost of the Wi-Max project over the past period, 2010-2019 period?

c) NPEI has not indicated that it has the necessary licences with respect to the 1800-1830 MHz band on which the Wi-Max network will function. What is the timeline for these approvals?

d) NPEI has outlined the qualitative value to customers from this project at page 67 of the first reference. How does NPEI intend to quantify the value to customers received from rollout of the Wi-Max project?

Response

a) The first phase of the WiMax project will be in service prior to the end of the 2014 calendar year.

b) The total projected cost of the Wi-Max project for the period 2010 through 2019 is $2.15M

c) NPEI acquired 33 licenses with Industry Canada in 2013 covering the scope of the project to 2019.

d) NPEI intends to quantify benefits to customers via:

- improvements in response time metrics based on the ability to remotely monitor and control field based devices
- reduction in SAIDI and SAIFI
- reduction in travel time for planned work activities such as protection blocking

46. 2-staff-17.Capital Expenditure Summary

Reference

1. Distribution System Plan, p. 48

NPEI has provided a capital expenditures summary table. Please provide a readable table in the size, format, and orientation as provided for at page 18 of *Chapter 5 of the Filing Requirements for Electricity Transmission and Distribution Rate Applications.*

Response

Table 5-24 is a copy of Appendix 2-AB of the Chapter 2 filing requirements. See Exhibit 2 Tab 2 Schedule 2 Attachment 2 of the originally filed rate application. The schedule is presented in landscape form.

47. 2-staff-18.Wholesale Pole Replacement Projects

References

1. Distribution System Plan, p. 34, page 38
2. Distribution System Plan, Appendix E, Kinectrics Report
3. Exhibit 2 Tab 1 Schedule 2 p. 56 – SR31

At page 34 of the DS Plan NPEI states that:

> "Areas with a high concentration of pole deficiencies are identified as targets for wholesale system renewal rather than individual change-outs. The decision to perform a wholesale rebuild is deemed to be more efficient when the area encompasses distribution transformers also at or near end of life…"

At page 38 of the DS Plan NPEI lists a description of material projects, including the replacement of “poles identified with limited structural integrity” for a total capital expenditure of approximately $1.2M.

a) What value is created through these wholesale replacement programs? Please quantify efficiencies realized through wholesale change-outs.

b) How is a “high concentration of pole deficiencies” defined? What analysis establishes whether wholesale change-out is preferable to individual change-out? Do these wholesale change-outs result in the replacement of poles that are not near end of life or at high risk of failure? How is the residual value of assets factored into the decision to replace on a wholesale vs. individual basis? What risk assessment is performed?

c) At page 25 of the second reference found at Appendix E to the DS Plan indicated for Wood Poles that, “Wood poles showed very significant improvement in overall health. This change may be due to the significant increase in sample size (i.e. improved knowledge about the asset population).” At page 28 it further states that, “In year 1 it is estimated that 79 and 216 pole-top transformers and wood poles respectively will require attention.”

    i. If there is an overall increase in the health index with respect to poles, how has this impacted NPEI’s planning and prioritizing of capital projects? Some information regarding NPEI’s pole replacement program has been provided. Please include the percentage of the total number of poles that are replaced in each year of the pole replacement program.

    ii. Does NPEI track interruptions caused by pole failure? If not, why not? If so, why aren’t interruptions caused by pole failure a proposed performance metric?

d) As an example, what is the typical or average cost per replaced pole:

    i. In the wholesale pole replacement project.

    ii. In the case of one-off pole replacements.

e) Were customers informed of the rate increases associated with these pole replacements?

f) With respect to the SR31 capital program, why do the averages for 2014 bridge and 2015 test year budgets vary so greatly from the expenditures from 2010-2013? (2014 is roughly 50% less than the 2010-2013 average for pole replacements under SR31.)

Response

a) The wholesale Replacements occur in areas which the majority of the distribution equipment is approaching end of useful life. The equipment consists of shorter pole heights, transformers installed below the secondary Buss attachment, with questionable working clearance. Efficiencies include the installation of taller poles at a higher strength class, with improved equipment and working clearance, more robust guying and anchoring of the line, improving the performance of the equipment during severe weather events which will improve the outage indices.

(b) A benchmark value for High concentration of poles would be in the order of 25% within a subdivision. These values are determined by a qualified third party contractor performing the 5-year cyclic pole testing program utilizing Journeyman Line-staff. A DSC Inspection is also completed during the pole test which also notes other deficiencies found with the installation. The majority of the distribution equipment has approached end of useful life when the wholesale change-out is determined. Many of these areas are still supplied at the 5KV level, and the new equipment will facilitate future voltage conversion options.

(c) If there is an overall increase in the health index with respect to poles, how has this impacted NPEI's planning and prioritizing of capital projects? Some information regarding NPEI's pole replacement program has been provided. Please include the percentage of the total number of poles that are replaced in each year of the pole replacement program.

Although the ACA indicates improvement in the overall health indices for poles, NPEI is still allocating significant capital expenditure in order to stabilize the quantity of pole changes required in a given year. The levelized action flagged for action plan provided in the ACA still indicates that a significant number of pole changes are required in the next five years. By year 5, the annual number of pole changes required will remain consistent at approximately 86 poles.

i. Does NPEI track interruptions caused by pole failure? If not, why not? If so, why aren't interruptions caused by pole failure a proposed performance metric?

Interruptions caused by pole failures usually occur during severe weather events, and are tracked within the respective indices.

(d) In the wholesale pole replacement project.

Generally poles in this category will include the installation of new primary conductor, secondary buss, transformers, sectionalizing switches, and the installation of Guys and anchors estimated at $ 10,000.00 per pole.

In the case of one-off pole replacements.

Generally poles supporting single phase circuits are estimated at $3,000.00, poles supporting three phase circuits are estimated at $ 5,000.00. , Transformer poles are in the order of $ 7,000.00. Existing primary & secondary circuits are transferred to the new pole

(e) The Standard Programs are outlined on the NPEI's website along with current Projects.

(f) After amalgamation with Pen West Utilities in 2008 it was determined that information regarding PCB results of oil testing of approximately 3000 units in the field was incomplete. The variance can be explained by the fact that resources were re-directed to PCB Transformer replacements which may have also included a pole replacement at the time of the transformer change, as a result of the oil testing results. These replacements will be complete in 2015, which will re-direct the efforts back to pole replacements.

48. 2-staff-19. Material Projects: Demand Based System Reinforcements for New Commercial Services

Reference

1. Distribution System Plan p. 38;
2. Appendix 2-AA

Preamble

NPEI has included approximately $2.4M of capital expenditures over the bridge and test year in respect of demand based reinforcements for new commercial services. In its load forecast evidence, NPEI has indicated a 3.1% decline in kWh consumption from 2011 to 2015 forecast. Similarly, NPEI's forecast billed demand from 2011 to 2015 forecast has shown a 4.2% decline.

At reference 2 NPEI has provided historical (2010-2013) and forecast (2014 bridge and 2015 test) expenditures for demand based reinforcements:

	2010	2011	2012	2013	2014 B	2015 T
Demand Based Reinforcements	453,393	573,712	711,788	1,011,493	1,410,778	1,007,500

a) NPEI has provided little commentary on how it defines “demand based reinforcement”. Please explain what this term means, with examples from past and/or future projects.

b) Please explain the significant increases, year over year, from 2010 onwards, when NPEI was at the same time experiencing a prolonged period of declining consumption and demand. Are the high year-to-year variations as a result of deferrals of planned work from earlier years to into later years? If yes, please identify and discuss the causes, and if value was provided to customers through these deferrals.

c) Please provide a summary of these projects, or indication of which specific projects (as included in the Appendix M- Project Narratives) are associated with these expenditures.

Response

(a) The term Demand Based does not refer to Electrical Demand as in measured usage, but refers to New Electrical Distribution Construction efforts resulting from new Customer/Commercial/Residential Development construction and the resultant new connections.

(b) In 2014 significant customer driven system expansions resulted in the higher costs as NPEI provides a basic entitlement of service to the Customer, as spelled out within the Service Regulations in addition to Capital Contributions which the Customer is required to pay.

(c) In 2014 significant customer driven system expansions (above the materiality threshold) included the Lowes Commercial Development, The Optimist Square Commercial Development, The RioCan L.A. Fitness Commercial Development, the new Niagara Regional Police Headquarters Development, and the Lincoln Square Commercial Development.

49. 2-staff-20. Vehicle Replacements

Reference

1. Distribution System Plan Appendix F

2. Appendix 2-AA

3. Exhibit 2 Tab 1 Schedule 2 p. 98

NPEI has provided a table of planned replacements and variances from age of replacements at Appendix 2-AA. NPEI has indicated that it has a policy of prioritizing the replacement of vehicles with the lowest ratings first.

a) In the table at Appendix F, what does the code "RBD" refer to?

b) An INTER 4900 bucket truck purchased in 2001 with a condition score of 38 and a variance of 0 from replacement year is recommended for replacement at a cost of $364,140. If the bucket truck is in good condition, why is it being replaced, regardless of planned replacement year?

c) Two other trucks large trucks are scheduled for purchase in 2018 and 2019 to replace trucks purchased in 1993 and 1992. Why is the truck purchased in 2001 being replaced first instead of these older trucks? Please explain how this provides value to customers.

d) At the second reference the following is provided in the Capital Projects Table:

	2010	2011	2012	2013	2014 Bridge	2015 Test
Vehicles	869,037	541,643	1,160,649	1,329,696	672,000	698,878

At the third reference, NPEI indicates that the 5-year average of $3,494,390 is included in the 2015 test year, $698,878.

What were the capital planning drivers of the 100% increase from 2011 to 2012-2013, and the subsequent 50% decline in 2014 and 2015? Is there a reason that fleet replacements are not performed in a manner that smooths capital expenditures from year-to-year? For instance, were there unexpected replacements in 2012 and 2013?

Response

a) Radial Boom Derrick. Typically called a "line truck" it is a truck with a boom device used primarily to lift and auger. These trucks install poles and anchors and lift heavy devices such as transformers and large switches.

b) This particular truck is a daily usage aerial device with material handling capabilities. It has high engine hours due to daily idling while the aerial device is in use. While some other conditional factors result in a higher ranking, the particular engine hour issue is the primary determinant for replacement.

c) Both of these trucks are RBD's. These types of trucks generally experience less usage than aerial (bucket) trucks. On a job site the aerial devices are operating continuously while RBD's work on a more sporadic basis. Overall RBD's last longer due to less wear and tear. Every attempt is made to schedule vehicle replacements based upon functional condition and vehicles are not replaced until their condition has negative implications on performance and upkeep.

d) In the years 2012 and 2013 a higher number of vehicle replacements than average occurred. The 2014 and 2015 numbers are more reflective of the average replacement requirements, while the 2011 number is below the average. The value of the purchases relates directly to the type and number of vehicles being replaced. Therefore, some variances per year are expected. Vehicles are conditionally assessed and replaced as required. Ideally the range of age of the fleet would enable a smoothed approach to replacements but differences in vehicle longevity and types result in yearly fluctuating costs.

50. 2-staff-21.Low Voltage Connections

Reference

a)Exhibit 2 Tab 3 Schedule 1 p. 6;

b)Appendix 2-G

At the reference NPEI discusses its lost efficiencies in the installation of new subdivision connections in 2013. NPEI indicates that it has engaged a private contractor, and reached agreement for the provision of these services.

a)Please discuss how the costs of the previous arrangement with Enbridge compare with the new arrangement with the Enbridge contractor. Please substantiate the change in costs and if NPEI sought competing bids to perform the work, or negotiated with the sole contractor.

b)Please provide a copy of the contract with the new “Enbridge contractor”. What did this change in business relationship have on forecast capital expenditures at Appendix 2-AA?

c)At Appendix 2-G, NPEI provides service reliability figures for Low Voltage Connections. Is the change in contractor solely responsible for the decrease in service reliability below the OEB minimum standard of 90%?

d)NPEI indicated that the reduced need for NPEI crews at site will, “further streamline the process for service connections, and the statistics should reflect these changes in 2014. Year to date, has NPEI seen an improvement in 2014 service reliability, over the drop observed in 2013 for Low Voltage Connections?

Response

a) The change that Enbridge made from company resources to contract resources to perform the service connection work resulted in the elimination of the requirement for NPEI staff to attend the site and perform cable installation and termination work in co-ordination with the civil installation activities. As a result, the costs to NPEI per service connection of this type will reduce as the contractor labour costs are less than the utility costs to perform the work. As Enbridge has engaged a specific contractor to perform the gas component of the work NPEI had no option but to engage the same contractor to perform the electrical component of the work. Negotiations with the Enbridge contractor resulted in an acceptable price to perform the work.

b) While the change will bring some reduction in the costs to connect new residential services in underground supplied subdivisions, the impact on the expenditures represented in the Attachment #12 are immaterial.

c) This specific change had the most significant impact on the performance figures, but other contributing factors play a minor role in the derivation of the numbers. This specific circumstance will not have continuing negative implications on future statistics.

d) Yes, NPEI has seen an improvement in 2014 service reliability.

51. 2-staff-22.Gross Assets – Scope, Urgency, and 'Demand Projects'

Reference

a. Exhibit 2 Tab 1 Schedule 2 p. 4

NPEI provides variance analysis with respect to numerous categories of Gross Assets. With respect to variances, NPEI indicates that, "due to changes in scope, urgent projects, or demand projects, the actual costs were higher on the conductor and lower on the conduit that originally budgeted." NPEI provides this explanation for several accounts.

a) For each of the projects listed under Accounts 1830, 1835, 1840, and 1845 at pages 4 and 5 (2011):

i. What were the changes in scope and why?

ii. How does an urgent project affect costs?

iii. How do 'demand projects' drive variances?

b) Ultimately, do changes in scope, urgency, and 'demand projects' provide or detract from value to customers versus planned expenditures?

Response

Note: as mentioned in response to 2-Staff-19 a) above, the term Demand Based does not refer to Electrical Demand as in measured usage, but refers to New Electrical Distribution Construction efforts resulting from new Customer/Commercial/Residential Development construction and the resultant new connections.

a)

i. The table provides a summary of the impacts to Accounts 1830, 1835, 1840 and 1845, with explanations of material variances given below.

Project #	Project Description	Difference - Actual vs Plan ($ 000) 1830	1835	1840	1845	Change in Scope Actual vs Plan
2011-0001	Robinson St. Rebuild			(49)	527	See below
2011-0002	Lundy's Lane Underground Rebuild			(180)		See below
2011-0003	Montrose -McLeod to Canadian	(114)				Immaterial
2011-0005	Riall St. Rebuild	(70)				Immaterial
2011-0007	Murray/Culp/Main Rebuilds	(97)	106	(167)		See below
2011-0008	Kalar Extend NS&T ROW to Beaverdams	(64)	45			Immaterial
2011-1010	Pole Replacements	(305)				See below
2011-0011	Sectionalize 4 areas		163			See below
2011-0013	Smithville Station upgrades		56			Immaterial
2011-0020	Kiosk Conversions			(117)	278	See below
2011-0052	Mountain Road 3 Ph Extension		33			Immaterial
2011-0065	Wind Storm Damage April 28		209			Not planned
	Total	(650)	612	(513)	805	

Changes in scope that are material:

2011-0001 - Robinson Street: Expansion of scope due to replacement of a 200A sub loop circuit in the area of the underground extension. The scope was expanded to include replacement of underground cable that was found to be deteriorated along with associated switching apparatus.

2011-0002 - Lundy's Lane Underground Rebuild: Reduction in scope based on customer feedback.

2011-0007 - Murray/Culp/Main Rebuilds: The 2011 budget for this project included costs under Account 1840 in error that should have been included in 1835.

2011-1010 - Pole Replacements: There was a significant reduction in the number of poles changes achieved in 2011 based on reallocation of resources to other projects. One significant project that contributed to resource re-allocation was 2011-0001 based on the above noted scope expansion.

2011-0011 - Sectionalizing: The budget for 2011 accounted for the addition of 4 ground operable, ganged switches to improve sectionalizing capability in the western portion of NPEI's service territory. Based on detailed design in advance of project implementation, 2 of the locations were targeted for the installation of electronic reclosing equipment to improve reliability on the associated circuits. The additional expenditure in 1835 was related to the additional cost incurred resulting from the implementation of electronic reclosing equipment.

2011-0020 - Kiosk Conversions: The budget estimate for Kiosk Conversions in 2011 allocated a significant amount to GL 1850. The actual Kiosk Conversions performed in 2011 did not include a significant number of transformer replacements. The majority of the kiosks converted only contained switching apparatus covered under GL 1845.

ii. In the reference given above to NPEI’s originally filed evidence, the term ‘urgent’ specifically applies to the wind storm of April 28, 2011 which caused outages to 18,853 of NPEI’s customers. For storm restoration projects, capital costs are recorded in the same manner as any other capital project. However, projects that are initiated to restore power when outages occur may include more overtime labour than discretionary projects.

iii. As indicated above, demand projects involve capital costs relating to new connections. Since the Distribution System Code requires NPEI to connect new customers within a certain period of time, these projects are non-discretionary in nature. High levels of demand projects may result in the rescheduling of discretionary capital projects. The specific nature of costs involved and the corresponding USoA accounts may differ between projects, which drives the variances between plan and actual.

b) Demand projects and storm restorations are non-discretionary. These projects provide value to customers by either restoring power where an outage has occurred, or establishing new connections within the timeframe specified in the Distribution System Code.

52. 2-staff-23. SA43 – Line Relocations

Reference

1. Exhibit 2 Tab 1 Schedule 2 p. 33

NPEI's evidence suggests that line relocations have averaged approximately $380,000 from 2010-2014, including a 2014 budgeted cost of $539,910.

a) What has NPEI spent year to date in 2014 on line relocations associated with SA43?

b) Why has NPEI budgeted $500,000 for line relocations when the average over the past five years was approximately $380,000?

c) Please explain any changes to strategy at the City of Niagara that validates the estimate.

Response

a) NPEI has projected a total cost of $728,530 for Road Relocation Works in 2014. Actuals at November 19, 2014 were $668,248.

b) There has been an increase in Road Improvement Projects specifically in the City of Niagara Falls, and since current regulations dictate that recovery for NPEI is based on a 50% Labour & Labour Saving Devices only, NPEI has increased the Budget amount in preparation for the increased Construction activity.

c) There has been a funding model change from the OLGC to the City of Niagara Falls which has enabled the City to fast-track Road Improvement Projects The City received a copy of the municipality contribution agreement from OLG on July 17 2013. The estimated new fee will be between $18 and $20 million per year. The new funding formula is based on OLG slot and table-game revenue, whereas the old payment was a flat fee of $3 million a year regardless of how the casinos performed. A new community recognition program is included in the new agreement, which will allow host municipalities, OLG and the province to publicly display and communicate how hosting fees are being used at the local level. How the money is spent will be at the full discretion of council, however OLG will have input to ensure the money is benefiting the community as a whole.

53. 2-staff-24.Niagara Parks Commission Asset Purchase

Reference

a)Exhibit 2 Tab 1 Schedule 2 p. 34

NPEI has indicated that it intends to acquire assets from the Niagara Parks Commission in 2015 at a forecast cost of $818,905.

a)Has NPEI executed an agreement to acquire the assets at the budgeted costs? When does NPEI expect to do so? If the agreement has not yet been signed, what is NPEI's confidence interval with respect to the budgeted estimate provided in this application?

b)Please provide the business case and approvals associated with this purchase.

c)Please provide a description of the plant NPEI intends to acquire, the basis for the acquisition costs NPEI expects, and the value that the purchase and assets will provide to customers.

Response

a) An Agreement between NPEI and the NPC has not yet been executed and is currently with Legal Counsel of the two parties to develop the Terms of Reference. The Budgetary amount was developed by NPEI based on approximate asset values and has not been disclosed to the NPC until an Agreement and negotiations have been finalized by the Parties involved. Rough estimates for the completion of the Agreement would be 2nd quarter of 2015. Costs would need to be negotiated, but from initial meetings, the Customer seems more concerned with relinquishing the Electrical Distribution System than cost recovery on the asset investment. They understand the Liabilities associated with the Ownership and realize as the assets age efficient replacement and refurbishment is not a core function of their Operation.

b) A business case has not been developed by NPEI. In the spirit of the Customer Engagement Plan, NPEI was approached in June of 2014 by the Customer, having recently been mandated by its Board to reduce Operating Costs. The NPC does not have qualified Staff or equipment capable of operating the High Voltage Distribution Equipment under their control and ownership, and cannot effectively react to problems on the system. They currently need to procure third party resources to affect repairs/replacements to equipment with timing being critical to some of their Operations. NPEI currently has an Operating Agreement with the Customer whereby NPEI acts as Switching Agent and exercises operating control of the system on the Customers behalf to react to these situations. The Customer recognizes the shortfall of Ownership in that spare equipment for failure replacement is not an efficient use of their resources, and energy conservation targets are difficult, as the system is metered at the high voltage level, via several demarcation points. Prior to the NPC turning the high voltage system over, low voltage metering would be installed at each transformer location, at the customer's expense, to enable the Customer to understand usage patterns. When the system was originally built, the NPC owned all the concessions throughout the Park. Private Vendors are now allowed to operate within the Property, and the NPC would prefer Customers be metered and billed for their usage. The Customer recognizes that NPEI has the Personnel, Equipment and Resources to effectively run the High Voltage System as a natural extension of the services already provided. Additionally, assuming control of the primary distribution system through NPC corridors provides additional back-feed capabilities that benefit NPEI Customers. Restoration times will positively impacted with the addition of redundant supply points on the distribution system.

c) NPEI would assume Ownership of the High Voltage System within NPC jurisdiction, including Primary Cable, Switch Gear and Transformers. Low Voltage Equipment would remain under NPC Ownership. Assets include approximately 6.0K.M. of primary cable, 19 Switchgear, 13 single-phase pad-mounted transformers, 9 three-phase 600/347V pad-mounted transformers, and 9- three-phase 120/208V pad-mounted transformers. The valuation is based on the installation of approximately 3.0 K.M. of primary cable/duct-bank completed by the NPC in 2012 through the Queen Victoria Park. The majority of other assets are approaching end of life cycles and as mentioned, the NPC does not have Staff or Equipment to replace the assets. The scope is well within the service provided to other NPEI Customers as outlined in NPEI's Conditions of Service, with the majority of the equipment within NPEI current stock compliment.

54. 2-staff-25. 4kV Conversion

Reference

1.Exhibit 2 Tab 1 Schedule 2 page 35-36 – SA40

NPEI plans to replace legacy 4.16kV underground system with 15kV underground conductor and pad-mounted transformation.

a) Please provide a copy of the original business case study justifying the conversion project investment and any updates to that study that includes justification for the continued conversion investment in this DSP period.

b) Please identify the steps that were taken to elicit the views of customers on this project, its merits, and the willingness of customers to abide by the associated rate increases c)Please indicate how customers' views were factored into the plan and its timing.

Response

a) The project in question was not a non-discretionary project driven by NPEI, but a joint road rebuild and intersection improvement project by the City of Niagara Falls and Regional Municipality of Niagara, to facilitate the widening of the roadway and turning lane provisions for the new Lundy's Lane Battlefield Gateway for the war of 1812 Bi-centennial. The existing underground distribution equipment, installed in 1966, was directly buried and of insufficient depth to facilitate the road widening. Property was purchased by the Road authority to meet the Design requirements, and provide space for utility relocations. All equipment installed by NPEI is dual-rated to the 15KV level to facilitate future voltage conversion opportunities and reduce stock levels required.

b) The Project was driven by the applicable Municipal Road Authorities following the Legislation and cost sharing required between NPEI, Regional Municipality of Niagara and the City of Niagara Falls.

c) Outages required during the change-over between the old and new system were co-ordinated with the various Commercial Operations affected by the construction, to facilitate their operations were practical. The BIA was involved by the Municipal Authorities in determining the final design Option of their project.

55. 2-staff-26. Municipal Substation Rehabilitation SR9

Reference

1.Exhibit 2 Tab 1 Schedule 2 p. 41

NPEI states in evidence that the existing transformer will be re-utilized as part of the design based on the results of the asset condition assessment (ACA) study.

a)What was the outcome of the ACA study with respect to the existing transformer?

b)Was the existing 5000kVA power transformer re-utilized? If not, please provide the cost of a new transformer and variance to 2014 expenditures.

Response

a) The transformer health index is presented on Page 40 of the ACA report. It indicates that transformer 800082 is in "Good" condition. The transformer is 34 years of age. Recent Oil Analysis and Electrical Integrity testing results indicate that the transformer has not experienced and significant degradation.

b) The power transformer was re-utilized and placed back into service in 2014.

56. 2-staff-27. Overhead to Underground Primary Conversion – Rolling Acres

Reference

a)Exhibit 2 Tab 1 Schedule 2 pages 52 – SR28

NPEI has included a system renewal project for 2014/2015 with respect to the Rolling Acres subdivision at a cost of approximately $1.3M. NPEI indicates that the primary facilities are currently situated on an inaccessible rear lot pole line within private property. 106 residential customers are affected by this renewal work.

a)Why have the primary facilities become inaccessible?

b)Have customers in the Rolling Acres subdivision experienced comparatively inferior service (e.g. more frequent outages, longer outages) when compared to average residential customers elsewhere in NPEI's service area?

c)Please explain the expected service improvements for the 106 affected customers that will result from undergrounding

d)Explain how this project was prioritized and ranked compared to other system renewal projects. What is the cost per avoided interruption?

e)Please identify the steps that were taken to elicit the views of customers on this project, its merits, and the willingness of customers to abide the associated rate increases.

f)Please indicate how customers' views were factored into the plan and its timing.

Response

a) The current equipment was installed in 1959, within rear lot easements, prior to the construction of any homes, as an improved aesthetics philosophy for electrically servicing the new subdivision, and was a popular and short-sighted construction method during that period. The pole lines were built prior to any construction within the subdivision, and, final construction of homes followed by tree plantings and subsequent growth, pool, shed, fencing and garage installations, have made the line difficult to access, maintain and service.

b) Rolling Acres Customers experienced longer outages during the ice storm of December 2013 as the lines cannot be serviced by traditional equipment (bucket trucks & RBD's) for line clearing and damaged equipment replacement. Poles need to be climbed by lineman to effect repairs, and the rigging required to replace significant equipment such as poles and transformers is significantly longer than equipment accessible from the roadway. It exposes Personnel to greater hazards and is a construction standard which is no longer practised

c) There are 106 Customers in Phase I of the Project, and reliability will increase significantly during ice and high wind events on the primary laterals servicing the subdivision as tree contact and subsequent damage will no longer be a factor. Transformer failure replacements will be expedited as the units will be pad-mounted within the road allowance.

d) Although a numerical ranking has not been assigned to this non-discretionary Project, criteria used ranks it high due to the rear lot construction and age of the plant, but the Municipal Sub-Station #23 supplying the 5KV Feeders sourcing the subdivision is scheduled for elimination per results of Dissolved Gas Analysis (DGA) testing and lack of component availability for the Switchgear.

e) The initial Customer contact was a hand delivered Notice of Construction which went out to each of the affected Customers which included Utility Contact information and a plan for the proposed routing and equipment placements along with the date and time of an upcoming Public Information Centre. A Public Information Centre was facilitated on September 24, 2014 for residents of Phase I at a local Cultural Centre where NPEI and Civil Contractor Staff outlined the plan, rationalized the alternative chosen, explained the Directional Boring Technology to be utilized for the Duct installations, supplied contact information to the residents for any future concerns that may arise during the project, and incorporated any practical changes requested by the Customers. 23 customers attended the meeting and were receptive to the idea of removing the high voltage lines from their backyards.

f) Customers with a pad-mount transformer proposed in front of their lot were generally receptive to the new equipment but inquired about tweaking the location due to some preferences they exhibited, and where practical these requests were taken into account by the Design Technician. Electromagnetic Fields (EMF)'s from pad-mounted transformers were expressed as a concern and NPEI Staff supplied an Institute of

Electrical and Electronic Engineers (IEEE) Paper which explained typical levels from day-to-day household activities. Several Customers requested site meetings with Staff to point out areas of concern which were arranged the following week.

57. 2-staff-28. SR30 – System Sustainment Allowance

Reference

2. Exhibit 2 Tab 1 Schedule 2 p. 54

At the reference NPEI provides its forecast sustainment expenditures allowance for 2015. The average of sustainment expenditures for 2010-2014 is approximately $516,000.

a) Please describe the process by which NPEI arrived at its 2015 budget allowance of $680,000 for system sustainment. In particular, please comment on the current loading of NPEI's stations.

b) Please break out the prior year actual costs, in absolute and percentage terms, between:

i. Underground failures;

ii. Overhead failures;

iii. Distribution modifications and component replacements; and

iv. Other

Response

a) NPEI has calculated the actual average cost from 2010 to 2014 as per Exhibit 2 Tab 1 Schedule 2 on page 54 at $611K. This is the basis for the budget allowance indicated.

The current loading of NPEI supplying transformer stations has not deviated significantly from the values presented in Table 5-11 of the Distribution System Plan. The current loading of NPEI owned Distribution Stations (DS) is at acceptable levels. The most significantly loaded DS is Campden which peaked at 75% of nameplate capacity in 2014.

b) The following tables summarize the 2011-2013 actual costs and 2014 projected costs, in absolute and percentage terms, categorized by underground failures, overhead failures, and failures of components (transformers or distribution station equipment):

2010	Cost	Percentage of Total
Underground Failures	$ 370,292	36.7%
Overhead Failures	$ 322,871	32.0%
Component Failures	$ 315,808	31.3%
Total	**$ 1,008,971**	**100.0%**

2011	Cost	Percentage of Total
Underground Failures	$ 283,815	62.9%
Overhead Failures	$ 71,575	15.9%
Component Failures	$ 96,185	21.3%
Total	**$ 451,575**	**100.0%**

2012	Cost	Percentage of Total
Underground Failures	$ 184,873	35.2%
Overhead Failures	$ 163,339	31.1%
Component Failures	$ 176,995	33.7%
Total	**$ 525,207**	**100.0%**

2013	Cost	Percentage of Total
Underground Failures	$ 226,706	33.8%
Overhead Failures	$ 266,279	39.7%
Component Failures	$ 177,743	26.5%
Total	**$ 670,727**	**100.0%**

2014 Projected	Cost	Percentage of Total
Underground Failures	$ 391,500	40.1%
Overhead Failures	$ 324,185	33.2%
Component Failures	$ 259,895	26.6%
Total	**$ 975,580**	**100.0%**

58. 2-staff-29. SR57 – NWTS Metering Replacement

Reference

1. Exhibit 2 Tab 1 Schedule 2 p. 57

NPEI indicates that there were several failures of the primary metering units at NWTS. NPEI indicates that these replacements will minimize system wide outages which occurred during the metering failures.

a) Were these metering failures expected?

b) What was the cause of these metering failures and was the distributor or transmitter deemed responsible?

c) Were these metering units under warranty? Or were these metering units at end of life?

Response

a) The metering failures were unexpected. The manufacture identified the cause of the failure was related to loss of insulating gas and has since retrofitted gauges and remote monitoring capabilities into all 6 units.

b) The cause of the metering failures was loss of insulating gas. The transmitter was deemed responsible for facilitate repairs and retrofits on the units.

c) The metering units were not at end of life. Niagara West Transformer Corporation facilitated repair of the failed units and was responsible for any associated costs.

59. 2-staff-30. Mobile 27.6kV/8.32kV Substation

Reference

1. Exhibit 2 Tab 1 Schedule 2 p. 65

NPEI indicated that, “All of the distribution substations in the Lincoln/West Lincoln portion of NPEI’s service territory are islanded and to [sic] not tie to other sources.” NPEI listed the four stations: Campden DS, Greenlane DS, Smithville DS, and Jordan DS).

a) Do any of the feeders associated the stations above appear in NPEI’s worst performing feeders list at Appendix C?

b) Did NPEI explore other alternatives with respect to providing these stations with an additional (permanent) level of redundancy through contingency planning?

c) Does the DS Plan address the contingency issues with respect to Lincoln / West Lincoln and its service reliability?

d) Please identify the steps that were taken to elicit the views of customers on this project, its merits, and the willingness of customers to abide by the associated rate increases.

e) Please indicate how customers’ views were factored into the plan and the alternatives.

Response

a) Yes, the following stations are supplied by a feeder identified as a poor performer:

- Campden DS as previously supplied by the Niagara West 2508M5 (now Vineland 4501F1).
- Jordan DS supplied by the Vineland 4501F1.

b) Other alternatives to achieve permanent redundancy would require 10's of kilometres of pole line construction to establish 8.32kV inter-ties. Several points of voltage regulation would be required on the inter-tie circuits based on the significant distance between the DS's. All of which would require capital and operational expenditures multiple times the investment of the mobile substation.

c) The DS Plan maximizes the reliability of station assets through capital expenditures that will:

- Convert Jordan DS loads to the Vineland F1 27.6kV circuit
- Replace the Campden DS power transformer based on age and asset condition
- Replace the Station DS transformer based on age and asset condition

Capital Expenditures in the historical period included significant investment in the rebuild of Campden DS, Greenlane DS, Smitvhille DS, and Station DS. Pelham DS was rebuilt in 2009. The WiMax project includes investment in communication, backup systems, and advanced protection systems in each of these stations.

d) The former Peninsula West Utilities experienced a multi-day outage affecting a large number of customers supplied from Jordan DS in 2004. The cause of the outage was premature failure of the power transformer at the station. The lack of redundant supply, a mobile substation, or a spare power transformer was direct contributors to the significant duration of the event. The significant potential impact on SAIDI was a key criteria in NPEI's priority ranking of this project.

Customer feedback received to date continues to indicate that response time in unplanned events is a top priority.

e) The implemented solution was derived at the lowest cost per unit of risk. The mobile substation has already been deployed in 3 instances to facilitate station maintenance or refurbishment, free of any disruption of service. The mobile substation has also been deployed at Jordan DS in 2014 following power transformer failure avoiding another multi-day outage catastrophe.

ENERGY PROBE

60. 2-Energy Probe-4

Ref: Exhibit 2, Tab 1, Schedule 1

Please update both bridge year continuity schedules (pages 6 and 7) to reflect the most recent year-to-date actual capital expenditures and the forecast for the remainder of the year. Please provide an updated test year continuity schedule (page 8) if the closing balance from 2014 is different from the original evidence.

Response

Please see an updated 2-BA-2014 Bridge Year, 2-BA-2014 Bridge Year OLD LIVES and 2-BA-2015 below.

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard: CGAAP PROJECTED
Year: 2014

CCA Class	OEB	Description	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 2,691,707	$ 682,468		$ 3,374,175	-$ 2,433,512	-$ 432,107		-$ 2,865,618	$ 508,557
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 507,273			$ 507,273	$ -			$ -	$ 507,273
47	1806	Land Rights	$ 1,604,396			$ 1,604,396	-$ 868,162	-$ 57,099		-$ 925,261	$ 679,136
47	1808	Buildings	$ 111,638			$ 111,638	-$ 111,637	$ -		-$ 111,637	$ 1
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment > 50 kV (1708, 1740, 1745)	$ 3,833,013			$ 3,833,013	-$ 701,334	-$ 76,660		-$ 777,994	$ 3,055,019
47	1815	Transformer Station Equipment > 50 kV (1715, 1815)	$ 1,519,065	$ 16,478		$ 1,535,543	-$ 212,606	-$ 36,672		-$ 249,278	$ 1,286,264
47	1815	Transformer Station Equipment > 50 kV (1716)	$ 46,955			$ 46,955	-$ 37,020	-$ 10,841		-$ 47,860	-$ 905
47	1815	Transformer Station Equipment > 50 kV (1717)	$ 610,734			$ 610,734	-$ 201,066	-$ 13,339		-$ 214,406	$ 396,328
47	1815	Transformer Station Equipment > 50 kV (1719)	$ 625,179			$ 625,179	-$ 227,914	-$ 35,747		-$ 263,660	$ 361,519
47	1820	Distribution Station Equipment <50 kV	$ 4,072,270	$ 166,899.75		$ 4,239,170	-$ 2,131,341	-$ 59,662		-$ 2,191,003	$ 2,048,167
47	1820	Distribution Station Equipment <50 Kv (1821)	$ 2,281,769	$ 338,097		$ 2,619,866	-$ 793,416	-$ 75,587		-$ 869,003	$ 1,750,863
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures - Wood	$ 40,535,275	$ 1,775,260.20		$ 42,310,535	-$ 23,356,813	-$ 421,190		-$ 23,778,003	$ 18,532,532
47	1830	Poles, Towers & Fixtures - (1831) Concrete	$ 3,038,668	$ 62,303		$ 3,100,971	-$ 1,273,545	-$ 34,203		-$ 1,307,748	$ 1,793,223
47	1835	Overhead Conductors & Devices	$ 23,335,990	$ 1,319,846.15		$ 24,655,836	-$ 8,694,270	-$ 278,648		-$ 8,972,918	$ 15,682,919
47	1835	Overhead Conductors & Devices (1836)	$ 2,606,710	$ 111,713		$ 2,718,424	-$ 1,135,177	-$ 213,500		-$ 1,348,676	$ 1,369,747
47	1835	Overhead Conductors & Devices (1837)	$ 2,242,028	$ 418,741		$ 2,660,769	-$ 526,796	-$ 76,729		-$ 603,525	$ 2,057,244
47	1840	Underground Conduit	$ 9,663,795	$ 1,129,330		$ 10,793,125	-$ 2,359,337	-$ 178,447		-$ 2,537,784	$ 8,255,341
47	1845	Underground Conductors & Devices	$ 64,503,462	$ 2,246,659.75		$ 66,750,122	-$ 37,486,296	-$ 1,697,999		-$ 39,184,294	$ 27,565,827
47	1845	Underground Conductors & Devices (1846)	$ 2,071,576	$ 139,264		$ 2,210,839	-$ 1,037,566	-$ 53,676		-$ 1,091,242	$ 1,119,597
47	1850	Line Transformers (1850) Polemount	$ 19,321,845	$ (193,867.67)	-$ 123,854	$ 19,004,123	-$ 13,332,426	-$ 206,717	$ 123,854	-$ 13,415,289	$ 5,588,834
47	1850	Line Transformers (1853) Padmount	$ 18,034,372	$ 1,638,266	-$ 68,643	$ 19,603,996	-$ 8,380,992	-$ 511,668	$ 68,643	-$ 8,824,017	$ 10,779,979
47	1855	Services (Overhead & Underground)	$ 5,430,061	$ 673,899		$ 6,103,960	-$ 1,310,965	-$ 230,680		-$ 1,541,644	$ 4,562,316
47	1860	Meters	$ 2,893,476	$ 535,335		$ 3,428,811	-$ 987,855	-$ 163,888		-$ 1,151,744	$ 2,277,067
47	1860	Meters (Smart Meters)	$ 4,202,487	$ 1,724,874		$ 5,927,361	-$ 975,073	-$ 467,441		-$ 1,442,514	$ 4,484,847
47	1865	Other Installations on Customer's Premises	$ -			$ -	$ -	$ -		$ -	$ -
47	1875	Street Lighting and Signal Systems	$ -			$ -	$ -			$ -	$ -
N/A	1905	Land	$ 508,970			$ 508,970	$ -			$ -	$ 508,970
47	1908	Buildings & Fixtures	$ 15,117,431	$ 1,639,743		$ 16,757,173	-$ 2,687,517	-$ 261,846		-$ 2,949,363	$ 13,807,810
13	1910	Leasehold Improvements	$ 120,252			$ 120,252	-$ 120,252			-$ 120,252	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 1,493,564	$ 158,000		$ 1,651,565	-$ 937,619	-$ 92,048		-$ 1,029,667	$ 621,897
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 1,257,769			$ 1,257,769	-$ 1,257,769			-$ 1,257,769	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 320,323			$ 320,323	-$ 315,054			-$ 315,054	$ 5,269
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 2,199,583	$ 275,153		$ 2,474,736	-$ 1,414,760	-$ 277,560		-$ 1,692,320	$ 782,416
10	1930	Transportation Equipment (1931)	$ 705,984	$ -		$ 705,984	-$ 363,891	-$ 68,307		-$ 432,198	$ 273,786
10	1930	Transportation Equipment (1932) Large Trucks	$ 7,544,698	$ 635,480	-$ 441,130	$ 7,739,048	-$ 3,897,852	-$ 281,521	$ 441,130	-$ 3,738,244	$ 4,000,804
10	1930	Transportation Equipment (1933) Trailers	$ 329,326	$ 20,575		$ 349,901	-$ 229,633	-$ 5,928		-$ 235,561	$ 114,341
8	1935	Stores Equipment	$ 236,414	$ 47,643		$ 284,057	-$ 202,066	-$ 6,595		-$ 208,661	$ 75,396
8	1940	Tools, Shop & Garage Equipment	$ 1,954,826	$ 67,513		$ 2,022,339	-$ 1,532,643	-$ 78,713		-$ 1,611,356	$ 410,983
8	1945	Measurement & Testing Equipment	$ 204,006	$ -		$ 204,006	-$ 194,127	$ 7,775		-$ 186,352	$ 17,654
8	1950	Power Operated Equipment	$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1955	Communications Equipment	$ 846,784	$ 258,142		$ 1,104,926	-$ 175,400	-$ 37,409		-$ 212,809	$ 892,117
8	1955	Communication Equipment (Smart Meters)	$ -	$ -		$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ 72,951	$ -		$ 72,951	-$ 70,632	-$ 2,072		-$ 72,704	$ 247
47	1970	Load Management Controls Customer Premises	$ -	$ -		$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 128,961			$ 128,961	-$ 128,961			-$ 128,961	-$ 0
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 21,516,863	-$ 967,842		-$ 22,484,705	$ 6,303,876	$ 847,339		$ 7,151,215	-$ 15,333,490
47	2440	Deferred Revenue[5]	$ -			$ -	$ -				$ -
47	2005	2005-Property Under Capital Leases	$ -			$ -	$ -				$ -
						$ -				$ -	$ -
		Sub-Total	**$ 227,308,724**	**$ 14,919,972**	**-$ 633,627**	**$ 241,595,069**	**-$ 115,799,421**	**-$ 5,589,382**	**$ 633,627**	**-$ 120,755,176**	**$ 120,839,893**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 227,308,724**	**$ 14,919,972**	**-$ 633,627**	**$ 241,595,069**	**-$ 115,799,421**	**-$ 5,589,382**	**$ 633,627**	**-$ 120,755,176**	**$ 120,839,893**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 5,589,382**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	
Stores Equipment	
Net Depreciation	-$ 5,589,382

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard: CGAAP PROJECTED
Year: 2014
Using Old Useful Lives

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 2,691,707	$ 682,468	$ -	$ 3,374,175	-$ 2,433,512	-$ 432,107		-$ 2,865,618	$ 508,557
CEC	1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -			$ -	$ -
N/A	1805	Land	$ 507,273	$ -	$ -	$ 507,273	$ -			$ -	$ 507,273
47	1806	Land Rights	$ 1,604,396	$ -	$ -	$ 1,604,396	-$ 868,162	-$ 57,099		-$ 925,261	$ 679,136
47	1808	Buildings	$ 111,638	$ -	$ -	$ 111,638	-$ 111,637	$ -		-$ 111,637	$ 1
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment > 50 kV (1708, 1740, 1745)	$ 3,833,013	$ -	$ -	$ 3,833,013	-$ 701,334	-$ 76,660		-$ 777,994	$ 3,055,019
47	1815	Transformer Station Equipment > 50 kV (1715, 1815)	$ 1,519,065	$ 16,478	$ -	$ 1,535,543	-$ 218,271	-$ 42,358		-$ 260,629	$ 1,274,914
47	1815	Transformer Station Equipment > 50 kV (1716)	$ 46,955	$ -	$ -	$ 46,955	-$ 15,459	-$ 1,026		-$ 16,484	$ 30,471
47	1815	Transformer Station Equipment > 50 kV (1717)	$ 610,734	$ -	$ -	$ 610,734	-$ 201,066	-$ 13,339		-$ 214,406	$ 396,328
47	1815	Transformer Station Equipment > 50 kV (1719)	$ 625,179	$ -	$ -	$ 625,179	-$ 205,822	-$ 13,655		-$ 219,477	$ 405,702
47	1820	Distribution Station Equipment <50 kV	$ 4,072,270.47	$ 166,900	$ -	$ 4,239,170	-$ 2,194,646	-$ 125,190		-$ 2,319,836	$ 1,919,334
47	1820	Distribution Station Equipment <50 Kv (1821)	$ 2,281,769	$ 338,097	$ -	$ 2,619,866	-$ 799,924	-$ 84,560		-$ 884,484	$ 1,735,383
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures - Wood	$ 40,535,274.96	$ 1,775,260	$ -	$ 42,310,535	-$ 24,159,488	-$ 1,242,181		-$ 25,401,668	$ 16,908,867
47	1830	Poles, Towers & Fixtures - (1831) Concrete	$ 3,038,668	$ 62,303	$ -	$ 3,100,971	-$ 1,347,669	-$ 108,796		-$ 1,456,465	$ 1,644,506
47	1835	Overhead Conductors & Devices	$ 23,335,990.29	$ 1,319,846	$ -	$ 24,655,836	-$ 9,311,883	-$ 920,768		-$ 10,232,652	$ 14,423,185
47	1835	Overhead Conductors & Devices (1836)	$ 2,606,710	$ 111,713	$ -	$ 2,718,424	-$ 922,076	-$ 110,013		-$ 1,032,089	$ 1,686,334
47	1835	Overhead Conductors & Devices (1837)	$ 2,242,028	$ 418,741	$ -	$ 2,660,769	-$ 545,623	-$ 97,961		-$ 643,584	$ 2,017,184
47	1840	Underground Conduit	$ 9,663,795	$ 1,129,330	$ -	$ 10,793,125	-$ 2,572,783	-$ 409,094		-$ 2,981,877	$ 7,811,248
47	1845	Underground Conductors & Devices	$ 64,503,461.77	$ 2,246,660	$ -	$ 66,750,122	-$ 38,118,057	-$ 2,266,148		-$ 40,384,205	$ 26,365,916
47	1845	Underground Conductors & Devices (1846)	$ 2,071,576	$ 139,264	$ -	$ 2,210,839	-$ 1,015,390	-$ 74,152		-$ 1,089,543	$ 1,121,297
47	1850	Line Transformers (1850) Polemount	$ 19,321,844.87	-$ 193,868	-$ 123,854	$ 19,004,123	-$ 13,652,068	-$ 390,536	$ 123,854	-$ 13,918,750	$ 5,085,373
47	1850	Line Transformers (1853) Padmount	$ 18,034,372	$ 1,638,266	-$ 68,643	$ 19,603,996	-$ 8,606,859	-$ 653,265	$ 68,643	-$ 9,191,481	$ 10,412,514
47	1855	Services (Overhead & Underground)	$ 5,430,061	$ 673,899	$ -	$ 6,103,960	-$ 1,310,965	-$ 230,680		-$ 1,541,644	$ 4,562,316
47	1860	Meters	$ 2,893,476	$ 535,335	$ -	$ 3,428,811	-$ 969,733	-$ 151,420		-$ 1,121,153	$ 2,307,658
47	1860	Meters (Smart Meters)	$ 4,202,487	$ 1,724,874	$ -	$ 5,927,361	-$ 975,073	-$ 467,441		-$ 1,442,514	$ 4,484,847
47	1865	Other Installations on Customer's Premises	$ -	$ -	$ -	$ -	$ -			$ -	$ -
47	1875	Street Lighting and Signal Systems	$ -	$ -	$ -	$ -	$ -			$ -	$ -
N/A	1905	Land	$ 508,970	$ -	$ -	$ 508,970	$ -			$ -	$ 508,970
47	1908	Buildings & Fixtures	$ 15,117,431	$ 1,639,743	$ -	$ 16,757,173	-$ 2,687,517	-$ 261,846		-$ 2,949,363	$ 13,807,810
13	1910	Leasehold Improvements	$ 120,252	$ -	$ -	$ 120,252	-$ 120,252			-$ 120,252	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 1,493,564	$ 158,000	$ -	$ 1,651,565	-$ 937,619	-$ 92,048		-$ 1,029,667	$ 621,897
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 1,257,769	$ -	$ -	$ 1,257,769	-$ 1,257,769			-$ 1,257,769	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 320,323	$ -	$ -	$ 320,323	-$ 315,054			-$ 315,054	$ 5,269
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 2,199,583	$ 275,153	$ -	$ 2,474,736	-$ 1,414,760	-$ 277,501		-$ 1,692,261	$ 782,474
10	1930	Transportation Equipment (1931)	$ 705,984	$ -	$ -	$ 705,984	-$ 363,891	-$ 68,307		-$ 432,198	$ 273,786
10	1930	Transportation Equipment (1932) Large Trucks	$ 7,544,698	$ 635,480	-$ 441,130	$ 7,739,048	-$ 4,172,932	-$ 599,124	$ 441,130	-$ 4,330,927	$ 3,408,121
10	1930	Transportation Equipment (1933) Trailers	$ 329,326	$ 20,575	$ -	$ 349,901	-$ 239,076	-$ 16,412		-$ 255,488	$ 94,414
8	1935	Stores Equipment	$ 236,414	$ 47,643	$ -	$ 284,057	-$ 202,066	-$ 6,595		-$ 208,661	$ 75,396
8	1940	Tools, Shop & Garage Equipment	$ 1,954,826	$ 67,513	$ -	$ 2,022,339	-$ 1,532,643	-$ 78,713		-$ 1,611,356	$ 410,983
8	1945	Measurement & Testing Equipment	$ 204,006	$ -	$ -	$ 204,006	-$ 194,127	$ 7,775		-$ 186,352	$ 17,654
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 846,784	$ 258,142	$ -	$ 1,104,926	-$ 263,064	-$ 188,758		-$ 451,822	$ 653,105
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1960	Miscellaneous Equipment	$ 72,951	$ -	$ -	$ 72,951	-$ 70,632	-$ 2,072		-$ 72,704	$ 247
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 128,961	$ -	$ -	$ 128,961	-$ 128,961			-$ 128,961	-$ 0
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 21,516,863	-$ 967,842	$ -	-$ 22,484,705	$ 6,303,876	$ 847,339		$ 7,151,215	-$ 15,333,490
47	2440	Deferred Revenue[5]	$ -	$ -	$ -	$ -	$ -				$ -
47	2005	2005-Property Under Capital Leases	$ -	$ -	$ -	$ -	$ -				$ -
						$ -				$ -	$ -
		Sub-Total	**$ 227,308,724**	**$ 14,919,972**	**-$ 633,627**	**$ 241,595,069**	**-$ 118,853,987**	**-$ 8,704,711**	**$ 633,627**	**-$ 126,925,071**	**$ 114,669,998**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 227,308,724**	**$ 14,919,972**	**-$ 633,627**	**$ 241,595,069**	**-$ 118,853,987**	**-$ 8,704,711**	**$ 633,627**	**-$ 126,925,071**	**$ 114,669,998**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 8,704,711**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 8,704,711

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard MIFRS WITH 2014 PROJECTED ADDITIONS

Year 2015 **CHANGE IN OPENING BALANCES**

		UPDATED		UPDATED		UPDATED	UPDATED	UPDATED		
		Cost				Accumulated Depreciation				
OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
1611	Computer Software (Formally known as Account 1925)	$ 3,374,175	$ 368,740		$ 3,742,916	-$ 2,865,618	-$ 172,869		-$ 3,038,488	$ 704,428
1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
1805	Land	$ 507,273			$ 507,273	$ -			$ -	$ 507,273
1806	Land Rights	$ 1,604,396			$ 1,604,396	-$ 925,261	-$ 57,034		-$ 982,295	$ 622,101
1808	Buildings	$ 111,638			$ 111,638	-$ 111,637	$ -		-$ 111,637	$ 1
1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
1815	Transformer Station Equipment > 50 kV (1708, 1740, 1745)	$ 3,833,013			$ 3,833,013	-$ 777,994	-$ 76,660		-$ 854,654	$ 2,978,359
1815	Transformer Station Equipment > 50 kV (1715, 1815)	$ 1,535,543			$ 1,535,543	-$ 249,278	-$ 36,851		-$ 286,129	$ 1,249,414
1815	Transformer Station Equipment > 50 kV (1716)	$ 46,955			$ 46,955	-$ 47,860	$ 905		-$ 46,955	-$ 0
1815	Transformer Station Equipment > 50 kV (1717)	$ 610,734			$ 610,734	-$ 214,406	-$ 13,339		-$ 227,745	$ 382,989
1815	Transformer Station Equipment > 50 kV (1719)	$ 625,179			$ 625,179	-$ 263,660	-$ 35,747		-$ 299,407	$ 325,772
1820	Distribution Station Equipment <50 kV	$ 4,239,170			$ 4,239,170	-$ 2,191,003	-$ 61,516		-$ 2,252,520	$ 1,986,650
1820	Distribution Station Equipment <50 Kv (1821)	$ 2,619,866			$ 2,619,866	-$ 869,003	-$ 81,222		-$ 950,226	$ 1,669,641
1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
1830	Poles, Towers & Fixtures - Wood	$ 42,310,535	$ 2,219,067		$ 44,529,603	-$ 23,778,003	-$ 460,546		-$ 24,238,549	$ 20,291,054
1830	Poles, Towers & Fixtures - (1831) Concrete	$ 3,100,971			$ 3,100,971	-$ 1,307,748	-$ 35,212		-$ 1,342,960	$ 1,758,011
1835	Overhead Conductors & Devices	$ 24,655,836	$ 1,164,812		$ 25,820,649	-$ 8,972,918	-$ 299,353		-$ 9,272,271	$ 16,548,377
1835	Overhead Conductors & Devices (1836)	$ 2,718,424	$ 101,000		$ 2,819,424	-$ 1,348,676	-$ 208,937		-$ 1,557,613	$ 1,261,810
1835	Overhead Conductors & Devices (1837)	$ 2,660,769	$ 30,162		$ 2,690,931	-$ 603,525	-$ 84,210		-$ 687,735	$ 2,003,196
1840	Underground Conduit	$ 10,793,125	$ 836,870		$ 11,629,994	-$ 2,537,784	-$ 198,109		-$ 2,735,892	$ 8,894,102
1845	Underground Conductors & Devices	$ 66,750,122	$ 2,444,065		$ 69,194,187	-$ 39,184,294	-$ 1,240,021		-$ 40,424,315	$ 28,769,872
1845	Underground Conductors & Devices (1846)	$ 2,210,839	$ 561,196		$ 2,772,036	-$ 1,091,242	-$ 61,092		-$ 1,152,334	$ 1,619,702
1850	Line Transformers (1850) Polemount	$ 19,004,123	$ 885,008		$ 19,889,131	-$ 13,415,289	-$ 215,357		-$ 13,630,646	$ 6,258,485
1850	Line Transformers (1853) Padmount	$ 19,603,996	$ 662,260		$ 20,266,256	-$ 8,824,017	-$ 547,748		-$ 9,371,765	$ 10,894,491
1855	Services (Overhead & Underground)	$ 6,103,960	$ 1,018,443		$ 7,122,403	-$ 1,541,644	-$ 264,526		-$ 1,806,171	$ 5,316,232
1860	Meters	$ 3,428,811	$ 284,541		$ 3,713,352	-$ 1,151,744	-$ 184,385		-$ 1,336,129	$ 2,377,223
1860	Meters (Smart Meters)	$ 5,927,361	$ 143,150		$ 6,070,511	-$ 1,442,514	-$ 409,581		-$ 1,852,095	$ 4,218,415
1865	Other Installations on Customer's Premises	$ -			$ -	$ -	$ -		$ -	$ -
1875	Street Lighting and Signal Systems	$ -			$ -	$ -			$ -	$ -
1905	Land	$ 508,970			$ 508,970	$ -			$ -	$ 508,970
1908	Buildings & Fixtures	$ 16,757,173	$ 44,000		$ 16,801,173	-$ 2,949,363	-$ 283,518		-$ 3,232,881	$ 13,568,293
1910	Leasehold Improvements	$ 120,252			$ 120,252	-$ 120,252			-$ 120,252	$ -
1915	Office Furniture & Equipment (10 years)	$ 1,651,565	$ 32,824		$ 1,684,388	-$ 1,029,667	-$ 110,019		-$ 1,139,686	$ 544,702
1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
1920	Computer Equipment - Hardware	$ 1,257,769			$ 1,257,769	-$ 1,257,769			-$ 1,257,769	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 320,323			$ 320,323	-$ 315,054			-$ 315,054	$ 5,269
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 2,474,736	$ 240,248		$ 2,714,984	-$ 1,692,320	-$ 272,863		-$ 1,965,183	$ 749,801
1930	Transportation Equipment (1931)	$ 705,984	$ 114,086	-$ 63,099	$ 756,970	-$ 432,198	-$ 65,721	$ 63,099	-$ 434,819	$ 322,151
1930	Transportation Equipment (1932) Large Trucks	$ 7,739,048	$ 513,992	-$ 250,482	$ 8,002,558	-$ 3,738,244	-$ 341,100	$ 250,482	-$ 3,828,862	$ 4,173,696
1930	Transportation Equipment (1933) Trailers	$ 349,901	$ 70,800		$ 420,701	-$ 235,561	-$ 8,382		-$ 243,943	$ 176,758
1935	Stores Equipment	$ 284,057	$ -		$ 284,057	-$ 208,661	-$ 9,770		-$ 218,430	$ 65,627
1940	Tools, Shop & Garage Equipment	$ 2,022,339	$ 60,803		$ 2,083,141	-$ 1,611,356	-$ 81,710		-$ 1,693,066	$ 390,075
1945	Measurement & Testing Equipment	$ 204,006	$ 1,000		$ 205,006	-$ 186,352	-$ 3,433		-$ 189,785	$ 15,221
1950	Power Operated Equipment	$ -	$ -		$ -	$ -	$ -		$ -	$ -
1955	Communications Equipment	$ 1,104,926	$ 215,000		$ 1,319,926	-$ 212,809	-$ 52,272		-$ 265,082	$ 1,054,844
1955	Communication Equipment (Smart Meters)	$ -	$ 1,000		$ 1,000	$ -			$ -	$ 1,000
1960	Miscellaneous Equipment	$ 72,951	$ -		$ 72,951	-$ 72,704	-$ 258		-$ 72,962	-$ 11
1970	Load Management Controls Customer Premises	$ -	$ -		$ -	$ -			$ -	$ -
1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
1980	System Supervisor Equipment	$ 128,961			$ 128,961	-$ 128,961			-$ 128,961	-$ 0
1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
1995	Contributions & Grants	-$ 22,484,705	-$ 827,800		-$ 23,312,505	$ 7,151,215	$ 883,252		$ 8,034,468	-$ 15,278,038
2440	Deferred Revenue[5]	$ -			$ -	$ -			$ -	$ -
2005	2005-Property Under Capital Leases	$ -			$ -	$ -				$ -
					$ -				$ -	$ -
	Sub-Total	**$ 241,595,069**	**$ 11,185,268**	**-$ 313,581**	**$ 252,466,756**	**-$ 120,755,176**	**-$ 5,089,205**	**$ 313,581**	**-$ 125,530,799**	**$ 126,935,957**
	Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
	Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
	Total PP&E	**$ 241,595,069**	**$ 11,185,268**	**-$ 313,581**	**$ 252,466,756**	**-$ 120,755,176**	**-$ 5,089,205**	**$ 313,581**	**-$ 125,530,799**	**$ 126,935,957**
	Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
	Total						**-$ 5,089,205**			

	Transportation
	Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 5,089,205

61. 2-Energy Probe-5

Ref: Exhibit 2, Tab 1, Schedule 1

Please confirm that NPEI does not allocate any depreciation expense to OM&A or to capital. If this cannot be confirmed, please provide the amounts allocated to each of OM&A and capital for each of 2011 through 2015.

Response

NPEI confirms that depreciation expense is not allocated to OM&A or to capital.

62. 2-Energy Probe-6

Ref: Exhibit 2, Tab 1, Schedule 1

Please indicate when NPEI removed stranded meters from rate base. If this occurred in 2011 through 2015, please show the amount removed from rate base in the continuity schedules.

Response

NPEI removed stranded meter costs from rate base each year from 2009-2012. The table below shows the amount of gross cost and accumulated depreciation that were removed each year.

Year	Amount Removed From Cost	Amount Removed From Accumulated Depreciation	Net Book Value Recorded in Account 1555
2009	631,140	(400,378)	230,762
2010	4,383,757	(3,098,371)	1,285,386
2011	236,260	(173,002)	63,259
2012	141,557	(103,655)	37,902
Total	5,392,714	(3,775,406)	1,617,308

63. 2-Energy Probe-7

Ref: Exhibit 2, Tab 2, Schedule 1 & Exhibit 2, Tab 1, Schedule 1

a) Are the figures shown in the table on page 1 capital additions closed to rate base in each of the years or capital expenditures, some of which may have been in CWIP at year end?

b) There is an actual column shown under the 2014 bridge year. Please confirm that the difference is related to smart meters. If confirmed, please explain why the smart meters are shown in the continuity schedules (Exhibit 2, Tab 1, Schedule 1) beginning with more than $4 million in opening rate base in 2011.

c) Please update the 2014 columns to reflect the most recent year-to-date actual capital additions to rate base and the most recent forecast for the remainder of the year.

Response

a) The figures shown in the table on page 1 are closed to rate base in each of the years. NPEI does not record capital additions as CWIP at year end.

b) Yes the difference between the Plan and Actual column under the 2014 bridge year is the smart meters that were added to rate base as a result of the final disposition of smart meter rate application.

NPEI applied to move $4,175K of smart meter capital costs into rate base in the 2011 COS Application (EB-2010-0138) because NPEI was more than 50% installed at the time. NPEI requested final disposition of smart meter capital costs, totalling $1,903K, in a Smart Meter Final Disposition rate application which was approved in 2014. Hence, NPEI moved these costs from the smart meter variance account to the fixed asset continuity schedule in 2014.

c) Please see the Table below which shows the actuals by GL account as at October 31, 2014 for the additions. Appendix 2-BA has been updated in the Chapter 2 appendices excel file.

		Per Appendix 2-BA				Additions	Disposals	Additions	Disposals
OEB	**Description**	**Opening Balance**	**Projected Additions**	**Projected Disposals**	**Closing Balance**	At October 31, 2014	At October 31, 2014	Projected Nov&Dec	Projected Nov&Dec
1611	Computer Software (Formally known as Account 1925)	$ 2,691,707	$ 682,468		$ 3,374,175	409,891		272,578	-
1612	Land Rights (Formally known as Account 1906)	$ -			$ -			-	-
1805	Land	$ 507,273			$ 507,273			-	-
1806	Land Rights	$ 1,604,396			$ 1,604,396			-	-
1808	Buildings	$ 111,638			$ 111,638			-	-
1810	Leasehold Improvements	$ -			$ -			-	-
1815	Transformer Station Equipment > 50 kV (1708, 1740, 1745)	$ 3,833,013			$ 3,833,013			-	-
1815	Transformer Station Equipment > 50 kV (1715, 1815)	$ 1,519,065	$ 16,478		$ 1,535,543	16,478		-	-
1815	Transformer Station Equipment > 50 kV (1716)	$ 46,955			$ 46,955			-	-
1815	Transformer Station Equipment > 50 kV (1717)	$ 610,734			$ 610,734			-	-
1815	Transformer Station Equipment > 50 kV (1719)	$ 625,179			$ 625,179			-	-
1820	Distribution Station Equipment <50 kV	$ 4,072,270	$ 166,899.75		$ 4,239,170	156,535		10,365	-
1820	Distribution Station Equipment <50 Kv (1821)	$ 2,281,769	$ 338,097		$ 2,619,866	342,793		(4,696)	-
1825	Storage Battery Equipment	$ -			$ -			-	-
1830	Poles, Towers & Fixtures - Wood	$ 40,535,275	$ 1,775,260.20		$ 42,310,535	1,326,253		449,007	-
1830	Poles, Towers & Fixtures - (1831) Concrete	$ 3,038,668	$ 62,303		$ 3,100,971	62,300		2	-
1835	Overhead Conductors & Devices	$ 23,335,990	$ 1,319,846.15		$ 24,655,836	1,273,922		45,925	-
1835	Overhead Conductors & Devices (1836)	$ 2,606,710	$ 111,713		$ 2,718,424	71,179		40,534	-
1835	Overhead Conductors & Devices (1837)	$ 2,242,028	$ 418,741		$ 2,660,769	213,278		205,462	-
1840	Underground Conduit	$ 9,663,795	$ 1,129,330		$ 10,793,125	393,693		735,637	-
1845	Underground Conductors & Devices	$ 64,503,462	$ 2,246,659.75		$ 66,750,122	1,758,243		488,417	-
1845	Underground Conductors & Devices (1846)	$ 2,071,576	$ 139,264		$ 2,210,839	182,519		(43,256)	-
1850	Line Transformers (1850) Polemount	$ 19,321,845	$ (193,867.67)	-$123,854	$ 19,004,123	(310,846)	(123,854)	116,979	-
1850	Line Transformers (1853) Padmount	$ 18,034,372	$ 1,638,266	-$ 68,643	$ 19,603,996	1,461,097	(68,643)	177,169	-
1855	Services (Overhead & Underground)	$ 5,430,061	$ 673,899		$ 6,103,960	713,150		(39,251)	-
1860	Meters	$ 2,893,476	$ 535,335		$ 3,428,811	465,780		69,555	-
1860	Meters (Smart Meters)	$ 4,202,487	$ 1,724,874		$ 5,927,361	1,776,884		(52,010)	-
1865	Other Installations on Customer's Premises	$ -			$ -			-	-
1875	Street Lighting and Signal Systems	$ -			$ -			-	-

		Per Appendix 2-BA				Additions	Disposals	Additions	Disposals
OEB	**Description**	**Opening Balance**	**Projected Additions**	**Projected Disposals**	**Closing Balance**	At October 31, 2014	At October 31, 2014	Projected Nov&Dec	Projected Nov&Dec
1905	Land	$ 508,970			$ 508,970			-	-
1908	Buildings & Fixtures	$ 15,117,431	$ 1,639,743		$ 16,757,173	1,460,370		179,373	-
1910	Leasehold Improvements	$ 120,252			$ 120,252			-	-
1915	Office Furniture & Equipment (10 years)	$ 1,493,564	$ 158,000		$ 1,651,565	122,727		35,273	-
1915	Office Furniture & Equipment (5 years)	$ -			$ -			-	-
1920	Computer Equipment - Hardware	$ 1,257,769			$ 1,257,769			-	-
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 320,323			$ 320,323			-	-
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 2,199,583	$ 275,153		$ 2,474,736	215,322		59,831	-
1930	Transportation Equipment (1931)	$ 705,984	$ -		$ 705,984			-	-
1930	Transportation Equipment (1932) Large Trucks	$ 7,544,698	$ 635,480	-$441,130	$ 7,739,048	473,820	(441,130)	161,660	(0)
1930	Transportation Equipment (1933) Trailers	$ 329,326	$ 20,575		$ 349,901	20,575		-	-
1935	Stores Equipment	$ 236,414	$ 47,643		$ 284,057	29,488		18,155	-
1940	Tools, Shop & Garage Equipment	$ 1,954,826	$ 67,513		$ 2,022,339	52,774		14,739	-
1945	Measurement & Testing Equipment	$ 204,006	$ -		$ 204,006			-	-
1950	Power Operated Equipment	$ -	$ -		$ -			-	-
1955	Communications Equipment	$ 846,784	$ 258,142		$ 1,104,926	88,443		169,699	-
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	-		-	-
1960	Miscellaneous Equipment	$ 72,951	$ -		$ 72,951			-	-
1970	Load Management Controls Customer Premises	$ -	$ -		$ -			-	-
1975	Load Management Controls Utility Premises	$ -			$ -			-	-
1980	System Supervisor Equipment	$ 128,961			$ 128,961			-	-
1985	Miscellaneous Fixed Assets	$ -			$ -			-	-
1990	Other Tangible Property	$ -			$ -			-	-
1995	Contributions & Grants	-$ 21,516,863	-$ 967,842		-$ 22,484,705	(792,373)		(175,469)	-
2440	Deferred Revenue[5]	$ -			$ -			-	-
2005	2005-Property Under Capital Leases	$ -			$ -			-	-
					$ -			-	-
	Sub-Total	**$ 227,308,724**	**$ 14,919,972**	**-$633,627**	**$ 241,595,069**	**11,984,293**	**(633,627)**	**2,935,679**	**(0)**
	Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				
	Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				
	Total PP&E	**$ 227,308,724**	**$ 14,919,972**	**-$633,627**	**$ 241,595,069**	**$ 11,984,293**	**-$ 633,627**	**$ 2,935,679**	**-$ 0**
	Net		$ 14,286,345			$ 11,350,666			

64. 2-Energy Probe-8

Ref: Exhibit 2, Tab 1, Schedule 2, page 34

a) Please provide a copy of the Operating Agreement with the Niagara Parks Commission.

b) Please show separately all the impacts on the 2015 revenue requirement associated with owning, operating and maintaining this system on behalf of the Niagara Parks Commission (for example, return on capital, depreciation PILs, OM&A, etc.).

c) What revenue will NPEI receive from the Niagara Parks Commission related to the operating agreement?

d) How has the 2-15 budgeted cost of $818,905 been calculated? For example, is it the estimated remaining net book value of these assets? If not, what is the calculation based on?

e) How has the revenue requirement associated with these assets been allocated to rate classes?

f) Did NPEI consider establishing a new rate class for these assets and this customer? If not, why not?

g) What is the current status of negotiations?

Response

a) Please find the current Operating Agreement based on the existing scenario with Niagara Parks Commission owning all distribution assets in Attachment # 13.

Please refer to NPEI's response to Ontario Energy Board Staff Interrogatories, Document EB-2014-0096, 2-staff-24, 1. a). As indicated in the response, NPEI and the NPC have not yet executed an agreement to reflect the asset ownership change.

b) NPEI is unable to estimate the impact on the 2015 revenue requirement at this time.

c) The Customer will no longer receive the benefit of a transformer allowance or metering side factor. The Customer, at their expense, will install revenue metering on the secondary side of each of the 18 3-Phase and 14 1-Phase transformers. This will result in increased service and volumetric charges to offset NPEI's additional operating and maintenance expenditures.

d) Please refer to NPEI's response to Ontario Energy Board Staff Interrogatories, Document EB-2014-0096, 2-staff-24, 1. c).

e) The revenue requirement associated with these assets has been allocated to rate classes consistent with the cost allocation model. No adjustments were made.

f) NPEI did not consider establishing a new rate class, based on the assumption that the currently bulk metered load will be converted to individually metered loads. These new services will be categorized as either General Service > 50kW or General Service <50kW.

g) Please refer to NPEI's response to Ontario Energy Board Staff Interrogatories, Document EB-2014-0096, 2-staff-24, 1. a).

65. 2-Energy Probe-9

Ref: Exhibit 2, Tab 1, Schedule 2

a) Are the amounts shown under SA43 the gross or net amounts after contributions related to line relocations due to municipal road improvements?

b) Please provide a table that shows for each of 2010 through 2015 the gross capital expenditures, the contributions received and the net capital expenditures associated with these relocations.

Response

a) The amounts shown in Exhibit 2, Tab 1, Schedule 2, under SA43 for line relocations are the gross amounts before capital contributions.

b) Please see the table below detailing the gross capital expenditures and the capital contributions.

					Original	Projected	
	2010	2011	2012	2013	2014	2014	2015
Line Relocation due to Municipal Requirements < Materiality	472,209	295,727	236,975	355,572	539,910	728,530	500,000
Capital Contributions	165,499	92,618	71,664	169,421	215,964	218,294	200,000

66. 2-Energy Probe-10

Ref: Exhibit 2, Tab 1, Schedule 2

a) For each of the areas where NPEI has calculated the 2015 capital additions based on one-fifth of the costs for the 2015 through 2019 period, please provide a table showing the category of expenditure, the one-fifth amount calculated in the evidence and NPEI's best forecast of capital expenditures in the 2015 test year.

b) NPEI has forecast the purchase of a number of vehicles in 2014 through 2019 (pages 97-98), yet there are no disposes shown in the continuity schedules for the bridge and test years (Exhibit 2, Tab 1, Schedule 1).

   i) Are any of the vehicle purchases in 2014 or 2015 replacement vehicles?

   ii) If there are replacement vehicles, please confirm that the vehicles being replaced will be fully depreciated when they are replaced.

   iii) If this cannot be confirmed, please provide the net book value of the vehicles being replaced upon their replacement.

c) If there are any vehicles being replaced in 2015, please provide the expected sales/scrap value of the vehicles being replaced.

Response

a) Please see the table below

	Budget 2015	Budget 2016	Budget 2017	Budget 2018	Budget 2019	Rate Application 2015
Land and Land Rights	0	0	0	0	0	0
Buildings & Fixtures	220,000	0	0	0	0	44,000
Sub Total	220,000	0	0	0	0	44,000
Distribution Station	0					0
Transformer Station	0					0
Overhead Distribution	4,533,485					4,533,485
Underground Distribution	3,842,131					3,842,131
Distribution Transformers	1,547,268					1,547,268
Scrap Transformers	0					0
Meters	427,691					427,691
Capital Contributions	(827,800)					(827,800)
Sub Total before unusual contributions	9,522,775	0	0	0	0	9,522,775
Office Furniture & Equipment	68,670	19,843	20,020	20,201	35,385	32,824
Computer Equipment, Hardware	235,350	243,100	245,940	240,550	236,300	240,248
Computer Software	488,000	356,800	265,100	280,500	453,302	368,740
Vehicles < 3 tonnes	71,400	168,300	111,427	142,015	77,286	114,086
Vehicles > 3 tonnes	607,000	434,140	636,725	441,632	450,465	513,992
Vehicle Other	175,000	157,000	0	22,000	0	70,800
Stores Equipment	0	0	0	0	0	0
Tools, Shop & Garage Equipment	68,340	53,060	71,101	55,204	56,308	60,803
Measurement & Testing Equipment	1,000	1,000	1,000	1,000	1,000	1,000
Communication equipment	215,000	250,000	250,000	250,000	250,000	215,000
Miscellaneous equipment	1,000	1,000	1,000	1,000	1,000	1,000
Sub Total	1,930,760	1,684,244	1,602,313	1,454,102	1,561,046	1,618,493
Gross Additions net of contributions	**11,673,535**	**1,684,244**	**1,602,313**	**1,454,102**	**1,561,046**	**11,185,268**

b)

i. Are any of the vehicle purchases in 2014 or 2015 replacement vehicles?

Yes the vehicle purchases in 2014 and 2015 are replacement vehicles. NPEI has added the vehicle disposals to 2-BA-2014 and 2-BA-2015 shown above in 2-Energy Probe-4.

ii) If there are replacement vehicles, please confirm that the vehicles being replaced will be fully depreciated when they are replaced.

NPEI confirms the vehicles being replaced are fully depreciated when they are replaced.

iii) If this cannot be confirmed, please provide the net book value of the vehicles being replaced upon their replacement.

See answer above.

c) NPEI disposes of its vehicles either by donation to an educational institution or by scrap to a junk yard. The proceeds for the 2015 vehicles would most likely be less than $5,000 in total.

67. 2-Energy Probe-11

Ref: Exhibit 2, Tab 1, Schedule 3

a) Does NPEI bill of its customers on a monthly basis? If not, please explain which classes are billed monthly and which customers are billed bi-monthly or some other frequency.

b) Has NPEI changed its billing frequency for any rate classes since its last cost of service rebasing application?

Response

a) Yes NPEI bills its customers on a monthly basis.

b) No, NPEI has not changed its billing frequency for any rate classes since its last cost of service rebasing application.

68. 2-Energy Probe-12

Ref: Exhibit 2, Tab 1, Schedule 3

a) Please update the cost of power to reflect the October 16, 2014 Regulated Price Plan Price Report.

b) What is the impact on the revenue requirement of this update?

c) What is the impact, if any, on the cost of power of the EB-2014-0344 application that would result in NPEI being charged a distribution rate of $1.77/kW as a distribution rate by Grimsby Power in place of the current Niagara West Transformation transmission rate?

Response

a) NPEI has updated the cost of power to reflect the October 16, 2014 Regulated Price Plan Report. The table below shows the impact of the price update applied to the originally filed 2015 load forecast.

2015	Originally Filed	Original Load Forecast Updated for October 16, 2014 RPP Report
Weighted Average COP ($/MWh)	$ 91.63	$ 95.28
Electricity Commodity Charges	$ 113,865,739	$ 118,399,339
Increase in Revenue Requirement		$ 44,177

b) This update increases NPEI's revenue requirement by $44,177.

c) In the Niagara West Transformation Corporation / Grimsby Power MAADs Application (EB-2014-0344), the applicants are not proposing any changes to the transformation connection rate of $1.77 / kW at this time. Therefore, there is no impact to NPEI's 2015 cost of power forecast.

69. 2-Energy Probe-13

Ref: Exhibit 2, Tab 2, Schedule 1

Has NPEI had an independent third party review of the DSP? If not, why not?

Response

NPEI's Distribution System Plan (DSP) was developed through consultation with Kinectrics Inc. Kinectrics reviewed and made recommendations prior to finalizing the current revision of the DSP.

70. 2-Energy Probe-14

Ref: Exhibit 2, Tab 2, Schedule 1

Please update Appendix 2-AA to reflect the most recent year-to-date actuals currently available for 2014 along with the most current forecast for the remainder of the year.

Response

Appendix 2-AA has been updated to reflect the most recent year-to-date actuals at October 31, 2014 along with the forecast for the remainder of the year. See below.

Appendix 2-AA
Capital Projects Table

Project #	Ref #	Projects	2010	2011	2012	2013	2014 Bridge Year	2015 Test Year	Total	Actuals at Oct 31	Nov to Dec	2014 Total Projected	Projected vs Bridge Year
		Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**					
		System Access											
		Subdivisions	682,640	290,295	518,409	703,212	400,000	587,004	3,181,561	813,642	152,480	966,122	566,122
	42	Customer Connection/Extension	161,656	389,962	269,890	177,811			999,318				-
	42	New Upgrade Services	331,699	458,414	196,437	84,734			1,071,284				-
	43	Line Relocation due to Municipal Requirements < Materiality	472,209	295,727	236,975	355,572	539,910	500,000	2,400,394	578,763	149,767	728,530	188,620
	42	Demand based system reinforcements	435,393	573,712	711,788	1,011,493	1,410,778	1,007,500	5,150,664	1,753,963	393,135	2,147,098	736,320
	55	Niagara Parks Commission						818,905	818,905				-
2013-0100	**38**	City of Niagara Falls Kalar @ Rideau				169,530			169,530				-
2010-0016	**39**	Dorchester NS&T to Morrison	180,976						180,976				-
2011-0072	**40**	Drummond & Lundy's Lane Conflicts			267,123				267,123				-
2010-0009	**41**	Kalar to Catalina relocation	164,362	483,044					647,406				-
2010-0053		Oakwood Drive relocation	159,399						159,399				-
2010-0026	**49**	South Pelham Street	816,593						816,593				-
		Capital contributions	-1,160,428	-1,571,526	-1,472,887	-991,373	-900,000	-827,800	-6,924,015	- 792,373	- 175,469	- 967,842	- 67,842
													-
		Sub-Total System Access	**2,244,499**	**919,629**	**727,734**	**1,510,979**	**1,450,689**	**2,085,609**	**8,939,139**	**2,353,995**	**519,913**	**2,873,908**	**1,423,219**
		Miscellaneous System Access	313,134	22,692	357,824	486,453	280,000	343,500	1,803,603	89,485	9,101	98,586	- 181,414
		Total System Access	**2,557,633**	**942,320**	**1,085,559**	**1,997,432**	**1,730,689**	**2,429,109**	**10,742,741**	**2,443,480**	**529,014**	**2,972,494**	**1,241,805**
		System Renewal											-
		MS/DS Rehabilitations											-
2010-0025	4	Pelham MS	226,046						226,046				-
2010-0017	10	Campden DS Feeder Egress	207,208						207,208				-
2011-0017	12	Campden DS Oil Containment		214,586					214,586				-
2011-0013	5	Smithville		361,959	274,090				636,049				-
2011-0022 2	6	Station Street		41,711	137,209	100,331			279,250				-
	7	Station #22 North of Pew						507,139	507,139				-
	8	Station #22 South of Pew						143,724	143,724				-
2012-0012	6	Greenlane			275,300	197,505			472,805				-
2013-0017	9	Station #8				191,113	252,037		443,150	291,747	5,752	297,499	45,462
2011-0011	11	4 Sectionalizing West Area		156,718					156,718				-
2011-0004	13	Lundy's Lane Pole Line -Montrose		156,213					156,213				-
2011-0007	14	Murray/Culp/Dunn/Main Rebuilds		395,970					395,970				-
2011-0005 &	15	Riall St Rebuild		143,116	357,948				501,064				-
2012-0002	16	Lundy's Lane/Ker St UG replacement			356,580				356,580				-
2012-0001	17	Montrose Kinsmen to Lundys			608,128				608,128				-
2012-0007	18	Murray/Dixon Rebuild			633,981				633,981				-
2012-0014 &	19	Victoria Ave Voltage Conversion			173,042	170,305			343,346				-
2013-0005	1	12-M-6 Replacement				538,747	372,631		911,378	265,264	10,343	275,607	- 97,024
2013-0011	2	Dorchester-Garden St to McMillan				198,807	362,018		560,825	518,962	15,043	534,005	171,987
2013-0008	3	High Street - Dorchester Stn 10 O/H				633,880			633,880				-
2013-0007	20	Murray/Culp				712,700			712,700				-
2013-0021	21	OH to UG Beacon Inn Jordan				259,593			259,593				-
2013-0003	22	UG Primary Weightman Bridge				113,001	701,810		814,811	761,764	43,395	805,159	103,349
2014-0009	23	3-M-28, 3-M-26, 3-M-29					417,731		417,731	21,288	421,538	442,826	25,095
2014-0001	24	Crawford Street Rebuild					516,557	282,324	798,880	9,124	52,066	61,190	- 455,367
	56	Frederica Street Rebuild						676,144	676,144				-
2014-0004	25	Fallsview Blvd -Ferry/Robinson					332,173		332,173		-	-	- 332,173
2014-0015	26	Jordan Rd-Red Maple to QEW					397,516		397,516	9,763	305,000	314,763	- 82,753
	26	Jordan Phase II						449,324	449,324				-
2014-1006	27	Wholesale Meter Replacement					300,000		300,000	278,372	84,608	362,980	62,980
2014-0008	28	OH to UG Rolling Acres Phase I					768,694	570,500	1,339,194	36,317	241,800	278,117	- 490,577
2014-0007	29	OH line rebuilds - 6 streets					516,513		516,513	464,497	96,128	560,625	44,112
1007 & 2007	30	System Sustainment/Minor Betterments	1,008,971	451,575	525,207	670,727	400,000	680,000	3,736,480	953,977	21,603	975,580	575,580
1010 & 2010	31	Replace poles identified with limited structural integrity	788,664	826,302	862,338	859,298	778,702	431,729	4,547,032	344,285	81,656	425,941	- 352,761
0020's	32	Replacement of Submersibles & Kiosks with EFD switches and posi-tects	501,362	508,036	705,374	643,270	624,457	647,029	3,629,528	246,317	43,206	289,523	- 334,934

Project #	Ref #	Projects	2010	2011	2012	2013	2014 Bridge Year	2015 Test Year	Total	Actuals at Oct 31	Nov to Dec	2014 Total Projected	Projected vs Bridge Year
		Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**					
2013-2011	33	Replacement of Transformers with >50PPM PCB Content				125,175	566,479	495,104	1,186,758	346,844	15,226	362,070	- 204,409
	57	NWTC Metering						289,605	289,605				-
	60	Willodell Rebuild						310,710	310,710				-
	59	Willoughby Dr. Extension						383,293	383,293				-
	58	Willoughby Drive						372,191	372,191				-
		Sub-Total System Renewal	**2,732,252**	**3,256,185**	**4,909,196**	**5,414,452**	**7,307,316**	**6,238,817**	**29,858,218**	**4,548,521**	**1,437,364**	**5,985,885**	**- 1,321,431**
		Miscellaneous System Renewal	37,016	905,710	240,415	492,575		144,237	1,819,953	-	-	-	-
		Total System Renewal	**2,769,268**	**4,161,895**	**5,149,611**	**5,907,027**	**7,307,316**	**6,383,054**	**31,678,171**	**4,548,521**	**1,437,364**	**5,985,885**	**- 1,321,431**
		System Service											-
		Smart meters	4,175,010			27,128	1,903,089		6,105,227	1,724,874	-	1,724,874	- 178,215
		MIST Meters						143,150	143,150				-
0006's	**34**	Switchgear replacement program	461,327	191,370	313,737	264,913	110,057	250,002	1,591,405	119,261	217	119,478	9,421
2010-0024	**35**	Cherry Avenue	179,386						179,386				-
2010-0023	**36**	Durham Voltage Conversion	364,430						364,430				-
2010-0002	**37**	High Street Area	255,782						255,782				-
2010-0008	**47**	Oakwood Drive	198,387						198,387				-
2011-0003	**50**	KM2 & KM6 Montrose-McLeod		347,760					347,760				-
2012-0003	**51**	Kalar MTS K-M-1			169,041				169,041				-
2014-0018	**53**	King Street 27.6 kV					112,554	114,460	227,014		10,000	10,000	- 102,554
2010-0007	**54**	Robinson St Primary Extension	306,869	733,072					1,039,940				-
	62	Culp St-Drummond to Main	211,701										-
	48	Kalar Extend NS&T ROW-Beaverdams		385,308	383,130				768,438				-
		Mobile Substation		214,555					214,555				-
		Wi-Max Project			332,339	348,370	227,500	215,000	1,123,209	88,443	169,699	258,142	30,642
		Sub-Total System Service	**6,152,892**	**1,872,065**	**1,198,247**	**640,410**	**2,353,200**	**722,612**	**12,939,426**	**1,932,578**	**179,916**	**2,112,494**	**- 240,706**
		Miscellaneous	312,460	94,319	225,537	206,861	130,000	203,000	1,172,176	82,250	47,777	130,027	27
		Total System Service	**6,465,352**	**1,966,383**	**1,423,783**	**847,272**	**2,483,200**	**925,612**	**14,111,602**	**2,014,828**	**227,693**	**2,242,521**	**- 240,679**
		General Plant											-
		Building	67,188	121,779	631,111	1,912,395	1,500,485	44,000	4,276,958	1,460,370	179,373	1,639,743	139,258
		Computer Hardware	257,960	247,812	370,710	274,903	297,040	240,248	1,688,673	215,322	59,831	275,153	- 21,887
		Computer Software	250,022	193,505	213,431	114,742	498,710	368,740	1,639,150	409,891	272,577	682,468	183,758
		Vehicles	869,037	541,643	1,160,649	1,329,696	672,000	698,878	5,271,903	53,265	161,660	214,925	- 457,075
		General Equipment	176,811	175,156	244,851	265,585	299,000	95,627	1,257,029	204,989	68,167	273,156	- 25,844
		Sub-Total General Plant	**1,621,018**	**1,279,896**	**2,620,751**	**3,897,320**	**3,267,235**	**1,447,492**	**14,133,713**	**2,343,837**	**741,608**	**3,085,445**	**-181,790**
		Miscellaneous-General Plant	0	0	0	0	0	0	-				-
		Total General Plant	**1,621,018**	**1,279,896**	**2,620,751**	**3,897,320**	**3,267,235**	**1,447,492**	**14,133,713**	**2,343,837**	**741,608**	**3,085,445**	**-181,790**
		Less Renewable Generation Facility Assets and Other Non Rate-Regulated Utility Assets (input as negative)		0	0	0	0	0	-				
		Total	**13,413,271**	**8,350,495**	**10,279,704**	**12,649,050**	**14,788,440**	**11,185,268**	**70,666,228**	**11,350,666**	**2,935,679**	**14,286,345**	**-502,095**

VECC

71. 2.0 – VECC - 5

Reference: 2/T1/S1

a) Please explain what the $602,414 in additions to account 1860 (Meters) in 2014 were for.

b) Please confirm that $3,780,431 2015 closing balance in account 1860 does not include any stranded meters for which NPEI is seeking recovery in this application.

Response

a. The $602,414 in additions in account 1860 in 2014 were for:

Project Description	2014 Meter Capital $	References to Originally Filed Evidence
3M28,29 Feeder Egress	171,864	E2/T1/S2 pg 49 (Reference #SR23). Distribution System Plan, Appendix M, pg 101.
Kiosk Conversions	550	E2/T1/S2 pg 55 (Reference #SR32). Distribution System Plan, Appendix M, pg 109.
Wholesale Metering	300,000	E2/T1/S2 pg 52 (Reference #SR27). Distribution System Plan, Appendix M, pg 105.
General Metering Capital	130,000	
Total	**602,414**	

b. NPEI confirms the $3,780,431 2015 closing balance in account 1860 does not include stranded meters for which NPEI is seeking recovery in this application.

72. 2.0 - VECC- 6

Reference: 2/T1/S2/pg.5

a) With respect to the $581,552 2011 variance for line transformers there is no explanation as to the source of the variance. Please explain if the variance was due to unit cost variance, units ordered or some other factor.

Response

a) The 2011 actual additions to Account 1850 Transformers was $221K less than 2011 Board approved additions. The 2011 gross asset variance of ($582K) also includes ($152K) relating to the difference between the 2011 actual and Board approved opening balances, and ($209K) relating to transformers scrapped during 2011.

When transformers that are beyond their useful lives are removed from service and scrapped, NPEI records an entry to remove the gross cost of the transformer and the equal and offsetting accumulated depreciation. NPEI does not budget for the level of transformers to be scrapped each year, as there is no impact to net book value. Therefore, the removal of scrapped transformers in 2011 was not included in the Board approved amount. The table below shows the components of the 2011 actual versus Board approved variance.

2011 - Account 1850 Transformers	Board Approved	Actual	Difference
Opening Balance	32,179,000	32,027,302	(151,698)
Additions	1,284,894	1,064,335	(220,559)
Remove cost of scrapped transformers		(209,294)	(209,294)
Ending Balance	33,463,894	32,882,342	(581,552)

73. 2.0-VECC- 7

Reference:2/T1/S2

a) In the same format of Table 2-6 (see page 8 of reference), please provide the actual as compared to the budgeted forecast for capital additions for the years 2012 and 2013.

Response

a) The tables below show budget versus actual capital additions for 2012 and 2013 in the requested format.

Capital Additions 2012 - Plan vs Actual

UsoA	Description	2012 Plan	2012 Actual	Variance $
	Land & Buildings			
1805	Land	-	-	-
1808	Buildings	-	-	-
1905	Land	-	-	-
1908	Buildings	484,000	625,695	141,695
1910	Leasehold Improvements		-	-
	Sub-total	484,000	625,695	141,695
	Transformer & Distribution Stations			
1815	Transformer Station Equipment	-	16,266	16,266
1820	Distribution Station Equipment	790,046	666,649	(123,397)
	Sub-total	790,046	682,915	(107,131)
	Poles & Wires			
1830	Poles, Towers & Fixtures	1,917,883	1,474,815	(443,067)
1835	Overhead Conductors & Devices	921,260	1,638,693	717,433
1840	Underground Conduit	1,024,890	802,096	(222,794)
1845	Underground Conductors & Devices	1,866,820	2,345,741	478,921
	Sub-total	5,730,852	6,261,345	530,493
	Line Transformers			
1850	Line Transformers	1,448,658	1,246,688	(201,971)
	Sub-total	1,448,658	1,246,688	(201,971)
	Services & Meters			
1855	Services	716,996	437,074	(279,921)
1860	Meters	200,000	209,382	9,382
	Sub-total	916,996	646,456	(270,540)
	IT Assets			
1920	Computer Equipment Hardware	455,203	370,710	(84,493)
	Sub-total	455,203	370,710	(84,493)
	Equipment			
1915	Office Furniture & Equipment	101,000	111,949	10,949
1930	Transportation Equipment	1,199,800	1,160,649	(39,151)
1935	Stores Equipment	10,000	-	(10,000)
1940	Tools, Shop & Garage Equipment	101,500	132,901	31,401
1945	Measurement & Testing Equipment	-	-	-
1955	Communications Equipment	346,000	332,339	(13,661)
1960	Miscellaneous Equipment	-	-	-
1980	System supervisor Equipment	-	-	-
	Sub-total	1,758,300	1,737,838	(20,462)
	Other General Assets			
1995	Contributions and Grants	(845,000)	(1,472,887)	(627,887)
	Sub-total	(845,000)	(1,472,887)	(627,887)
	Intangible Assets			
1611	Computer Software	417,700	213,431	(204,269)
1612	Land Rights	-	5,416	5,416
	Sub-total	417,700	218,847	(198,853)
	Other			
	Purchase M2 Assets from Hydro One	2,360,000	-	(2,360,000)
	Smart Meters	1,114,300	-	(1,114,300)
	Sub-total	3,474,300	-	(3,474,300)
	Total - Gross Assets	14,631,055	10,317,607	(4,313,448)

	Capital Additions 2013 - Plan vs Actual			
UsoA	**Description**	**2013 Plan**	**2013 Actual**	**Variance $**
	Land & Buildings			
1805	Land		-	-
1808	Buildings		-	-
1905	Land		-	-
1908	Buildings	3,435,000	1,911,585	(1,523,415)
1910	Leasehold Improvements		-	-
	Sub-total	3,435,000	1,911,585	(1,523,415)
	Transformer & Distribution Stations			
1815	Transformer Station Equipment	30,000	16,679	(13,321)
1820	Distribution Station Equipment	556,848	484,535	(72,313)
	Sub-total	586,848	501,214	(85,634)
	Poles & Wires			
1830	Poles, Towers & Fixtures	2,263,230	2,020,540	(242,690)
1835	Overhead Conductors & Devices	1,272,922	1,964,012	691,090
1840	Underground Conduit	793,238	590,886	(202,351)
1845	Underground Conductors & Devices	2,076,512	1,885,219	(191,293)
	Sub-total	6,405,902	6,460,657	54,755
	Line Transformers			
1850	Line Transformers	1,594,281	1,370,621	(223,660)
	Sub-total	1,594,281	1,370,621	(223,660)
	Services & Meters			
1855	Services	627,145	800,998	173,853
1860	Meters	400,000	275,497	(124,503)
	Sub-total	1,027,145	1,076,495	49,350
	IT Assets			
1920	Computer Equipment Hardware	593,000	276,353	(316,647)
	Sub-total	593,000	276,353	(316,647)
	Equipment			
1915	Office Furniture & Equipment	185,000	170,426	(14,574)
1930	Transportation Equipment	1,395,000	1,330,574	(64,426)
1935	Stores Equipment	25,000	-	(25,000)
1940	Tools, Shop & Garage Equipment	88,000	83,082	(4,918)
1945	Measurement & Testing Equipment		-	-
1955	Communications Equipment	200,000	343,864	143,864
1960	Miscellaneous Equipment		-	-
1980	System supervisor Equipment		-	-
	Sub-total	1,893,000	1,927,946	34,945
	Other General Assets			
1995	Contributions and Grants	(845,000)	(991,373)	(146,373)
	Sub-total	(845,000)	(991,373)	(146,373)
	Intangible Assets			
1611	Computer Software	283,000	114,742	(168,258)
1612	Land Rights	25,000	810	(24,190)
	Sub-total	308,000	115,552	(192,448)
	Total - Gross Assets	14,998,175	12,649,048	(2,349,128)

74. 2.0-VECC-8

Reference:2/T1/S2

a) In the same format of Appendix 2-AA please provide the actual 2014 capital expenditures to date. In an additional column please show the remaining forecast spending for 2014.

b) Please provide any required update to the 2015 budget based on current 2014 expected project completion.

Response

a) See response to 2-Energy Probe-14 above.

b) NPEI requires the 2015 budget to be increased by $491K based on the current 2014 expected project completion. Please see SEC #5 IRR above for more detail.

75. 2.0-VECC-9

Reference:E2/T1/S2

a) Please provide an update on the Rolling Acres Subdivision project indicating the monies spent to date. Please indicate the amount for this project (if any) that is included in 2015 rate base.

Response

Public consultation, design, and all approvals are completed to permit construction of this project. Construction commenced in December 2014 based on the equipment/resource availability of the civil contractor awarded the bid. Current projections indicated that approximately $278K of expenditure will occur on the project in 2014. The remainder of ($1,339,194 - $278,117) $1,061K will occur in 2015, resulting in a carry forward of $491K. Please see SEC #5 above for more detail related to the 2014 carry forward.

76. 2.0-VECC-10

Reference:E2/T1/S2

a) Please provide the cost-benefit analysis that was undertaken to justify the acquisition of the Niagara Parks Commission high voltage assets. Please show the projected incremental revenue stream and 5 year projected maintenance costs.

b) What is the net book value of the assets in question and what is the remaining life of the assets?

Response

a) Please refer to NPEI's response to Ontario Energy Board Staff Interrogatories, Document EB-2014-0096, 2-staff-24, 1. b).

b) Please refer to NPEI's response to Ontario Energy Board Staff Interrogatories, Document EB-2014-0096, 2-staff-24, 1. c).

77. 2.0-VECC-11

Reference:E4/T3

a) Please provide a breakdown of the $1,903,089 in 2014 smart meter costs. Please shown the number and cost of new residential meters and the replacement of old smart meters separately.

b) What is NPEI's expected failure rate of recently installed smart meters? Please contrast that to the prior generation of standard mechanical meters.

Response

a) The $1,903,089 in smart meter costs does not relate to costs actually incurred in 2014. These are smart meter capital costs that NPEI recorded in Account 1555 Smart Meter Capital and Recovery Offset Variance Account between 2010 and 2013. In the Decision and Order in NPEI's Smart Meter Application (EB-2013-0359), dated February 27, 2014, NPEI received approval from the Board for disposition of these costs. Accordingly, NPEI recorded the smart meter capital costs into Accounts 1860 Meters, 1925 Hardware and 1920 Software during 2014. The table below provides details of the year in which these cost were actually incurred.

Account	Description	Recorded in Account 1555				Total - Transferred to PP&E Accounts in 2014
		2010	2011	2012	2013	
1860	Smart Meters	202,285	615,088	786,114	55,092	1,658,578
1925	Software	45,705	193,551			239,256
1920	Hardware		1,600	710	2,945	5,255
Total		250,000	812,250	788,836	60,050	1,903,089

b) The data on a smart meter failure provides for detail analysis as to cause, duration, and impact. This amount of information was not available on standard mechanical meters. On a standard mechanical meter, failure was found upon review at time of meter reading or customer inquiry. The duration of meter failure was unknown; and estimation was based on last actual read available. An average number of meters reported and % of average number of smart meters provides for an estimate of expected failure rate of the recently installed meter. Not all meter events results in the meter failure. An update to communications or configuration of the meter may mitigate a meter failure. Therefore, unlike the standard mechanical meter, not all meter events may lead to an exchange of the meter.

NPEI's expected failure rate of recently installed meters is 0.23% or 117 meters per year based on the 4 year average from 2011-2014; this excludes missing interval reads and power failure or restore, as these events would represent an estimate being used and not a meter failure.

78. 2.0-VECC-12

Reference:2/T2/S3/

Please provide NPEI's actual average working capital for the years 2011 through 2013 (e.g. current assets – current liabilities).

Response

Please see the table below. The numbers provided below are from NPEI's audited financial statements which were included in Exhibit 1 of the originally filed rate application. Average working capital has increased due to NPEI receiving two $10M interest repayment only loans, one in 2012 and one in 2013. The calculation below is a definition of average working capital, however for purposes of revenue requirement calculations the table does not provide sufficient information.

Average Working Capital						
					31-Oct	31-Oct
	2010	2011	2012	2013	2014	2013
Current Assets	33,133,662	34,173,966	38,960,135	42,618,606	31,338,188	36,922,634
Current Liabilities	22,714,322	27,023,564	25,086,680	24,965,616	17,810,631	27,199,828
Regulatory Liabilities	7,616,488	3,764,714	2,894,654	4,107,313	4,797,594	(589,916)
Total Current Liabilities	30,330,810	30,788,278	27,981,334	29,072,929	22,608,225	26,609,912
Working Capital	2,802,852	3,385,688	10,978,801	13,545,677	8,729,963	10,312,722
Average Working Capital		3,094,270	7,182,245	12,262,239	9,521,343	

School Energy Coalition

79. SEC #23 [App. 2-BA, p. 8]

Please provide the full calculation of the depreciation for contributions and grants for each of 2014 and 2015 under MIFRS.

Response

NPEI has provided an excel file named IRR_SEC#23_deprec on Capital Contributions due to the size of some of the spreadsheets. The Summary tab is linked to the individual general ledger accounts that make up the calculation.

The table below is a summary of the gross capital contributions amount and the depreciation for contributions and grants that illustrates where the gross capital contribution amount and the corresponding depreciation expense amount are presented on schedule 2-BA Fixed Asset Continuity Schedule for 2015.

Summary				
		2015	2-BA Continuity	2-BA Continuity
Capital Contributions	GL	Cost	2014	2015
			Depreciation	Depreciation
		per 2-BA	Expense	Expense
Accum Depreciation		16,289,907	577,700	611,756
Accum Depreciation PW		4,916,055	219,560	219,560
Accum Deprec PW #2		1,205,566	48,222	48,223
Included in Accum Depreciation in 1995	1995	22,411,528	845,482	879,539
Included in Accum Depreciation in 1835	1835	398,089	5,705	5,705
Included in Accum Depreciation in 1836	1836	34,065	2,797	2,797
Included in Accum Depreciation in 1837	1837	82,055	2,608	2,608
Included in Accum Depreciation in 1860	1860	318,927	14,726	15,351
		833,136	25,834	26,459
		23,244,664	871,316	905,998

The continuity schedule shows a total cost value for 1995 of $23,244,664 at the end of 2015. This balance is broken down into three separate 1995 general ledger accounts, 1835, 1836, 1837 and 1860, hence there are several corresponding excel spreadsheets to calculate the depreciation. In 2007 and 2008, Niagara Falls Hydro received a capital contribution related to a capital project that qualified for the CDM funding. The total amount received was $514,209. This contribution was recorded in a separate general ledger account and included on the 1835 depreciation excel spreadsheet and amortized over 25 years. Subsequent to IFRS componentization the $514,209 was also inherently split out from account 1835 to 1836 and 1837 (398,089 + 34,065 +82,055). The contribution now resides in 1835, 1936 and 1837 spreadsheets with new depreciation lives. The excel spreadsheet, Summary tab, calculates the difference between not extending the life of the $514,209 original contribution and 25 years. Also, beginning in 2009, non-smart meter capital contributions were grouped with account 1860 for the purposes of calculating depreciation. The exercise of estimating assets useful lives changed the depreciation from 25 to 20 years. As a result the depreciation related to the meter contributions is shown in account 1860 whereas the contribution is shown in account 1995 on the 2-BA continuity schedule.

80. SEC #24 [Ex. 2/1/2, p. 26]

Please identify the Hydro One contribution in Table 2-9.

Response

NPEI does not have any Hydro One contributions in Table 2-9.

81. SEC #25 [Ex. 2/1/2, p. 32]

Please provide details of all commercial services costs in 2014 to date.

Response

The table below shows NPEI's 2014 commercial service costs as at October 31, 2014.

Project #	Project Description	Total Cost as at October 31, 2014
2014-2008	Demand Capital West Area	394,761
2014-1008	Demand Capital NF	193,547
2014-0040	Jordan Station Tx Failure	180,912
2013-0117	Optimist Square	58,198
2013-0096	Hornblower--Maid of the Mist	56,198
2013-0062	7151 McLEOD--BLD D&G	53,791
2013-0080	4838 Lincoln Ave--Freeman Herb	44,861
2014-0066	4706 Christie Dr--3ph Upgrade	38,701
2013-0099	Beamsville Arena	36,323
2013-0063	7151 McLEOD--BLD E&F	34,914
2013-0089	6249 St John--400 amp 600/347V	32,531
2014-0079	4245 King St-RedStone Winery	32,429
2013-0119	Gun Club Upgrade	29,485
2014-0084	4711 Ontario St.-Wendys	28,282
2013-0019	Sixteen Rd HAF Energy Metering	24,025
2013-0128	Ice Storm--Dec 22, 2013	21,966
2014-0069	3659 Stanley--Commercial Mall	21,834
2013-0121	Beamsville Plaza-Serena Drive	20,632
	Other - Projects under $20,000	286,708
Total		1,590,098

82. SEC #26 [Ex. 2/1/2, p. 34]

With respect to the new arrangements with the Niagara Parks Commission:

1. Please provide a copy of the agreement with NPC, including all schedules, amendments, and other related documents.

2. Please provide details of the assets to be acquired from NPC, including type and value, vintage, etc.

3. Please provide a table showing all costs (capital and operating) and revenues expected for each of 2015-2019 due to the new arrangements with the NPC.

Response

1) Please refer to NPEI's response to Ontario Energy Board Staff Interrogatories, Document EB-2014-0096, 2-staff-24, 1. a).

2) Please refer to NPEI's response to Ontario Energy Board Staff Interrogatories, Document EB-2014-0096, 2-staff-24, 1. c).

3) Please refer to NPEI's response to Ontario Energy Board Staff Interrogatories, Document EB-2014-0096, 2-staff-24, 1. b).

83. SEC #27 [Ex. 2/1/3]

Attached as Appendix D to these interrogatories is an excerpt from Appendix E to the SEC interrogatories in EB-2010-0138, describing the savings from monthly billings. This details an improvement in cash flow (i.e. reduction in working capital requirements) of $3 million as a result of moving the remaining customers to monthly billing. Please advise why, in light of this information, the Applicant did not carry out a lead/lag study to determine if its working capital allowance should be adjusted.

Response

NPEI is requesting a WCA of 13% of the eligible controllable expenses including property taxes and cost of power in its 2015 Cost of Service rate application. NPEI submits that this request is consistent with the Board's Filing Requirements which suggest one of two approaches for the calculation of the allowance for working capital, namely, either the default 13% allowance approach or filing a lead/lag study. NPEI did not conduct a lead/lag study, as it did not believe that it had been directed to do so by the Board and it therefore relied on the Board's Filing Requirements in the preparation of its Application.

Exhibit 3 Operating Revenues

84. 3 Staff 31.Load Forecast Model

Reference

1. Niagara_appl_CoS_Weather Normalization Regression_20140923.XLSX

Preamble

In the Purchased Power Model tab of the Reference NPEI determines the statistical parameters of the proposed regression model. There is no parameter that tested for autocorrelation.

Please review the models results, specifically the residuals, and comment on the autocorrelation of the model.

Response

In statistics, the Durbin-Watson statistic is a test statistic used to detect the presence of autocorrelation (a relationship between values separated from each other by a given time lag) in the residuals (prediction errors) from a regression analysis.[1]

To test for autocorrelation in the weather normalization regression model, NPEI has calculated the Durbin-Watson test statistic, which is given by:

$$d = \frac{\sum_{t=2}^{n}(e_t - e_{t-1})^2}{\sum_{t=1}^{n} e_t^{\,2}}, \textit{where } e_t \textit{ are the residuals and}$$

$$n = 144 \textit{ the number of observations.}$$

The results of this calculation give d = 1.645. The value of Durbin-Watson test statistic always lies between 0 and 4. A value of d = 2 indicates that no autocorrelation is present. Generally, a Durbin-Watson test statistic less than 1 or greater than 3 indicates that the residuals are positively or negatively correlated, respectively.

In NPEI's view, the test statistic d = 1.645 indicates that there is no significant autocorrelation effect present in the weather normalization regression model.

[1] http://en.wikipedia.org/wiki/Durbin%E2%80%93Watson_statistic

85. 3 Staff 32.Load Forecast Adjustments

References

1. Exhibit 3 Tab 1 Schedule 1 p. 24 Table 3-18
2. Report of the Board Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach October 18, 2012
3. Report of the Board Review of the Board's Cost Allocation Policy for Unmetered Loads EB-2012-0383. November 19, 2013

Preamble

In *Table 3-18: Growth Rate in Usage per Customer/Connection for Energy* the forecast for Street Lighting declines slightly for 2013 and 2014. Board staff is aware that there is a trend in communities to install more efficient street Lighting. Board staff is also aware of a similar trend for other unmetered loads. In Reference 2 in regards to customer input, the Board stated:

> "***Customer Focus:*** services are provided in a manner that responds to identified customer preferences.[2]

In Reference 3, the Board commented on communications between distributors and unmetered load customers:

> *"The Board believes that there should be ongoing communication between distributors and unmetered load customers. This will enable the municipalities and other unmetered load customers to bring to the attention of their distributor any technological changes that impact the electricity consumption or the load profiles of their unmetered loads. Unmetered load customers should be able to determine, and distributors should be able to validate, what the appropriate consumption levels and load profiles are for particular devices that will reflect the technology used in street lights and other unmetered loads."*[3]

Board staff is interested in determining the level of customer engagement NPEI has undertaken in preparing this application.

1. Please state if NPEI discussed street lighting plans regarding plans related to technology for new and replacement devices that would affect electricity loads in the municipalities that it serves. If it did not please describe how the reduction was developed.

[2] Page 2
[3] 3.1.4 The Board's Approach

2. Please state if NPEI discussed with other unmetered load customers plans related to technology for new and replacement devices that would affect electricity loads. If it did not please describe how the reduction was developed.
3. If NPEI did not engage its customers to assist in setting a forecast of electricity demand, please, on a best efforts basis, consult with them and review the forecast in light of the discussion.

Response

1. Niagara Peninsula Energy Inc. met with City of Niagara Falls staff regarding street lighting plans related to technology for new and replacement devices that would affect electricity loads on the following dates:

   September 29, 2014
   October 30, 2014
   December 4, 2014

2. NPEI did not discuss with other unmetered load customers plans related to technology for new and replacement devices that would affect electricity loads. Reductions in unmetered load customers are observed as customers update and change to a metered service. We are observing the move from unmetered scattered load to metered General Service <50kW.

3. NPEI will attempt to consult with these customers.

86. 3 Staff 33.Load Forecast 2015 CDM Adjustment

References

1. Exhibit 3 Tab 1 Schedule 1 p. 27
2. http://www.powerauthority.on.ca/opa-conservation/conservation-first-framework-tool-kit/targets-and-budgets

Preamble

NPEI states in Reference 1 that there are no details regarding the CDM programmes, and so it relied upon its 2011 – 2014 target of 58.0 GWh to estimate a savings value by applying 5% to the target. In Reference 2, the OPA has published a *Draft LDC CDM Target and Budget Allocations as of September 4, 2014* in which the OPA has set 74.4 GWh as NPEI's CDM target for the period 2015 to 2020.

a) Please state why NPEI did not use that target?

b) Please update the 2015 CDM adjustment for 74.4 GW, or in the alternative a more probable target if NPEI has, discussed this with OPA

c) Please update Appendix 2-I Load Forecast CDM Adjustment Work Form (2015) for 74.4 GW, or in the alternative a more probable target if NPEI has, discussed this with OPA.

Response

a) NPEI had completed the weather normalized load forecast in July 2014. To update the rate application after September 4, 2014 would have delayed NPEI's filing even further. NPEI felt it would be more efficient to update during interrogatories for the published 2015-2020 CDM targets.

b) NPEI has updated the 2015 CDM target to 12.41 GWh, which is one sixth of the six year 2015-2020 target of 74.44 GWh. NPEI's updated Weather Normalization Regression Model is being filed in Excel format along with these interrogatory responses.

c) NPEI has updated the Appendix 2-I Load Forecast CDM Adjustment Work Form to reflect the update. The updated Appendix 2-I is being filed along with these interrogatory responses.

87. 3 Staff 34.Obsolete Inventory

References

1. Exhibit 4 Tab 1 Schedule 1 p. 8
2. Exhibit 3 Tab 3 Schedule 1 p. 16 - 17

Preamble

In Reference 1 NPEI states that it engaged a third party consultant to review the purchasing, receiving, and issuance of inventory processes and procedures. This resulted in scrapping obsolete inventory. Reference 2 are Other Operating Revenue accounts 4355 Gain on Disposition of Utility and Other Property and 4360 Loss on Disposition of Utility and Other Property.

Please state the amount, in which account, and what year any loss or proceeds were recorded.

Response

NPEI recorded the obsolete inventory in the amount of $40,177 in December 2013. The obsolete items included fuses, insulator dead-ends, bolts, nuts, washers, sleeve adapters etc. NPEI recorded the obsolete inventory to account 9040 Stores expenses which is included in the total Operations Expenses.

88. 3 Staff 35. Non-Utility Revenue and Expenses

References

1. Exhibit 3 Tab 3 Schedule 1 p. 18
2. http://www.powerauthority.on.ca/opa-conservation/conservation-first-framework-tool-kit/targets-and-budgets

Preamble

In reference 1 are Accounts 4375 Revenue from Non-Utility Operations and 4380 Expenses from Non-Utility Operations. Horizon is forecasting no revenue or expense for the OPA CDM programmes. In Reference 2, the OPA has published a *Draft LDC CDM Target and Budget Allocations as of September 4, 2014* in which the OPA has set $19,056,865 as NPEI's CDM budget for the period 2015 – 2020.

In Reference 1 it appears that revenues exactly offset expenses in the historical years, except for 2014 where revenues are expected to be less than expenses.

a) On the premise that the OPA fully compensates NPEI for its CDM, why is there a 2014 variance?

b) Based on the OPA Draft in Reference 2, please provide a revenue and expense forecast for 2015.

Response

a) Exhibit 3 Tab 3 Schedule 1 p. 18, Account 4380 detail is incorrect. The total for Account 4380 in the Bridge Year should be $1,606,051 which is the total shown in Table 3-45 in Exhibit 3 Tab 3 Schedule 1 p. 7 of the originally filed evidence. NPEI has shown below a restated Account 4380 that agrees to Table 3-45. CDM expenses in 2014 equal the CDM revenues included in Account 4375.

b) Based on the Final v1-October 31, 2014, NPEI CDM Budget $ is $19,056.865. NPEI forecasts 25% of its total target as revenues and expenses in 2015, for a total of $4,764,216. Accounts 4375 and 4380 have been updated below in yellow highlights for the 2015 test year.

Table 3-45 Comparison 2011 Board Approved restated through to 2015TY – originally filed

USoA #	USoA Description	2011 Board	2011 Actual	Difference	2011 Board	2012 Actual			2013 Actual[2]			Bridge Year[3]	Difference		Test Year			Difference	2014
		Approved Restated	2011	2011 Board Approved Restated vs. 2011 Actual	Approved Restated vs 2011 Actual%	2012	Difference 2011 Actual vs 2012 Actual	2011 Actual vs 2012 Actual %	2013	Difference 2012 Actual vs 2013 Actual	2012 Actual vs 2013 Actual %	2014	2013 Actual vs 2014 Bridge	2013 Actual vs 2014 Bridge %	2015	Difference 2014 Bridge vs 2015 Test	2014 Bridge vs 2015 Test %	2015 Test vs 2011 Board Approved	Bridge vs 2015 Test %
	Reporting Basis	CGAAP	CGAAP			CGAAP			CGAAP			CGAAP			MIFRS				
	Other Revenue																		
4235	Specific Service Charges	$924,416	$874,868	($49,547)	-5%	$794,766	($80,102)	-9%	$810,536	$15,770	2%	$805,434	($5,102)	-1%	$803,285	($2,149)	0%	($121,131)	-13%
4225	Late Payment Charges	$381,550	$419,155	$37,605	10%	$372,203	($46,952)	-11%	$353,574	($18,629)	-5%	$357,661	$4,087	1%	$361,000	$3,339	1%	($20,550)	-5%
4080-01	MicroFit Charges	$0	$4,486	$4,486	100%	$11,087	$6,601	147%	$16,187	$5,100	46%	$20,542	$4,354	27%	$21,060	$518	3%	$21,060	100%
4082	Retail Services Revenues	$80,748	$68,150	($12,598)	-16%	$49,123	($19,027)	-28%	$44,006	($5,117)	-10%	$44,318	$311	1%	$44,424	$107	0%	($36,324)	-45%
4084	Service Transaction Requests (STR) Revenues	$2,970	$1,898	($1,072)	-36%	$1,323	($575)	-30%	$1,071	($252)	-19%	$1,024	($47)	-4%	$1,047	$23	2%	($1,923)	-65%
4086	SSS Administration Revenue	$126,094	$132,759	$6,665	5%	$138,403	$5,644	4%	$142,218	$3,815	3%	$141,294	($924)	-1%	$140,656	($638)	0%	$14,562	12%
4215	Other Utility Operating Income	$32,416	$43,664	$11,248	35%	$42,683	($981)	-2%	$48,359	$5,676	13%	$43,100	($5,259)	-11%	$44,000	$900	2%	$11,584	36%
4355	Gain on Disposition of Utility and Other Property	$0	$16,397	$16,397	100%	$359	($16,038)	-98%	$11,121	$10,762	2999%	$0	($11,121)	-100%	$0	$0		$0	0%
4360	Loss on Disposition of Utility and Other Property	$0	$0	$0		$0	$0		($1,135)	($1,135)	100%	$0	$1,135	-100%	$0	$0		$0	0%
4362	Loss from Retirements of Utility and Other Property	$0	$0	$0		$0	$0		($66,865)	($66,865)	100%	$0	$66,865	-100%	$0	$0		$0	0%
4375	Revenue from Non-Utility Operations	$550,885	$1,334,964	$784,079	142%	$1,825,918	$490,954	37%	$2,018,308	$192,390	11%	$1,632,123	($386,185)	-19%	$0	($1,632,123)	-100%	($550,885)	-100%
4380	Expenses from Non-Utility Operations	($260,000)	($1,136,686)	($876,686)	337%	($1,482,009)	($345,323)	30%	($1,871,113)	($389,105)	26%	($1,606,051)	$265,062	-14%	$0	$1,606,051	-100%	$260,000	-100%
4390	Miscellaneous Non-Operating Income	$40,000	$58,882	$18,882	47%	$118,923	$60,041	102%	$118,062	($861)	-1%	$111,027	($7,035)	-6%	$81,003	($30,024)	-27%	$41,003	103%
4405	Interest and Dividend Income	$127,863	$140,673	$ 12,810	10%	$174,715	$34,042	24%	$180,173	$5,458	3%	$307,684	$127,511	71%	$157,000	($150,684)	-49%	$29,137	23%
	Gross Other Revenues	**$ 2,006,942**	**$ 1,959,211**	-$ 47,731	-2%	**$ 2,047,495**	$ 88,284	5%	**$ 1,804,503**	**-$ 242,992**	-12%	**$ 1,858,155**	$ 53,652	3%	**$ 1,653,475**	**-$ 204,680**	-11%	($353,467)	-18%
4405	Remove Variance Account Interest	($45,195)	($55,431)	($10,236)	23%	($54,350)	$1,081	-2%	($63,298)	($8,948)	16%	-$ 187,684	-$ 124,386	197%	-$ 57,000	$ 130,684	-70%	($11,805)	26%
	Adjusted Other Revenue	**$ 1,961,747**	**$ 1,903,780**	-$ 57,967	-3%	**$ 1,993,145**	$ 89,365	5%	**$ 1,741,205**	**-$ 251,940**	-13%	**$ 1,670,471**	-$ 70,734	-4%	**$ 1,596,475**	**-$ 73,996**	-4%	($365,272)	-19%

Updated 4375 Revenue from Non-Utility Operations and 4380 Expenses from Non-Utility Operations

4375 - Revenue from Non-Utility Operations

	2011 Board Approved CGAAP Restated	2011 Actual 2011 CGAAP	Difference 2011 Board Approved Restated vs. 2011 Actual	2011 Board Approved Restated	2012 Actual 2012 CGAAP	Difference 2011 Actual vs 2012 Actual	2011 Actual vs 2012 Actual %	2013 Actual[2] 2013 CGAAP	Difference 2012 Actual vs 2013 Actual	2012 Actual vs 2013 Actual %	Bridge Year[3] 2014 CGAAP	Difference 2013 Actual vs 2014 Bridge	2013 Actual vs 2014 Bridge %	Test Year 2015 MIFRS	Difference 2014 Bridge vs 2015 Test	2014 Bridge vs 2015 Test %
Water Late payment revenue	137,007	109,990	(27,017)	-20%	124,111	14,120	13%	126,184	2,074	2%	30,901	(95,284)	-76%		(30,901)	-100%
Water Collection charge revenue	32,463	33,470	1,007	3%	41,351	7,881	24%	42,032	681	2%	10,326	(31,706)	-75%		(10,326)	-100%
Water Occupancy change revenue	20,766	23,895	3,129	15%	24,264	369	2%	24,867	603	2%	5,751	(19,116)	-77%		(5,751)	-100%
Water revenue for fixed asset mail machine	18,108	18,108	-	0%	18,108	-	0%	18,108	-	0%	4,527	(13,581)	-75%		(4,527)	-100%
Water administration revenue	277,061	303,336	26,275	9%	300,913	(2,423)	-1%	303,122	2,209	1%	81,254	(221,868)	-73%		(81,254)	-100%
CDM Incentives	65,480	44,606	(20,874)	-32%	187,551	142,945	320%	(11,826)	(199,377)	-106%	-	11,826	-100%	-	-	
Installation of poles for Bell Canada	-	12,963	12,963	100%	-	(12,963)	-100%	-	-		-	-		-	-	
OPA 2011 to 2014 Programs revenue	-	788,596	788,596	100%	1,129,621	341,025	43%	1,515,821	386,201	34%	1,499,364	(16,457)	-1%	-	(1,499,364)	-100%
OPA 2015 to 2020 programs revenue														4,764,216	4,764,216	100%
Total	550,885	1,334,964	784,079	142%	1,825,918	490,954	37%	2,018,308	192,390	11%	1,632,123	(386,185)	-19%	4,764,216	3,132,093	192%

4380 - Expenses from Non-Utility Operations

	2011 Board Approved CGAAP Restated	2011 Actual 2011 CGAAP	Difference 2011 Board Approved Restated vs. 2011 Actual	2011 Board Approved Restated vs 2011	2012 Actual 2012 CGAAP	Difference 2011 Actual vs 2012 Actual	2011 Actual vs 2012 Actual %	2013 Actual[2] 2013 CGAAP	Difference 2012 Actual vs 2013 Actual	2012 Actual vs 2013 Actual %	Bridge Year[3] 2014 CGAAP	Difference 2013 Actual vs 2014 Bridge	2013 Actual vs 2014 Bridge %	Test Year 2015 MIFRS	Difference 2014 Bridge vs 2015 Test	2014 Bridge vs 2015 Test %
Water billing and collecting expenses	186,892	272,788	85,896	46%	279,400	6,612	2%	282,146	2,746	1%	78,885	(203,261)	-72%		(78,885)	-100%
Water general and admin expenses	55,000	57,194	2,194	4%	54,880	(2,314)	-4%	55,038	158	0%	21,766	(33,272)	-60%		(21,766)	-100%
Water depreciation expense for fixed asset mail machine	18,108	18,108	-	0%	18,108	-	0%	18,108	-	0%	6,036	(12,072)	-67%		(6,036)	-100%
OPA 2011 to 2014 Programs expenses		788,596	788,596	100%	1,129,621	341,025	43%	1,515,821	386,201	34%	1,499,364	(16,457)	-1%	-	(1,499,364)	-100%
OPA 2015 to 2020 programs expenses														4,764,216	4,764,216	100%
			-			-			-			-			-	
Total	260,000	1,136,686	876,686	337%	1,482,009	345,323	30%	1,871,113	389,105	26%	1,606,051	(265,062)	-14%	4,764,216	3,158,165	197%

ENERGY PROBE

89. 3-Energy Probe-15

Ref: Exhibit 3, Tab 1, Schedule 1

How has the annual average basis of number of customers/connections shown in Table 3-4 determined? Is this average the average of monthly figures or the average of January and December, or some other average?

Response

The annual average number of customers/connections in Table 3-4 is determined using an average of monthly figures.

90. 3-Energy Probe-16

Ref: Exhibit 3, Tab 1, Schedule 1

Please provide the actual number of customers in the same level of detail as shown in Table 3-5 for the most recent year-to-date figure in 2014, along with the corresponding figures for the same month in 2013.

Response

The table below shows NPEI's customer and connection counts by rate class, as at October 2014 compared to October 2013. The values provided are averages of monthly customer/connection counts for the first 10 months of each year.

Rate Class		Oct-13	Oct-14
Residential		46,041	46,598
GS<50 kW		4,258	4,356
GS>50 kW		850	815
Unmetered Scattered Load		450	427
Sentinel Lights		346	330
Streetlighting		12,911	12,736

91. 3-Energy Probe-17

Ref: Exhibit 3, Tab 1, Schedule 1

Energy Probe has been unable to replicate the prediction model used by NPEI to predict weather normal purchases using the spreadsheet provided. Energy Probe provides the following regression coefficients and regression statistics:

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.973181195
R Square	0.947081639
Adjusted R Square	0.9443579
Standard Error	2523927.78
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	7	1.55051E+16	2.21501E+15	347.7137788	1.71521E-83
Residual	136	8.66349E+14	6.37021E+12		
Total	143	1.63714E+16			

	Coefficients	*Standard Error*	*t Stat*
Intercept	-214115646.3	3207486(	-6.675497292
Heating Degree Days	23664.55187	1562.617808	15.14417136
Cooling Degree Days	192313.0075	7649.117127	25.14185681
Ontario Real GDP Monthly %	318305.0414	131378.4904	2.422809399

Number of Days in Month	2931010.239	270679.1755	10.82835513
CDM kWh Saved in month	-5.301641153	0.728558517	-7.276891323
Spring Fall Flag	-5192919.546	577070.8679	-8.998755327
Population	1344.135769	347.6962698	3.86583316

Please explain the difference in the regression equations.

Response

Upon re-running the regression procedure in the originally filed Weather Normalization Regression Model, NPEI obtained the same results that Energy Probe presents above.

The various Excel models and files utilized by NPEI in preparing this rate application make extensive use of linked cell references. As far as NPEI can determine, a cell reference was not updated at the time that NPEI performed the regression analysis. The table below shows the impact of the corrected regression equation on the 2014 Bridge Year and 2015 Test Year forecasts (total billed GWh, weather normalized, after CDM manual adjustment).

Total Billed GWh	2014	2015
Originally Filed	1,184.45	1,185.82
Corrected	1,186.16	1,187.58
Difference	1.70	1.76

NPEI notes that the 2015 load forecast has been amended to reflect updated estimates for 2013 and 2015 CDM savings, as well as to correct for double counting of 2014 and 2015 CDM savings. Please see NPEI's responses to 3-VECC-16, 3-VECC-17 and 3-VECC-18.

NPEI manually updated all links in the Weather Normalization Regression Model prior to updating the regression equation to ensure that this issue has been resolved.

92. 3-Energy Probe-18

Ref: Exhibit 3, Tab 1, Schedule 1

a) For each of the three columns shown in Table 3-27, please provide a regression analysis with the dependent variable being the historical kWh/kW ratio and the independent variable being the year (2003 through 2013).

b) For each equation that is significant at a 90% level of confidence, please show the resulting 2015 ratio forecast.

c) For each ratio forecast in part (b) above, please provide the 2015 forecast, as shown in Table 3-28 and show the impact on the revenue deficiency.

Response

a) NPEI performed the regression analyses as requested. The regression outputs for each rate class are shown below.

SUMMARY OUTPUT	GS>50					
Regression Statistics						
Multiple R	0.52291305					
R Square	0.273438058					
Adjusted R Square	0.192708953					
Standard Error	0.000121481					
Observations	11					
ANOVA						
	df	*SS*	*MS*	*F*	*Significance F*	
Regression	1	4.99858E-08	5E-08	3.38710628	0.09884728	
Residual	9	1.32819E-07	1.48E-08			
Total	10	1.82805E-07				
	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	0.045631477	0.023258237	1.961949	0.08138901	-0.00698231	0.098245264
Year	-2.1317E-05	1.15828E-05	-1.84041	0.09884728	-4.7519E-05	4.88501E-06

SUMMARY OUTPUT	Streetlighting					
Regression Statistics						
Multiple R	0.51742431					
R Square	0.267727916					
Adjusted R Square	0.186364351					
Standard Error	0.000120914					
Observations	11					
ANOVA						
	df	*SS*	*MS*	*F*	*Significance F*	
Regression	1	4.81076E-08	4.81E-08	3.29051359	0.103083032	
Residual	9	1.31581E-07	1.46E-08			
Total	10	1.79688E-07				
	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	-0.039264135	0.023149559	-1.69611	0.12410045	-0.09163208	0.013103806
Year	2.09127E-05	1.15287E-05	1.813977	0.10308303	-5.1669E-06	4.69923E-05

SUMMARY OUTPUT	Sentinal Lights					
Regression Statistics						
Multiple R	0.548307312					
R Square	0.300640908					
Adjusted R Square	0.222934342					
Standard Error	0.000257038					
Observations	11					
ANOVA						
	df	*SS*	*MS*	*F*	*Significance F*	
Regression	1	2.55615E-07	2.56E-07	3.86892543	0.080736119	
Residual	9	5.94618E-07	6.61E-08			
Total	10	8.50233E-07				
	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	0.099498073	0.049211392	2.02185	0.07390086	-0.01182583	0.210821977
Year	-4.82055E-05	2.45076E-05	-1.96696	0.08073612	-0.00010365	7.23462E-06

b) None of the equations are significant at the 90% confidence level.

c) Not applicable.

93. 3-Energy Probe-19

Ref: Exhibit 3, Tab 3, Schedule 1

Please provide a table in the same level of detail as found in Appendix 2-H that shows the most recent year-to-date figures for 2014 and the corresponding figures for the same year-to-date period in 2013.

Response

The table below shows the year-to-date figures, as at October 31, 2014, projections for November and December 2014, as well as the corresponding figures for 2013.

USoA #	USoA Description	Actuals at 10/31/2014	Projected Nov +Dec 2014	Total Projected 2014	Actuals at 10/31/2013	Actual Nov +Dec 2013	Total Actual 2013
	Reporting Basis						
4305	Regulatory Debit	(2,451,418)	(663,911)	(3,115,329)	0	(3,054,566)	(3,054,566)
	Other Revenue						
4235	Specific Service Charges	699,979	113,740	813,719	713,269	97,267	810,536
4225	Late Payment Charges	349,686	66,000	415,686	297,661	55,913	353,574
4080-01	MicroFit Charges	17,589	3,600	21,189	13,019	3,168	16,187
4082	Retail Services Revenues	34,886	6,800	41,686	36,829	7,178	44,006
4084	Service Transaction Requests (STR) Revenu	841	154	995	869	202	1,071
4086	SSS Administration Revenue	120,050	24,272	144,322	118,126	24,092	142,218
4215	Other Utility Operating Income	47,592	7,183	54,776	40,241	8,118	48,359
4355	Gain on Disposition of Utility and Other Property	8,500	0	8,500	11,121	0	11,121
4360	Loss on Disposition of Utility and Other Property	0	0	0	0	(1,135)	(1,135)
4362	Loss on Retirement of Utility & Other Property	0	0	0	0	(66,865)	(66,865)
4375	Revenue from Non-Utility Operations	2,102,789	175,818	2,278,607	1,583,421	446,713	2,018,308
4380	Expenses from Non-Utility Operations	(2,021,403)	(175,818)	(2,197,221)	(1,423,294)	(447,820)	(1,871,114)
4390	Miscellaneous Non-Operating Income	(8,601)	0	(8,601)	0	118,062	118,062
4405	Interest and Dividend Income including Carrying Charges	345,441	27,600	373,041	143,808	36,365	180,173
		$ 1,697,349	$ 249,349	$ 1,946,698	$ 1,535,071	$ 281,257	$ 1,804,502
	Less Carrying Charges in 4405	(250,551)	(18,000)	(268,551)	(49,613)	(13,685)	(63,298)
	Total Miscellaneous Revenue	$ 1,446,798	$ 231,349	$ 1,678,147	$ 1,485,458	$ 267,572	$ 1,741,204
Summary							
Specific Service Charges		$ 699,979	$ 113,740	$ 813,719	$ 713,269	$ 97,267	$ 810,536
Late Payment Charges		$ 349,686	$ 66,000	$ 415,686	$ 297,661	$ 55,913	$ 353,574
Other Operating Revenues		$ 220,959	$ 42,009	$ 262,968	$ 209,084	$ 42,757	$ 251,841
Other Income or Deductions Excluding Carrying Charges		$ 176,174	$ 9,600	$ 185,774	$ 265,444	$ 71,635	$ 325,253
Total		**$ 1,446,798**	**$ 231,349**	**$ 1,678,147**	**$ 1,485,458**	**$ 267,572**	**$ 1,741,204**

Description
Specific Service Charges:
Late Payment Charges:
Other Distribution Revenues:
Other Income and Expenses:

Note: Add all applicable accounts listed above to the table and include all relevant information.

Account Breakdown Details

For each "Other Operating Revenue" and "Other Income or Deductions" Account, a detailed breakdown of the account

USoA #	USoA Description	Actuals at 10/31/2014	Projected Nov +Dec 2014	**Total Projected 2014**	Actuals at 10/31/2013	Actual Nov +Dec 2013	**Total Actual 2013**
4235	**Specific Service Charges**						
Reporting Basis							
Specific Charge for Access to the Power Poles – per pole/year		253,837	-	253,837	252,370	- 3,044	249,326
Legal letter charge		5,357	2,400	7,757	9,087	1,635	10,722
Collection of account charge – no disconnection		180,580	44,167	224,747	221,811	33,035	254,846
Returned Cheque charge (plus bank charges)		6,705	1,450	8,155	7,379	1,220	8,599
Disconnect/Reconnect at meter – during regular hours		15,600	4,167	19,767	21,580	3,475	25,055
Disconnect/Reconnect at meter – after regular hours		6,955	900	7,855	4,810	555	5,365
Disconnect/Reconnect at pole – during regular hours		5,920	1,217	7,137	5,920	665	6,585
Account set up charge / change of occupancy charge		157,140	37,440	194,580	151,290	33,030	184,320
Miscellaneous Service Revenues-Other		67,885	22,000	89,885	39,022	26,696	65,719
Total		699,979	113,740	813,719	713,269	97,267	810,536
4080-01	**MicroFit Charges**						
Reporting Basis							
MicroFit charges		17,589	3,600	21,189	13,019	3,168	16,187
Total		17,589	3,600	21,189	13,019	3,168	16,187
4082	**Retail Services Revenues**						
Reporting Basis							
Retailer Service Agreement -- standard charge							
Retailer Service Agreement -- monthly fixed charge (per retailer)							
Retailer Service Agreement -- monthly variable charge (per customer)		23,184	4,500	27,684	24,368	4,771	29,139
Distributor-Consolidated Billing -- monthly charge (per customer)		11,702	2,300	14,002	12,461	2,407	14,867
Retailer-Consolidated Billing -- monthly credit (per customer)							
Total		34,886	6,800	41,686	36,829	7,178	44,006
4084	**Service Transaction Request**						
Reporting Basis							
Service Transaction Request -- request fee (per request)		298	54	352	322	69	391
Service Transaction Request -- processing fee (per processed		543	100	643	548	133	680
Total		841	154	995	869	202	1,071
4086	**SSS Admin Fee**						
Reporting Basis							
Residential		108,124	21,800	129,924	106,010	21,580	127,590
GS < 50		9,943	2,000	11,943	9,753	2,034	11,787
GS > 50		358	73	431	366	1,996	2,362
Streetlight		1,575	388	1,963	1,947	- 1,901	46
Sentinel Lights		13	3	15	12	3	15
USL		37	8	45	38	381	419
Total		120,050	24,272	144,322	118,126	24,092	142,218

USoA #	USoA Description	Actuals at 10/31/2014	Projected Nov +Dec 2014	**Total Projected 2014**	Actuals at 10/31/2013	Actual Nov +Dec 2013	**Total Actual 2013**
4215	**Other Utility Operating Income**						
Reporting Basis							
	Sale of Scrap Materials	40,295	5,833	46,128	32,943	6,106	39,049
	Transformer Rentals	7,297	1,350	8,647	7,297	2,012	9,309
Total		47,592	7,183	54,776	40,241	8,118	48,359
4305	**Regulatory Debit**						
Reporting Basis							
	Regulatory Debit - Accounting Change for Capital Assets Depreciation Lives	- 2,451,418	- 663,911	- 3,115,329	-	- 3,054,566	- 3,054,566
Total		- 2,451,418	- 663,911	- 3,115,329	-	- 3,054,566	- 3,054,566
4355	**Gain on Disposition of Utility and Other Property**						
Reporting Basis							
	Vehicle - insurance settlement Vehicle sales	8,500	-	8,500	11,121	-	11,121
Total		8,500	-	8,500	11,121	-	11,121
4360	**Loss on Disposition of Utility and Other Property**						
Reporting Basis							
	Office equipment	-	-	-	-	- 1,135	- 1,135
Total		-	-	-	-	- 1,135	- 1,135
4362	**Loss on Retirement of Utility & Other Property**						
Reporting Basis							
	Retirement of 3 DS stations	-	-	-	-	- 66,865	- 66,865
Total		-	-	-	-	- 66,865	- 66,865

USoA #	USoA Description	Actuals at 10/31/2014	Projected Nov +Dec 2014	**Total Projected 2014**	Actuals at 10/31/2013	Actual Nov +Dec 2013	**Total Actual 2013**
4375	**Revenue from Non-Utility Operations**						
Reporting Basis							
	Water Late Payment Charges	46,504	-	46,504	103,088	23,097	126,184
	Water Occupancy Charge Revenue	6,318	-	6,318	20,250	4,617	24,867
	Water Collection Charge Revenues	12,197	-	12,197	36,791	5,241	42,032
	Water Billing Administration Charge	131,753	-	131,753	252,391	68,839	321,230
	OPA Peak Saver and ERIP revenues					-	11,826
	Installation of Poles for Bell Canada						
	OPA fixed and incentive revenues	1,906,017	175,818	2,081,835	1,170,902	344,919	1,515,821
Total		2,102,789	175,818	2,278,607	1,583,421	446,713	2,018,308
4380	**Expenses from Non-Utility Operations**						
Reporting Basis							
	Water Billing expenses	115,386	-	115,386	252,391	102,901	355,292
	OPA expenses and incentives	1,906,017	175,818	2,081,835	1,170,903	344,919	1,515,822
Total		2,021,403	175,818	2,197,221	1,423,294	447,820	1,871,114
4390	**Miscellaneous Non-Operating Income**						
Reporting Basis							
	Apprenticeship Tax Credit	- 8,601	-	- 8,601	-	118,062	118,062
Total		- 8,601	-	- 8,601	-	118,062	118,062
4405	**Interest and Dividend Income**						
Reporting Basis							
	Interest and Dividend Income	94,890	9,600	104,490	94,195	22,680	116,875
	Interest and Dividend Carrying Charges	250,551	18,000	268,551	49,613	13,685	63,298
Total		345,441	27,600	373,041	143,808	36,365	180,173

94. 3-Energy Probe-20

Ref: Exhibit 3, Tab 3, Schedule 1

Please explain how the retailer revenue (accounts 4082, 4084) and the SSS admin charges (account 4086) reflect the growth in customers in the bridge and test years. For example please show how the forecast of 47,067 residential customers in 2015 (average) results in $126,150 in SSS admin fees. Please show all calculations and assumptions used.

Response

Please see the Table below showing all calculations for SSS Admin charges. The amounts originally filed for the Residential class and GS<50 class were calculated incorrectly. NPEI has updated the SSS Admin charges and has been included as a tracked item on the RRWF, see IRR # 1 1-Staff-1 above. The total difference results in an increase of $6,047 to Miscellaneous Revenue Offsets which results in a decrease of $6,047 to the Revenue Requirement.

2014				
	Originally Filed 2014 $	Updated 2014 $	Difference 2014 $	
SSS Admin Charge - Residential	126,784	130,601	3,817	
SSS Admin Charge - Unmetered Scattered Load	439	438	(1)	
SSS Admin Charge - GS > 50	2,334	2,333	(1)	
SSS Admin Charge - Sentinel lights	13	12	(1)	
SSS Admin Charge - Streetlights	42	42	-	
SSS Admin Charge - GS<50	11,682	11,980	298	
	141,294	145,406	4,112	

Calculation based on # of customers	# of customers/connections	Less # Retailer Customers at 10/31/2014	# of customers	
SSS Admin Charge - Residential	46,669	3,135	43,534	
SSS Admin Charge - Unmetered Scattered Load	422		-	
SSS Admin Charge - GS > 50	863	85	778	
SSS Admin Charge - Sentinel lights	320		-	
SSS Admin Charge - Streetlights	5		-	
SSS Admin Charge - GS<50	4,350	357	3,993	
	52,628	3,577	48,305	

	# of accounts
SSS Admin Charge - Residential	46,669
SSS Admin Charge - Unmetered Scattered Load	146
SSS Admin Charge - GS > 50	863
SSS Admin Charge - Sentinel lights	4
SSS Admin Charge - Streetlights	14
SSS Admin Charge - GS<50	4,350
	52,046

	# Bills for SSS Admin Revenue	Rate	# of months	Updated 2014
SSS Admin Charge - Residential	43,534	0.25	12	$ 130,601
SSS Admin Charge - Unmetered Scattered Load	146	0.25	12	$ 438
SSS Admin Charge - GS > 50	778	0.25	12	$ 2,333
SSS Admin Charge - Sentinel lights	4	0.25	12	$ 12
SSS Admin Charge - Streetlights	14	0.25	12	$ 42
SSS Admin Charge - GS<50	3,993	0.25	12	$ 11,980
	48,469			$ 145,406

2015				
	Originally Filed	Restated Originally	Updated	Difference
	2015	2015 Filed	2015	2015
	$	$	$	$
SSS Admin Charge - Residential	126,150	126,150	131,795	5,645
SSS Admin Charge - Unmetered Scattered Load	11,677	429	438	9
SSS Admin Charge - GS > 50	429	2,343	2,331	(12)
SSS Admin Charge - Sentinel lights	2,343	14	12	(2)
SSS Admin Charge - Streetlights	14	43	42	(1)
SSS Admin Charge - GS<50	43	11,677	12,085	408
	140,656	140,656	146,703	6,047

Calculation based on # of customers			
	# of customers	Less # Retailer Customers at 10/31/2014	# of Customers
SSS Admin Charge - Residential	47,067	3,135	43,932
SSS Admin Charge - Unmetered Scattered Load	422		422
SSS Admin Charge - GS > 50	862	85	777
SSS Admin Charge - Sentinel lights	303		303
SSS Admin Charge - Streetlights	12,989		12,989
SSS Admin Charge - GS<50	4,385	357	4,028
	66,028	3,577	62,451

	# Bills for SSS Admin Revenue
SSS Admin Charge - Residential	43,932
SSS Admin Charge - Unmetered Scattered Load	146
SSS Admin Charge - GS > 50	777
SSS Admin Charge - Sentinel lights	4
SSS Admin Charge - Streetlights	14
SSS Admin Charge - GS<50	4,028
	48,901

Calculation based on # of customers	# of customers	Rate	# of months	Updated 2015
SSS Admin Charge - Residential	43,932	0.25	12	131,795
SSS Admin Charge - Unmetered Scattered Load	146	0.25	12	438
SSS Admin Charge - GS > 50	777	0.25	12	2,331
SSS Admin Charge - Sentinel lights	4	0.25	12	12
SSS Admin Charge - Streetlights	14	0.25	12	42
SSS Admin Charge - GS<50	4,028	0.25	12	12,085
	48,901			146,703

95. 3-Energy Probe-21

Ref: Exhibit 3, Tab 1, Schedule 1

NPEI has included assets owned by the Niagara Parks Commission in the 2015 rate base.

a) How did NPEI bill distribution costs to the Niagara Parks Commission before NPEI owned the assets? (eg. how many accounts, which rate classes, etc.)

b) How will NPEI bill distribution costs to the Niagara Parks Commission now that NPEI owns the assets? (eg. how many accounts, which rate classes, etc.)

c) How has NPEI taken this change into account in terms of the load forecast, and in particular in terms of allocating the Niagara Parks Commission among rate classes if the answers to parts (a) and (b) reflect a change.

Response

a) NPEI bills distribution costs to the following types of accounts in the name of Niagara Parks Commission:

Rate Class	Number of Active Accounts
Residential	1
General Service < 50kW	11
General Service > 50kW	12
Unmetered scattered load	1 account / 1 connection

b) At this time, this information is not available as NPEI does not own the assets.

c) NPEI did not take into account the load forecast in terms of allocating the Niagara Parks Commission among rate classes noted above.

VECC

96. 3.0 –VECC -13

Reference: E3/T1/S1, pg. 4 (Table 3-2)
E3/T2/S1, pg. 4

a) Please explain more fully why the actual 2011 revenues for Street lighting and Sentinel Lights were both significantly less than the Board approved values for that year.
b) Please explain why the actual 2012 revenues for Street lighting and Sentinel Lights are significantly higher than the Board approved 2011 revenues.

Response

a) Please see the table A below which explains the difference in actual revenue in 2011 versus Board Approved. The rates were harmonized in 2011 and the effective date was June1, 2011. The Board approved amount is for a full year. Also, there was a significant decline in the number of sentinel lights subsequent to June 1, 2011 in the Peninsula West service area. The volumetric revenue for sentinel lights was recorded in the residential accounts for the Peninsula West customers in 2011 and was separated beginning in 2012.

b) See table B below. The rate increased in May 2012 due to the revenue to cost ratio rate mitigation as per NPEI's settlement agreement. The revenue to cost ratios were as follows:

	2011	2012	2013
Sentinel	39%	54%	70%
Streetlight	48%	59%	70%

Table A

			Board Approved	2011 Actual				
Sentinel	Final Rate	# Connections/#kW	Base Revenue					
Fixed	6.85	580	47,637	18,664				
Volumetric	8.5542	837	7,162	3,579				
			54,799	22,243				
Streetlight								
Fixed	0.76	12,888	117,542	90,368				
Volumetric	2.976	20,922	62,263	47,912				
			179,805	138,280				
Service Charge $								
	Rate	Rate	Average # connections	Average # connections		$ Revenue	$ Revenue	Total
Sentinel	Jan-June	July to Dec	Jan-June	July to Dec		Jan-June	July to Dec	
NF	$ 1.10	$ 6.85	35	26		231.00	1,068.60	
PW	$ 1.04	$ 6.85	619	343		3,862.56	14,097.30	
						4,093.56	15,165.90	19,259.46
	Rate	Rate				$ Revenue	$ Revenue	Total
Streetlight	Jan-June	July to Dec	Average # connections	Average # connections		Jan-June	July to Dec	
NF	$ 0.32	$ 0.76	9819	9859		18,852.48	44,957.04	
PW	$ 0.59	$ 0.76	2664	2680		9,430.56	12,220.80	
						28,283.04	57,177.84	85,460.88
Volumetric $								
	Rate	Rate	Average kW	Average kW		$ Revenue	$ Revenue	Total
Sentinel	Jan-June	July to Dec	Jan-June	July to Dec		Jan-June	July to Dec	
NF	$ 4.08	$ 8.55	27	57		661.45	2,925.54	
PW	$ 0.93	$ 8.55	0	0		-	-	
						661.45	2,925.54	3,586.98
	Rate	Rate				$ Revenue	$ Revenue	Total
Streetlight	Jan-June	July to Dec	Average kW	Average kW		Jan-June	July to Dec	
NF	$ 1.69	$ 2.98	1283	1287		13,024.25	22,980.67	
PW	$ 0.80	$ 2.98	416	412		1,987.07	7,356.67	
						15,011.31	30,337.34	45,348.66

Table B

			Board Approved	2012 Actual				
Sentinel	Final Rate	# Connections/#kW	Base Revenue					
Fixed	6.85	580	47,637	36,993				
Volumetric	8.5542	837	7,162	7,647				
			54,799	44,640				
Streetlight								
Fixed	0.76	12,888	117,542	132,314				
Volumetric	2.976	20,922	62,263	71,095				
			179,805	203,409				
Service Charge $								
	Rate	Rate	Average # connections	Average # connections		$ Revenue	$ Revenue	Total
Sentinel	Jan-June	July to Dec	Jan-June	July to Dec		Jan-June	July to Dec	
NPEI	$ 6.85	$ 9.76	379	343		15,576.90	20,086.08	
						15,576.90	20,086.08	35,662.98
	Rate	Rate				$ Revenue	$ Revenue	Total
Streetlight	Jan-June	July to Dec	Average # connections	Average # connections		Jan-June	July to Dec	
NPEI	$ 0.76	$ 0.94	12955	12507		59,074.80	70,539.48	
						59,074.80	70,539.48	129,614.28
Volumetric $								
	Rate	Rate	Average kW	Average kW		$ Revenue	$ Revenue	Total
Sentinel	Jan-June	July to Dec	Jan-June	July to Dec		Jan-June	July to Dec	
NPEI	$ 8.5500	$ 12.1787	57	63		2,924.10	4,603.55	
						2,924.10	4,603.55	7,527.65
	Rate	Rate				$ Revenue	$ Revenue	Total
Streetlight	Jan-June	July to Dec	Average kW	Average kW		Jan-June	July to Dec	
NPEI	$ 2.9760	$ 3.6880	1807	1699		32,265.79	37,595.47	
						32,265.79	37,595.47	69,861.26

97. 3.0 –VECC -14

Reference: E3/T1/S1, pg. 15 (lines 293-296)
http://www.fin.gov.on.ca/en/budget/fallstatement/2014/

a) Please provide a table that compares the real GDP growth rates used by NPEI for 2013 to 2015 with those in the most recent economic outlook produced by the Ontario Ministry of Finance.

Response

The table below compares the Ontario real GDP growth rates used in NPEI's load forecast with the most recent economic outlook produced by the Ontario Ministry of Finance.

	Ontario Real GDP Growth	
Year	Used in NPEI's Load Forecast Model	Per 2014 Fall Statement
2013	1.50%	1.30%
2014	2.30%	1.90%
2015	2.40%	2.40%

98. 3.0 –VECC -15

Reference: E3/T1/S1, pg. 23
E2/T1/S2, pg. 34
E2, Appendix N, pg. 2
Preamble:The purpose of this interrogatory is to understand the customers and load served by the assets NPEI is planning on acquiring from the Niagara Parks Commission and how this will impact the number of customers by customer class served by NPEI in 2015.

a) How many delivery/connection points does NPEI currently have with the Niagara Parks Commission assets its plans on purchasing?
b) From a customer count and customer class perspective, how are there delivery points treated ((i.e., How many customers do they represent and in what classes?). Please provide a schedule summarizing the number of customers by class for 2013.
c) Following the purchase of the "primary assets" by NPEI how many delivery points/points of connection will there be with the Niagara Parks Commission? If the number does not change, please explain why.
d) After the purchase, how many customers by customer class will these delivery points represent after the purchase?
e) With respect to the responses to parts (b) and (d), if there is no change please explain why. If there is a change, please indicate how this has been factored into the forecast customer count by class for 2015.

Response

a) There are currently twenty five active delivery/connection points that NPEI currently has with the Niagara Parks Commission.

b)

Rate Class	Number of Active Accounts
Residential	1
General Service < 50kW	11
General Service > 50kW	12
Unmetered scattered load	1 account / 1 connection

c) NPEI is unable to determine the number of delivery points with the Niagara Parks Commission at this time.

d) At this point it is unknown how many customers by customer class that these delivery points will represent.

e) There are no changes at this point.

99. 3.0 –VECC -16

Reference: E3/T1/S1, pg. 15 (lines 298-303)

a) Is the OPA's Preliminary/Final CDM Results report for 2013 now available and, if so, please provide a copy.
b) If the 2013 preliminary/final OPA CDM Results report is available please undertake the following:
   - Update Table 3-22
   - Update NPEI's load forecast regression model files
   - Re-estimate the load forecast equation set out on pages 13-14
   - Provide a copy of the revised load forecast excel model.
   - Update Tables 3-7, 3-9, 3-11, 3-23, 3-25, 3-28 and 3-29

Response

a) The OPA's Final Verified Annual 2013 CDM Report is now available. NPEI has provided this report in Attachment #14.

b) The updated tables are provided below.

Table 3.22 - Updated for Final 2013 CDM Results

4 Year 2011 to 2014 kWh Net Savings Forecast					
58,000,000					
	2011	2012	2013	2014	Total
2011 Programs	8.67%	8.67%	8.52%	8.52%	34.38%
2012 Programs	0.00%	9.68%	9.72%	9.68%	29.09%
2013 Programs	0.00%	0.00%	6.35%	6.35%	12.70%
Adj. to Prior Year	1.03%	5.86%	5.86%	5.86%	18.62%
2014 Programs	0.00%	0.00%	0.00%	5.22%	5.22%
	9.70%	24.21%	30.46%	35.63%	100.00%
kWh					
2011 Programs	5,026,978	5,026,978	4,942,830	4,942,830	19,939,616
2012 Programs	-	5,615,949	5,639,392	5,615,949	16,871,290
2013 Programs	-	-	3,682,087	3,682,087	7,364,174
Adj. to Prior Year	597,125	3,400,379	3,400,379	3,400,379	10,798,262
2014 Programs	-	-	-	3,026,658	3,026,658
	5,624,103	14,043,306	17,664,688	20,667,903	58,000,000

Table 3.7
Annual CDM Data - Updated for 2013 Final CDM Results
kWh Saved in the Year

2006 through 2013 Final Results - kWh 2014 through 2015 Forecast - kWh				
2006	**2007**	**2008**	**2009**	**2010**
4,211,271	7,800,592	9,396,789	13,106,362	14,225,868
2011	**2012**	**2013**	**2014**	**2015**
18,457,992	26,565,051	30,071,190	32,535,183	33,382,327

Table 3.9
Statistical Results
Regression Equation Updated for 2013 Final CDM Results

Statistic	**Value**
R Square	94.8%
Adjusted R Square	94.5%
F Test	352.8
MAPE (Calculated monthly)	1.89%
T-stats by Coefficient	
Intercept	-6.6
Heating Degree Days	15.3
Cooling Degree Days	25.4
Ontario Real GDP Monthly %	2.7
Number of Days in Month	10.9
CDM kWh Saved in month	-7.5
Spring Fall Flag	-9.0
Population	3.7

Table 3.11: Total System Purchases			
Forecast Updated for 2013 Final CDM Results			
Year	**Actual**	**Predicted**	**Difference**
Purchased Energy (kWh)			
2002	1,162,710,674	1,162,650,263	0.0%
2003	1,152,043,160	1,167,421,517	1.3%
2004	1,205,241,074	1,182,063,908	-2.0%
2005	1,272,191,339	1,271,260,641	-0.1%
2006	1,248,057,840	1,249,622,188	0.1%
2007	1,283,916,366	1,272,269,890	-0.9%
2008	1,247,356,069	1,258,431,534	0.9%
2009	1,216,807,819	1,227,629,641	0.9%
2010	1,264,714,637	1,259,070,261	-0.4%
2011	1,266,311,662	1,267,891,508	0.1%
2012	1,260,789,451	1,272,243,930	0.9%
2013	1,250,000,080	1,239,584,890	-0.8%
2014 Weather Normal - 12 year average		**1,256,837,889**	
2015 Weather Normal - 12 year average		**1,272,423,411**	
2015 Weather Normal - 10 year average		**1,271,029,452**	
2015 Weather Normal - 20 year trend		**1,275,927,143**	

	Table 3-23: 5 Year CDM Results				
	Updated for 2013 Final CDM Results				
5 Year 2011 to 2015 kWh Net Savings Forecast					
	2011	**2012**	**2013**	**2014**	**2015**
2011 Programs	5,026,978	5,026,978	4,942,830	4,942,830	4,942,830
2012 Programs	-	5,615,949	5,639,392	5,615,949	5,615,949
2013 Programs	-	-	3,682,087	3,682,087	3,682,087
Adj. to Prior Year	597,125	3,400,379	3,400,379	3,400,379	3,400,379
2014 Programs	-	-	-	3,026,658	3,026,658
2015 Programs					2,900,000
	5,624,103	14,043,306	17,664,688	20,667,903	23,567,903

Table 3.25 Alignment of Non-Weather Normal to Weather Normal Forecast for Energy
Forecast Updated for 2013 Final CDM Results

Year	Residential	General Service < 50 kW	General Service > 50 kW	Streetlights	Sentinel Lights	Unmetered Scattered Load	Total
Non-Normalized Weather Billed Energy Forecast (kWh)							
2014 Non-Normalized Bridge	411,649,947	123,963,294	667,180,301	7,411,072	262,521	2,231,402	1,212,698,537
2015 Non-Normalized Test	411,002,636	123,747,060	678,583,419	7,477,962	259,459	2,215,047	1,223,285,582
Adjustment for Weather (kWh)							
2014	(2,490,928)	(750,112)	(3,756,504)				(6,997,544)
2015	(928,047)	(279,422)	(1,425,727)				(2,633,196)
CDM Adjustment (kWh)							
2014	(294,788)	(340,060)	(878,481)				(1,513,329)
2015	(872,027)	(1,005,949)	(2,598,682)				(4,476,658)
Weather Normalized Billed Energy Forecast (kWh)							
2014 Normalized Bridge	408,864,232	122,873,122	662,545,315	7,411,072	262,521	2,231,402	1,204,187,663
2015 Normalized Test	409,202,562	122,461,689	674,559,010	7,477,962	259,459	2,215,047	1,216,175,729

Table 3.28 Annual kW Forecast per Applicable Rate Class
Forecast Updated for 2013 Final CDM Results

Year	General Service > 50 kW	Streetlights	Sentinel Lights	Total
Predicted Bill kW				
2014 Normalized Bridge	1,752,012	20,995	713	1,773,721
2015 Normalized Test	1,783,781	21,184	705	1,805,670

		Table 3.29				
		Summary of Forecast Data				
		Forecast Updated for 2013 Final CDM Results				
	2011 Board Approved	2011 Actual	2012 Actual	2013 Actual	2014 Weather Normalized Bridge	2015 Weather Normalized Test
Actual kWh Purchases		1,266,311,662	1,260,789,451	1,250,000,080		
Predicted kWh Purchases	1,286,014,423	1,267,897,961	1,272,267,672	1,239,570,992	1,256,837,889	1,272,423,411
% Difference		0.1%	0.9%	-0.8%		
Purchased kWh	1,286,014,423	1,266,311,662	1,260,789,451	1,250,000,080	1,256,837,889	1,272,423,411
Distribution Losses	(62,706,294)	(33,312,835)	(46,774,137)	(47,694,815)	(51,136,897)	(51,771,024)
Manual CDM Adjustment					(1,513,329)	(4,476,658)
Billed kWh	1,223,308,130	1,232,998,827	1,214,015,314	1,202,305,265	1,204,187,663	1,216,175,729
By Class						
Residential						
Customers	46,900	45,996	45,871	46,274	46,669	47,067
kWh	462,790,265	418,849,931	414,592,237	412,298,278	408,864,232	409,202,562
Usage per Customer	9,868	9,106	9,038	8,910	8,761	8,694
General Service < 50 kW						
Customers	4,352	4,307	4,260	4,315	4,350	4,385
kWh	122,331,880	129,680,926	125,465,897	124,179,905	122,873,122	122,461,689
Usage per Customer	28,107	30,111	29,453	28,776	28,245	27,925
General Service > 50 kW						
Customers	848	859	855	863	863	862
kWh	628,090,148	675,128,624	664,095,955	655,968,805	662,545,315	674,559,010
kW	1,818,411	1,793,543	1,761,221	1,721,554	1,752,012	1,783,781
Usage per Customer	740,379	786,394	776,553	760,337	768,073	782,115
Sentinel Lights						
Connections	560	369	343	337	320	303
kWh	292,817	246,192	267,435	265,619	262,521	259,459
kW	809	679	721	716	713	705
Usage per Connection	523	667	779	787	822	857
Streetlighting						
Connections	12,408	12,540	12,507	12,702	12,845	12,989
kWh	7,467,591	7,294,838	7,329,519	7,344,781	7,411,072	7,477,962
kW	20,107	20,391	21,037	20,809	20,995	21,184
Usage per Connection	602	582	586	578	577	576
Unmetered Scattered Load						
Connections	465	424	384	422	422	422
kWh	2,335,428	1,798,316	2,264,271	2,247,877	2,231,402	2,215,047
Usage per Connection	5,020	4,241	5,904	5,332	5,293	5,255
Total of Above						
Customer/Connections	65,533	64,494	64,220	64,913	65,467	66,028
kWh	1,223,308,130	1,232,998,827	1,214,015,314	1,202,305,265	1,204,187,663	1,216,175,729
kW from applicable classes	1,839,327	1,814,614	1,782,980	1,743,079	1,773,721	1,805,670

100. 3.0 –VECC -17

Reference: E3/T1/S1, pg. 15 (lines 303-307)
http://www.powerauthority.on.ca/opa-conservation/conservation-first-framework-tool-kit/targets-and-budgets
3-Staff 33

a) If the response to Staff 33 c) regarding the impact of 2015 CDM programs in 2015 differs from the 2.9 GWh used in the Application, using the revised forecast equation from the preceding question please undertake the following:
- Update Table 3-7
- Update the forecast CDM assumptions in NPEI's load forecast model files and provide a copy of the revised load forecast excel model.
- Update Tables 3-7, 3-9, 3-11, 3-23, 3-25, 3-28 and 3-29

Response

As noted in the response to 3-Staff-33 c), NPEI has updated the 2015 CDM savings estimate from 2.9 GWh to 12.41 GWh based on the OPA's target of 74.44 GWh for 2015-2020.

The updated tables are provided below.

Table 3.7
Annual CDM Data - Updated Estimate of 2015 CDM Savings
kWh Saved in the Year

2006 through 2013 Final Results - kWh				
2014 through 2015 Forecast - kWh				
2006	**2007**	**2008**	**2009**	**2010**
4,211,271	7,800,592	9,396,789	13,106,362	14,225,868
2011	**2012**	**2013**	**2014**	**2015**
18,457,992	26,565,051	30,071,190	32,535,183	42,888,993

Table 3.9
Statistical Results
Load Forecast Revised for Updated 2015 CDM Estimate

Statistic	**Value**
R Square	94.8%
Adjusted R Square	94.5%
F Test	352.8
MAPE (Calculated monthly)	1.89%
T-stats by Coefficient	
Intercept	-6.6
Heating Degree Days	15.3
Cooling Degree Days	25.4
Ontario Real GDP Monthly %	2.7
Number of Days in Month	10.9
CDM kWh Saved in month	-7.5
Spring Fall Flag	-9.0
Population	3.7

Table 3.11: Total System Purchases
Load Forecast Revised for Updated 2015 CDM Estimate

Year	**Actual**	**Predicted**	**Difference**
Purchased Energy (kWh)			
2002	1,162,710,674	1,162,650,263	0.0%
2003	1,152,043,160	1,167,421,517	1.3%
2004	1,205,241,074	1,182,063,908	-2.0%
2005	1,272,191,339	1,271,260,641	-0.1%
2006	1,248,057,840	1,249,622,188	0.1%
2007	1,283,916,366	1,272,269,890	-0.9%
2008	1,247,356,069	1,258,431,534	0.9%
2009	1,216,807,819	1,227,629,641	0.9%
2010	1,264,714,637	1,259,070,261	-0.4%
2011	1,266,311,662	1,267,891,508	0.1%
2012	1,260,789,451	1,272,243,930	0.9%
2013	1,250,000,080	1,239,584,890	-0.8%
2014 Weather Normal - 12 year average		**1,256,837,889**	
2015 Weather Normal - 12 year average		**1,254,368,503**	
2015 Weather Normal - 10 year average		**1,252,974,544**	
2015 Weather Normal - 20 year trend		**1,257,872,235**	

Table 3-23 - 5 Year CDM Results
Revised for Updated 2015 CDM Estimate

5 Year 2011 to 2015 kWh Net Savings Forecast					
	2011	**2012**	**2013**	**2014**	**2015**
2011 Programs	5,026,978	5,026,978	4,942,830	4,942,830	4,942,830
2012 Programs	-	5,615,949	5,639,392	5,615,949	5,615,949
2013 Programs	-	-	3,682,087	3,682,087	3,682,087
Adj. to Prior Year	597,125	3,400,379	3,400,379	3,400,379	3,400,379
2014 Programs	-	-	-	3,026,658	3,026,658
2015 Programs					12,406,667
	5,624,103	14,043,306	17,664,688	20,667,903	33,074,570

Table 3.25 Alignment of Non-Weather Normal to Weather Normal Forecast for Energy
Load Forecast Revised for Updated 2015 CDM Estimate

Year	Residential	General Service < 50 kW	General Service > 50 kW	Streetlights	Sentinel Lights	Unmetered Scattered Load	Total
Non-Normalized Weather Billed Energy Forecast (kWh)							
2014 Non-Normalized Bridge	411,649,947	123,963,294	667,180,301	7,411,072	262,521	2,231,402	1,212,698,537
2015 Non-Normalized Test	411,002,636	123,747,060	678,583,419	7,477,962	259,459	2,215,047	1,223,285,582
Adjustment for Weather (kWh)							
2014	(2,490,928)	(750,112)	(3,756,504)				(6,997,544)
2015	(7,032,441)	(2,117,368)	(10,803,696)				(19,953,505)
CDM Adjustment (kWh)							
2014	(294,788)	(340,060)	(878,481)				(1,513,329)
2015	(1,797,948)	(2,074,070)	(5,357,973)				(9,229,991)
Weather Normalized Billed Energy Forecast (kWh)							
2014 Normalized Bridge	408,864,232	122,873,122	662,545,315	7,411,072	262,521	2,231,402	1,204,187,663
2015 Normalized Test	402,172,247	119,555,622	662,421,749	7,477,962	259,459	2,215,047	1,194,102,086

Table 3.28 Annual kW Forecast per Applicable Rate Class
Load Forecast Revised for Updated 2015 CDM Estimate

Year	General Service > 50 kW	Streetlights	Sentinel Lights	Total
Predicted Bill kW				
2014 Normalized Bridge	1,752,012	20,995	713	1,773,721
2015 Normalized Test	1,751,686	21,184	705	1,773,575

Table 3.29
Summary of Forecast Data
Load Forecast Revised for Updated 2015 CDM Estimate

	2011 Board Approved	2011 Actual	2012 Actual	2013 Actual	2014 Weather Normalized Bridge	2015 Weather Normalized Test
Actual kWh Purchases		1,266,311,662	1,260,789,451	1,250,000,080		
Predicted kWh Purchases	1,286,014,423	1,267,897,961	1,272,267,672	1,239,570,992	1,256,837,889	1,254,368,503
% Difference		0.1%	0.9%	-0.8%		
Purchased kWh	1,286,014,423	1,266,311,662	1,260,789,451	1,250,000,080	1,256,837,889	1,254,368,503
Distribution Losses	(62,706,294)	(33,312,835)	(46,774,137)	(47,694,815)	(51,136,897)	(51,036,425)
Manual CDM Adjustment					(1,513,329)	(9,229,991)
Billed kWh	1,223,308,130	1,232,998,827	1,214,015,314	1,202,305,265	1,204,187,663	1,194,102,086
By Class						
Residential						
Customers	46,900	45,996	45,871	46,274	46,669	47,067
kWh	462,790,265	418,849,931	414,592,237	412,298,278	408,864,232	402,172,247
Usage per Customer	9,868	9,106	9,038	8,910	8,761	8,545
General Service < 50 kW						
Customers	4,352	4,307	4,260	4,315	4,350	4,385
kWh	122,331,880	129,680,926	125,465,897	124,179,905	122,873,122	119,555,622
Usage per Customer	28,107	30,111	29,453	28,776	28,245	27,262
General Service > 50 kW						
Customers	848	859	855	863	863	862
kWh	628,090,148	675,128,624	664,095,955	655,968,805	662,545,315	662,421,749
kW	1,818,411	1,793,543	1,761,221	1,721,554	1,752,012	1,751,686
Usage per Customer	740,379	786,394	776,553	760,337	768,073	768,042
Sentinel Lights						
Connections	560	369	343	337	320	303
kWh	292,817	246,192	267,435	265,619	262,521	259,459
kW	809	679	721	716	713	705
Usage per Connection	523	667	779	787	822	857
Streetlighting						
Connections	12,408	12,540	12,507	12,702	12,845	12,989
kWh	7,467,591	7,294,838	7,329,519	7,344,781	7,411,072	7,477,962
kW	20,107	20,391	21,037	20,809	20,995	21,184
Usage per Connection	602	582	586	578	577	576
Unmetered Scattered Load						
Connections	465	424	384	422	422	422
kWh	2,335,428	1,798,316	2,264,271	2,247,877	2,231,402	2,215,047
Usage per Connection	5,020	4,241	5,904	5,332	5,293	5,255
Total of Above						
Customer/Connections	65,533	64,494	64,220	64,913	65,467	66,028
kWh	1,223,308,130	1,232,998,827	1,214,015,314	1,202,305,265	1,204,187,663	1,194,102,086
kW from applicable classes	1,839,327	1,814,614	1,782,980	1,743,079	1,773,721	1,773,575

101. 3.0 –VECC -18

Reference: E3/T1/S1, pg. 15-16
E3/T1/S1, pg. 28-29

a) Please confirm that in preparing the 2015 purchased power forecasts (per Table 3-11) NPEI increased the CDM variable in the load forecast equation to include the impact of CDM programs introduced in 2014 and 2015.

b) If confirmed, please explain why the CDM adjustment set out in Table 3-25 does not result in a double counting of the impact of 2014 and 2015 CDM programs.

c) Using NPEI's original load forecast model, please provide a revised purchase power forecast for 2015 (a la per Table 3-11) where the impacts of 2014 and 2015 CDM programs are excluded from the CDM input variable used and provide a copy of the revised excel model supporting this forecast.

d) Using the results from part (c), please provide revised total billed energy forecasts for 2014 and 2015 (a la page 25, lines 17-19) and revised versions of Tables 3-25 and 3-28.

Response

a) NPEI confirms that in preparing the 2015 power purchased forecast, NPEI increased the CDM variable in the load forecast equation to include the impact of CDM programs introduced in 2014 and 2015.

b) Upon review of the 2015 power purchased forecast with respect to CDM savings, NPEI agrees with VECC that inclusion of 2014 and 2015 CDM savings in both the CDM variable and the manual adjustment results in a double counting of the impact of 2014 and 2015 CDM programs.

c) NPEI has revised its load forecast model to exclude the impact of 2014 and 2015 CDM programs form the CDM input variable.

d) The updated tables are provided below.

Table 3.25 Alignment of Non-Weather Normal to Weather Normal Forecast for Energy
2014 and 2015 CDM Impacts Removed from the CDM Variable

Year	Residential	General Service < 50 kW	General Service > 50 kW	Streetlights	Sentinel Lights	Unmetered Scattered Load	Total
Non-Normalized Weather Billed Energy Forecast (kWh)							
2014 Non-Normalized Bridge	411,649,947	123,963,294	667,180,301	7,411,072	262,521	2,231,402	1,212,698,537
2015 Non-Normalized Test	411,002,636	123,747,060	678,583,419	7,477,962	259,459	2,215,047	1,223,285,582
Adjustment for Weather (kWh)							
2014	(7,552,016)	(2,274,196)	(11,389,003)	-	-	-	(21,215,216)
2015	(2,111,895)	(635,862)	(3,244,432)	-	-	-	(5,992,189)
CDM Adjustment (kWh)							
2014	(294,788)	(340,060)	(878,481)	-	-	-	(1,513,329)
2015	(1,797,948)	(2,074,070)	(5,357,973)	-	-	-	(9,229,991)
Weather Normalized Billed Energy Forecast (kWh)							
2014 Normalized Bridge	403,803,143	121,349,037	654,912,817	7,411,072	262,521	2,231,402	1,189,969,992
2015 Normalized Test	407,092,792	121,037,129	669,981,013	7,477,962	259,459	2,215,047	1,208,063,402

Table 3.28 Annual kW Forecast per Applicable Rate Class				
2014 and 2015 CDM Impacts Removed from the CDM Variable				
Year	General Service > 50 kW	Streetlights	Sentinel Lights	Total
Predicted Bill kW				
2014 Normalized Bridge	1,731,829	20,995	713	1,753,537
2015 Normalized Test	1,771,675	21,184	705	1,793,564

102. 3.0 –VECC -19

Reference: E3/T1/S1, pg. 19 (Table 3-11)
E3/T1/S1, pg. 36

Please provide the model used to estimate the 20-year trend values for HDD and CDD and indicate whether the trend is statistically significant for either parameter.

Response

NPEI used Microsoft Excel's TREND function to estimate the 20 year trend values for HDD and CDD. For example, the formula used to calculate 20 year trend value of HDD for January of 638.3 is =TREND(E323:X323, E322:X322, 2015), where E323:X323 contain the actual HDD values for January from 1994-2013, and E322:X322 contains the years 1994, 1995, 2013.

The TREND function does not return any regression statistics.

103. 3.0 –VECC -20

Reference: E3/T1/S1, pg. 19 (lines 298-303)

a) Please estimate the 2013 weather normal purchases by undertaking to following calculation:
   i. Multiplying the difference between the 2013 actual and weather normal values for CDD and HDD by their respective coefficients, per page 13.
   ii. Adding the results from (i) to the actual System Purchases for 2013.

   Please provide a schedule setting out the calculations undertaken.

Response

The table below shows the estimated 2013 weather normalized purchases based on the method outlined above:

	Calculation of Weather Normalized Purchases	2013
a	2013 Actual Purchased kWh	1,250,000,080
b	Actual HDD	3,400
c	12 Year Average HDD	3,375
d = c - b	Difference	(25)
e	HDD Regression Coefficient	23,740
f = d * e	Adjustment to Weather Normalize HDD	(588,770)
g	Actual CDD	347
h	12 Year Average CDD	395
i = h - g	Difference	48
j	CDD Regression Coefficient	192,796
k = i * j	Adjustment to Weather Normalize CDD	9,294,388
l = a + f + k	**2013 Weather Normalized Purchased kWh**	**1,258,705,697**

104. 3.0 –VECC -21

Reference: E3/T1/S1, pg. 21

a) Please indicate NPEI did not consider using a 12 year average loss value (consistent with the historical period used to estimate the load forecast model).

Response

NPEI is using the 5 year average loss value of 1.0432 versus the 12 year average loss value of 1.0473 due to the billing systems for the two former utilities were amalgamated in 2011 and as a result the data used to calculate the loss value is improved. Please see E8/T9/S1 pg. 1 of the originally filed evidence.

105. 3.0 –VECC -22

Reference: E3/T1/S1, pg. 28 (Table 3-24)
Appendix 2-I

a) Please explain why the LRAMVA value shown in Table 3-24 (26.7 GWh) differs from that in Appendix 2-I (2.9 GWh).
b) Which value is NPEI proposing for purposes of the LRAMVA for 2015?
c) If NPEI is proposing an LRAMVA value for 2015 that includes CDM results from CDM programs implemented prior to 2014, please explain why.

Response

a) The LRAMVA value of 26.7 GWh shown in Table 3-24 is NPEI's estimate of savings in 2015 from CDM programs implemented from 2011-2015. The value of 2.9 GWh in Appendix 2-I is the originally filed estimate of 2015 savings from 2015 programs only.

b) NPEI believes that the LRAMVA net kWh value for 2015 should consist of all CDM savings included in the load forecast that have been estimated (i.e. years for which the OPA has not yet issued Final Results). Therefore, NPEI now proposes the following LRAMVA values for 2015, which include updated estimates for the impact of 2014 and 2015 CDM programs only.

2015 Expected Savings for LRAM Variance Accounts

	Residential	General Service < 50 kW	General Service > 50 kW	Streetlights	Sentinel Lights	Unmetered Scattered Load	Total
2015 CDM net kWh	3,006,321	3,468,020	8,958,983	-	-	-	15,433,325
2015 CDM kW	-	-	25,326	-	-	-	25,326

c) Not applicable.

106. 3.0 –VECC -23

Reference: E3/T1/S1, pg. 23

a) Please provide the actual customer/connection count by class as of June 30, 2014.

Response

The table below shows the actual customer/connection count by rate class as of June 30, 2014. The figures provided are averages of the monthly values from January to June 2014.

Rate Class	Jun-14
Residential	46,493
GS<50 kW	4,344
GS>50 kW	823
Unmetered Scattered Load	466
Sentinel Lights	331
Streetlighting	12,690

107. 3.0 –VECC -24

Reference: E3/T3/S1, pg. 13-15

a) At page 14 the Application states that there is a trending decrease in customer with retailers. If this is the case, why are the forecast SSS Admin Charge revenues for 2015 less than the actual revenues for 2013?

Response

Please see response to 3-EP-20 above IRR# 94. 2013 Actual SSS Admin Charge was $142,218. Revised SSS Admin Charges for 2014 and 2015 are $145,406 and $146,703 respectively. The number of customers with retailers in October 2013 was 3,753 and 3,577 in October 2014 which results in a decrease of 176 customers with retailers.

108. 3.0 –VECC -25

Reference: E3/T3/S1, pg. 7

Please provide version of Table 3-45 showing the year to date actual 2014 values for each account and the corresponding values for 2013 for the same time frame.

Response

The table below shows the year-to-date figures, as at October 31, 2014, projections for November and December 2014, as well as the corresponding figures for 2013

USoA #	USoA Description	Actuals at 10/31/2014	Projected Nov +Dec 2014	Total Projected 2014	Actuals at 10/31/2013	Actual Nov +Dec 2013	Total Actual 2013
	Reporting Basis						
4305	Regulatory Debit	(2,451,418)	(663,911)	(3,115,329)	0	(3,054,566)	(3,054,566)
	Other Revenue						
4235	Specific Service Charges	699,979	113,740	813,719	713,269	97,267	810,536
4225	Late Payment Charges	349,686	66,000	415,686	297,661	55,913	353,574
4080-01	MicroFit Charges	17,589	3,600	21,189	13,019	3,168	16,187
4082	Retail Services Revenues	34,886	6,800	41,686	36,829	7,178	44,006
4084	Service Transaction Requests (STR) Revenu	841	154	995	869	202	1,071
4086	SSS Administration Revenue	120,050	24,272	144,322	118,126	24,092	142,218
4215	Other Utility Operating Income	47,592	7,183	54,776	40,241	8,118	48,359
4355	Gain on Disposition of Utility and Other Property	8,500	0	8,500	11,121	0	11,121
4360	Loss on Disposition of Utility and Other Property	0	0	0	0	(1,135)	(1,135)
4362	Loss on Retirement of Utility & Other Property	0	0	0	0	(66,865)	(66,865)
4375	Revenue from Non-Utility Operations	2,102,789	175,818	2,278,607	1,583,421	446,713	2,018,308
4380	Expenses from Non-Utility Operations	(2,021,403)	(175,818)	(2,197,221)	(1,423,294)	(447,820)	(1,871,114)
4390	Miscellaneous Non-Operating Income	(8,601)	0	(8,601)	0	118,062	118,062
4405	Interest and Dividend Income including Carrying Charges	345,441	27,600	373,041	143,808	36,365	180,173
		$ 1,697,349	$ 249,349	$ 1,946,698	$ 1,535,071	$ 281,257	$ 1,804,502
	Less Carrying Charges in 4405	(250,551)	(18,000)	(268,551)	(49,613)	(13,685)	(63,298)
	Total Miscellaneous Revenue	$ 1,446,798	$ 231,349	$ 1,678,147	$ 1,485,458	$ 267,572	$ 1,741,204
Summary							
Specific Service Charges		$ 699,979	$ 113,740	$ 813,719	$ 713,269	$ 97,267	$ 810,536
Late Payment Charges		$ 349,686	$ 66,000	$ 415,686	$ 297,661	$ 55,913	$ 353,574
Other Operating Revenues		$ 220,959	$ 42,009	$ 262,968	$ 209,084	$ 42,757	$ 251,841
Other Income or Deductions Excluding Carrying Charges		$ 176,174	$ 9,600	$ 185,774	$ 265,444	$ 71,635	$ 325,253
Total		**$ 1,446,798**	**$ 231,349**	**$ 1,678,147**	**$ 1,485,458**	**$ 267,572**	**$ 1,741,204**

Exhibit 4 Operating Costs

109. 4 Staff 36.Water Billing

Reference

1. Exhibit 4 Tab2 Schedule 1 P. 7

Preamble

NPEI ceased water billing, customer service, and collections service for NPEI's affiliate, Niagara Falls Hydro Services Inc. Effective May 1, 2014. This resulted in costs that were incurred for providing these services being stranded in the distribution company. As a result NPEI has seen its revenue requirement increase. NPEI states that it gave notice to its union and unionized staff of its restructuring plan.

a) Direct labour to provide water billing services is $476K. Were there any supervision charges to water billing services?

b) Please provide the restructuring plan for NPEI.

c) Please state the alternatives NPEI considered in developing its plan to address the water billing cost impact.

d) Please explain why the variable cost of $337K for providing water services is considered a cost driver and not a cost that it now avoids incurring.

e) Please provide a table of variable costs items and annual cost with an explanation of the cost item. State also why the variable cost is not avoidable.

f) Please provide an explanation of any options NPEI explored in an attempt to retain providing the billing services, and why they were rejected.

g) Please provide a version of Appendix 2-L with the costs that are being absorbed by NPEI for the water billing removed.

Response

a) Yes there were supervision charges to water billing services. The FTE equivalent of 0.5 for a Billing supervisor and 0.5 for a Customer Service supervisor. See E4/T2/S1 page 7 last paragraph and 2-JB "Water supervision not recovered" 2014 = $77,172 and 2015 = $43,000 for a total of $120,172

b) See E4/T2/S1 pages 6 and 7 of the originally filed evidence for NPEI's restructuring plan.

c) See E4/T2/S1 pages 6 and 7 of the originally filed evidence for NPEI's restructuring plan.

d) The $337K "variable costs" are actually shared fixed costs. The term variable was meant to reference the postage costs and billing form costs can vary depending on the number of water only bills. The $337K relates to a fee that NPEI charged Niagara Falls Hydro Services for administration costs. The fee was $4.20 per water only bill. In 2013 there were approximately 12,000 water only bills. The $4.20 covered postage, billing forms and envelopes, accounting, software maintenance costs etc. See part e) for a table of these costs.

e) Please see the table below.

Breakdown of Water Administration	Board approved 2011	Actuals 2011	Actuals 2012	Actuals 2013	Budget 2014	Projected 2014
Postage Water & hydro bills combined 50%	65,000	78,641	80,838	81,803	20,451	28,549
Postage Water only bills	35,000	42,611	43,703	44,716	11,179	17,605
Envelopes, Billing Forms combined bills 50%	5,000	5,332	5,301	5,278	1,320	1,757
Envelopes, Billing Forms water only bills	2,800	2,889	2,866	2,885	721	1,083
One Cashier	72,000	74,236	76,463	78,222	19,556	25,576
Accounting management	6,000	6,000	6,000	6,000	1,500	1,500
Accounting clerks 2 hours per week	15,048	15,512	15,977	16,854	4,214	5,510
Receptionist 10 hours per week	17,278	17,796	18,329	18,751	4,688	6,130
% of office supplies, telephone, brinks, software and	23,766	86,965	84,803	82,675	37,024	27,676
hardware maintenance,	241,892	329,982	334,280	337,184	100,651	115,386

The variable costs that are unavoidable amount to $47,601. Postage, envelopes and billing forms will continue for hydro only bills. NPEI did reduce the number of cashiering positions from 3 to 2. The accounting and receptionist positions will continue to exist. However, there will no longer be a recovery from water billing services. The telephone, software, hardware, Brinks etc. costs will continue to support hydro services as well.

f) The City of Niagara Falls decided to resume water & billing activities in March 2013 with a public report. NPEI had informal discussions regarding this decision with City of Niagara Falls.

g) Please see the table below which is a version of Appendix 2-L with the costs that are being absorbed by NPE for the water billing removed.

	2015 Test Year	
Reporting Basis	MIFRS	
Number of Customers	52,638	
Total Recoverable OM&A	$ 652,304	
OM&A cost per customer	12.39	
Number of FTEs	4.0	
Customers/FTEs	13,159.50	
OM&A Cost per FTE	163,076	
	$	FTE's
Water allocated expenses	337,184	1
Water only costs avoidable	(47,601)	
Water allocated expenses unavoidable	289,583	
Water supervision	120,172	1
Water labour and benefits	475,829	5
Reduction of cashier and temporary services	(129,000)	-2
Billing Clerk retired in 2013 not replaces	(104,280)	-1
	652,304	4

110. 4 Staff 37.Staffing, Wages and Benefits

References

1. Appendix 2-K
2. Exhibit 4 Tab 3 Schedule 2 Table 4-7 FTE's by Revenue Source

Preamble

Based on Appendix 2-K, NPEI has reduced its non-management staff by 10 FTEs, which is 9.4% of the staffing levels proposed in 2011. During the same period, NPEI hired 7 management including executives FTEs, increasing the FTEs by 24.1%. Over this period salaries and benefits for management, including executives increased by 42 % or 10% per annum. In total, for NPEI, Salaries and benefits increased 36.4%, or 5.8% per year. NPEI now has a non-management FTE to management and executive FTE ratio of less than 3:1.

a) Please state the business case for the trend. Please provide any strategic analysis or plans that NPEI has developed.

b) Please state the longer term improvements that NPEI expects to achieve in regards to the four RRFE outcomes (Customer Focus, Operational Effectiveness, Public Policy Responsiveness, and Financial Performance) that will arise from this trend.

Table 4-7 FTE's by Revenue Sources indicate that between 2012 and 2013 NPEI reduced part-time FTEs and increased Unionized FTEs.

c) Please explain the business case for this change in staffing. Please provide any strategic analysis or plans that NPEI has developed.

d) Please state the longer term improvements that NPEI expects to achieve in regards to the four RRFE outcomes that will result from this trend.

Response

a) NPEI usually hires potential management staff and unionized staff on a contract basis now versus prior to 2010 most new hires were hired full-time with benefits. NPEI uses a contract period now to ensure there are a good fit and a long term need before hiring full-time. The 7 management personnel were first hired on a contract and shown as non-management personnel FTE's on Schedule 2-K, and then hired full time and moved to Management FTE's on Schedule 2-K. The smart meter co-ordinators and CDM co-ordinators, were hired to achieve the initiatives related to these activities. The Engineering Services Manager was hired for succession planning as well as for Smart Grid initiatives and the Regulatory Affairs & Accounting Manager was hired due to an increase in regulatory activities. With the apprentices, NPEI hires this position on a co-op basis first and then depending on performance will offer a 6 to 12 month contract before hiring the apprentice full-time.

b) The longer term improvements with respect to the RRFE outcomes will be higher skilled employees being hired to implement new initiatives and ensures the need for these positions is long-term. The apprentices hired are for succession planning due to the aging of NPEI's lineman and the length of time it takes to become a full journeyman lineman.

c) NPEI does not have any part-time FTE's. The partial FTE's represent the co-op apprentices, or the start date of a new contract employee or the date in which a contract employee left. The co-op apprentices work either for a 4 month term or an 8 month term depending on what college they are from and what year they are in. Depending on the apprentices performance NPEI may hire the apprentice on a contract basis at first depending on the need.

d) Please see part b).

111. 4 Staff 38.Regulatory Costs

Reference

- Exhibit 4 Tab 3 Schedule 6

Preamble

NPEI state that legal costs are $225K of which $200K is for an oral hearing. At the moment NPEI's application is a written hearing which will go to ADR.

What is the total estimate if a full settlement is reached and approved?

Response

The total estimate for legal costs if a full settlement is reached and approved is between $45,000 and $50,000.

112. 4 Staff 39.Other Post-Employment Benefits ("OPEB")

Reference

- Exhibit 4, Tab 3, Schedule 2, Attachment 2

Preamble

As per the cover letter of the Actuarial Valuation report on Post-Retirement Non-Pension Benefit Plan in Reference 1, there is a $1,570,620 reduction in the net liability which NPEI will record in retained earnings on transition to IFRS.

a) Please explain how NPEI has addressed this reduction in the liability in this rate application.

b) Is NPEI going to refund the amount to ratepayers? If no, please explain why not.

Response

a) NPEI did not reduce the Employee Future Benefits liability or change the retained earnings for the gain on transition to IFRS in the rate application as there is no impact on the revenue requirement for 2015 and there is no impact on the Deferral and Variance accounts.

b) NPEI is not going to refund the gain in the actuarial valuation report related to Post-Retirement Non-Pension Benefit Plan. NPEI is not aware there is any direction from the OEB to record any gain or loss from Post-Retirement Non-Pension Benefits due to the transition to IFRS.

113. 4 Staff 40.OPEB

Reference

- Exhibit 4, Tab 3, Schedule 2

Preamble

NPEI has recovered OPEB through its revenue requirement in prior applications.

a) Please indicate if OPEBs were recovered on a cash or accrual accounting basis for each year since NPEI started to recover OPEBs.

b) Please complete the table below in a live Excel worksheet to show how much more than the actual cash benefit payments, if any, have been recovered from ratepayers from the year NPEI started recovering amounts for OPEBs.

OPEBs	First year of recovery to 2011	2012	2013	2014	2015	Total

Amounts included in rates						
OM&A						
Capital expenditures						
Sub-total						
Paid benefit amounts						
Net excess amount included in rates greater than amounts actually paid						

c)Please describe what NPEI has done with the recoveries in excess of cash benefit payments, if any.

Response

a) OPEB's were recovered on an accrual accounting basis for each year since NPEI started to recover OPEB's.

b) Please see the table below.

c) Both the premiums paid and the annual change in the Other Post Employment Benefit liability account, are included in the payroll overhead burden.

OPEBs	**First year of recovery to 2011**	**2012**	**2013**	**2014**	**2015**	**Total**
Amounts included in rates	237,000	237,000	237,000	237,000	273,909	
OM&A	188,699	184,339	175,427	175,973	199,570	924,008
Capital expenditures	53,214	89,650	132,347	11,795	74,339	361,345
Sub-total	**241,913**	**273,989**	**307,774**	**187,768**	**273,909**	1,285,353
Paid benefits & change in accrual	241,913	273,989	307,774	187,768	273,909	1,285,353
Net excess amount included in rates greater than amounts actually paid	(4,913)	(36,989)	(70,774)	49,232	-	(63,444)
Premiums amount in rates	193,000	193,000	193,000	193,000	172,000	
Change in accrual in rates	44,000	44,000	44,000	44,000	101,909	
Total	237,000	237,000	237,000	237,000	273,909	

114. 4 Staff 41.PILS Model

Reference

- Exhibit 4, Tab 5, Schedule 1, Attachment 1, PILS Model

Preamble

The recent Ontario government budget, which received Royal Assent, changed the Ontario small business credit.

a) Please indicate if NPEI believes changes to the PILs calculation for 2015 are required as a result of the passage of the Ontario budget.

b) Irrespective of the response to part a), please provide a calculation for the 2015 PILs that reflects the change in the Ontario small business credit.

Response

a) Yes NPEI believes changes to the PILS calculation for 2015 are required as a result of the passage of the Ontario Budget.

b) The change to the 2015 PILS that reflects the change in the Ontario small business credit is an increase in the 2015 PILS amount. Prior to updating any of the models for CDM, cost of capital parameters etc. NPEI originally filed a PILS provision for 2015 of $43,189. Updating the original filing to account for the change in the Ontario Budget the 2015 PILS provision would be higher by $51,254 for a total provision of $94,620. See below:

PILs Tax Provision - Test Year

						Wires Only	
Regulatory Taxable Income						$ 568,108	A
Ontario Income Taxes							
Income tax payable	**Ontario Income Tax**	11.50%	B	$ 65,332	C = A * B		
Small business credit	Ontario Small Business Threshold	$ -	D				
	Rate reduction	-11.50%	E	$ -	F = D * E		
Ontario Income tax						$ 65,332	J = C + F
Combined Tax Rate and PILs	Effective Ontario Tax Rate			11.50%	K = J / A		
	Federal tax rate (Maximum 15%)			15.00%	L		
	Combined tax rate					26.50%	M = K + L
Total Income Taxes						**$ 150,549**	N = A * M
Investment Tax Credits						$ 6,208	O
Miscellaneous Tax Credits						$ 74,795	P
Total Tax Credits						**$ 81,003**	Q = O + P
Corporate PILs/Income Tax Provision for Test Year						**$ 69,546**	R = N - Q
Corporate PILs/Income Tax Provision Gross Up [1]				73.50%	S = 1 - M	**$ 25,074**	T = R / S - R
Income Tax (grossed-up)						**$ 94,620**	U = R + T

ENERGY PROBE

115. 4-Energy Probe-22

Ref: Exhibit 4, Tab 1

a) Please confirm that in 2010 through 2013 NPEI was assigned to the middle of the three efficiency cohort groupings.

b) Please confirm that in 2014 and 2015 NPEI was assigned to Group III for stretch factors.

Response

a) NPEI confirms that they were assigned to the middle of the three efficiency cohort groupings in 2010 through 2013.

b) NPEI confirms that in 2014 and for the 2015 IRM rate applications NPEI was assigned to the Group III for stretch factors.

116. 4-Energy Probe-23

Ref: Exhibit 4, Tab 2, Schedule 1, Appendix 2-JA

(a) Please update Appendix 2-JA to reflect the most recent year-to-date actuals available for 2014 along with the current forecast for the remainder of the year.

(b) Please provide the most recent-year-to-date figures for 2014 in the same level of detail as shown in the table, along with the figures the corresponding period in 2013. Please remove the smart meter costs recorded in 2014 for prior years and include the actual smart meter related costs incurred in each of 2013 and 2014 in the calculation of the year-to-date figures.

Response

a) Please see the table below. Appendix 2-JA yellow highlighted tab has also been updated for the actuals at October 31, with the current forecast for the remainder of 2014.

Appendix 2-JA
Summary of Recoverable OM&A Expenses

	Last Rebasing Year (2011 Board-Approved)	Last Rebasing Year (2011 Actuals)	2012 Actuals	2013 Actuals	2014 Bridge Year	2015 Test Year	2014 October Actuals	2014 Projected Total	Variance 2014 Projected vs 2014 Bridge Year
Reporting Basis									
Operations	$ 3,517,644	$ 4,071,987	$ 4,326,888	$ 4,131,174	$ 4,299,653	$ 4,291,150	$ 3,662,070	$ 4,216,124	-$ 83,529
Maintenance	$ 2,528,132	$ 2,209,781	$ 2,381,216	$ 2,149,552	$ 2,336,691	$ 2,554,924	$ 2,014,596	$ 2,434,789	$ 98,098
SubTotal	**$ 6,045,776**	**$ 6,281,768**	**$ 6,708,104**	**$ 6,280,726**	**$ 6,636,344**	**$ 6,846,074**	**$ 5,676,666**	**$ 6,650,913**	$ 14,569
%Change (year over year)			6.8%	-6.4%	5.7%	3.2%	9.1%	5.9%	0.2%
%Change (Test Year vs Last Rebasing Year - Actual)						9.0%			
Billing and Collecting	$ 3,913,667	$ 3,875,994	$ 3,697,637	$ 3,735,692	$ 6,193,652	$ 5,609,882	$ 5,046,391	$ 5,835,679	-$ 357,973
Community Relations	$ 81,464	$ 60,687	$ 79,068	$ 81,554	$ 85,525	$ 69,600	$ 73,136	$ 78,028	-$ 7,497
Administrative and General	$ 4,035,775	$ 3,888,611	$ 4,284,082	$ 4,054,337	$ 4,342,309	$ 4,496,362	$ 3,621,301	$ 4,343,648	$ 1,339
SubTotal	**$ 8,030,906**	**$ 7,825,292**	**$ 8,060,787**	**$ 7,871,583**	**$ 10,621,486**	**$10,175,844**	**$ 8,740,828**	**$ 10,257,355**	-$ 364,131
%Change (year over year)			3.0%	-2.3%	34.9%	-4.2%	33.6%	30.3%	-3.4%
%Change (Test Year vs Last Rebasing Year - Actual)						30.0%			
Total	**$ 14,076,682**	**$ 14,107,060**	**$ 14,768,891**	**$ 14,152,309**	**$ 17,257,830**	**$17,021,918**	**$ 14,417,494**	**$ 16,908,268**	**-$ 349,562**
%Change (year over year)			4.7%	-4.2%	21.9%	-1.4%	22.7%	19.5%	-2.0%

b) Please see the table below.

Appendix 2-JA
Summary of Recoverable OM&A Expenses

	Last Rebasing Year (2011 Board-Approved)	Last Rebasing Year (2011 Actuals)	2012 Actuals	2013 Actuals	2014 Bridge Year	2015 Test Year	2014 October Actuals excluding Prior Year Smart Meter entry	2014 Projected excluding prior year smart meter entry	2013 October Actuals	2013 Actuals with 12 months smart meter costs	Total 2014 vs Total 2013 excluding smart meters	Oct 2014 vs Oct 2013 with 10 months smart meter costs
Reporting Basis												
Operations	$ 3,517,644	$ 4,071,987	$ 4,326,888	$ 4,131,174	$ 4,299,653	$ 4,291,150	$ 3,662,070	$ 4,216,124	$ 3,399,199	$ 4,131,174	$ 84,950	$ 262,871
Maintenance	$ 2,528,132	$ 2,209,781	$ 2,381,216	$ 2,149,552	$ 2,336,691	$ 2,554,924	$ 1,933,221	$ 2,353,414	$ 1,803,229	$ 2,149,552	$ 203,862	$ 129,992
SubTotal	**$ 6,045,776**	**$ 6,281,768**	**$ 6,708,104**	**$ 6,280,726**	**$ 6,636,344**	**$ 6,846,074**	**$ 5,595,291**	**$ 6,569,538**	**$ 5,202,428**	**$ 6,280,726**	**$ 288,812**	**$ 392,863**
%Change (year over year)			6.8%	-6.4%	5.7%	3.2%	7.6%	4.6%				
%Change (Test Year vs Last Rebasing Year - Actual)						9.0%						
Billing and Collecting	$ 3,913,667	$ 3,875,994	$ 3,697,637	$ 3,735,692	$ 6,193,652	$ 5,609,882	$ 3,904,605	$ 4,693,893	$ 3,376,459	$ 3,797,337	$ 896,556	$ 528,146
Community Relations	$ 81,464	$ 60,687	$ 79,068	$ 81,554	$ 85,525	$ 69,600	$ 73,136	$ 78,028	$ 72,738	$ 81,554	-$ 3,526	$ 398
Administrative and General	$ 4,035,775	$ 3,888,611	$ 4,284,082	$ 4,054,337	$ 4,342,309	$ 4,496,362	$ 3,621,301	$ 4,343,648	$ 3,372,354	$ 4,054,337	$ 289,311	$ 248,947
SubTotal	**$ 8,030,906**	**$ 7,825,292**	**$ 8,060,787**	**$ 7,871,583**	**$ 10,621,486**	**$ 10,175,844**	**$ 7,599,042**	**$ 9,115,569**	**$ 6,821,551**	**$ 7,933,228**	$ 1,182,341	$ 777,491
%Change (year over year)			3.0%	-2.3%	34.9%	-4.2%	11.4%	15.8%				
%Change (Test Year vs Last Rebasing Year - Actual)						30.0%						
Total	**$ 14,076,682**	**$ 14,107,060**	**$ 14,768,891**	**$ 14,152,309**	**$ 17,257,830**	**$ 17,021,918**	**$ 13,194,333**	**$ 15,685,107**	**$ 12,023,979**	**$ 14,213,954**	$ 1,471,153	$ 1,170,354
%Change (year over year)			4.7%	-4.2%	21.9%	-1.4%	9.7%	10.8%			10.4%	9.7%

117. 4-Energy Probe-24

Ref: Exhibit 4, Tab 2, Schedule 1, Appendix 2-JB

The cost driver table shows $1,223,161 in 2014 for prior year smart meter costs. Please provide a breakdown of this amount by year when the costs were actually incurred.

Response

Please see Exhibit 4, Tab 2, Schedule 1 page 6, Table 4-3 for a breakdown of the smart meter costs by year of the originally filed evidence.

118. 4-Energy Probe-25

Ref: Exhibit 4, Tab 2, Schedule 1, Appendix 2-JB

Based on the cost driver table, it appears that more than $800,000 of the increase between 2013 and 2015 is related to the loss of the water billing.

a) Please verify the following cost increases/decreases between 2013 and 2015 and correct if necessary:

Water supervision not recovered	$120,172
Water labour not recovered	$475,829
Allocated water expenses	$337,184
Billing expense reduced	($129,000)
Total water related	$804,185

b) Please add any other impacts related to the loss of the water billing to those listed in part (a) above.

Response

(a)NPEI verifies the cost increases/decreases between 2013 and 2015 is correct with the exception of the savings from the Billing Clerk that retired in 2013 that was not replaced.

(b)See the table below for the full impact of water.

GL account 4375	E3/T3/S1 pg 2 to 6 Board approved 2011 Table 3-43	E3/T3/S1 pg 18 Actuals 2011 Table 3-45	Actuals 2012 Table 3-45	Actuals 2013 Table 3-45	FTE 2013	3 months Budget 2014 Table 3-45	4 months Projected 2014	FTE 2014	Budget 2015 Table 3-45	FTE 2015	2015-2013 Total impact of loss of water
Water collection revenues	32,463	33,470	41,351	42,032		10,326	12,197		-		(42,032)
Late payment charge revenues	137,007	109,990	124,111	126,184		30,901	46,504		-		(126,184)
Water occupancy change revenues	20,766	23,895	24,264	24,867		5,751	6,318		-		(24,867)
Water administration revenue	277,061	303,336	300,913	303,122		81,254	131,753		-		(303,122)
Water revenue for fixed asset mail machine	18,108	18,108	18,108	18,108		4,527	6,036		-		-
	485,405	488,799	508,747	514,313		132,759	202,808		-		(496,205)
GL account 4380											
Water billing & collecting expenses	186,892	272,788	279,400	282,146		78,885	96,924		-		47,601
Water general & admin	55,000	57,194	54,880	55,038		21,766	18,462		-		-
Water administration expenses	241,892	329,982	334,280	337,184		100,651	115,386		-		47,601
Depreciation for mail machine allocated to water	18,108	18,108	18,108	18,108		3,036	6,036		-		-
	260,000	348,090	352,388	355,292		103,687	121,422		-		47,601
Net	225,405	140,709	156,359	159,021		29,072	81,386		-		(543,806)
Breakdown of Water Administration	Board approved 2011	Actuals 2011	Actuals 2012	Actuals 2013	FTE 2013	Budget 2014	Projected 2014				
Postage Water & hydro bills combined 50%	65,000	78,641	80,838	81,803		20,451	28,549		-		
Postage Water only bills	35,000	42,611	43,703	44,716		11,179	17,605		-		
Envelopes, Billing Forms combined bills 50%	5,000	5,332	5,301	5,278		1,320	1,757		-		
Envelopes, Billing Forms water only bills	2,800	2,889	2,866	2,885		721	1,083		-		
One Cashier	72,000	74,236	76,463	78,222	1	19,556	25,576		-		
Accounting management	6,000	6,000	6,000	6,000		1,500	1,500		-		
Accounting clerks 2 hours per week	15,048	15,512	15,977	16,854		4,214	5,510		-		
Receptionist 10 hours per week	17,278	17,796	18,329	18,751	0.29	4,688	6,130		-		
% of office supplies, telephone, brinks, software and	23,766	86,965	84,803	82,675		37,024	27,676		-		
hardware maintenance,	241,892	329,982	334,280	337,184	1.29	100,651	115,386		-	-	
Direct Labour											
Water Supervision	99,678	139,936	139,824	120,172	0.83	42,600	42,600		-		(120,172)
Water labour and benefits	344,119	407,417	473,637	475,829	5.01	130,130	130,130		-	(1)	(475,829)
	443,797	547,353	613,461	596,001	5.84	172,730	172,730		-	(1)	(596,001)
Reduction of cashier and temporary services											129,000
Billing clerk retired in 2013 not replaced											104,280
											(362,721)
Total impact for loss of water billing											(906,527)
Summary of Labour											
Labour and wages from above	554,123	660,897	730,230	715,828	7.12	202,687	211,446		-		
Reduction of contract cashier	40,000	40,784	43,576	44,179	1	11,045	30,421			(1)	
Temporary services 1 cashier & 1 receptionist	60,000	63,075	71,289	85,085	2	21,271	50,218			(2)	
	100,000	103,859	114,865	129,264	3	32,316	80,639		-	(3)	
Total FTE'srecovered by water					7.12					(4.00)	
FTE reduction by year	Board approved 2011	Actuals 2011	Actuals 2012	Actuals 2013	FTE 2013	Budget 2014	Projected 2014	FTE 2014	Budget 2015	FTE 2015	Total
1 Billing clerk retired in October 2013 and not replaced					(0.20)			(0.80)			(1.00)
Reduction of 1 cashier position on contract								(0.75)		(0.25)	(1.00)
Reduction of 1 cashier & 1 receptionist temp service								(1.25)		(0.75)	(2.00)
					(0.20)			(2.80)		(1.00)	(4.00)
Total Employees charged to water	7.00										
Reduction per above	(4.00)										
Remaining	3.00										
One billing supervisor through attrition/retirement	(1)										
2 Billing Clerks/Customer Service FTE's eligible to retire	(2)										
	-										

119. 4-Energy Probe-26

Ref: Exhibit 4, Tab 3, Schedule 1, page 3

a) Please provide the business case used to determine that outsourcing the mail machine activities was less costly than replacing the machine.

b) Please provide the estimated savings in labour and labour-related costs to outsourcing the mail machine activities.

Response

(a) The estimated costs to outsource the mail machine are annual cost of approximately $65,000. The benefits of outsourcing the mail machine is increase confidence that mail will be processed on schedule without risk of delays due to mail machine equipment failure; outsourcing provides opportunity to redesign the bill utilizing colour, allowing the bill to be more customer focused: easy to read, reformatted for clarity and impact; outsourcing provides opportunity to use customized meaningful messages that get the customer to take action; outsourcing provides opportunity to leverage intelligence printing with enhanced data cleansing and pre-sorts. Replacement of the machine represents replacement of both the inserter and the mail machine; the total purchase price of both pieces of equipment is quoted as $81,558.69, with monthly maintenance and consumable expenses of $707.56 per month.

(b) Resources would be available for billing call centre coverage and other billing related tasks.

120. 4-Energy Probe-27

Ref: Exhibit 4, Tab 2, Schedule 1 &
Exhibit 4, Tab 3, Schedule 1

Appendix 2-L shows an increase in FTE's between 2013 and 2015 of 0.9. Please reconcile this figure with the amounts shown in Table 4-5 by adding a column to the table that shows the associated FTE's with each line item.

Response

Please see the table below. Please also note the line description in Table 4-5 “2013 medical leaves returned full-time in 2015” should have read “2013 medical leaves returned full-time in 2015 and other changes in non-unionized and unionized staff". NPEI has reflected the FTE's related to water billing services in the table below as well.

	Excludes CDM FTE's which are not in OM&A and FTE's recovered by water					
IN OM&A	Table 4-7 2013	FTE changes in 2014	Table 4-7 2014	FTE changes in 2015	Table 4-7 2015	Change from 2015 to 2013
Management	29.6	3.4	33	0	33	3.4
Supervision recovered by water	0.00	0.67	0.67	0.33	1	1
Net Management in OM&A	29.60	4.07	33.67	0.33	34	4.40
Union	84.9	5.1	90	-2	88	3.1
Union recovered by water	0	-2	-2	7	5	5
	84.9	3.1	88	5	93	8.1
Non-Union	3.8	0	3.8	-2.6	1.2	-2.6
Total	118.30	7.17	125.47	2.73	128.20	9.9
Original Table 4-7 excludes impact of water recovery	125.3		126.8		128.2	
DifferenceRecovered by water	7.00		1.33		0.00	

Management	In OM&A 2013	In OM&A 2015	In OM&A Change	$ in Table 4-5
Billing Supervisor	0	1	1	120,172
Controller maternity leave	0.6	1	0.4	67,000
2 smart meter co-ordinators in OM&A	0	2	2	188,000
System analyst	0	1	1	111,000
	0.6	5	4.4	486,172
Non-union				
Cashier on contract	1	0	-1	(34,000)
Apprentices	2.8	1.2	-1.6	(24,288)
	3.8	1.2	-2.6	(58,288)
Union				
Recovered by water	0	5	5	475,829
Retirements	0.9	-1	-1.9	(106,280)
Sick leaves	1	2	1	69,014
Hired lineman	0	1	1	79,960
Unionized & non-union that left	1	0	-1	(58,306)
Billing clerk maternity leave	1	1	0	-
Apprentices hired full time	0	4	4	258,080
	3.9	12	8.1	718,297
Note the 2 temporary cashier & receptionist are not included in 2013 as FTE's				
Changes in union & non-unionized				218,180

121. 4-Energy Probe-28

Ref: Exhibit 4, Tab 3, Schedule 1

Table 4-5 shows increases of wages and benefits of 3.1% in 2014 and 2.5% in 2015.

a) What does NPEI benchmark these increases against?

b) If NPEI benchmarks against other distributors, please provide a list of these distributors and their corresponding increases.

Response

a)The 3.1% for 2014 is as per the collective agreement NPEI has with its union IBEW local 636. The collective agreement expires March 31, 2015. At the time of union negotiations in 2011 NPEI compared its negotiated wage increases against other neighbouring utilities. The 2.5% wage increase for 2015 is an average of 11 utilities wage increases.

b)NPEI completed a calculation of 11 utilities wage increases for 2015. The average for these LDC's was 2.56%. Due to many of these utilities filed their collective agreements in confidence with the OEB, NPEI is unable to disclose the names of these distributors and their corresponding increases.

122. 4-Energy Probe-29

Ref: Exhibit 4, Tab 3, Schedule 2 &
Exhibit 4, Tab 2, Schedule 1

a) Please reconcile the total employee costs shown in Appendix 2-K and the figures shown in Table 4-1 for each year shown.

b) Please add a line to Appendix 2-K that shows the actual and forecasted amounts for 2011 through 2015 that are capitalized.

Response

a) Please see the table below. The wages in Appendix 2-K are from the T4 summary. These wages represent an employee's total employment income which may include lump sum payments for vacation and vested sick leave. These payments reduce the liabilities for vacation and vested sick leave but are not recorded as an expense in that year because the earned/accrued vacation and sick leave entitlements were expensed in the previous year in which they were earned. Table 4-1 shows all of the wages that are expensed in OM&A or capital along with total benefits. Total benefits include EHT, WSIB, the employer portion of CPP, EI, OMERS, other employee benefits, health, dental and life insurance premiums, the vacation accruals, sick time entitlements and statutory holiday pay. Some of these benefits are included in employment income on a T4 and others are not.

Appendix 2-K	2011	2012	2013	2014	2015
Wages per T4 summary	9,546,131	10,152,181	10,612,484	10,874,154	11,156,960
Benefits OMERS, Post EE benefits, Health, Dental & Life Insurance	1,907,552	2,097,773	2,299,012	2,247,624	2,378,973
Total Wages & Benefits	11,453,683	12,249,954	12,911,496	13,121,778	13,535,933
Table 4-1					
Wages total	7,819,170	8,311,135	8,469,759	9,242,013	10,084,039
Benefits - All benefits	4,454,193	4,706,763	5,075,419	4,940,226	4,984,070
Wages in OM&A and all benefits	12,273,363	13,017,898	13,545,178	14,182,239	15,068,109
Differences are the benefits not on a T4	819,680	767,944	633,682	1,060,461	1,532,176
Paid benefits accrued vacation, sick, stat paid, meals	1,724,745	1,773,577	2,013,681	1,833,736	1,879,579
Benefits not in earnings on a T4 EHT, WSIB, CPP, EI, Safety shoes, clothing, meals	(2,544,425)	(2,541,521)	(2,647,363)	(2,894,197)	(3,411,755)
	(819,680)	(767,944)	(633,682)	(1,060,461)	(1,532,176)
OMERS	744,039	916,947	1,076,748	1,115,456	1,143,342
Post EE	241,913	273,989	307,774	187,768	273,909
Health	921,599	906,837	914,490	944,401	961,722
	1,907,551	2,097,773	2,299,012	2,247,625	2,378,973

(b)Appendix 2K comes from the T4 summary and does not represent the wages and benefits included in OM&A or in capital as Table 4-1 does. See below the originally filed Table 4-1

	2011	**2012**	**2013**	**2014**	**2015**
Total wages & Benefits - not capitalized	9,772,028.00	10,124,993.00	10,025,483.00	10,530,676.00	10,978,742.00
Total Capitalized Labour & Benefits	2,501,334.94	2,892,904.62	3,519,694.90	3,651,562.99	4,089,367.23
Total wages & benefits	12,273,362.94	13,017,897.62	13,545,177.90	14,182,238.99	15,068,109.23
% of wages and benefits included in OM&A	79.62%	77.78%	74.02%	74.25%	72.86%
% of wages and benefits capitalized	20.38%	22.22%	25.98%	25.75%	27.14%

123. 4-Energy Probe-30

Ref: Exhibit 4, Tab 3, Tab 4

Please provide an additional column on the 2013 non-affiliate purchases that shows which purchases are included in the 2013 OM&A costs.

Response

The table below shows the 2013 non-affiliate purchases included on OM&A.

		2013 Non-Affilate Purchases		
Vendor	Total Amount	Nature of Product/Service	Purchasing Method	Included in OM&A
Independant Electricity Market Operator	128,332,195.44	Power	Exempt per Appendix B	
Ontario Electricity Financial Corp	9,288,689.97	Debt Retirement	Exempt per Appendix B	
Receiver General	3,191,338.63	HST	Exempt per Appendix B	
Receiver General of Canada	3,136,669.77	Payroll Liabilities	Exempt per Appendix B	CPP and EI Employer Portion
Hydro One	3,055,799.26	Network & Connection fees	Exempt per Appendix B	
OMERS	2,140,922.37	Pension	Exempt per Appendix B	Payroll Burden
Just Energy	1,779,799.45	Retailer settlements	Exempt per Appendix B	
NIAGARA WEST TRANSFORMATION	1,401,100.02	Connection fees	Exempt per Appendix B	
Posi-Plus Ontario Inc	1,148,344.82	Vehicle purchases	RFP/Quotation	
The Mearie Group	967,580.26	Health & Dental Benefits, Insurance, Life Insurance	RFP/Quotation	Payroll Burden
Newman Brothers Ltd.	953,693.96	Wire Building	RFP/Quotation	
GLENRIDGE GAS UTILIZATION INC	929,012.96	Fit refund	Exempt per Appendix B	
Endura Construction	736,650.68	Civil Services	RFP/Quotation	Partial Capital, Partial OM&A
Moloney Electric	719,889.11	Transformers	RFP/Quotation	
H D Supply Utilities	672,933.12	Transformers	RFP/Quotation	
O'Hara Trucking & Excavating	667,356.23	Excavation of yard	RFP/Quotation	
G A M S	648,131.84	Kiosks, Pole Replacements	RFP/Quotation	
Constellation New Energy	552,063.57	Retailer settlements	Exempt per Appendix B	
Postage By Phone System	519,800.00	Postage	Exempt per Appendix B	Yes
Nexans	491,810.74	Wire	RFP/Quotation	
Harris Computer Systems	425,579.98	CIS Maintenance	Exempt per Appendix B	Yes
BAYVIEW FLOWERS (JORDAN STATIO	417,760.91	Fit refund	Exempt per Appendix B	
Direct Energy Marketing Ltd.	406,803.43	Retailer settlements	Exempt per Appendix B	
Wajax Equipment	398,231.07	Vehicle purchases	RFP/Quotation	
S & C Electric Canada Ltd	372,264.03	Switchgear	RFP/Quotation	
Summitt Energy Management Inc.	332,632.43	Retailer settlements	Exempt per Appendix B	
UTILITY SCANNING SOLUTIONS LTD	325,830.04	Pole Testing, PCB Testing	RFP/Quotation	Yes
Anixter Canada Inc	313,769.40	Wire	RFP/Quotation	
Niagara Meter Services Inc.	307,644.40	Meter Reading	Exempt per Appendix B	Yes
PARK ROAD POWER	293,200.94	Fit refund	Exempt per Appendix B	
Sonepar Canada	277,651.76	CDM services	Exempt per Appendix B	OPA - Account 4375
Gales Fuels	266,732.71	Fuel	RFP/Quotation	Yes
Wajax Industries	266,591.91	Vehicle purchases	RFP/Quotation	
Peninsula Video & Sound Inc.	260,856.95	Locates	Exempt per Appendix B	Yes
Utilismart Corporation	245,373.85	Settlement fees	Exempt per Appendix B	Yes
Siemens Canada Ltd.	229,030.48	Wi-max project	RFP/Quotation	
1825059 ONTARIO LTD	220,341.54	Fit refund	Exempt per Appendix B	
Base Mechanical Inc.	219,156.16	Engineering Consulting	RFP/Quotation	
Minister of Finance	212,816.11	EHT	Exempt per Appendix B	Payroll Burden
HY Grade Precast Concrete	207,605.86	Pole Bunks	RFP/Quotation	
Shadow Graphic	201,874.13	CDM Marketing	RFP/Quotation	OPA - Account 4375
Frank Agnes Lee	192,900.06	Hydro overpayment refund	Exempt per Appendix B	
Anderson's Electronics Inc	189,020.67	Wi-max project	RFP/Quotation	
Guelph Utility Pole Co. Ltd	185,982.18	Poles	RFP/Quotation	
ABB Inc.	177,833.75	Transformers	RFP/Quotation	
Bell Canada	173,990.60	Telephone, Joint Use Poles, Software Maintenance	Exempt per Appendix B	Yes
Ontario Energy Board	173,177.30	Regulatory Expenses	Exempt per Appendix B	Yes
Asplundh Canada Inc.	169,760.42	Tree Trimming	RFP/Quotation	Yes
T.R. Hinan Contractors Inc.	169,669.73	Administration Building Renovation	RFP/Quotation	
Brock Ford Sales Inc.	169,258.90	Vehicle purchases	RFP/Quotation	
Manulife Financial	168,297.94	Health & Dental Benefits	RFP/Quotation	Payroll Burden
BAYVIEW FLOWERS	168,211.93	Fit refund	Exempt per Appendix B	
Laprairie Inc.	162,700.98	Inventory	RFP/Quotation	
Noramco Wire & Cable	160,237.53	Wire	RFP/Quotation	
Wiens Underground	159,295.07	Underground installation services	RFP/Quotation	Partial Capital, Partial OM&A
DAVEY TREE EXPERT CO OF CANADA	158,553.94	Tree Trimming	RFP/Quotation	Yes
Intergraph Canada Ltd.	157,547.80	GIS Maintenance & Licenses	Exempt per Appendix B	Yes
Archer Truck Services	147,202.41	Vehicle purchases	RFP/Quotation	
Bel Volt Sales Limited	145,371.43	Inventory	RFP/Quotation	
Badger Daylighting LP	140,848.27	Hydrovac services	RFP/Quotation	Yes

124. 4-Energy Probe-31

Ref: Exhibit 4, Tab 3, Schedule 6

Please provide the actual legal and consulting costs incurred to date associated with the one-time costs of this application.

Response

The actual legal and consulting costs incurred to date associated with the one-time cost of this application are $19,521 and $85,250 respectively.

125. 4-Energy Probe-32

Ref: Exhibit 4, Tab 4, Schedule 1

Please provide a table that shows for each of 2011 through 2013 the depreciation expense actually recorded (including that calculated by Worth-It) and the amount that would have been recorded if the depreciation expense for all accounts had been calculated using the half-year rule for asset additions in the year.

Response

The tables below show the depreciation expense actually recorded and the depreciation expense using the half-year rule for each of 2011 through 2013.

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard
Year

		2011	Cost				
CCA Class	**OEB**	**Description**	**Additions**	**Depreciation on Additions Calculated Using Half Year**	**Actual Depreciaton on Additions**	**Difference**	**Dep'n Expense Restated for Half Year**
12	1611	Computer Software (Formally known as Account 1925)	$ 247,505	$ 41,251	$ 29,615	$ 11,636	116,441
CEC	1612	Land Rights (Formally known as Account 1906)				$ -	0
N/A	1805	Land				$ -	0
47	1806	Land Rights				$ -	56,850
47	1808	Buildings				$ -	4,111
13	1810	Leasehold Improvements				$ -	0
47	1815	Transformer Station Equipment >50 kV				$ -	146,009
47	1820	Distribution Station Equipment <50 kV	$ 799,780	$ 15,996	$ 15,996	$ -	158,386
47	1825	Storage Battery Equipment		$ -	$ -	$ -	0
47	1830	Poles, Towers & Fixtures	$ 1,760,405	$ 35,208	$ 35,208	$ -	886,143
47	1835	Overhead Conductors & Devices	$ 1,721,225	$ 34,425	$ 34,425	$ -	1,228,547
47	1840	Underground Conduit	$ 470,858	$ 9,417	$ 9,417	$ -	203,336
47	1845	Underground Conductors & Devices	$ 2,311,906	$ 46,238	$ 46,238	$ -	2,365,136
47	1850	Line Transformers	$ 1,064,335	$ 17,100	$ 17,100	$ -	1,130,747
47	1855	Services (Overhead & Underground)	$ 338,070	$ 6,761	$ 6,761	$ -	160,916
47	1860	Meters	$ 177,180	$ 11,039	$ 11,039	$ -	419,378
47	1860	Meters (Smart Meters)		$ -	$ -	$ -	0
47	1865	Other Installations on Customer's Premises		$ -	$ -	$ -	0
47	1875	Street Lighting and Signal Systems		$ -	$ -	$ -	841
N/A	1905	Land		$ -	$ -	$ -	0
47	1908	Buildings & Fixtures	$ 121,779	$ 1,015	$ 1,015	$ -	211,195
13	1910	Leasehold Improvements		$ -	$ -	$ -	0
8	1915	Office Furniture & Equipment (10 years)	$ 68,799	$ 1,376	$ 2,278	$ (902)	72,342
8	1915	Office Furniture & Equipment (5 years)		$ -	$ -	$ -	0
10	1920	Computer Equipment - Hardware		$ -	$ -	$ -	0
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -	$ -	$ -	0
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 247,812	$ 24,781	$ 5,195	$ 19,586	251,985
10	1930	Transportation Equipment	$ 541,641	$ 10,833	$ 14,742	$ (3,909)	434,178
8	1935	Stores Equipment	$ 9,817	$ 196	$ 293	$ (97)	4,639
8	1940	Tools, Shop & Garage Equipment	$ 77,760	$ 1,555	$ 2,792	$ (1,237)	64,915
8	1945	Measurement & Testing Equipment	$ 15,160	$ 303	$ 1,922	$ (1,619)	15,673
8	1950	Power Operated Equipment		$ -	$ -	$ -	0
8	1955	Communications Equipment	$ 1,985	$ 40	$ -	$ 40	21,244
8	1955	Communication Equipment (Smart Meters)			$ -	$ -	0
8	1960	Miscellaneous Equipment			$ -	$ -	6,973
47	1970	Load Management Controls Customer Premises			$ -	$ -	0
47	1975	Load Management Controls Utility Premises			$ -	$ -	0
47	1980	System Supervisor Equipment			$ -	$ -	0
47	1985	Miscellaneous Fixed Assets			$ -	$ -	0
47	1990	Other Tangible Property			$ -	$ -	0
47	1995	Contributions & Grants	-$ 1,571,526	$ (30,095)	$ (30,095)	$ -	(705,962)
47	2440	Deferred Revenue[5]			$ -	$ -	0
47	2005	2005-Property Under Capital Leases			$ -	$ -	0
						$ -	0
		Sub-Total	**$ 8,404,491**	$ 227,439	$ 203,941	**$ 23,498**	**$ 7,254,022**

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard Year

CCA Class	OEB	Description (2012)	Cost Additions	Depreciation on Additions Calculated Using Half Year	Actual Depreciaton on Additions	Difference	Dep'n Expense Restated for Half Year
12	1611	Computer Software (Formally known as Account 1925)	$ 213,431	$ 35,572	$ 16,400	$ 19,172	178,784
CEC	1612	Land Rights (Formally known as Account 1906)				$ -	0
N/A	1805	Land		$ -	$ -	$ -	0
47	1806	Land Rights	$ 5,416	$ 108	$ 108	$ -	64,029
47	1808	Buildings		$ -	$ -	$ -	7,559
13	1810	Leasehold Improvements		$ -	$ -	$ -	0
47	1815	Transformer Station Equipment >50 kV	$ 16,266	$ 203	$ 203	$ -	146,212
47	1820	Distribution Station Equipment <50 kV	$ 666,649	$ 13,333	$ 13,333	$ -	191,905
47	1825	Storage Battery Equipment		$ -	$ -	$ -	0
47	1830	Poles, Towers & Fixtures	$ 1,474,815	$ 29,496	$ 29,496	$ -	945,170
47	1835	Overhead Conductors & Devices	$ 1,638,693	$ 32,774	$ 32,774	$ -	1,299,638
47	1840	Underground Conduit	$ 802,096	$ 16,042	$ 16,042	$ -	228,692
47	1845	Underground Conductors & Devices	$ 2,345,741	$ 46,915	$ 46,915	$ -	2,266,640
47	1850	Line Transformers	$ 1,246,688	$ 24,934	$ 24,934	$ -	1,204,681
47	1855	Services (Overhead & Underground)	$ 437,074	$ 8,741	$ 8,741	$ -	176,420
47	1860	Meters	$ 209,382	$ 4,954	$ 4,954	$ -	362,629
47	1860	Meters (Smart Meters)		$ -	$ -	$ -	0
47	1865	Other Installations on Customer's Premises		$ -	$ -	$ -	0
47	1875	Street Lighting and Signal Systems		$ -	$ -	$ -	1,313
N/A	1905	Land		$ -	$ -	$ -	0
47	1908	Buildings & Fixtures	$ 625,695	$ 5,944	$ 5,944	$ -	217,483
13	1910	Leasehold Improvements	$ -			$ -	0
8	1915	Office Furniture & Equipment (10 years)	$ 111,949	$ 5,597	$ 1,816	$ 3,781	81,834
8	1915	Office Furniture & Equipment (5 years)				$ -	0
10	1920	Computer Equipment - Hardware				$ -	0
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -	0
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 370,710	$ 37,071	$ 13,386	$ 23,685	290,284
10	1930	Transportation Equipment	$ 1,160,649	$ 72,541	$ 6,623	$ 65,918	521,359
8	1935	Stores Equipment	$ -	$ -	$ -	$ -	5,424
8	1940	Tools, Shop & Garage Equipment	$ 132,901	$ 6,645	$ 2,843	$ 3,802	74,747
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	7,821
8	1950	Power Operated Equipment	$ -			$ -	0
8	1955	Communications Equipment	$ 332,339	$ 41,542	$ 1,695	$ 39,848	62,176
8	1955	Communication Equipment (Smart Meters)				$ -	0
8	1960	Miscellaneous Equipment				$ -	6,974
47	1970	Load Management Controls Customer Premises				$ -	0
47	1975	Load Management Controls Utility Premises				$ -	0
47	1980	System Supervisor Equipment				$ -	0
47	1985	Miscellaneous Fixed Assets				$ -	0
47	1990	Other Tangible Property				$ -	0
47	1995	Contributions & Grants	-$ 1,472,887	$ (28,242)	$ (28,242)	$ -	(764,297)
47	2440	Deferred Revenue[5]				$ -	0
47	2005	2005-Property Under Capital Leases				$ -	0
						$ -	0
		Sub-Total	**$ 10,317,607**	$ 354,171	$ 197,965	**$ 156,206**	**$ 7,577,477**

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard

2013 Year

CCA Class	OEB	Description	Cost Additions	Depreciation on Additions Calculated Using Half Year	Actual Depreciaton on Addition	Difference	Dep'n Expense Restated for Half Year
12	1611	Computer Software (Formally known as Account 1925)	$ 114,742	$ 19,124	$ 16,830	$ 2,294	225,406
CEC	1612	Land Rights (Formally known as Account 1906)				$ -	0
N/A	1805	Land				$ -	0
47	1806	Land Rights	$ 810	$ 16	$ 16	$ -	57,098
47	1808	Buildings				$ -	0
13	1810	Leasehold Improvements				$ -	0
47	1815	Transformer Station Equipment > 50 kV (1708, 1740, 1745)	$ -			$ -	76,660
47	1815	Transformer Station Equipment > 50 kV (1715, 1815)	$ 16,679	$ 208	$ 208	$ -	36,280
47	1815	Transformer Station Equipment > 50 kV (1716)				$ -	22,587
47	1815	Transformer Station Equipment > 50 kV (1717)				$ -	13,339
47	1815	Transformer Station Equipment > 50 kV (1719)				$ -	35,747
47	1820	Distribution Station Equipment <50 kV	$ 83,151	$ 924	$ 924	$ -	80,230
47	1820	Distribution Station Equipment <50 Kv (1821)	$ 401,384	$ 6,690	$ 6,690	$ -	63,263
47	1825	Storage Battery Equipment			$ -	$ -	0
47	1830	Poles, Towers & Fixtures - Wood	$ 1,900,121	$ 19,001	$ 19,001	$ -	384,436
47	1830	Poles, Towers & Fixtures - (1831) Concrete	$ 120,419	$ 1,003	$ 1,003	$ -	32,680
47	1835	Overhead Conductors & Devices	$ 1,518,020	$ 12,650	$ 12,650	$ -	254,999
47	1835	Overhead Conductors & Devices (1836)	$ 105,662	$ 3,522	$ 3,522	$ -	318,767
47	1835	Overhead Conductors & Devices (1837)	$ 340,330	$ 5,672	$ 5,672	$ -	64,078
47	1840	Underground Conduit	$ 590,887	$ 5,909	$ 5,909	$ -	161,244
47	1845	Underground Conductors & Devices	$ 1,698,459	$ 24,497	$ 24,497	$ -	1,626,237
47	1845	Underground Conductors & Devices (1846)	$ 186,760	$ 3,113	$ 3,113	$ -	91,621
47	1850	Line Transformers (1850) Polemount	$ 432,676	$ 5,408	$ 5,408	$ -	211,500
47	1850	Line Transformers (1853) Padmount	$ 937,945	$ 13,475	$ 13,475	$ -	467,996
47	1855	Services (Overhead & Underground)	$ 800,998	$ 16,020	$ 16,020	$ -	201,182
47	1860	Meters	$ 248,020	$ 3,577	$ 3,577	$ -	146,928
47	1860	Meters (Smart Meters)	$ 27,477	$ 2,741	$ 2,741	$ -	279,238
47	1865	Other Installations on Customer's Premises	$ -			$ -	0
47	1875	Street Lighting and Signal Systems	$ -			$ -	0
N/A	1905	Land	$ -			$ -	0
47	1908	Buildings & Fixtures	$ 1,911,585	$ 8,557	$ 8,557	$ -	231,984
13	1910	Leasehold Improvements	$ -			$ -	0
8	1915	Office Furniture & Equipment (10 years)	$ 170,426	$ 8,521	$ 1,521	$ 7,000	92,857
8	1915	Office Furniture & Equipment (5 years)				$ -	0
10	1920	Computer Equipment - Hardware				$ -	0
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -	0
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 276,353	$ 27,635	$ 19,247	$ 8,388	312,453
10	1930	Transportation Equipment (1931)	$ 180,597	$ 11,287	$ 15,079	$ (3,792)	61,059
10	1930	Transportation Equipment (1932) Large Trucks	$ 1,141,557	$ 38,052	$ 1,446	$ 36,606	249,673
10	1930	Transportation Equipment (1933) Trailers	$ 8,420	$ 211	$ 70	$ 140	5,373
8	1935	Stores Equipment	$ -			$ -	5,424
8	1940	Tools, Shop & Garage Equipment	$ 83,082	$ 4,154	$ 4,617	$ (463)	74,950
8	1945	Measurement & Testing Equipment	$ -			$ -	7,508
8	1950	Power Operated Equipment	$ -			$ -	0
8	1955	Communications Equipment	$ 343,864	$ 8,597	$ 1,943	$ 6,653	26,072
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	0
8	1960	Miscellaneous Equipment	$ -			$ -	3,318
47	1970	Load Management Controls Customer Premises				$ -	0
47	1975	Load Management Controls Utility Premises				$ -	0
47	1980	System Supervisor Equipment				$ -	0
47	1985	Miscellaneous Fixed Assets				$ -	0
47	1990	Other Tangible Property				$ -	0
47	1995	Contributions & Grants	-$ 991,373	$ (17,722)	$ (17,722)	$ -	(810,261)
47	2440	Deferred Revenue[5]				$ -	0
47	2005	2005-Property Under Capital Leases				$ -	0
						$ -	0
		Sub-Total	**$ 12,649,050**	$ 232,844	$ 176,016	**$ 56,827**	**$ 5,111,926**

126. 4-Energy Probe-33

Ref: Exhibit 4, Tab 5, Schedule 3

Does NPEI have any positions eligible for the Co-operative Education Tax Credit? If yes, please provide the number of eligible positions in 2015.

Response

NPEI does not have any positions eligible for the Co-operative Education Tax Credit.

VECC

127. 4.0 - -VECC -26

Reference:E4/T2/S1

a) Please provide separately and for each year 2011 through 2015 (forecast) the annual membership costs for these corporate memberships and specifically for: (1) EDA; (2) Utility Partners Cooperative, (3) NEPA and (4) Grid SmartCity.

Response

Please see the table below.

	2011	2012	2013	2014	2015
EDA	73,111	77,066	80,795	84,298	87,123
GridSmart City	10,000	10,000	10,000	10,000	10,000
	83,111	87,066	90,795	94,298	97,123

128. 4.0 -VECC -27

Reference:E4/T1

1. Please provide a list of NPEI corporate memberships.
2. Please provide separately and for each year 2011 through 2015 (forecast) the annual membership costs for these corporate memberships and specifically for: (1) EDA; (2) Utility Partners Cooperative, (3) NEPA and (4) Grid SmartCity.

Response

See answer to IRR # 128 4.0-VECC-27 above.

129. 4.0-VECC-28

Reference: E4/T1/S1

a) What would be the annual OM&A savings if the compensation budget were based on a 1% increase in costs beginning April 1, 2015?

Response

As noted in E4/T3/S2 page 4, Table 4-8, the management wage increases are effective January 1st and the Union increases are effective April 1, 2015. The annual OM&A savings would be $142,995 based on a 1% increase effective January 1, 2015 for management wages and a 1% increase effective April 1, 2015 for union wages.

130. 4.0-VECC- 29

Reference:E4/T1/S1/pg.3

a) Please provide the Statistics Canada CPI annual inflation figures for each of 2011 through 2014.

b) Please provide NPEI's IRM stretch factor and productivity offset factors for the period 2011 through 2014.

Response

a) The table below shows the percentage change in annual inflation for the years 2011-2014.

b) The table below shows NPEI's productivity factor, stretch factor and the resulting price cap index adjustment for each year from 2011 to 2014. Note: NPEI's distribution rates for 2011 were set on a cost of service basis. The figures for 2011 in the table represent the price index adjustment that would have applied to NPEI under 3rd Generation IRM, based on NPEI's assigned cohort for 2011.

Rate Year	a Price Escalator (Annual percentage change in GDP - IPI)	b Productivity Factor	c Stretch Factor	d = a - b - c Price Cap Index Adjustment
2011	1.30%	0.72%	0.40%	0.18%
2012	2.00%	0.72%	0.40%	0.88%
2013	1.60%	0.72%	0.40%	0.48%
2014	1.70%	0.00%	0.30%	1.40%

131. 4.0-VECC-30

Reference:E4/T2/S1/pg.2

a) Please confirm that NPEI is stating that OM&A costs in 2015 are approximately 7% lower in 2015 than would otherwise been the case had their not been a change in capitalization policies (i.e. confirm that is what is being shown in Table 4-1).

Response

NPEI did not complete Appendix 2-D correctly. Appendix 2-D includes the wages per Appendix 2-K which are as per the T4 earnings for 2011, 2012 and 2013. Total OM&A wages including benefits as per Table 4-1 should go in OM&A before Capitalization. The only costs capitalized are the payroll overhead burden – employee benefits. Below NPEI has restated Appendix 2-D. The total employee benefits capitalized has also been updated in Appendix 2-D. See the table below. The benefit % being capital is increasing due to the percentage of total capital wages and benefits are increasing, see Table 4-1 for more detail.

Originally filed Appendix 2-D					
OM&A Before Capitalization	2011	2012	2013	2014	2015
Total Wages as per Appendix 2K (T4 earnings for 2011, 2012 and 2013)	9,546,131	10,152,181	10,612,484	10,874,154	11,156,960
% of Capitalized OM&A before Capitalization (B)	**9,546,131**	**10,152,181**	**10,612,484**	**10,874,154**	**11,156,960**
Capitalized OM&A					
Employee Benefits	4,454,193	4,706,763	5,075,419	4,940,226	4,984,070
Total Capitalized OM&A (A)	**4,454,193**	**4,706,763**	**5,075,419**	**4,940,226**	**4,984,070**
% of Capitalized OM&A (=A/B)	**47%**	**46%**	**48%**	**45%**	**45%**

Updated Appendix 2-D					
OM&A Before Capitalization	**2011**	**2012**	**2013**	**2014**	**2015**
Total wages including benefits per Table 4-1	12,273,363	13,017,898	13,545,178	14,182,239	15,068,109
% of Capitalized OM&A before Capitalization (B)	**12,273,363**	**13,017,898**	**13,545,178**	**14,182,239**	**15,068,109**
Capitalized OM&A					
Employee Benefits	938,001	1,084,839	1,319,886	1,369,336	1,533,513
Total Capitalized OM&A (A)	**938,001**	**1,084,839**	**1,319,886**	**1,369,336**	**1,533,513**
% of Capitalized OM&A (=A/B)	**8%**	**8%**	**10%**	**10%**	**10%**

132. 4.0-VECC-31

Reference:E4/T2/S1/pg.7 & E4/T3/S3

a)It is not clear whether Table 4-10 is showing an actual reduction in FTEs as between 2013 and 2015 of 28 to 24 or a reallocation of some and removal of others. Form comparison basis please provide a table showing the number of (each) Billing Staff, Cashiers, Receptionists, Supervisors that were responsible for both NPEI and City of Niagara water services in 2013 and in a separate column the number expected to be employed in 2015. Please note those positions remaining employed but in a different role and those made redundant.

b)Why was one supervisor billing position not eliminated as part of the change in water billing services?

c) Please explain what role the 3 unionized positions whose costs were 100% charged to the Affiliate will be doing in 2015.

d) Please provide the 2015 total compensation costs for the 3 unionized employees, and the 50% of the billing and customer service supervisor costs referred to at page 7 of the reference.

e) What costs in addition to the $120k in supervision and $476k in labour are no longer being recovered through the $4.20 water bill charge?

Response

a) Table 4-10 illustrates the restructuring Plan for FTE's. The actual FTE's related to water along with the $ impact are shown in IRR # 118 4-EP-25 and IRR# 120 4-EP-27. The table in IRR #118 illustrates the FTE's responsible for water. Please see the table below.

	2013			
				# responsible for
	Unionized	Contract	Third Party	Water
Billing	13	0	0	3
Customer Service	11	0	0	2
Cashier	1	1	1	1
Receptionist	0	0	1	
	25	1	2	6
	2015			
	Unionized	Contract	Third Party	
Billing	11	0	0	
Customer Service	10	0	0	
Cashier	2	0	0	
Receptionist	1	0	0	
	24	0	0	
Net change	-1	-1	-2	

b) Each Billing supervisor has in excess of 30 years of service.

c) The customer service positions rotate on a monthly basis to cash and reception.

d) The 2015 total compensation for the three unionized positions and 50% of the billing supervisor and 50% of the customer service supervisor is $410,722.

e) See IRR # 118 for the total impact of water billing services.

133. 4.0-VECC-32

Reference:E4/T3/S4

a) Does NPEI purchase insurance from the MEARIE Group?

b) If yes, please provide the premiums for each of 2011 through 2015 (forecast)
c) Please indicate the form of procurement for insurance services (e.g. tender, sole source, etc.).

Response

a) Yes NPEI purchases insurance from the MEARIE group as well as from Olsen-Sottile Insurance. Boiler insurance, crime, fire and substation/transformers > 1000 kVa are purchased from Olsen-Sottile.

b) Please see the table below:

	2011	2012	2013	2014	2015
The Mearie Group	200,028	177,394	203,183	221,032	191,743
Olsen Sottile Insurance	80,491	88,292	89,361	89,361	90,361
	280,520	265,686	292,544	310,394	282,104

c) Insurance is sole sourced.

134. 4-VECC-33

Reference: E4/

a) Please provide all training and conference costs for the 2011-2015 period broken down into the following categories
   i. Training – operations/maintenance
   ii. Training – other
   iii. Conferences

Response

Please see the table below. Please note the table below does not include Board of Director training/conferences as was noted in IRR #6 1-Energy Probe-3 above.

	2011	2012	2013	2014	2015
Training-operations/maintenance	27,119	35,217	42,587	44,793	36,676
Training-other	24,929	66,475	30,377	22,792	9,596
Conference	31,361	31,680	35,034	36,941	34,704
	83,409	133,371	107,998	104,526	80,976

135. 4.0 -VECC -34

Reference:E4/T2/S1/Appendix 2-JA

a) Please confirm 2015 is shown in MIFRS and 2014 in CGAAP.
b) Approximately 45% of the increase in OM&A costs is under the category of Billing and Collection. The evidence explains the increases between 2011 and 2015 but not by category. Please provide a comparison of the 2011 Billing and Collection actual costs and the 2015 forecast costs which explain this category's increase.

Response

(a) NPEI confirms that Schedule 2-JA 2015 is shown in MIFRS and 2014 is shown in CGAAP.

(b) Please see the table A below which comes from Appendix 2-JC of the originally filed evidence. Table B illustrates Billing and collecting expenses by GL account.

Table A – data from Appendix 2-JC

Programs	Last Rebasing Year (2011 Actuals)	2015 Test Year	$ Variance	% Variance
Billing Costs				
Meter Reading				
Labour and Other Costs	6,290	1,170	(5,121)	-81%
Outside Services	356,519	477,680	121,161	34%
Billing and Customer Service				
Labour	1,759,549	2,856,456	1,096,907	62%
Outside Services	664,061	900,577	236,515	36%
Reallocated for affiliate water activities	(272,789)	-	272,789	-100%
Information Technology Expenses	339,346	416,000	76,654	23%
Collection Expenses				
Labour	366,537	327,453	(39,083)	-11%
Outside Services	84,244	118,729	34,484	41%
Bad Debt Expense	330,713	265,000	(65,713)	-20%
Miscellaneous Customer Accounts	241,522	246,819	5,296	2%
Total	3,875,993	5,609,882	1,733,889	45%

Table B – Billing and collecting expenses by GL account

5305-Supervision	486,752	1,089,144	602,391	124%
5310-Meter Reading Expense	362,810	478,850	116,039	32%
5315-Customer Billing	2,003,416	3,083,889	1,080,473	54%
5320-Collecting	450,652	446,182	(4,470)	-1%
5325-Collecting- Cash Over and Short	129	-	(129)	-100%
5335-Bad Debt Expense	330,713	265,000	(65,713)	-20%
5340-Miscellaneous Customer Accounts Exp	241,522	246,819	5,296	2%
	3,875,994	5,609,882	1,733,888	45%

62% of the increase comes from labour. As noted in the originally filed evidence in E4/T3/S1 page 1 the explanations comparing the 2013 Actuals to the 2015 Test year would also explain the majority of the increases from 2011 actuals to the 2015 test year with the exception of the wages increases in 2012 through to 2014. Smart meter co-ordinators and a systems analyst are forecast in 2015 and were not in 2011 actuals. The direct labour and the variable costs charged to water were eliminated in 2015. The smart meter reading costs previously recorded in the regulatory asset account in 2011 are recorded in 2015 OM&A. The outsourcing of the mail machine and the MIST meter expenses are also in the 2015 forecast test year but were not incurred in 2011.

136. 4.0 - VECC - 35

Reference: E4/ T2/S1 Smart Meter Incremental Operating Costs

Preamble: The purpose of this interrogatory is to understand the elements which have caused billing and collection to increase from 2010 to 2014).

a) Please compare the cost components of Billing and Collection USoA accounts 5305, 5310, 5315, 5320,5325, 5335, 5340 for 2010 for Board approved 2011 and 2015 forecast.

Response

a) Please see the table below. The changes from 2015 test year to Board approved, 2015 to 2013 Actuals and 2015 test year to 2011 Board approved as well as year over year comparisons are explained in E4/T1, E4/T2 and E4/T3 of the originally filed evidence.

	2011 Board Approved	2011	2012	2013	2014	2015
5305-Supervision	480,012	486,752	576,200	624,638	1,440,310	1,089,144
5310-Meter Reading Expense	433,321	362,810	188,961	154,043	832,593	478,850
5315-Customer Billing	1,862,527	2,003,416	1,999,682	2,060,234	2,959,413	3,083,889
5320-Collecting	469,501	450,652	436,346	429,058	423,331	446,182
5325-Collecting- Cash Over and Short	-	129	0	70	-	-
5335-Bad Debt Expense	410,000	330,713	266,257	223,842	265,000	265,000
5340-Miscellaneous Customer Accounts Expenses	258,306	241,522	230,190	243,808	272,950	246,819
	3,913,667	3,875,994	3,697,637	3,735,692	6,193,597	5,609,882

137. 4.0-VECC- 36

Reference:E4/T3/S1/pg.3 & 5

a)NPEI states that it has included $132k in incremental OM&A costs for MIST meter reading in 2015. Please confirm that in 2019 NPEI is forecasting the cost of reading these meters as $219,600 for reading 2,745 meters.

b)Please explain how the incremental MIST meter reading cost of $332k shown at page 5 is calculated. Are these meters remotely read? Are the costs for actual meter reading or hardware/software for remote reading?

Response

(a) In 2019, NPEI is forecasting the cost of reading 915 meters @ $20/meter/month for a total of $219,600.

(b) On page 5, the $332K represents:

- An increase of $200K related to smart meters that were recorded in prior years in the regulatory asset account and will be recorded as expenses in 2014. The $200K consists of $44K for a third party to store historical meter reading data due to the provincial MDMR only stores current reads and $156K relates to monthly base station fees and the monthly electronic meter reading costs for smart meters.
- The $132K is the incremental meter reading costs associated with the MIST meters.

138. 4.0-VECC- 37

Reference:E4/T3/S1/Attachment 1

a) Please provide the reason(s) for the increase in Meter Reading – Outside Services of $153,072 in 2013 increasing to $354,400 in 2014 and $477,680 in 2015.

Response

The increase from 2014 over 2013 is $201,328 which represents the meter reading costs identified in IRR # 137 b) above which related to smart meter reading costs previously recorded in the regulatory asset in 2013 and prior years.

The increase from 2015 over 2014 is $ 122,262. The incremental costs for MIST meters is $131,760 (electronic reading) offset by a decrease of ($9,498) in the costs for the third party vendor who currently reads these meters by "walking reads".

139. 4.0-VECC-38

Reference:E4/T3/S2/

a) Please provide the actual and forecast cost for temporary resources/third party agencies employees for each of 2011 through 2015.
b) Please provide Appendix 2-K breaking out union and non-union FTEs and compensation.
c) Please provide a listing (job description) of each of the 7 incremental management positions added since 2011.
d) Please provide the total compensation cost of the 7 new incremental positions.
e) Please provide the same information as c) and d) for the decrement of 10 FTES in the non-management category.

Response

a) See IRR #118 4-Energy Probe-25 part b). The table shows the actual and forecast cost for temporary resources/third party agencies for employees from 2011 to 2015 in the "Summary of Labour" section.

b) Please see the table below.

Number of Employees (FTEs including Part-Time)[1]	2011	2011	2012	2012	2013	2013	2014	2014	2015	2015
Management (including executive)		29.60		33.80		34.60		35.00		36.00
Non-Union		13.75		10.30		3.80		3.80		1.20
Union		83.45		84.60		90.90		90.00		93.00
Total		126.80		128.70		129.30		128.80		130.20
Total Salary and Wages including ovetime and incentive pay	**$**	**FTE's**	**$**	**FTE's**	**$**	**FTE's**	**$**	**FTE's**	**$**	**FTE's**
Management (including executive)	2,864,484	29.60	3,311,489	33.80	3,499,353	34.60	3,652,122	35.00	3,819,388	36.00
Non-Union management	186,648	2.70	0	0	0	0	0	0	0	0
Non-Union hourly	326,382	11.05	466,578	10.30	152,384	3.80	170,762	3.80	53,622	1.20
Union	6,168,617	83.45	6,374,114	84.60	6,960,747	90.90	7,051,269	90.00	7,283,949	93.00
Total	$ 9,546,131	126.80	$ 10,152,181	128.70	$ 10,612,484	129.30	$ 10,874,153	128.80	$ 11,156,959	130.20

c) Please see the table below detailing the management positions referred to in part c). There are only 3 incremental management positions since 2011. The CDM co-ordinator relates to the CDM initiatives, the Manager Regulatory Affairs & Accounting relates to regulatory activities and the Manager Business Application support relates to the reasons described in E4/T3/S2 page 11 of the originally filed evidence. The total management FTE's in 2011 were 32.7. The Controller returned in 2012 for 0.7 FTE's for a total of 33 management FTE's. In 2015, there are 36 FTE's for a total increment of 3 management positions, which are the Manager Business Application Support, Manager Regulatory Affairs & Accounting and the Engineering Services Manager. Please see Attachment #15 for the job descriptions.

Position	Non-Union FTE Contract start date	Contract end date	Management FTE Full Time Start date	Full Time End Date	Description of movements	2015 Vacant Yes or No	Incremental Yes or No
CDM Co-ordinator			Mar-11			NO	YES
EA Assistant	Mar-10	Feb-11			Promoted to Marketing Co-ordinator CDM -	YES	
Marketing Co-ordinator CDM			Mar-11		Previously was the EA Assistant	NO	NO
HR Co-ordinator	Jan-09	Jul-11	Aug-11			NO	NO
Systems Analyst			Dec-07	Dec-13	Promoted to Manager Business Application support - replace in 2015	YES	
Manager Business Application Support			Jan-14			NO	YES
Regulatory Financial Analyst			Mar-09	Dec-12	Promoted to Manager Regulatory Affairs	NO	
Manager Regulatory Affairs & Accounting			Jan-13			NO	YES
Regulatory Financial Analyst	Jun-12	Mar-13	Apr-13			NO	NO
Business Analyst	May-10	Dec-11	Jan-12			NO	NO
Smart Meter Co-ordinator	May-10	Dec-11	Jan-12			NO	NO
Smart Meter Co-ordinator	May-09	Dec-10	Jan-11			NO	NO
Engineering Services Supervisor					Included in 2011 COS rate application but was never filled	YES	
Engineering Services Manager			Sep-11			NO	NO

d) The total compensation of the 3 new incremental positions is $430,771. Note the CDM co-ordinator and the Marketing Co-ordinator positions are not included in NPEI's 2015 distribution expenses as they are funded by the OPA program.

e) The total compensation of the 10 FTE's which have either been hired full time or have left or retired is ($296,711). The FTE's in 2011 consisted of 7.55 contract employees of which 3 were hired full time in February 2013 and the remaining employees left. The balance of 3.5 FTE's consists of co-op apprentices who have since 2011 been hired full time.

SEC

140. SEC #28 [Ex. 4/1/1, p. 2]

Please confirm that the 2.5% increase in compensation was assumed only for the period April 1, 2015 to December 31, 2015.

Response

As noted in E4/T3/S2 page 4, Table 4-8, the management wages increases are effective January 1st and the Union increases are effective April 1, 2015.

141. SEC #29 [Ex. 4/1/1, p. 3-5]

Please reconcile the explanations for the increases in OM&A from 2013 to 2015 with the fact that $1,874,190 of the increase is in Billing and Collecting on the App. 2-JA. For each of the explanations in 4/1/1, please track that explanation to the line on App. 2-JA where that result is shown.

Response

Please see the table below.

per 2-JB	2014	2015	Total
OMERS	37,362	21,600	58,962
Management	108,480	91,303	199,783
Union	133,644	112,489	246,133
	279,486	225,392	504,878

Descriptions on pages 3-5	Category on 2-JA Operations	Category on 2-JA Maintenance	Category on 2-JA Utilization	Category on 2-JA Billing	Category on 2-JA G&A	Total
Inflationary increases	177	71		155	102	505
Controller returning from maternity leave					67	67
Water returning to City Labour impact				561		561
Smart meter Co-ordinators				188		188
System Analyst				111		111
Medical leaves and other changes in non-union and union staff		149		69		218
Subtotal labour impact	177	220	-	1,084	169	1,650
Meter reading MIST meters and Smart meters				325		325
Water unavoidable costs				282	55	337
Reduction due to cashiers and receptionist third party				(129)		(129)
Mail machine				102		102
Legal consulting, regulatory etc					197	197
	177	220	-	1,664	421	2,482
Increase on 2-JA	160	405	(12)	1,874	442	2,869
Not explained on pages 3-5	17	(185)	12	(210)	(21)	(387)

142. SEC #30 [Ex. 4/2/1, p. 2]

Please confirm that the following additional distribution costs are claimed to arise out of the loss of water billing:

Category	2014	2015	Totals
Water Supervision not recovered	$77,172	$43,000	$120,172
Water labour not recovered	$345,829	$130,000	$475,829
Allocated water expenses	$236,589	$100,595	$337,184
Totals	$659,590	$273,595	$933,185

Please reconcile these costs with the annual water revenues of $485,405 [Ex.3/3/1], and explain how the previous water billing complied with the Affiliate Relationships Code. Please provide a breakdown of these costs, and show for each of these costs why it cannot be reduced in light of the reduced workload due to loss of water billing.

Response

For the direct labour costs, the employees recorded the time they spent on water related activities every pay week. The same overhead burden used for hydro related activities was applied to water. The water revenues and expenses including HST were reconciled monthly and payments were made to the City of Niagara Falls. Meter reading invoices from the third party vendor separated hydro reads from water reads. The deposits held for water were tracked in separate general ledger accounts and reconciled to the sub-ledger monthly. The allocated fixed costs were related to the $4.20 per water only bill administration charge. NPEI prevented the utility from cross-subsidizing affiliate services.

NPEI separated the water from hydro into two accounts if the account was in collections and/or with a retailer in order to protect the confidentiality of information related to hydro services. NPEI provided an on-line view of only water services in its billing system to select City of Niagara Falls staff.

NPEI complied with the Affiliate Relationships Code section 1.1 by way of the items noted above.

Please see IRR #109 4 Staff 36 part d) and e) for a breakdown of the costs associated with water and why not all costs can be avoided.

Exhibit 5 Cost of Capital

143. 5 Staff 42.Long Term Debt

References

1. Exhibit 5 Tab 2 Schedule 1 p. 3
2. Appendix 2-OB
3. Exhibit 5 Tab 2 Schedule 1 Attachment 2 of 8
4. Board Letter November 20, 2014: Cost of Capital Parameter Updates for 2015 Applications

Preamble

In Reference 1 NPEI indicates that it is planning to issue a request for proposal (RFP) from 5 banks and one credit union for financing in the amount of $10,000,000 in September 2014 and that for the purposes of this application estimated an interest rate of 3.05%.

a) Please state the status of the RFP.

b) Please provide the terms if negotiations are complete.

c) If NPEI has not completed negotiations, when is the estimated date it will complete and NPEI will be able to update its proposed debt costs?

NPEI borrowed $9 million from the TD Bank starting July 20, 2009 for 10 years. On Appendix 2-OB, NPEI has recorded interest for 2015 of $193,728 which is the total interest for 2015 from the Loan Amortization in Reference 3. However, NPEI is stating that the Principal to which this applies is the opening 2016 balance of $3,645,616.

d) Please provide Appendix 2-OA with the average 2015 principal of $4,111,207.

e) If NPEI is of the opinion that the average principal balance is not appropriate, please explain why

NPEI has included $21 million of notional debt in Appendix 2-OB at the deemed rate of 4.88%. This results in a weighted cost of debt reported in Appendix 2-OA of 4.28%.

f) Please provide a rationale, and any regulatory direction that supports the proposal for setting a rate for notional debt.

g) Please remove the $21 million notional debt from the calculation of the average cost of debt.

In Reference 4, the Board issued new cost of capital parameters for 2015 applications. In the interrogatories above, some other parameters in NPEI's cost of capital proposal may have changed.

h)Please provide a complete update to Appendix 2-OA and 2-OB.

Response

a) NPEI completed the RFP for the financing in the amount of $10,000,000.

b) The RFP was awarded to TD bank. The $10,000,000 was received on November 13, 2014. The loan is a fixed rate loan for 5 years with interest only repayments. The final all-in rate was 2.663%. NPEI originally filed an estimated interest rate of 3.05%.

   NPEI has updated the weighted average cost of capital calculation. The RRWF, PILS, Cost of Capital and Chapter 2 Appendices 2-OB and Appendices 2-OA.

c) NPEI completed negotiations pertaining to the RFP for loan financing.

d) Per the amortization schedule for the TD loan, the ending balance for 2014 is $4,652,144.63 and the ending balance for 2015 is $3,724,569.64. This results in an average outstanding balance for 2015 of ((4,652,144.63 + 3,724,569.64)/2 = $4,188,358.)

   NPEI has updated Appendix 2-OB with an average balance of $4,188,358 for 2015.

e) NPEI agrees the average principal balance should be used. The originally filed evidence excluded the current principal portion of the TD loan that is payable in 2015.

f) NPEI is not aware of Board direction regarding the appropriate rate for notional debt. NPEI is obligated to use a corporate structure of 60% debt (56% long-term and 4% short-term) and 40% equity which does not reflect the actual debt: equity ratio of NPEI. NPEI used the deemed rate for affiliate debt for the notional debt rather than an equity rate which would otherwise apply using actual numbers.

   NPEI is not aware of a situation where the Board has ruled on this specific issue. However, NPEI is aware of a situation in which the Board permitted a utility to factor a "compensating balance" into the cost of long-term debt in EB-2010-0018. NPEI is also aware of situations where actuals were used.

g) When the notional debt is removed from the calculation the weighted average cost of capital totals 3.92%.

h) NPEI has updated Appendix 2-OA and 2-OB as per below:

In summary:

- The Cost of Capital parameters have been updated as per the letter from the OEB dated November 201, 2014.
- The average balance for the TD loan has been updated from $3,724,570 to $4,188,358
- The 2014 RFP financing interest rate was updated from 3.05% to 2.663%.
- The updated long term debt rate including the notional debt is 4.14%.

Appendix 2-OA
Capital Structure and Cost of Capital UPDATED

This table must be completed for the last Board approved year and the test year.

Year: 2015

Line No.	Particulars	Capitalization Ratio			Cost Rate	Return
		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	56.00%		$81,033,944	4.14%	$3,354,805
2	Short-term Debt	4.00%	(1)	$5,788,139	2.16%	$125,024
3	**Total Debt**	60.0%		$86,822,083	4.01%	$3,479,829
	Equity					
4	Common Equity	40.00%		$57,881,389	9.30%	$5,382,969
5	Preferred Shares	0.00%		$ -		$ -
6	**Total Equity**	40.0%		$57,881,389	9.30%	$5,382,969
7	**Total**	100.0%		$144,703,471	6.12%	$8,862,798

Notes

(1) 4.0% unless an applicant has proposed or been approved for a different amount.

Year: 2011 Board Approved

Line No.	Particulars	Capitalization Ratio			Cost Rate	Return
		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	56.00%		$66,964,502	5.16%	$3,452,039
2	Short-term Debt	4.00%	(1)	$4,783,179	2.46%	$117,666
3	**Total Debt**	60.0%		$71,747,680	4.98%	$3,569,705
	Equity					
4	Common Equity	40.00%		$47,831,787	9.58%	$4,582,285
5	Preferred Shares	0.00%		$ -	0.00%	$ -
6	**Total Equity**	40.0%		$47,831,787	9.58%	$4,582,285
7	**Total**	100.0%		$119,579,467	6.82%	$8,151,990

File Number:	EB-2014-0096
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Appendix 2-OB
Debt Instruments

This table must be completed for all required historical years, the bridge year and the test year.

Year 2009 This is 2010

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	Long Term Note Payable	City of Niagara Falls	Affiliated	Fixed Rate	1-Apr-00	20	$ 22,000,000	0.0725	$ 1,595,000	
2	Long Term Note Payable	Niagara Falls Hydro Holding Corporation	Affiliated	Fixed Rate	1-Apr-00	20	$ 3,605,090	0.0725	$ 261,369	
3	Long Term Bank Loan Payable	Scotiabank	Third-Party	Fixed Rate	1-Jun-04	10	$ 4,237,226	0.0644	$ 248,408	Per amortization schedule
4	Term Loan payable	TD Bank	Third-Party	Fixed Rate	19-Jul-09	10	$ 8,703,329	0.0458	$ 383,217	Per amortization schedule
5	Non-revolving term loan payable	Scotiabank	Third-Party	Fixed Rate	30-Sep-10	5	$ 4,500,000	0.0497	$ 81,384	Per amortization schedule
12									$ -	
Total							$ 43,045,645	0.0597	$ 2,569,378	

Year 2009 This is 2011 BOARD APPROVED

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	Long Term Note Payable	City of Niagara Falls	Affiliated	Fixed Rate	1-Apr-00	20	$ 22,000,000	0.0532	$ 1,170,400	
2	Long Term Note Payable	Niagara Falls Hydro Holding Corporation	Affiliated	Fixed Rate	1-Apr-00	20	$ 3,605,090	0.0532	$ 191,791	
3	Long Term Bank Loan Payable	Scotiabank	Third-Party	Fixed Rate	1-Jun-04	10	$ 3,398,502	0.0644	$ 192,771	Per amortization schedule
4	Term Loan payable	TD Bank	Third-Party	Fixed Rate	19-Jul-09	10	$ 7,965,243	0.0458	$ 348,793	Per amortization schedule
5	Non-revolving term loan payable	Scotiabank	Third-Party	Fixed Rate	30-Sep-10	5	$ 4,143,643	0.0497	$ 215,605	Per amortization schedule
6									$ -	
Total							$ 41,112,478	0.0516	$ 2,119,360	

Year 2009 This is 2011 ACTUAL

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	Long Term Note Payable	City of Niagara Falls	Affiliated	Fixed Rate	1-Apr-00	20	$ 22,000,000	0.0725	$ 1,595,000	
2	Long Term Note Payable	Niagara Falls Hydro Holding Corporation	Affiliated	Fixed Rate	1-Apr-00	20	$ 3,605,090	0.0725	$ 261,369	
3	Long Term Bank Loan Payable	Scotiabank	Third-Party	Fixed Rate	1-Jun-04	10	$ 2,951,322	0.0644	$ 192,771	Per amortization schedule
4	Term Loan payable	TD Bank	Third-Party	Fixed Rate	19-Jul-09	10	$ 7,578,939	0.0458	$ 348,692	Per amortization schedule
5	Non-revolving term loan payable	Scotiabank	Third-Party	Fixed Rate	30-Sep-10	5	$ 4,180,500	0.0497	$ 207,786	Per amortization schedule
12									$ -	
Total							$ 40,315,851	0.0646	$ 2,605,618	

Year 2012

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	Long Term Note Payable	City of Niagara Falls	Affiliated	Fixed Rate	1-Apr-00	20	$ 22,000,000	0.058	$ 1,276,550	
2	Long Term Note Payable	Niagara Falls Hydro Holding Corporation	Affiliated	Fixed Rate	1-Apr-00	20	$ 3,605,090	0.0582	$ 209,740	
3	Long Term Bank Loan Payable	Scotiabank	Third-Party	Fixed Rate	1-Jun-04	10	$ 2,027,297	0.0644	$ 133,443	Per amortization schedule
4	Term Loan payable	TD Bank	Third-Party	Fixed Rate	19-Jul-09	10	$ 6,788,719	0.0458	$ 313,473	Per amortization schedule
5	Non-revolving term loan payable	Scotiabank	Third-Party	Fixed Rate	30-Sep-10	5	$ 3,712,500	0.0497	$ 186,416	Per amortization schedule
6	Term Loan payable	TD Bank	Third-Party	Fixed Rate	27-Jun-12	5	$ 10,000,000	0.028	$ 135,781	Interest only repayments
Total							$ 48,133,606	0.0469	$ 2,255,403	

Year 2013

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	Long Term Note Payable	City of Niagara Falls	Affiliated	Fixed Rate	1-Apr-00	20	$ 22,000,000	0.0532	$ 1,170,400	
2	Long Term Note Payable	Niagara Falls Hydro Holding Corporation	Affiliated	Fixed Rate	1-Apr-00	20	$ 3,605,090	0.0532	$ 191,791	
3	Long Term Bank Loan Payable	Scotiabank	Third-Party	Fixed Rate	1-Jun-04	10	$ 1,041,976	0.0644	$ 70,180	Per amortization schedule
4	Term Loan payable	TD Bank	Third-Party	Fixed Rate	19-Jul-09	10	$ 5,961,538	0.0458	$ 274,771	Per amortization schedule
5	Non-revolving term loan payable	Scotiabank	Third-Party	Fixed Rate	30-Sep-10	5	$ 3,262,500	0.0497	$ 162,554	Per amortization schedule
6	Term Loan payable	TD Bank	Third-Party	Fixed Rate	27-Jun-12	5	$ 10,000,000	0.028	$ 288,035	Interest only repayments
7	Term Loan payable	TD Bank	Third-Party	Fixed Rate	3-Dec-13	5	$ 10,000,000	0.02933	$ 14,465	Interest only repayments
Total							$ 55,871,104	0.0389	$ 2,172,196	

Year 2014 BRIDGE YEAR

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	Long Term Note Payable	City of Niagara Falls	Affiliated	Fixed Rate	1-Apr-00	20	$ 22,000,000	0.0532	$ 1,170,400	
2	Long Term Note Payable	Niagara Falls Hydro Holding Corporation	Affiliated	Fixed Rate	1-Apr-00	20	$ 3,605,090	0.0532	$ 191,791	
3	Long Term Bank Loan Payable	Scotiabank	Third-Party	Fixed Rate	1-Jun-04	10	$ 223,632	0.0644	$ 10,065	Per amortization schedule
4	Term Loan payable	TD Bank	Third-Party	Fixed Rate	19-Jul-09	10	$ 5,095,208	0.0458	$ 235,175	Per amortization schedule
5	Non-revolving term loan payable	Scotiabank	Third-Party	Fixed Rate	30-Sep-10	5	$ 2,812,500	0.0497	$ 140,680	Per amortization schedule
6	Term Loan payable	TD Bank	Third-Party	Fixed Rate	27-Jun-12	5	$ 10,000,000	0.028	$ 280,000	Interest only repayments
7	Term Loan payable	TD Bank	Third-Party	Fixed Rate	3-Dec-13	5	$ 10,000,000	0.02933	$ 293,300	Interest only repayments
7	Term Loan payable-NEW	To be Determined	Third-Party	Fixed Rate	30-Nov-14	5	$ 849,315	0.02663	$ 35,020	Updated for 48 days O/S vs 31 days
Total							$ 54,585,745	0.0432	$ 2,356,431	

Year 2015 TEST YEAR

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	Long Term Note Payable	City of Niagara Falls	Affiliated	Fixed Rate	1-Apr-00	20	$ 22,000,000	0.04806	$ 1,057,356	4 months @4.88% 8mths @ 4.77%
2	Long Term Note Payable	Niagara Falls Hydro Holding Corporation	Affiliated	Fixed Rate	1-Apr-00	20	$ 3,605,090	0.04806	$ 173,267	4 months @4.88% 8mths @ 4.77%
4	Term Loan payable	TD Bank	Third-Party	Fixed Rate	19-Jul-09	10	$ 4,188,358	0.0458	$ 193,728	Per amortization schedule
5	Non-revolving term loan payable	Scotiabank	Third-Party	Fixed Rate	30-Sep-10	5	$ -	0.0497	$ 90,905	Per amortization schedule
6	Term Loan payable	TD Bank	Third-Party	Fixed Rate	27-Jun-12	5	$ 10,000,000	0.028	$ 280,000	Interest only repayments
7	Term Loan payable	TD Bank	Third-Party	Fixed Rate	3-Dec-13	5	$ 10,000,000	0.02933	$ 293,300	Interest only repayments
7	Term Loan payable-NEW	To be Determined	Third-Party	Fixed Rate	30-Nov-14	5	$ 10,000,000	0.02663	$ 266,300	Interest only repayments
Total							$ 59,793,448	0.0394	$ 2,354,856	

Notes

1 If financing is in place only part of the year, calculate the pro-rated interest and input in the cell.

2 Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, issued December 11, 2009, or with any subsequent update issued by the Board.

3 Add more lines above row 12 if necessary.

Year 2015 Deemed Interest Calculation

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	Long Term Note Payable	City of Niagara Falls	Affiliated	Fixed Rate	1-Apr-00	20	$ 22,000,000	0.0477	$ 1,049,400	Updated for 2014 parameters
2	Long Term Note Payable	Niagara Falls Hydro Holding Corporation	Affiliated	Fixed Rate	1-Apr-00	20	$ 3,605,090	0.0477	$ 171,963	Updated for 2014 parameters
4	Term Loan payable	TD Bank	Third-Party	Fixed Rate	19-Jul-09	10	$ 4,188,358	0.0458	$ 193,728	Per amortization schedule
5	Non-revolving term loan payable	Scotiabank	Third-Party	Fixed Rate	30-Sep-10	5	$ -	0.0497	$ 90,905	Per amortization schedule
6	Term Loan payable	TD Bank	Third-Party	Fixed Rate	27-Jun-12	5	$ 10,000,000	0.028	$ 280,000	Interest only repayments
7	Term Loan payable	TD Bank	Third-Party	Fixed Rate	3-Dec-13	5	$ 10,000,000	0.02933	$ 293,300	Interest only repayments
7	Term Loan payable-NEW	To be Determined	Third-Party	Fixed Rate	30-Nov-14	5	$ 10,000,000	0.02663	$ 266,300	Interest only repayments
Total							$ 59,793,448	0.0392	$ 2,345,596	
			Remaining subject to deemed interest				$ 21,240,496	0.0477	$ 1,013,172	
							$ 81,033,944	0.0414	$ 3,354,805	

Year 2015 Deemed Interest Calculation with Notional debt removed

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	Long Term Note Payable	City of Niagara Falls	Affiliated	Fixed Rate	1-Apr-00	20	$ 22,000,000	0.0477	$ 1,049,400	
2	Long Term Note Payable	Niagara Falls Hydro Holding Corporation	Affiliated	Fixed Rate	1-Apr-00	20	$ 3,605,090	0.0477	$ 171,963	
4	Term Loan payable	TD Bank	Third-Party	Fixed Rate	19-Jul-09	10	$ 4,188,358	0.0458	$ 193,728	Per amortization schedule
5	Non-revolving term loan payable	Scotiabank	Third-Party	Fixed Rate	30-Sep-10	5	$ -	0.0497	$ 90,905	Per amortization schedule
6	Term Loan payable	TD Bank	Third-Party	Fixed Rate	27-Jun-12	5	$ 10,000,000	0.028	$ 280,000	Interest only repayments
7	Term Loan payable	TD Bank	Third-Party	Fixed Rate	3-Dec-13	5	$ 10,000,000	0.02933	$ 293,300	Interest only repayments
7	Term Loan payable-NEW	To be Determined	Third-Party	Fixed Rate	30-Nov-14	5	$ 10,000,000	0.02663	$ 266,300	Interest only repayments
Total							$ 59,793,448	0.0392	$ 2,345,596	
			Remaining subject to deemed interest				$ -	0	$ -	
							$ 59,793,448	0.03923	$ 2,345,596	

ENERGY PROBE

144. 5-Energy Probe-34

Ref: Exhibit 5, Tab 1, Schedule 1

Please update the relevant schedules, such as Appendix 2-OA, Appendix 2-OB to reflect the Board's November 20, 2014 letter detailing the Cost of Capital Parameter Updates for 2015 Applications.

Response

Please see IRR #143 5-Staff-42 above.

145. 5-Energy Probe-35

Ref: Exhibit 5, Tab 2, Schedule 1

a) What is the current status of the September, 2014 RFP for $10 million? If a rate has been determined, please update the 2015 long term debt tables in Exhibit 5, Tab 2, Schedule 1 to reflect the updated interest rate.

b) If an agreement has been signed, please provide the agreement and any supporting documentation.

c) Please explain why NPEI believes it is appropriate and consistent with Board policy to apply the Board's deemed long term debt rate to the difference between the actual and deemed long term debt?

Response

a) Please see IRR #143 5-Staff-42 above.
b) Please see Attachment # 16
c) Please see IRR #143 5-Staff-42 above.

VECC

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146. 5.0 – VECC -39

Reference: E5/T1/S1

a) Please provide separately NPEI's actual and deemed return on equity for the years 2011 through 2014 (excluding FMV).

Response

The tables below show NPEI's actual and deemed return on equity for the years 2011-2014 excluding FMV bump.

	2011		2012	
	Updated using the 2013 template		Updated using the 2013 template	
Regulatory Net Income Calculation:				
Net Income per Financial Statements		$ 2,311,889		$ 2,751,369
Remove:				
Depreciation expense on FMV Bump		$ 1,086,669		$ 1,137,424
Net repayment of PILs effective October 2012		$ 0		$ 365,815
Regulated net income, as per RRR 2.1.13 reconciliation		$ 3,398,558		$ 4,254,608
Remove:				
Future/deferred taxes		$ (1,152,536)		$ (40,217)
Non rate regulated items		$ 198,278		$ 343,909
Adjustment to interest expense - for deemed debt		$ 520,880		$ 706,982
Adjusted regulated net income		$ 3,831,936		$ 3,243,933
Deemed Equity Calculation:				
Rate Base:				
Cost of power		$ 114,642,681		$ 121,234,036
Operating expenses		$ 16,975,809		$ 17,468,062
Total		$ 131,618,491		$ 138,702,098
Working capital allowance %		15%		15%
Total working capital allowance		$ 19,742,774		$ 20,805,315
Fixed Assets				
Opening balance - regulated fixed assets (NBV)	$ 100,033,163		$ 101,075,768	
Closing balance - regulated fixed assets (NBV)	$ 101,075,768		$ 103,934,202	
Average regulated fixed assets	$ 100,554,465	$ 100,554,465	$ 102,504,985	$ 102,504,985
Total rate base		**$ 120,297,239**		**$ 123,310,300**
Regulated deemed short-term debt	4%	$ 4,811,890	4%	$ 4,932,412
Regulated deemed long-term debt	56%	$ 67,366,454	56%	$ 69,053,768
Regulated deemed equity	40%	$ 48,118,896	40%	$ 49,324,120
		$ 120,297,239		$ 123,310,300
Regulated Rate of Return on Deemed Equity				
		8.0%		**6.6%**
ROE% from most recent cost of service applicatio	**last approved EDR**	**9.58%**	**last approved EDR**	**9.58%**
Difference - maximum deadband 3%		**-1.62%**		**-3.00%**

	2011		2012	
	Updated using the 2013 template		Updated using the 2013 template	
Interest adjustment on deemed debt:				
Regulated deemed short-term debt - as above	$ 4,811,890	6.67%	$ 4,932,412	6.67%
Regulated deemed long-term debt - as above	$ 67,366,454	93.33%	$ 69,053,768	93.33%
	$ 72,178,343	100.00%	$ 73,986,180	100.00%
Short-term debt rate	2.46%	0.16%	2.46%	0.16%
Long-term debt rate	5.16%	4.82%	5.16%	4.82%
Average debt rate		4.98%		4.98%
Regulated deemed debt - as above	$ 72,178,343		$ 73,986,180	
Weighted average interest rate	4.98%		4.98%	
Deemed interest	$ 3,594,481 T		$ 3,684,512 T	
Interest expense as per the OEB trial balance	$ 2,868,517 U		$ 2,699,170 U	
Difference	$ 725,965 V = T - U		$ 985,341 V = T - U	
Utility tax rate	28.25%		28.25%	
Tax effect on interest expense	$ (205,085)		$ (278,359)	
Interest adjustment on deemed debt:	$ 520,880 W		$ 706,982 W	

	2013		2014 Projected		
Regulatory Net Income Calculation:					
Net Income per Financial Statements		$ 1,458,180		$ 1,595,251	
Remove:					
Depreciation expense on FMV Bump		$ 1,132,277		$ 1,099,112	
Net repayment of PILs effective October 2012		$ 1,554,749		$ 632,525	
Regulated net income, as per RRR 2.1.13 reconciliation		$ 4,145,206		$ 3,326,888	A
Remove:					
Future/deferred taxes		$ (510,994)		$ 0	B
Non rate regulated items		$ 147,194		$ 81,386	C
Adjustment to interest expense - for deemed debt		$ 1,027,353		$ 1,135,789	D (=W)
Adjusted regulated net income		$ 3,481,652		$ 2,109,713	E = A-B-C-D
Deemed Equity Calculation:					
Rate Base:					
Cost of power		$ 130,559,982		$ 137,756,785	F
Operating expenses		$ 16,598,017		$ 19,500,685	G
Total		$ 147,157,999		$ 157,257,470	H = F + G
Working capital allowance %		15%		15%	
Total working capital allowance		$ 22,073,700		$ 23,588,620	J
Fixed Assets					
Opening balance - regulated fixed assets (NBV)	$ 103,934,202		$ 111,460,559		
Closing balance - regulated fixed assets (NBV)	$ 111,460,559		$ 120,839,893		
Average regulated fixed assets	$ 107,697,380	$ 107,697,380	$ 116,150,226	$ 116,150,226	K
Total rate base		**$ 129,771,080**		**$ 139,738,847**	L = J + K
Regulated deemed short-term debt	4%	$ 5,190,843	4%	$ 5,589,554	M
Regulated deemed long-term debt	56%	$ 72,671,805	56%	$ 78,253,754	N
Regulated deemed equity	40%	$ 51,908,432	40%	$ 55,895,539	P
		$ 129,771,080		$ 139,738,847	
Regulated Rate of Return on Deemed Equity					
		6.7%		3.8%	Q = E / P
ROE% from most recent cost of service application	last approved EDR	**9.58%**	last approved EDR	**9.58%**	R
Difference - maximum deadband 3%		**-2.87%**		**-5.81%**	S = Q - R

	2013		2014 Projected	
Interest adjustment on deemed debt:				
Regulated deemed short-term debt - as above	$ 5,190,843	6.67%	$ 5,589,554	6.67%
Regulated deemed long-term debt - as above	$ 72,671,805	93.33%	$ 78,253,754	93.33%
	$ 77,862,648	100.00%	$ 83,843,308	100.00%
Short-term debt rate	2.46%	0.16%	2.46%	0.16%
Long-term debt rate	5.16%	4.82%	5.16%	4.82%
Average debt rate		4.98%		4.98%
Regulated deemed debt - as above	$ 77,862,648		$ 83,843,308	
Weighted average interest rate	4.98%		4.98%	
Deemed interest	$ 3,877,560 T		$ 4,175,397 T	
Interest expense as per the OEB trial balance	$ 2,445,708 U		$ 2,592,416 U	
Difference	$ 1,431,851 V = T - U		$ 1,582,981 V = T - U	
Utility tax rate	28.25%		28.25%	
Tax effect on interest expense	$ (404,498)		$ (447,192)	
Interest adjustment on deemed debt:	$ 1,027,353 W		$ 1,135,789 W	

147. 5.0-VECC- 40

Reference:E5/T2/S1/pg.5 & RRWF Excel

(a) Appendix 2-OB shows interest expenses of $3,455,899. The RRWF Excel form shows under the tab Revenue Requirement Deemed Interest Expenses of $3,567,234. Please reconcile.

Response

Please see Appendix 2-OB below which reconciles the Deemed Interest Expense of the originally filed evidence. The difference is the deemed short term interest.

	Year	2015		Deemed Interest Calculation				
Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term	Principal	Rate (%)	Interest ($)	Additional Comments, if any
City of Niagara Falls	Affiliated	Fixed Rate	1-Apr-00	20	22,000,000	0.04880	1,073,600	
Niagara Falls Hydro Holding Corporation	Affiliated	Fixed Rate	1-Apr-00	20	3,605,090	0.04880	175,928	
TD Bank	Third-Party	Fixed Rate	19-Jul-09	10	3,724,570	0.04580	193,728	Per amortization schedule
Scotiabank	Third-Party	Fixed Rate	30-Sep-10	5	-	0.04970	90,905	Per amortization schedule
TD Bank	Third-Party	Fixed Rate	27-Jun-12	5	10,000,000	0.02800	280,000	Interest only repayments
TD Bank	Third-Party	Fixed Rate	3-Dec-13	5	10,000,000	0.02933	293,300	Interest only repayments
To be Determined	Third-Party	Fixed Rate	30-Nov-14	5	10,000,000	0.03050	305,000	Interest only repayments
					59,329,660	0.04066	2,412,461	
		Remaining subject to deemed interest			21,177,005	0.04880	1,033,438	
					80,506,665	0.04280	3,445,899	
Short term interest expense per 2-OA							121,335	
Deemed interest expense per RRWF originally filed							3,567,234	

Appendix 2-OA
Capital Structure and Cost of Capital

This table must be completed for the last Board approved year and the test year.

Year: 2015

Line No.	Particulars	Capitalization Ratio			Cost Rate	Return
		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	56.00%		$80,506,665	4.28%	$3,445,899
2	Short-term Debt	4.00%	(1)	$5,750,476	2.11%	$121,335
3	**Total Debt**	60.0%		$86,257,141	4.14%	$3,567,234
	Equity					
4	Common Equity	40.00%		$57,504,761	9.36%	$5,382,446
5	Preferred Shares	0.00%		$ -		$ -
6	**Total Equity**	40.0%		$57,504,761	9.36%	$5,382,446
7	**Total**	100.0%		$143,761,902	6.23%	$8,949,680

Exhibit 6Revenue Requirement

ENERGY PROBE

148. 6-Energy Probe-36

Ref: Exhibit 6, Tab 1, Schedule 1

Based on any corrections, changes or updates (such as the cost of capital updates and the cost of power updates), please:

a) Provide an updated Table 6-5; and,

b) Provide an updated RRWF (Attachment) that includes the appropriate and necessary entries in the Tracking Form.

Response

(a) Please see updated Table 6-5 below and Attachment #1 for the updated RRWF.

Table 6-5 Calculation of Revenue Deficiency or Surplus				
			IR 6-Energy Probe -36	
	2015 Test Year at Existing Rates	2015 Test Proposed Rates	2015 Test Year at Existing Rates	2015 Test Proposed Rates
Revenue				
Suff/ Def From Below.		1,003,773		648,501
Distribution Revenue	28,371,080	28,371,080	28,665,192	28,665,192
Other Operating Revenue (Net)	1,596,475	1,596,475	1,602,522	1,602,522
Total Revenue	**29,967,555**	**30,971,328**	**30,267,714**	**30,916,215**
Distribution Costs				
Operation, Maintenance, and Administration	16,754,348	16,754,348	16,734,686	16,734,686
Depreciation & Amortization	4,936,879	4,936,879	4,936,879	4,936,879
Property & Capital Taxes	287,232	287,232	287,232	287,232
Interest- Deemed Interest	3,567,234	3,567,234	3,479,829	3,479,829
Total Costs and Expenses	**25,545,693**	**25,545,693**	**25,438,626**	**25,438,626**
Utility Income Before Income Taxes	4,421,862	5,425,635	4,829,088	5,477,589
Net Adjustments per Pils	(4,814,861)	(4,814,861)	(4,814,861)	(4,814,861)
Taxable Income	(392,999)	610,774	14,227	662,728
Tax Rate	20.33%	20.33%	26.50%	26.50%
Income Tax	(79,911)	124,192	3,770	175,623
Income Tax Credits	(81,003)	(81,003)	(81,003)	(81,003)
Utility Income	4,582,775	5,382,446	4,906,321	5,382,969
Rate Base	143,761,898	143,761,898	144,703,471	144,703,471
Equity	40.00%	40.00%	40.00%	40.00%
Equity Component Rate Base	57,504,759	57,504,759	57,881,389	57,881,389
Income / Equity Rate Base %	7.97%	9.36%	8.48%	9.30%
Target Return -Equity on Rate Base	9.36%	9.36%	9.30%	9.30%
Indicated Rate of Return	5.67%	6.23%	5.80%	6.12%
Requested Rate of Return on Rate Base	6.23%	6.23%	6.12%	6.12%
Difference	(0.56%)	0.00%	(0.33%)	0.00%
Return- Equity on Rate Base	5,382,445	5,382,445	5,382,969	5,382,969
Revenue Deficiency	799,670		476,648	
Revenue Deficiency (Gross-up)	1,003,773		648,501	

(b)Please see the updated tracking form and refer to IRR # 1, 1-Staff-1 for more detail.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2015 Filers

Tracking Form

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.)

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	$ 8,949,680	6.23%	$ 143,761,898	$ 153,984,823	$ 20,018,027	$ 4,936,879	$ 43,189	$ 16,754,348	$ 30,971,328	$ 1,596,475	$ 29,374,853	$ 1,003,773
1	1-EP-2	Correct amortization period of regulatory costs to 5 years	$ 8,949,306	6.23%	$ 143,759,342	$ 153,965,160	$ 20,015,471	$ 4,936,879	$ 43,156	$ 16,734,685	$ 30,951,258	$ 1,596,475	$ 29,354,783	$ 983,703
		Change	-$ 374	0.00%	-$ 2,556	-$ 19,663	-$ 2,556	$ -	-$ 33	-$ 19,663	-$ 20,070	$ -	-$ 20,070	-$ 20,070
2	8-VECC-48	Update RTSR Model for proposed 2015 UTRs	$ 8,950,011	6.23%	$ 143,770,651	$ 154,052,148	$ 20,026,779	$ 4,936,879	$ 43,300	$ 16,734,685	$ 30,952,107	$ 1,596,475	$ 29,355,632	$ 984,552
		Change	$ 705	$ -	$ 11,309	$ 86,988	$ 11,308	$ -	$ 144	$ -	$ 849	$ -	$ 849	$ 849
3	3-EP-12	Update COP for Oct 2014 RPP Report	$ 8,986,700	6.23%	$ 144,360,019	$ 158,585,748	$ 20,616,147	$ 4,936,879	$ 50,787	$ 16,734,685	$ 30,996,285	$ 1,596,475	$ 29,399,809	$ 1,028,729
		Change	$ 36,689	$ -	$ 589,368	$ 4,533,600	$ 589,368	$ -	$ 7,487	$ -	$ 44,178	$ -	$ 44,177	$ 44,177
4	3-EP-20, 3-VECC-24	Update SSS Admin Revenue	$ 8,986,700	6.23%	$ 144,360,019	$ 158,585,748	$ 20,616,147	$ 4,936,879	$ 50,787	$ 16,734,685	$ 30,996,285	$ 1,602,522	$ 29,393,762	$ 1,022,682
		Change	-$ 0	$ -	$ 0	$ -	$ -	$ -	-$ 0	$ -	$ -	$ 6,047	-$ 6,047	-$ 6,047
5	3-VECC-16, 3-VECC-17, 3-VECC-18	Update CDM for 2013 final verified. Update 2015 CDM target. Correct double counting of CDM variable in regression model	$ 9,008,080	6.23%	$ 144,703,471	$ 161,227,692	$ 20,959,600	$ 4,936,879	$ 55,165	$ 16,734,685	$ 31,022,042	$ 1,602,522	$ 29,419,520	$ 754,328
		Change	$ 21,380	$ -	$ 343,452	$ 2,641,944	$ 343,453	$ -	$ 4,378	$ -	$ 25,757	$ -	$ 25,758	-$ 268,354
6	5-EP-34	Update 2015 Cost of Capital Parameters	$ 8,862,798	6.12%	$ 144,703,471	$ 161,227,692	$ 20,959,600	$ 4,936,879	$ 43,366	$ 16,734,685	$ 30,864,961	$ 1,602,522	$ 29,262,439	$ 597,247
		Change	-$ 145,282	-$ 0	$ -	$ -	$ -	$ -	-$ 11,799	$ -	-$ 157,081	$ -	-$ 157,081	-$ 157,081
7	4-Staff-41	Update 2015 PILs to reflect elimination of Small Business Deduction	$ 8,862,798	6.12%	$ 144,703,471	$ 161,227,692	$ 20,959,600	$ 4,936,879	$ 94,620	$ 16,734,685	$ 30,916,215	$ 1,602,522	$ 29,313,693	$ 648,501
		Change	-$ 0	$ -	$ 0	-$ 0	-$ 0	$ -	$ 51,254	$ -	$ 51,254	-$ 0	$ 51,254	$ 51,254

Exhibit 7 Cost Allocation

149. 7 Staff 43.Connections/Customers

Reference

i. Cost Allocation Model

Preamble

On Tab I6.2 Customer Data Worksheet, NPEI records number of customer and number of connections for street lighting, sentinel lighting, and USL. For street lighting there are 4 customers and 1,299 connections, a ratio of 327.5 connections to customer.

a) What has NPEI done to determine the number of connections?

b) How does NPEI maintain the records for connections to customer?

Response

a) NPEI connects both individually controlled and group controlled streetlights to its secondary distribution system. Individually controlled streetlights consist of a single streetlight fixture connected directly to NPEI's 120/240V secondary distribution circuit. The streetlight fixture is controlled by a photo-eye mounted on top of the light. Group controlled streetlights consist of multiple streetlight fixtures daisy chained together. The group of streetlights is connected to NPEI's secondary distribution system through a single point of disconnect and control using a streetlight conductor. The streetlight conductor, disconnect, and control are owned by the streetlight owner. There are typically 10 to 14 streetlight fixtures supplied by a single streetlight disconnect in this scenario. Approximately 375 streetlights are individually controlled and connect directly to NPEI's secondary distribution system. Approximately 12,615 streetlights are connected indirectly to NPEI's secondary distribution system through 924 streetlight disconnects. Therefore, the total number of streetlight service connections is 1,299 (375 + 924). This is based on the limited amount of streetlight data modeled in our GIS. NPEI is currently developing a more accurate streetlight model based on data supplied from the streetlight owners. NPEI is still in the process of mapping the streetlight connections in its GIS system.

b) NPEI maintains the records for connections to customers within the CIS. Data from the GIS model, as well as customer updates are input into the CIS for billing and record keeping.

150. 7 Staff 44.Revenue-to-Cost Ratios

Reference

- Exhibit 7 Tab 4 Schedule 1 Attachment 1 of 1

Preamble

NPEI is proposing to lower the Revenue-to-Cost ("R:C") ratio for General Service >50 ("GS>50") kW class in three steps over the 2015 – 2017 period. The proposal also is to make up the revenue shortfall by raising the residential R:C ratios over the same period.

a) What would the rate impact to the residential customer be if GS>50 kW was set at 120% for 2015?

b) Why is NPEI proposing to balance revenues by only adjusting the residential class?

c) Could GS>50 kW be set at 120 in 2015 by adjusting all other classes? Please explain.

d) What steps did NPEI take to engage its customers on this proposed resolution? What were the views of the two affected classes? What changes, if any, did NPEI make to its proposal given the feedback it received?

Response

a) To reduce the revenue-to-cost ratio for the GS>50 kW class to 120% in 2015, the revenue-to-cost ratio for the Residential class would have to be set at 91.95%. The table below shows the impacts.

	2015 as Proposed					Adjust GS>50 to 120% in 2015				
Rate Class	R:C Ratio	% of Base Revenue	Base Revenue $	Monthly Service Charge	Volumetric Charge	R:C Ratio	% of Base Revenue	Base Revenue $	Monthly Service Charge	Volumetric Charge
Residential	87.0%	59.1%	$ 17,314,792	$19.93	$0.0149	92.0%	62.7%	$ 18,371,707	$21.14	$0.0158
General Service < 50 kW	118.3%	12.8%	$ 3,741,794	$46.22	$0.0108	118.3%	12.8%	$ 3,741,794	$46.22	$0.0108
General Service > 50 kW	138.5%	26.5%	$ 7,779,262	$156.61	$3.7301	120.0%	22.9%	$ 6,722,346	$135.33	$3.2578
Sentinel Lights	80.0%	0.2%	$ 67,519	$19.70	$0.0138	80.0%	0.2%	$ 67,519	$19.70	$0.0138
Streetlighting	88.5%	1.0%	$ 280,050	$14.95	$18.6534	88.5%	1.0%	$ 280,050	$14.95	$18.6534
USL	120.0%	0.4%	$ 130,276	$1.18	$4.5667	120.0%	0.4%	$ 130,276	$1.18	$4.5667
Total		100.0%	$ 29,313,693				100.0%	$ 29,313,692		

b) The revenue-to-cost ratios for the GS<50 kW and Unmetered Scattered Load classes are already at or close to the maximum of the Board's established ranges. NPEI could adjust the revenue-to-cost ratios for the Sentinel and Street lighting classes also, as per response to 7-Energy Probe-38 b). However, the resulting impact on the Residential class is very small, given the relatively low levels of revenue from the Sentinel and USL classes.

c) Yes. Please see the response to b) above and 7-Energy Probe-38 b).

d) NPEI did not engage its customers on this issue. NPEI's proposal is guided by the requirement to move the revenue-to-cost ratio for the GS>50 kW class into the Board's range, while also considering bill impacts to the Residential customers.

ENERGY PROBE

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151. 7-Energy Probe-37

Ref: Exhibit 7, Tab 1, Schedule 2

a) Is there any impact on the allocation of costs as a result of the purchase of assets from the Niagara Parks Commission? Please fully explain the answer.

b) What rate class or classes included the account(s) associated with the Niagara Parks Commission consumption prior to the assets being purchased by NPEI?

c) What rate class or classes include the account(s) associated with the Niagara Parks Commission consumption after the assets are purchased by NPEI?

Response

a) NPEI has not made any adjustments to the cost allocation model for the Niagara Parks Commission assets. Please see the responses to 2-Staff-24 and 2-Energy Probe-8 e).

b) Please see the response to 3-Energy Probe-21 a).

c) Please see the response to 3-Energy Probe-21 b).

152. 7-Energy Probe-38

Ref: Exhibit 7, Tab 1, Schedule 4

a) Table 7-11 does not appear to show the revenue-to-cost ratios that would be required for all rate classes in order to reduce the GS>50 class to 120%. Please provide a version of Table 7-11 that does so.

b) Please provide a version of Table 7-11 that sets all of the revenue-to-cost ratios for those classes below 100% (residential, sentinel lights, street lighting) equal to one another and allows the GS>50 class to be set at 120%.

Response

a) The table below shows the 2015 revenue-to-cost ratios that would be required to reduce the GS > 50 kW class to 120% in 2015, based on only adjusting the Residential class.

Class	Revenue Requirement - 2015 Cost Allocation Model	2015 Base Revenue Allocated based on Proportion of Revenue at Existing Rates	Miscellaneous Revenue Allocated from 2015 Cost Allocation Model	Total Service Revenue Cost Allocation Model	Check Revenue Cost Ratios from 2015 Cost Allocation Model	Proposed Revenue to Cost Ratio	Proposed Service Revenue	Miscellaneous Revenue	Proposed Base Revenue
Residential	21,351,822	15,978,348	1,261,294	17,239,642	80.7%	91.950%	19,633,001	1,261,294	18,371,707
GS < 50 kW	3,322,653	3,741,794	189,243	3,931,037	118.31%	118.31%	3,931,037	189,243	3,741,794
GS >50	5,717,372	9,122,015	138,617	9,260,632	161.97%	120.0021%	6,860,963	138,617	6,722,346
Sentinel Lights	90,961	59,429	5,250	64,679	71.11%	80.00%	72,769	5,250	67,519
Street Lighting	323,064	280,050	5,984	286,034	88.54%	88.54%	286,034	5,984	280,050
USL	110,342	132,057	2,134	134,191	121.61%	120.00%	132,411	2,134	130,276
TOTAL	**30,916,215**	**29,313,693**	**1,602,522**	**30,916,215**	**100.0%**		**30,916,215**	**1,602,522**	**29,313,693**

b) The table below shows the 2015 revenue-to-cost ratios that would be required to reduce the GS > 50 kW class to 120% in 2015, based on setting the Residential, Sentinel and Street lighting classes equal to one another.

Class	Revenue Requirement - 2015 Cost Allocation Model	2015 Base Revenue Allocated based on Proportion of Revenue at Existing Rates	Miscellaneous Revenue Allocated from 2015 Cost Allocation Model	Total Service Revenue Cost Allocation Model	Revenue Cost Ratio	Proposed Revenue to Cost Ratio	Proposed Service Revenue	Miscellaneous Revenue	Proposed Base Revenue
Residential	21,351,822	15,978,348	1,261,294	17,239,642	80.7%	91.850%	19,611,639	1,261,294	18,350,345
GS < 50 kW	3,322,653	3,741,794	189,243	3,931,037	118.3%	118.31%	3,931,037	189,243	3,741,794
GS >50	5,717,372	9,122,015	138,617	9,260,632	162.0%	120.0000%	6,860,846	138,617	6,722,229
Sentinel Lights	90,961	59,429	5,250	64,679	71.1%	91.85%	83,548	5,250	78,298
Street Lighting	323,064	280,050	5,984	286,034	88.5%	91.85%	296,734	5,984	290,751
USL	110,342	132,057	2,134	134,191	121.6%	120.00%	132,411	2,134	130,276
TOTAL	30,916,215	29,313,693	1,602,522	30,916,215	100.0%		30,916,215	1,602,522	29,313,693

153. 7-Energy Probe-39

Ref: Exhibit 7, Tab 1, Schedule 4

Please provide versions of Tables 7-12, 7-13, 7-14 that set the revenue-to-cost ratios for the residential, sentinel and street lighting classes equal to one another in each year of the three year phase in.

Response

The tables below show the revenue-to-cost ratios for each year of the three year phase in based on setting the Residential, Sentinel and Street lighting classes equal to one another.

Class	Revenue Requirement - 2015 Cost Allocation Model	2015 Base Revenue Allocated based on Proportion of Revenue at Existing Rates	Miscellaneous Revenue Allocated from 2015 Cost Allocation Model	Total Service Revenue Cost Allocation Model	Revenue Cost Ratio	Proposed Revenue to Cost Ratio 2015	Proposed Service Revenue	Miscellaneous Revenue	Proposed Base Revenue
Residential	21,351,822	15,978,348	1,261,294	17,239,642	80.7%	87.026%	18,581,673	1,261,294	17,320,379
GS < 50 kW	3,322,653	3,741,794	189,243	3,931,037	118.3%	118.31%	3,931,037	189,243	3,741,794
GS >50	5,717,372	9,122,015	138,617	9,260,632	162.0%	138.3640%	7,910,784	138,617	7,772,167
Sentinel Lights	90,961	59,429	5,250	64,679	71.1%	87.03%	79,160	5,250	73,910
Street Lighting	323,064	280,050	5,984	286,034	88.5%	87.03%	281,151	5,984	275,167
USL	110,342	132,057	2,134	134,191	121.6%	120.00%	132,411	2,134	130,276
TOTAL	**30,916,215**	**29,313,693**	**1,602,522**	**30,916,215**	100.0%		**30,916,215**	**1,602,522**	**29,313,693**

Class	Revenue Requirement - 2015 Cost Allocation Model	2015 Base Revenue Allocated based on Proportion of Revenue at Existing Rates	Miscellaneous Revenue Allocated from 2015 Cost Allocation Model	Total Service Revenue Cost Allocation Model	Revenue Cost Ratio	Proposed Revenue to Cost Ratio 2016	Proposed Service Revenue	Miscellaneous Revenue	Proposed Base Revenue
Residential	21,351,822	15,978,348	1,261,294	17,239,642	80.7%	88.986%	19,000,210	1,261,294	17,738,916
GS < 50 kW	3,322,653	3,741,794	189,243	3,931,037	118.3%	118.31%	3,931,037	189,243	3,741,794
GS >50	5,717,372	9,122,015	138,617	9,260,632	162.0%	130.9016%	7,484,131	138,617	7,345,514
Sentinel Lights	90,961	59,429	5,250	64,679	71.1%	88.99%	80,943	5,250	75,693
Street Lighting	323,064	280,050	5,984	286,034	88.5%	88.99%	287,483	5,984	281,499
USL	110,342	132,057	2,134	134,191	121.6%	120.00%	132,411	2,134	130,276
TOTAL	**30,916,215**	**29,313,693**	**1,602,522**	**30,916,215**	100.0%		**30,916,215**	**1,602,522**	**29,313,693**

Class	Revenue Requirement - 2015 Cost Allocation Model	2015 Base Revenue Allocated based on Proportion of Revenue at Existing Rates	Miscellaneous Revenue Allocated from 2015 Cost Allocation Model	Total Service Revenue Cost Allocation Model	Revenue Cost Ratio	Proposed Revenue to Cost Ratio 2017	Proposed Service Revenue	Miscellaneous Revenue	Proposed Base Revenue
Residential	21,351,822	15,978,348	1,261,294	17,239,642	80.7%	91.850%	19,611,639	1,261,294	18,350,345
GS < 50 kW	3,322,653	3,741,794	189,243	3,931,037	118.3%	118.31%	3,931,037	189,243	3,741,794
GS >50	5,717,372	9,122,015	138,617	9,260,632	162.0%	120.0000%	6,860,846	138,617	6,722,229
Sentinel Lights	90,961	59,429	5,250	64,679	71.1%	91.85%	83,548	5,250	78,298
Street Lighting	323,064	280,050	5,984	286,034	88.5%	91.85%	296,734	5,984	290,751
USL	110,342	132,057	2,134	134,191	121.6%	120.00%	132,411	2,134	130,276
TOTAL	**30,916,215**	**29,313,693**	**1,602,522**	**30,916,215**	100.0%		**30,916,215**	**1,602,522**	**29,313,693**

VECC

154. 7.0 – VECC – 41

Reference:E7/T1/S1, pg. 3 (lines 28-29)

a) Since the service weighting factors are meant to reflect the relative cost, by customer class, of a single service connection, please explain why/how the infrequency of service connections for streetlights, unmetered loads and sentinel lights impacts the weighting factor.

Response

NPEI has changed the service weighting factors for the Street lighting, Sentinel and Unmetered Scattered Load classes from 0.3 to zero based on the fact that costs in Account 1855 do not relate to services for the connection of these classes. Sentinel and Unmetered Scattered Load connections are trending downward.

155. 7.0 – VECC – 42

Reference:E7/T1/S1, pg. 4
E8/T6/S1

a) Please indicate what costs savings accrue to NPEI as a result of the IESO's MDMR activity (i.e. what activities are performed by the IESO that NPEI would otherwise have to undertake?).
b) Please indicate how these savings have been factored into the billing and collecting factors proposed for Residential and GS<50 versus the weighing factor proposed for GS>50.

Response

a) The cost savings that would accrue to NPEI as a result of the IESO's MDMR activity would be insignificant as NPEI currently performs all of these activities within its' own Operational Data Storage System.

b) The Residential service factor is set at one for cost allocation. Only costs that NPEI does incur are a part of the costs allocated in cost allocation.

156. 7.0 – VECC -43

Reference: E7/T1/S1, pg. 6
Cost Allocation Model, Tab I-7.1

a) Please explain why the number of meters for the GS<50 class used in the cost allocation (4356) is less than the number of GS<50 customers forecast for 2015 (4385).
b) Please explain why the number of Residential meters used in the cost allocation (46,764) is less than the number of Residential customers forecast for 2015 (47,067).

Response

a) NPEI has corrected the Sheet I.7.1 Meter Capital in the Cost Allocation model by increasing the GS<50 kW meter count by 29 to agree with the 2015 forecast. NPEI has also adjusted Sheet I.7.2 Meter Reading to reflect the correct number of GS<50 kW meters. See the yellow highlighted cells in NPEI's updated Cost Allocation Model.

b) NPEI has corrected the Sheet I.7.1 Meter Capital in the Cost Allocation model by increasing the Residential meter count by 303 to agree with the 2015 forecast. NPEI has also adjusted Sheet I.7.2 Meter Reading to reflect the correct number of Residential meters. See the yellow highlighted cells in NPEI's updated Cost Allocation Model.

157. 7.0 – VECC -44

Reference: E7/T1/S1, pg.7-8
Cost Allocation Model, Tab I-7.2

- Please clarify the treatment of meter reading costs in the Application:
  - i. Do the metering reading costs included in the application for 2015 reflect the MIST forecast meter reading costs for 2015 ($43,920) or have they been adjusted upwards per Table 7-5 to $131,760 based on the five year average (2015-2019)?
  - ii. Please explain more fully how the number of meter reads by meter type were established for each customer class in Table I-7.2.
  - iii. Please reconcile the total number of meter reads for each customer class shown in Tab I-7.2 with the number of meters by customer class per Tab I-7.1.

Response

i. The MIST meter reading costs included in the Application reflect the five year average of $131,760. Please see cell BM29 of Sheet I.7.2 Meter Reading Costs in the Cost Allocation Model, which contains the MIST meter reading costs.

ii. The number of meter reads by meter type is grouped by the cost per meter read, multiplied by 12 reads per year for billing purposes. Please see the table in part iii) below for further details.

iii. The table below reconciles the number of meters by customer class from I.7.1 with the meter reading costs by type from I.7.2. NPEI notes that these figures are as corrected per 7-VECC-43 above. In calculating the meter reading costs by meter type, the forecast number of MIST meters in 2015 of 184 has been multiplied by 3 in order to incorporate the average cost for the 2015-2019 period, as indicated in response to part i) above.

Meter Type	Residential	GS<50 kW	GS>50 kW	Total # Meters	Adjusting Factor for MIST Meters	Cost / Meter Read	# of Reads per Year	Total Meter Reading Cost
Single Phase 100 amp	6			6		2.39	12	172
Central Meter	7	46	44	97		2.39	12	2,782
Network Meter		2		2		2.39	12	57
3 Phase - No Demand - Residential Walking	2			2		2.39	12	57
3 Phase - No Demand		16		16		1.15	12	221
Smart Meters	47,052	4,000	22	51,074		0.32	12	196,124
Demand without IT		29	96	125		1.15	12	1,725
Demand with IT - Walking		176	267	443		1.15	12	6,113
Demand with IT - Vehicle		24	85	109		30.00	12	39,240
Demand with IT and Interval - Secondary			223	223		32.86	12	87,932
Demand with IT and Interval - Primary			33	33		32.86	12	13,012
MIST Meters		92	92	184	3	20.00	12	132,480
Total	47,067	4,385	862	52,314				479,916

158. 7.0 – VECC -45

Reference: E7/T1/S2, pg. 1
Cost Allocation Model, Tab I-6.1 and I-6.2

a) Does NPEI or the customer own the conductor that serves as the daisy-chain connection for each group of streetlights past the point of disconnect as described at lines 16-19?

b) It is noted that for purposes of determining the revenue at current rates in Tab I-6.1 the number of Streetlight connections was increased by a factor of 10. Is the service charge applicable to Streetlights applied per device/fixture or per connection for billing purposes?

Response

a) The customer owns the conductor that serves as the daisy-chain connection for each group of streetlights past the point of disconnect.

b) NPEI's street lighting data is as follows:

- 5 customers
- 14 accounts
- 1,299 connections
- 12,999 devices

For billing purposes, NPEI's monthly service charge applies to the number of devices.

159. 7.0 – VECC – 46

Reference: E7/T1/S2
E2/T1/S2, pg. 34

Preamble: Please only complete this interrogatory if there has been no explicit adjustment made to the 2015 number of customers by customer class as a result of the planned purchase of the Niagara Parks Commission's assets.

a) Please provide a revised 2015 Cost Allocation Model which includes an additional customer class labelled – NPC-Direct Assignment. For this new class:

- Please directly assign to this class the assets proposed to be purchased from the Niagara Parks Commission and any associated O&M for 2015 included in the proposed revenue requirement.

Please set both the 2015 load values and customer/connection count for the class at zero.

Response

a) As explained in response to 2-Staff-24, an agreement between NPEI and NPC has not yet been executed and is currently with legal counsel of the two parties to develop the terms of reference.
Until an agreement is in place, NPEI is not able to determine the nature of costs that would be allocated to NPC, and therefore is not able to respond to this interrogatory.

Exhibit 8 Rate Design

160. 8 Staff 45.Fixed Charges

Reference

- Exhibit 8 Tab 1 Schedule 1

Preamble

NPEI proposes to increase the fixed/variable split for the Residential and General Service < 50 kW classes, and to maintain the existing fixed/variable split for the General Service > 50 kW, Unmetered Scattered Load, Sentinel Lights and Street lighting classes.

This results in fixed charges for the GS<50 kW and USL moving above the ceiling, and GS>50 kW dropping below the ceiling. This is illustrated in the following table:

From Table 8-3

	col. 1	*col. 2*	*col. 3*	*col. 4*
	Current	**Maintaing Split**	**Proposed**	**Ceiling**
Res	16.06	17.97	19.96	28.59
GS<50	37.79	39.13	46.39	38.26
GS>50	179.58	159.22	159.22	179.58
USL	19.53	20.14	20.14	19.53
Sent	12.87	15.26	15.26	24.43
Street	1.15	1.19	1.19	16.53

Moving up
Moving down

On April 3, 2014, the Board released its *Draft Report on Rate Design for Electricity Distributors (EB-2012-0410)*, which proposes implementing a fixed monthly charge for distribution services for the Residential and General Service < 50 kW classes. The draft rate design report sets out three rate design proposals for revenue recovery.

NPEI states on page 3 of Reference 1 that does not propose to adopt any of the three specific proposals described in the draft report for its 2015 rates. However, given that the Board has determined it will proceed with revenue decoupling for the low volume classes, NPEI submits that it is appropriate to begin increasing the fixed proportion of the Residential and General Service < 50 kW classes at this time.

a) Given NPEI's position, why is it lowering the fixed charge for GS>50 kW?

b) Street Lighting and sentinel lighting have fixed charges considerably below the ceiling. Why is there not a larger increase?

Response

a) The proposed fixed charge for the GS>50 kW class is lower than NPEI's current Board-approved fixed charge due to maintaining the existing fixed / variable proportion, while also taking into account the movement towards the Board's new maximum level of revenue-to-cost ratio of 120% for this class. The Board's revenue decoupling initiative does not apply to this class.

b) NPEI's proposed rate design for the Street lighting and Sentinel classes maintains the existing fixed / variable proportions for these classes. The Board's revenue decoupling initiative does not apply to these classes.

ENERGY PROBE

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161. 8-Energy Probe-40

Ref: Exhibit 8, Tab 7, Schedule 1

Does NPEI offer customers the option of receiving their bill by e-mail rather than receiving an e-mail and then having to retrieve it from the NPEI website? If not, why not?

Response

NPEI does not offer customers the option of receiving their bill by email rather than receiving an email and then having to retrieve it from the NPEI website. NPEI does not offer this option due to security of data (regular email is not the most secured method of sending of customer information), and size of data transmission. In addition the use of the notification and access to My Account web portal provides for a secure delivery method, with options to view other account information, as well as, access other self-service tools.

VECC

162. 8.0 –VECC -47

Reference: E8/T1/S1, pg. 3 - 5

a) Please explain more fully how the proposed 65% fixed / 35% variable split for the Residential and GS<50 classes was established (i.e., why this particular ratio in each case?).
b) What is rationale for proposing service charges for the GS<50 and USL classes that are above the ceiling rates calculated by the cost allocation model?

Response

a) NPEI's proposed movement toward a greater fixed proportion for the Residential and GS<50 kW classes is aimed at mitigating bill impacts upon future implementation of full revenue decoupling. The particular ratio of 65% fixed / 35% variable was selected for the Residential class since it results in a lower bill impact than the existing fixed / variable split for a typical Residential customer consuming an average of 800 kWh or more per month.

Please see the tables below which provides a summary of Residential monthly bill impacts for the existing fixed / variable split, NPEI's proposed 65% / 35% split, and 100% fixed, for the consumption levels requested in 8-VECC-49. The yellow highlights indicate where the proposed 65:35 split results in lower bill impacts than the existing fixed / variable split.

TOU May - October	Total Bill	Total Bill	Total Bill	Total Bill	Total Bill	Total Bill
Usage	$ Change	% Change	$ Change	% Change	$ Change	% Change
kWh / month	Existing Fixed/Variable Split	Existing Fixed/Variable Split	65:35 split	65:35 split	100% fixed	100% fixed
100	2.18	6.78%	4.05	12.60%	13.45	41.77%
250	2.74	5.16%	4.18	7.89%	11.30	21.26%
500	3.69	4.20%	4.39	4.99%	7.73	8.78%
800	4.83	3.72%	4.64	3.57%	3.42	2.64%
1000	5.58	3.54%	4.79	3.04%	0.55	0.35%
1500	7.47	3.28%	5.21	2.26%	(6.61)	-2.91%
2000	9.36	3.15%	5.62	1.89%	(13.77)	-4.63%

TOU November - April	Total Bill	Total Bill	Total Bill	Total Bill	Total Bill	Total Bill
Usage	$ Change	% Change	$ Change	% Change	$ Change	% Change
kWh / month	Existing Fixed/Variable Split	Existing Fixed/Variable Split	65:35 split	65:35 split	100% fixed	100% fixed
100	2.18	6.78%	4.05	12.58%	13.45	41.77%
250	2.74	5.16%	4.18	7.89%	11.30	21.26%
500	3.69	4.20%	4.39	4.99%	7.73	8.78%
800	4.82	3.88%	4.64	3.57%	3.42	2.64%
1000	5.58	3.54%	4.79	3.04%	0.55	0.35%
1500	7.47	3.28%	5.21	2.29%	(6.61)	-2.91%
2000	9.36	3.15%	5.62	1.89%	(13.77)	-4.63%

RPP May - October	Total Bill	Total Bill	Total Bill	Total Bill	Total Bill	Total Bill
Usage	$ Change	% Change	$ Change	% Change	$ Change	% Change
kWh / month	Existing Fixed/Variable Split	Existing Fixed/Variable Split	65:35 split	65:35 split	100% fixed	100% fixed
100	2.18	6.93%	4.05	12.86%	13.45	42.71%
250	2.75	5.36%	4.18	8.14%	11.31	22.02%
500	3.69	4.37%	4.38	5.19%	7.72	9.14%
800	4.82	3.79%	4.63	3.64%	3.42	2.69%
1000	5.58	3.56%	4.80	3.06%	0.56	0.36%
1500	7.47	3.24%	5.21	2.26%	(6.61)	-2.87%
2000	9.36	3.07%	5.62	1.85%	(13.77)	-4.53%

RPP November - April	Total Bill	Total Bill	Total Bill	Total Bill	Total Bill	Total Bill
Usage	$ Change	% Change	$ Change	% Change	$ Change	% Change
kWh / month	Existing Fixed/Variable Split	Existing Fixed/Variable Split	65:35 split	65:35 split	100% fixed	100% fixed
100	2.18	6.93%	4.05	12.86%	13.45	42.71%
250	2.75	5.36%	4.18	8.14%	11.31	22.02%
500	3.69	4.37%	4.38	5.19%	7.72	9.14%
800	4.82	3.88%	4.63	3.73%	3.42	2.76%
1000	5.58	3.70%	4.79	3.18%	0.55	0.36%
1500	7.47	3.33%	5.21	2.32%	(6.61)	-2.95%
2000	9.36	3.14%	5.62	1.88%	(13.77)	-4.62%

NPEI is proposing the 65% fixed / 35% variable split for the GS<50 kW class to be consistent with the Residential class.

Please see the table below which shows typical monthly bill impacts for the existing fixed / variable split and NPEI's proposed 65% / 35% split, for a GS<50 kW customer consuming 2,000 kWh per month.

GS< 50				
TOU	Total Bill	Total Bill	Total Bill	Total Bill
Usage	$ Change	% Change	$ Change	% Change
kWh / month	Existing Fixed/Variable Split	Existing Fixed/Variable Split	65:35 split	65:35 split
2000	3.15	1.00%	4.15	1.32%
RPP	Total Bill	Total Bill	Total Bill	Total Bill
Usage	$ Change	% Change	$ Change	% Change
kWh / month	Existing Fixed/Variable Split	Existing Fixed/Variable Split	65:35 split	65:35 split
2000	3.15	0.99%	4.15	1.30%

b) NPEI is proposing a service charge that is above the ceiling rate for the GS<50 kW class due to movement towards revenue decoupling, and the associated bill impacts, as indicated in the response to part a) above.

NPEI's proposal for a service charge that is above the ceiling rate for the Unmetered Scattered Load class is based on maintaining the existing fixed / variable split for this class.

163. 8.0 –VECC -48

Reference: E8/T3/S1

a) Please update the proposed RTSR rates for 2015 to reflect the 2015 transmission rates recently proposed by Hydro One (EB-2014-0140).

Response

NPEI's RTSR Model has been updated to reflect the 2015 Uniform Transmission Rates ("UTRs") proposed by Hydro One in EB-2014-0140):

Network - $3.80 / kW
Line Connection - $0.86 / kW
Transformation Connection-$2.01 / kW

The table below shows NPEI's RTSRs as originally filed, and as updated for the 2015 UTRs.

Network	Billing Determinat	RTSR Model - Originally Filed		RTSR Model - Updated for Proposed 2015 UTRs	
		2015 Forecast Wholesale $	2015 RTSR Rate	2015 Forecast Wholesale $	2015 RTSR Rate
Residential	kWh	3,318,860	0.0076	3,304,272	0.0076
General Service Less Than 50 kW	kWh	903,753	0.0069	899,781	0.0069
General Service 50 to 4,999 kW	kW	4,892,913	2.8421	4,871,407	2.8297
Unmetered Scattered Load	kWh	16,360	0.0069	16,288	0.0069
Sentinel Lighting	kW	1,507	2.1043	1,501	2.0951
Street Lighting	kW	44,709	2.1486	44,512	2.1391
		9,178,102		9,137,760	

Connection	Billing Determinat	RTSR Model - Originally Filed		RTSR Model - Updated for Proposed 2015 UTRs	
		2015 Forecast Wholesale $	2015 RTSR Rate	2015 Forecast Wholesale $	2015 RTSR Rate
Residential	kWh	2,252,405	0.0052	2,300,676	0.0053
General Service Less Than 50 kW	kWh	596,993	0.0046	609,787	0.0047
General Service 50 to 4,999 kW	kW	3,111,286	1.8073	3,177,964	1.8460
Unmetered Scattered Load	kWh	10,807	0.0046	11,038	0.0047
Sentinel Lighting	kW	1,082	1.5101	1,105	1.5425
Street Lighting	kW	28,893	1.3885	29,512	1.4183
		6,001,465		6,130,083	

164. 8.0 –VECC -49

Reference: E8/T13/S1, Attachment 1

a) Please provide Residential bill impact schedules based on the following monthly usage levels that include the updated RTSR rates from the preceding question:
- 100 kWh
- 250 kWh
- 500 kWh
- 800 kWh
- 1,000 kWh
- 1,500 kWh and
- 2,000 kWh

b) Based on the most recent 12 months of billing data available, please provide a breakdown as to the number of residential customers that fall into the following ranges of monthly usage:
- 0-100 kWh
- >100 – 250 kWh
- >500 – 800 kWh
- >800 – 1,000 kWh

- >1,000 – 1,500 kWh
- >1,500 – 2,000 kWh
- >2,000 kWh

Response

a) The bill impacts are included in Attachment #17. Please see the response to 8-VECC-47 above for the bill impacts summary table for the requested levels of consumption.

b) The table below shows the breakdown of Residential customers into the given ranges of consumption.

Range of Average Monthly Consumption	Number of Residential Customers	% of Total
0 - 100 kWh	690	1.5%
100 - 250 kWh	2,800	6.0%
250 - 500 kWh	12,717	27.0%
500 - 800 kWh	15,943	33.9%
800 - 1000 kWh	6,221	13.2%
1000 - 1500 kWh	6,007	12.8%
1500 - 2000 kWh	1,641	3.5%
> 2000 kWh	1,026	2.2%
Total	47,045	100.0%

Exhibit 9 Deferral and Variance Accounts

165. 9 Staff 46.EDDVAR Continuity Schedule

Reference

- Exhibit 9, Tab 1, Schedule 1, Attachment 1, EDDVAR Continuity Schedule

Preamble

In year 2014 of the EDDVAR continuity schedule, the Principal Disposition and Interest Disposition during 2014 instructed by the Board for Account 1595 (2010) and Account 1595 (2011) is different than that as approved in NPEI's 2014 IRM Decision and Rate Order EB-2013-0154.

Please reconcile the difference and adjust the EDDVAR continuity schedule as applicable.

Response

For Account 1595 (2010), the total balance (principal and interest) included in the 2015 EDDVAR Model under disposition in 2014 is ($116,574). The Account 1595 (2010) balance approved in NPEI's 2014 IRM Rate Application (EB-0213-0154) is ($103,082), for a difference of ($13,492).

For Account 1595 (2011), the total balance (principal and interest) included in the 2015 EDDVAR Model under disposition in 2014 is ($109,514). The Account 1595 (2011) balance approved in NPEI's 2014 IRM Rate Application (EB-0213-0154) is ($108,712), for a difference of ($803).

These differences relate to billing journals that were recorded in Account 1595 (2010) and Account 1595 (2011) in error after the corresponding Rate Riders were no longer in effect. NPEI reversed these billing journals in 2014. These amounts have been included under 2014 dispositions in the 2015 EDDVAR Model since there is no other column relating to adjustments in 2014. The Table below shows the reconciliation between the balances approved in EB-2013-0154 and the 2015 EDDVAR Model.

Description	1595 (2010)	1595 (2011)
Balance Requested for Disposition in 2014 IRM Rate Application (EB-2013-0154) including forecast carrying charges to April 30, 2014	(103,082)	(108,712)
Billing Journals recorded after Rate Rider ceased	(13,492)	(803)
Balance as at April 30, 2014 (Included in 2015 EDDVAR)	(116,574)	(109,514)
Disposition approved in 2014 IRM	103,082	108,712
Correction of Billing Journals that were recorded after Rate Rider ceased	13,492	803
Current Balance	-	-

NPEI submits that no adjustment to the Account 1595 (2010) or Account 1595 (2011) balances in the 2015 EDDVAR Model are necessary.

166. 9 Staff 47.1592 PILs and Tax Variances, Sub-account HST/OVAT Input Tax Credits (ITCs)

Reference

- Exhibit 9, Tab 3, Schedule 1, p 4

Preamble

In its 2010 IRM, NPEI was directed to use Account 1592 PILs and Tax Variances, Sub-account HST/OVAT Input Tax Credits (ITCs) until its next cost of service. NPEI's next cost of service was in 2011.

Please explain why this account was not disposed in NPEI's 2011 cost of service?

Response

NPEI did not dispose of Account 1592 PILs and Tax Variances, Sub-account HST/OVAT Input Tax Credits (ITCs) in its 2011 COS Rate Application (EB-2010-0138) due to the required timing of recording the incremental ITCs and having the balances audited prior to disposition.

The Decision and Order in NPEI's 2010 IRM Rate Application (EB-2010-0205, EB-2010-0206) states: *"The Board therefore directs that, beginning July 1, 2010, NPEI shall record in deferral* *account 1592 (PILs and Tax Variances, Sub-account HST / OVAT Input Tax Credits (ITCs)) the incremental ITC it receives on distribution revenue requirement items that were previously subject to PST and become subject to HST. Tracking of these amounts will continue in the deferral account until the effective date of NPEI's next cost of service rate order."*

The effective date of NPEI's 2011 COS Rate Order was June 1, 2011. Accordingly, NPEI was required to record the incremental ITCs during the period July 1, 2010 to May 31, 2011. Therefore, the appropriate balance for disposition was not determined in time for NPEI's 2011 COS Application. Further, the final balance was audited as part of NPEI's 2011 year end audit, which was completed in early 2012.

Therefore, NPEI submits that disposition of Account 1592 PILs and Tax Variances, Sub-account HST/OVAT Input Tax Credits (ITCs) is appropriate in this current Application.

167. 9 Staff 48.Account 1576 Accounting Changes Under CGAAP

Reference

- Exhibit 9, Tab 3, Schedule 1, p 5

Preamble

With regards to Account 1576, in the past, the Board has typically approved the disposition of Account 1576 with no true-up to actuals. In addition, given that it is currently November 2014, NPEI should be able to reasonably forecast the 2014 PP&E value.

Please explain why NPEI is requesting to true up the account.

Response

NPEI requested a true up of Account 1576 because the balances that were originally filed were based on NPEI's 2014 budget. Based on NPEI's projected 2014 capital additions, the expected 2014 incremental PP&E difference to be recorded in Account 1576 is a credit of ($3,115,329). NPEI has added Sheet App. 2-EC_Account 1576 Projected to the 2015 Filing Requirements Chapter 2 Appendices which shows the updated projection for Account 1576.

File Number:	EB-2014-0096
Exhibit:	9
Tab:	3
Schedule:	8
Attachment:	2
Date:	29-Aug-14

Appendix 2-EC
Account 1576 - Accounting Changes under CGAAP
2013 Changes in Accounting Policies under CGAAP

For applicants that made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2013

	2011 Rebasing Year	2011	2012	2013	2014	2015 Rebasing Year
Reporting Basis	CGAAP	IRM	IRM	IRM	IRM	MIFRS
	Forecast	Actual	Actual	Actual	Forecast	Forecast
					$	$
PP&E Values under former CGAAP						
Opening net PP&E - Note 1				103,982,941	108,454,734	
Net Additions - Note 4				11,439,655	14,286,345	
Net Depreciation (amounts should be negative) - Note 4				-6,967,863	-8,071,084	
Closing net PP&E (1)				108,454,734	114,669,995	
PP&E Values under revised CGAAP (Starts from 2013)						
Opening net PP&E - Note 1				103,982,941	111,509,300	
Net Additions - Note 4				11,439,655	14,286,345	
Net Depreciation (amounts should be negative) - Note 4				-3,913,296	-4,955,755	
Closing net PP&E (2)				111,509,300	120,839,891	
Difference in Closing net PP&E, former CGAAP vs. revised CGAAP				-3,054,567	-6,169,896	

Effect on Deferral and Variance Account Rate Riders		
Closing balance in Account 1576	-	6,169,896
Return on Rate Base Associated with Account 1576 balance at WACC - Note 2	-	755,788
Amount included in Deferral and Variance Account Rate Rider Calculation	-	6,925,683

WACC	6.12%
# of years of rate rider disposition period	2

168. 9 Staff 49.Account 1508 Other Regulatory Assets, Sub-account Deferred IFRS Transition Costs

References

- Exhibit 9, Tab 3, Schedule 7, p. 1, Table 9-13

1. Chapter 2 Cost of Service Rate Application based on a Forward Test Year

Preamble

NPEI recorded costs in Account 1508 Deferred IFRS Transition Costs for 2009 to 2012. There does not appear to be any costs recorded or forecasted from 2013 to 2015. In Reference 2, an applicant should request for review and disposal of the account for the balance including the unaudited actuals for the bridge year and a forecast of any remaining costs to be incurred for the test year.

a) Please confirm whether NPEI is indicating that no further costs were incurred or will be incurred from 2013 to 2015.

b) If not, please quantify or forecast these costs and the related carrying charges and update the evidence.

Response

a) NPEI confirms that no further incremental costs were incurred or will be incurred from 2013 to 2015.

b) Not applicable.

169. 9 Staff 50.Account 1575 CGAAP Transitional PP&E

References

- Exhibit 2, Tab 2, Schedule 6

2. Exhibit 9, Tab 3, Schedule 7, Page 1

Preamble

In Reference 1, NPEI indicated that beginning in 2015, it will begin to derecognize grouped assets at the end of their actual service lives as required under IFRS.

a) In the transition to IFRS in 2014, has NPEI identified and recognized any derecognition gains or losses for grouped assets?

b) If yes, how much were the gains or losses and please explain why they were not captured in Account 1575

Response

a) NPEI has not identified or recorded any de-recognition gains or losses for grouped assets in 2014.
b) Not applicable.

In Reference 2, NPEI indicated that “since NPEI will remain on CGAAP until December 2014, NPEI has not recorded any balances in Account 1575”. Account 1575 is to record differences arising as a result of accounting policy changes caused by the transition from previous Canadian GAAP to modified IFRS relating to PP&E. NPEI is transitioning to IFRS in 2014 and adopting IFRS in 2015.

a) Please confirm that there are no further differences in PP&E arising from the adoption of IFRS.
b) If there are differences, please quantify the differences in Account 1575 and update the evidence.

Response

a) NPEI confirms that there are no further differences in PP&E arising from the adoption of IFRS.
b) Not applicable.

170. 9 Staff 51.Differences in PP&E Balances

References

- Exhibit 9, Tab 3, Schedule 8, Attachment 1 Appendix 2-BA
- Exhibit 9, Tab 3, Schedule 8, Attachment 1 Appendix 2-EC

Preamble

The 2013 and 2014 ending net book values under former and revised CGAAP in Reference 1 do not agree with that as shown in Reference 2 by $1,141,805.

Please explain and reconcile the difference in PP&E values.

Response

The difference of $1,141,805 between Reference 1 and Reference 2 relates to accumulated depreciation on PP&E disposals. Appendix 2-BA includes both additions and disposals of accumulated depreciation. Appendix 2-EC, as originally filed, only includes the accumulated depreciation additions.

The Table below shows the PP&E values from Appendix 2-EC as originally filed and as corrected to include disposals.

	As Originally Filed			Corrected	
	2013 IRM Actual	2014 IRM Forecast		2013 IRM Actual	2014 IRM Forecast
	$	$		$	$
PP&E Values under former CGAAP					
Opening net PP&E	103,982,941	107,312,932		103,982,941	108,454,734
Net Additions - Note 4	11,439,655	14,788,439		11,439,655	14,788,439
Net Depreciation (amounts should be negative)	(8,109,665)	(9,011,923)		(6,967,863)	(9,011,923)
Closing net PP&E	107,312,932	113,089,448		108,454,734	114,231,250
PP&E Values under revised CGAAP					
Opening net PP&E	103,982,941	110,367,498		103,982,941	111,509,300
Net Additions	11,439,655	14,788,439		11,439,655	14,788,439
Net Depreciation	(5,055,098)	(5,678,061)		(3,913,296)	(5,678,061)
Closing net PP&E	110,367,498	119,477,877		111,509,300	120,619,679
Difference in Closing net PP&E, former CGAAP vs. revised CGAAP	(3,054,567)	(6,388,428)		(3,054,567)	(6,388,428)
Effect on Deferral and Variance Account Rate Riders					
Closing balance in Account 1576		(6,388,428)			(6,388,428)
Return on Rate Base Associated with Account 1576 balance at WACC		(795,404)			(795,404)
Amount included in Deferral and Variance Account Rate Rider Calculation		(7,183,832)			(7,183,832)

NPEI notes that this correction has no impact on the closing balance of Account 1576. NPEI is filing a corrected Appendix 2-EC along with these interrogatory responses which now agrees to the balances in Appendix 2-BA.

171. 9 Staff 52.Accounts 1518 and 1548

Reference

- Exhibit 9, Tab 3, Schedule 9, Pages 1-2

In the variance calculation of Accounts 1518 and 1548, please explain:

a) What the expenses for interest on prudential letter of credit pertains to and why they are included in Accounts 1518 and 1548.

b) On what basis is the direct labour costs calculated and why it is so high

Response

a) The prudential interest expense relates to a standby letter of credit that NPEI holds with Scotia Bank. The Independent Electricity Market Operator ("IESO") is the beneficiary for $11,910,187. This is to provide support to the IESO for the purchase of electricity. The commission rate on this standby letter of credit is 0.5% per annum.

The commission on the standby letter of credit is an expense that NPEI incurs for participating in Ontario's electricity market and relates to both retailer and non-retailer customers. NPEI allocates a portion of the commission expense to the RCVA accounts based on the proportion of NPEI's retailer and Standard Supply Service ("SSS") customers.

b) The direct labour costs that are recorded in NPEI's RCVA accounts consist of:

- Management time – 3.5 hours per week of review/supervision for retailer settlements and reconciliations
- Retail Settlement Clerk – actual hours spent on retailer settlement (recorded on timesheet)

The Retail Settlement Clerk may perform duties that do not relate to retailer settlement, for example billing of SSS customers. In this case, the hours spent on SSS billing activities would be recorded on the weekly timesheet, and the corresponding labour expense would not be recorded in the RCVA accounts. Prior to May 1, 2014, a portion of the Retail Settlement Clerk's time was regularly charged as direct labour to water billing activities. This ceased when water billing and related activities returned to the City of Niagara Falls.

NPEI currently employs two Retail Settlement Clerks. One was an incremental position that was created by Niagara Falls Hydro, one of NPEI's predecessors, upon market opening. The other Retail Settlement Clerk was employed by NPEI's other predecessor LDC, Peninsula West Utilities. However, the Peninsula West Utilities position was not incremental upon market opening. Therefore, NPEI only charges direct labour for one Retail Settlement Clerk to the RCVA accounts.

172. 9 Staff 53.Allocation and Rate Rider Design

Reference

- Niagara_appl_CoS_EDDVAR_Continuity Sched_20140923.XLSM

Preamble

On Tab 5 Allocation of Balances, Board staff suggests that there is an error in the number of customers allocator, specifically for Street Lighting.

a)Please review and correct, or comment if NPEI considers the allocators correct.

NPEI is proposing to return Account 1576 over two years while it is proposing to return the remaining DVA balances over 1 year.

b)Please explain why NPEI is proposing to allocate 1576 over two years while it is proposing to return the DVA balances over 1 year, and not both over the same term

Response

a) NPEI agrees with Board staff that there is an error in the number of customers allocator for Street lighting. Further, NPEI has identified a similar error for the Unmetered Scattered Load class. In both cases, NPEI has used the number of connections, not the number of customers. The correct values for number for customers are as follows:

Street lighting 5 Customers

Unmetered Scattered Load 17 Customers

NPEI has made the required corrections on Sheet 4. Billing Determinants of the EDDVAR Model. NPEI is submitting the revised EDDVAR model in Excel format along with these interrogatory responses.

The Table below shows the impact of the correction to the proposed Deferral and Variance Rate Rider.

		Originally Filed			Corrected	
Rate Class	Units	Allocated Balance	Rate Rider		Allocated Balance	Rate Rider
Residential	kWh	(258,487)	-0.0006	$/kWh	(201,212)	-0.0005 $/kWh
General Service < 50 kW	kWh	(124,020)	-0.0010	$/kWh	(118,680)	-0.0010 $/kWh
General Service > 50	kW	(755,503)	-0.4388	$/kW	(754,435)	-0.4382 $/kW
Unmetered Scattered Load	kWh	(612)	-0.0003	$/kWh	(2,574)	-0.0011 $/kWh
Sentinel Lighting	kW	1,307	1.8253	$/kW	1,724	2.4077 $/kW
Street Lighting	kW	53,611	2.5764	$/kW	(8,529)	-0.4099 $/kW
		(1,083,705)			**(1,083,705)**	

b) The *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative* ("EDDVAR Report"), issued July 31, 2009, states:

"The Board also agrees the default disposition period used to clear the Account balances through a rate rider should be one year. However, a distributor could propose a different disposition period to mitigate rate impacts or address any other applicable considerations."

The total Deferral and Variance account balance as originally filed (excluding Account 1576 Accounting Changes Under CGAAP and the Account 1555 Stranded Meter sub-account) is $498,756 to be collected from NPEI's customers. Given this relatively small balance, it is

NPEI's view that no rate impact mitigation is required, and the EDDVAR Report default period of one year should apply to this balance.

However, the Account 1576 balance proposed for disposition is a credit to NPEI's customers of $6,388,428 plus $397,702 per year in the return on rate base component. Due to the size of credit balance on this account, a one year disposition period would result in large fluctuations in bill impacts to the customer. Therefore, NPEI is proposing a 2 year disposition period for Account 1576 to mitigate bill impacts.

Further, it is NPEI's view that there is no requirement that the general DVA disposition period match the disposition period of Account 1576. The *Filing Requirements for Electricity Distribution Rate Applications (2014 Edition for 2015 Rate Applications)*, Section 2.12.5, requires that an applicant must provide:

- *"A separate volumetric rate rider for Account 1576 for the clearance of the account balance over the proposed disposition period, including all calculations showing its derivation. The applicant must show that the rate rider is comprised of the amortized amount of account balance over the number of years proposed for the disposition period (e.g. five years);"*
- *"An explanation for the basis of the proposed disposition period to clear the account balance through the Account 1576 Rate Rider. The Board's determination of the disposition period will be on a case-by-case basis and will be guided primarily by such considerations as bill impacts and the financial impact on distributors;"*

173. 9 Staff 54.LRAMVA

Reference

- Exhibit 9, Tab 3, Schedule 10, Page 1 of 2, LRAMVA Preamble

Preamble

NPEI notes that its actual CDM savings for 2011 programs (10,053,956 kWh) and 2012 (5,615,949 kWh) are greater than the CDM component (11,600,000 kWh) that was included in its approved load forecast as part of its 2011 cost of service application (EB-2010-0138). As the actual CDM savings are greater than that included in its load forecast, the resulting lost revenue amount is a debit balance to NPEI. NPEI has decided to not make an LRAM claim for 2011 or 2012.

a) Please discuss if NPEI has updated its LRAMVA amount to include final 2013 CDM results which were included in NPEI's 2013 CDM Annual Report filed on September 30, 2014. If not, please update Table 9-16: Final CDM Results to include 2013 CDM savings.

b) Please provide further rationale as to why NPEI has opted to not make an LRAM claim for 2011 or 2012.

c) Please confirm that NPEI will not make an LRAM claim for 2011 or 2012 CDM savings in a future rate application.

d) Please discuss if NPEI has considered whether it will make an LRAM claim in relation to its 2013 final CDM savings.

e) Please expand Table 9-16 and include all relevant detailed lost revenue calculations, including CDM initiative-specific savings in each program year that NPEI delivered and that produced verified CDM results, the rate allocation of the savings from each CDM initiative, the applicable rate for each rate class, the CDM amount embedded in rates and the resulting lost revenue for each rate class. The following table can be used as an example:

Response

a) Table 9-16 has been updated to reflect the 2013 Final Verified CDM results, which includes adjustments to 2011 and 2012.

Table 9-16: Final CDM Results

			Updated Final Verified results	
CDM kWh	**2011**	**2012**	**2013**	**Total**
2011 CDM Programs (OPA Final Results)	5,026,978	5,026,978	4,942,830	14,996,786
2012 CDM Programs (OPA Final Results)	-	5,615,949	5,639,392	11,255,341
Adjustment to prior years final verified results	597,125	3,400,379	3,400,379	7,397,883
2013 CDM Programs (OPA Final Results)	-	-	3,682,087	3,682,087
Total in Year	5,624,103	14,043,306	17,664,688	37,332,097
CDM Embedded in Load Forecast	5,800,000	5,800,000	5,800,000	17,400,000
Difference (CDM in excess of amount included in Load Forecast)	(175,897)	8,243,306	11,864,688	19,932,097

b) NPEI's initial estimate of the LRAM revenue associated with the 2011 and 2012 CDM results, as originally filed, is $51,152. Further details of this calculation are given in the table below.

Original Estimate of LRAM Variance			
	2011	2012	Total
CDM in Excess of amount included in Load Forecast	(773,022)	4,842,927	4,069,905
Allocation to Rate Classes:			
Residential	(150,580)	943,374	792,794
GS<50	(173,706)	1,088,253	914,548
GS>50	(448,736)	2,811,300	2,362,564
	(773,022)	4,842,927	4,069,905
GS>50 kW to kWh ratio	0.2657%	0.2652%	
GS>50 kW for LRAM	(1,192)	7,456	6,264
Volumetric Distribution Rate			
Residential	0.0157	0.0158	
GS<50	0.0134	0.0135	
GS>50	4.1794	4.1887	
Lost Revenue (Excess Revenue)			
Residential	$ (2,364)	$ 14,905	$ 12,541
GS<50	$ (2,328)	$ 14,691	$ 12,364
GS>50	$ (4,982)	$ 31,230	$ 26,248
Total	$ (9,674)	$ 60,827	$ 51,152

NPEI notes that preparing an LRAM claim for 2011 and 2012 would involve additional consulting and legal expense, internal labour and increased intervenor time and expense.

In NPEI's view, given the immaterial amount of estimated lost revenue for 2011-2012, it is not prudent to incur the time and expense required to make an LRAM claim at this time.

c) NPEI will consider making an LRAM claim for 2011 and 2012 in a future application.

d) NPEI will consider filing an LRAM claim for 2013 in a future application. NPEI proposes to review the CDM impacts with respect to LRAM for the entire 2011-2014 period, once the final 2014 results are known. At that time, NPEI will determine whether to file an LRAM claim for the entire 4 year period in one application.

e) The table below shows NPEI's detailed LRAM calculations for the years 2011-2013, including CDM initiative specific savings and the rate class allocation for each initiative. NPEI notes that this table is not identical in format to the example provided by Board Staff, but contains the same information. The table that NPEI has included is based on the Final Verified 2013 CDM Savings that were provided by the OPA.

Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				2011 - 2013 Net Cumulative Energy Savings (kWh)				Allocation to Rate Classes			
2011	2012	2013	2014	2011	2012	2013	Total	Residential	<50kW	>50kW	
214,685	135,814	67,743		214,685	343,231	410,758	968,673	968,673			Residential
4,714	14,737	14,778		4,714	19,291	33,813	57,817	57,817			Residential
504,642	253,365	253,570		504,642	740,923	995,391	2,240,956	2,016,860	224,096		Residential (10% <50kW)
272,325	13,904	76,648		272,325	277,010	356,766	906,100	906,100			Residential
292,245	266,332	170,846		292,245	548,683	717,495	1,558,423	1,558,423			Residential
0	0	0		0	0	0	0	-			
0	0	208		0	0	208	208	208			
0	0	0		0	0	0	0				
0	0	0		0	0	0	0				
1,288,610	**684,152**	**583,793**		**1,288,610**	**1,929,136**	**2,514,431**	**5,732,177**	**5,508,081**	**224,096**	**0**	
927,120	3,486,336	2,142,104		927,120	4,382,069	6,461,321	11,770,510		1,059,346	10,711,164	91% >50kW 9%<50kW
903,623	712,848	620,149		903,623	1,585,880	2,202,104	4,691,606		4,691,606		<50kW
0	0	0		0	0	0	0				
0	0	0		0	0	0	0				
0	201,410	48,451		0	201,410	245,560	446,970			446,970	
0	0	5		0	0	5	5			5	
0	0	0		0	0	0	0				
4,146	1,548	1,500		4,146	5,553	7,072	16,771			16,771	>50kW
1,834,889	**4,402,143**	**2,812,209**		**1,834,889**	**6,174,912**	**8,916,062**	**16,925,863**	**0**	**5,750,952**	**11,174,911**	
0	0	0		0	0	0	0				
0	0	0		0	0	0	0				
0	0	0		0	0	0	0				
13,815	0	0		13,815	13,348	13,520	40,683			40,683	>50kW
3,710	1,578	10,747		3,710	5,163	15,923	24,795			24,795	>50kW
17,526	**1,578**	**10,747**		**17,526**	**18,510**	**29,443**	**65,479**	**0**	**0**	**65,479**	
9,137	54,743	181,895		9,137	63,571	244,411	317,118	317,118			
9,137	**54,743**	**181,895**		**9,137**	**63,571**	**244,411**	**317,118**	**317,118**	**0**	**0**	
0	0	0									
0	0	0									
0	**0**	**0**									
1,480,972	0	0		1,480,972	1,430,834	1,449,349	4,361,155	**0**	392,504	3,968,651	91% >50kW 9%<50kW
395,844	643,518	0		395,844	1,025,962	1,017,170	2,438,976			2,438,976	>50kW
0	0	0		0	0	0	0				
0	0	0		0	0	0	0				
0	0	0		0	0	0	0				
1,876,816	**643,518**	**0**		**1,876,816**	**2,456,796**	**2,466,519**	**6,800,131**	-	392,504	6,407,627	
0	0	93,443		0	0	93,443	93,443	93,443			
0	0	0		0	0	0	0				
0	**0**	**93,443**		**0**	**0**	**93,443**	**93,443**	93,443	-	-	
								5,918,642	6,367,552	17,648,016	29,934,210
								19.77%	21.27%	58.96%	
	-170,184	**1,313,384**		**597,125**	**1,313,384**	**1,313,384**	**3,223,893**	637,434	685,781	1,900,679	3,223,893
		2,086,995			**2,086,995**	**2,086,995**	**4,173,990**	825,288	887,884	2,460,818	4,173,990
5,019,121	**5,783,008**	**3,669,626**		**5,624,102**	**14,043,304**	**17,664,688**	**37,332,094**	**7,381,364**	**7,941,216**	**22,009,513**	**37,332,094**

The following table provides the difference between CDM results achieved and the CDM component embedded in NPEI’s load forecast, and the resulting lost revenue.

Updated Estimate of LRAM Variance	2011	2012	2013	Total
CDM Savings in Year	5,624,102	14,043,304	17,664,688	37,332,094
CDM Embedded in Load Forecast	5,800,000	5,800,000	5,800,000	17,400,000
CDM in Excess of amount included in Load Forecast	(175,898)	8,243,304	11,864,688	19,932,094
Allocation to Rate Classes:				
Residential	(34,779)	1,629,880	2,345,906	3,941,007
GS<50	(37,417)	1,753,501	2,523,835	4,239,919
GS>50	(103,703)	4,859,923	6,994,947	11,751,167
	(175,898)	8,243,304	11,864,688	19,932,094
GS>50 kW to kWh ratio	0.2657%	0.2652%	0.2624%	
GS>50 kW for LRAM	(275)	12,889	18,358	30,971
Volumetric Distribution Rate				
Residential	0.0157	0.0158	0.0159	
GS<50	0.0134	0.0135	0.0136	
GS>50	4.1794	4.1887	4.1815	
Lost Revenue (Excess Revenue)				
Residential	$ (546)	$ 25,752	$ 37,300	$ 62,506
GS<50	$ (501)	$ 23,672	$ 34,324	$ 57,495
GS>50	$ (1,151)	$ 53,987	$ 76,763	$ 129,599
Total	$ (2,199)	$ 103,412	$ 148,387	$ 249,600

VECC

174. 9.0 –VECC -50

Reference: 9/T3/S6

a) NPEI proposes to dispose of $16,992 in account 1508, but maintain the account until the transition to IFRS is complete. What further costs does NPEI anticipate booking into this (sub) account?

Response

NPEI does not anticipate booking any further incremental IFRS costs in Account 1508 Deferred IFRS Transition costs.

APPENDIX A

APPENDIX A

Excerpt from Letter to OEB dated September 24, 2007, in EB-2010-0138, SEC IR Responses, App. B, pp. 433/4 of 687

In addition to the quantitative benefits of the proposed transaction in reference to the net savings of $350, 358 annually, the parties of the proposed transaction would like the Board to consider the evidence provided which supports that the transaction does have a positive/neutral effect on the attainment of statutory objectives being: 1.) To protect the interests of consumers with respect to prices and adequacy, reliability and quality of electricity service; 2.) To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry ("no harm's test".)

In consideration of the "no harm" test, the parties anticipate that the proposed transaction expects to result in the following benefits for customers and municipal shareholders with respect to prices and the adequacy, reliability and quality of electricity service:

- Elimination of duplication (e.g. billing systems) and economies of scale will reduce current operational expenses and assist in avoiding future costs, which will help mitigate future rate increases in local distribution rates. Local distribution rates represent approximately 20 percent of a customer's total electricity bill.

- It will improve the utilization of existing resources such as employees, technologies and facilities, and will improve distribution system planning.

- By combining resources, employee expertise and best practices, the parties expect that there will be improved reliability of the local electricity distribution system for both
urban and rural customers, enhanced customer service, and a greater emergency response capability.

- The larger customer base combined with reduced operational costs through economies of scale results in a greater financial ability to invest in the maintenance and upgrading of the local electricity distribution infrastructure (i.e. poles, wires, transformers).

- An initial study of a harmonization of the current local distribution rates in the two service areas shows there would be minimal impact on customer rates and would result in a consistent, fair and competitive rate structure for all customers, along with improved services.

- The proposed transaction will maintain local presence and control over the management of electricity services and distribution rates increasing the consumer confidence in the delivery of reliable quality electricity service.

- Customers of Peninsula West will benefit from a larger, centrally located service centre in West Lincoln. This will provide for improved customer service and response times during emergencies.

APPENDIX B

Niagara Peninsula Energy
License Number ED-2007-0749, File Number EB-2010-0138

Niagara Peninsula Energy
Revenue Deficiency Determination

Description	2006	2007	2008	2009	2010 Bridge	2010 Actual	Bridge vs 2010 Actual	2011 Test Existing Rates	2011 Test - Required Revenue
Revenue									
Revenue Deficiency	0	0	0	0	0	0		0	**3,378,275**
Distribution Revenue	24,283,344	25,802,563	25,731,545	25,714,295	25,989,747	25,851,420	-138,327	26,857,308	26,857,308
Other Operating Revenue (Net)	2,260,825	2,503,646	1,960,023	2,300,073	1,999,852	1,972,628	-27,224	2,185,747	2,185,747
Total Revenue	**26,544,169**	**28,306,209**	**27,691,568**	**28,014,368**	**27,989,599**	**27,824,048**	**-165,551**	**29,043,055**	**32,421,330**
Costs and Expenses									
Administrative & General, Billing & Collecting	6,996,933	7,271,213	7,272,731	7,528,149	7,766,452	7,837,306	70,853	8,153,328	8,153,328
Operation & Maintenance	5,555,764	5,950,110	5,519,882	5,542,515	5,935,146	5,690,750	-244,396	6,142,107	6,142,107
Depreciation & Amortization	6,667,024	6,896,734	7,732,755	7,754,076	7,000,940	7,014,282	13,342	7,143,688	7,143,688
Property Taxes	194,863	201,207	231,271	215,254	232,000	219,631	-12,369	222,474	222,474
Capital Taxes	219,248	193,300	207,218	250,731	83,846	83,846	0	0	0
Deemed Interest	3,357,626	3,470,003	3,874,940	4,375,681	4,100,818	4,133,886	33,069	4,340,146	4,340,146
Total Costs and Expenses	**22,991,458**	**23,982,567**	**24,838,797**	**25,666,406**	**25,119,202**	**24,979,700**	**-139,502**	**26,001,743**	**26,001,743**
Less OCT Included Above	-219,248	-193,300	-207,218	-250,731	-83,846	-83,846	0	0	0
Total Costs and Expenses Net of OCT	**22,772,210**	**23,789,267**	**24,631,579**	**25,415,675**	**25,035,356**	**24,895,854**	**-139,502**	**26,001,743**	**26,001,743**
Utility Income Before Income Taxes	**3,771,959**	**4,516,942**	**3,059,989**	**2,598,693**	**2,954,243**	**2,928,194**	**-26,049**	**3,041,312**	**6,419,587**
Income Taxes:									
Corporate Income Taxes	1,987,152	1,520,059	918,023	763,489	893,733	698,485	-195,249	798,315	1,725,276
Total Income Taxes	**1,987,152**	**1,520,059**	**918,023**	**763,489**	**893,733**	**698,485**	-195,249	**798,315**	**1,725,276**
Utility Net Income	**1,784,806**	**2,996,883**	**2,141,966**	**1,835,204**	**2,060,510**	**2,229,709**	169,199	**2,242,997**	**4,694,311**
Capital Tax Expense Calculation:									
Total Rate Base	94,183,053	97,335,286	101,964,324	108,236,325	114,503,962	115,427,312	923,350	119,144,943	119,144,943
Exemption	10,000,000	12,500,000	15,000,000	15,000,000	15,000,000	15,000,000	0	15,000,000	15,000,000
Deemed Taxable Capital	**84,183,053**	**84,835,286**	**86,964,324**	**93,236,325**	**99,503,962**	**100,427,312**	923,350	**104,144,943**	**104,144,943**
Ontario Capital Tax	219,248	193,300	207,218	250,731	83,846	83,846	0	0	0
Income Tax Expense Calculation:									
Accounting Income	3,771,959	4,516,942	3,059,989	2,598,693	2,954,243	2,928,194	-26,049	3,041,312	6,419,587
Tax Adjustments to Accounting Income	1,870,700	-167,454	-167,454	-167,454	93,207	-300,064	-393,270	-131,884	-131,884
Taxable Income	**5,642,659**	**4,349,488**	**2,892,535**	**2,431,239**	**3,047,450**	**2,628,130**	-419,320	**2,909,428**	**6,287,703**
Income Tax Expense	1,987,152	1,520,059	918,023	763,489	893,733	698,485	-195,249	798,315	1,725,276
Tax Rate Refecting Tax Credits	35.22%	34.95%	31.74%	31.40%	29.33%	26.58%	-2.75	27.44%	27.44%
Actual Return on Rate Base:									
Rate Base	94,183,053	97,335,286	101,964,324	108,236,325	114,503,962	115,427,312	923,350	119,144,943	119,144,943
Interest Expense	3,357,626	3,470,003	3,874,940	4,375,681	4,100,818	4,133,886	33,069	4,340,146	4,340,146
Net Income	1,784,806	2,996,883	2,141,966	1,835,204	2,060,510	2,229,709	169,199	2,242,997	4,694,311
Total Actual Return on Rate Base	**5,142,432**	**6,466,886**	**6,016,906**	**6,210,885**	**6,161,327**	**6,363,595**	202,268	**6,583,143**	**9,034,456**
Actual Return on Rate Base	5.46%	6.64%	5.90%	5.74%	5.38%	5.51%	0.13	5.53%	7.58%
Required Return on Rate Base:									
Rate Base	94,183,053	97,335,286	101,964,324	108,236,325	114,503,962	115,427,312	923,350	119,144,943	119,144,943
Return Rates:									
Return on Debt (Weighted)	6.64%	6.62%	6.85%	6.09%	5.97%	5.97%	0.00	6.07%	6.07%
Return on Equity	9.00%	9.00%	9.00%	9.00%	9.00%	9.00%	0.00	9.85%	9.85%
Deemed Interest Expense	3,357,626	3,470,003	3,874,940	4,375,681	4,100,818	4,133,886	33,069	4,340,146	4,340,146
Return On Equity	4,238,237	4,380,088	4,285,561	4,217,970	4,122,143	4,155,383	33,241	4,694,311	4,694,311
Total Return	**7,595,863**	**7,850,091**	**8,160,501**	**8,593,650**	**8,222,960**	**8,289,269**	66,309	**9,034,456**	**9,034,456**
Expected Return on Rate Base	8.07%	8.07%	8.00%	7.94%	7.18%	7.18%	0.00	7.58%	7.58%
Revenue Deficiency After Tax	**2,453,431**	**1,383,205**	**2,143,595**	**2,382,766**	**2,061,633**	**1,925,674**	-135,958	**2,451,313**	**0**
Revenue Deficiency Before Tax	**3,787,129**	**2,126,306**	**3,140,231**	**3,473,586**	**2,917,154**	**2,622,722**	-294,432	**3,378,275**	**0**

APPENDIX C

Company	# of Customers	OM&A/ Customer	DX. Rev/ Customer	Gross PPE/ Customer	Net PPE/ Customer	Aging Ratio	Efficiency Assessment					Cost per Customer	Cost per km of Line
							2010	2011	2012	2013	3 Year		
BLUEWATER POWER DISTRIBUTION CORPORATION	35,982	$348.52	$586.73	$2,595.76	$1,454.40	56.03%	-3.2%	1.7%	6.4%	5.9%	4.6%	646	29,017
BRANTFORD POWER INC.	38,543	$229.54	$410.02	$2,432.12	$1,546.89	63.60%	3.8%	-2.5%	4.7%	0.7%	0.9%	507	39,373
BURLINGTON HYDRO INC.	66,704	$260.13	$488.62	$3,636.99	$1,552.52	42.69%	-7.6%	-7.1%	-9.0%	-7.5%	-8.0%	587	25,773
CAMBRIDGE and NORTH DUMFRIES HYDRO INC.	52,212	$274.72	$529.45	$3,925.69	$1,999.24	50.93%	-10.1%	-7.8%	-3.3%	0.5%	-3.7%	624	28,714
CANADIAN NIAGARA POWER	28,584	$310.04	$677.89	$4,599.85	$2,862.47	62.23%	16.4%	15.6%	10.0%	13.8%	13.2%	726	20,275
ENTEGRUS	40,385	$237.24	$486.59	$3,076.35	$1,656.40	53.84%	-13.1%	-13.4%	-10.9%	-12.5%	-12.3%	531	22,407
ENWIN UTILITIES LTD.	86,018	$263.76	$597.17	$2,690.54	$2,387.23	88.73%	17.8%	16.8%	23.9%	10.3%	16.9%	652	48,500
ESSEX POWERLINES CORPORATION	28,400	$212.94	$413.98	$2,329.64	$1,514.47	65.01%	-17.0%	-17.1%	-12.6%	-17.2%	-15.7%	482	29,323
GREATER SUDBURY HYDRO INC.	47,074	$258.34	$577.89	$3,987.62	$1,577.16	39.55%	-2.4%	14.1%	16.7%	4.8%	11.9%	560	26,887
GUELPH HYDRO ELECTRIC SYSTEMS INC.	52,323	$298.11	$527.28	$2,975.54	$2,561.05	86.07%	12.4%	14.7%	-2.0%	0.8%	4.2%	608	28,952
KINGSTON HYDRO CORPORATION	27,098	$258.89	$499.49	$2,285.16	$1,411.87	61.78%	0.1%	2.2%	2.4%	3.7%	2.8%	517	38,667
KITCHENER-WILMOT	90,018	$186.18	$460.79	$3,583.42	$2,011.28	56.13%	-22.9%	-22.8%	-20.7%	-19.3%	-21.1%	466	22,062
MILTON HYDRO DISTRIBUTION INC.	34,073	$247.59	$460.40	$3,477.35	$1,783.50	51.29%	-4.1%	-3.0%	-37.6%	-4.5%	-15.7%	654	22,402
NEWMARKET-TAY	34,626	$214.87	$465.80	$3,095.86	$1,596.64	51.57%	-14.6%	-21.0%	-19.5%	-19.5%	-20.1%	543	22,272
NIAGARA PENINSULA ENERGY INC.	51,213	$276.34	$572.30	$4,441.31	$2,176.45	49.00%	5.4%	5.2%	10.2%	1.1%	5.4%	672	17,408
OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.	64,793	$270.31	$565.55	$4,182.19	$2,421.98	57.91%	7.6%	12.4%	10.6%	13.8%	12.0%	730	26,377
OSHAWA PUC NETWORKS INC.	53,969	$207.71	$363.15	$2,981.88	$1,436.07	48.16%	-21.7%	-18.0%	-14.5%	-17.4%	-16.7%	505	27,050
PETERBOROUGH DISTRIBUTION INCORPORATED	35,845	$276.62	$454.98	$2,711.97	$1,557.00	57.41%	14.0%	15.6%	13.2%	14.5%	14.4%	562	35,731
PUC DISTRIBUTION INC.	33,367	$365.81	$600.59	$4,077.41	$2,441.57	59.88%	-8.5%	-5.2%	13.4%	22.7%	10.2%	687	30,950
THUNDER BAY HYDRO	50,190	$264.18	$390.69	$3,718.51	$1,728.59	46.49%	9.6%	8.0%	-2.8%	8.2%	4.4%	585	25,631
WATERLOO NORTH HYDRO INC.	54,165	$244.24	$614.81	$5,705.02	$3,279.02	57.48%	-3.1%	6.4%	4.3%	10.6%	7.0%	728	25,066
WHITBY HYDRO ELECTRIC CORPORATION	41,200	$266.29	$580.23	$3,591.16	$1,671.05	46.53%	0.4%	-3.0%	-7.0%	-0.9%	-4.1%	642	24,806
Averages of 22 Distributors	47,581	$262.38	$514.75	$3,459.15	$1,937.58	56.01%	-1.8%	-0.4%	-1.1%	0.6%	-0.4%	601	28,075

APPENDIX D

Appendix E
Costs/Savings Monthly Billing

NPEI
Cost and Benefits for Monthly Billing
2010

		(Savings)/Costs
Postage	Residential customers converte	30,400
	GS<50 customers converted	2,287
	Total customers converted	32,687
	Cost of postage	0.52
	Additional bills	6
		101,983
Envelopes	Total customers	32,687
		0.029
		6
		5,782
Bills	Total customers	32,687
		0.0175
		6
		3,432
Bad Debts Due to Final Bill being only a one month value vs bi-monthly	reduction in 2010 estimate	(100,000)
Unbilled Revenue Reconciliation & Power variance reconciliation		(37,800)
Reminder Notices	# of notices	15,000
	Notice & Envelope	0.047
	# times per year	6
		(4,228)
Interest on Cash Flow	Change in Unbilled to Billed to Cash	(3,000,000)
	per annum rate	0.02
		(60,000)
Net (Savings)/Cost		(90,831)

Appendix F
Internal Memo

Memorandum

To: **Board of Directors**

Cc: **Brian Wilkie, CEO**

From: **Suzanne Wilson, VP Finance**

Date: **2/11/2011**

Re: **Cost and Benefits of Residential Monthly Billing**

Currently residential customers in the Niagara Falls territory are billed bi-monthly or approximately every 60 days and residential customers in the Peninsula West territory are billed monthly or approximately every 30 days. Niagara Falls residential customers are billed on the Harris billing software and Peninsula West residential customers are billed on the Advance billing software. Efforts of conversion of the Peninsula West customers from Advance to Harris have been on going with an expected conversion go-live date of September 25th, 2009.

Niagara Falls residential customers receive a benefit of having their electric and water bills combined onto one bill and in one envelope. The billing costs related to processing the water portion of the bill is paid for by the City of Niagara Falls via the Niagara Falls Hydro Services Corporation. The incremental costs of monthly billing are as follows; envelope, pre-printed bill, paper for journals, postage and ink cartridges. These incremental costs total approximately $106,000 annually with the electric portion totaling $53,000 annually.

The benefits of monthly billing are numerous. First, cash flow increases for both the collection of electric and water usage by 30 days. This increase in cash flow represents approximately $55,000 of interest on cash held in our bank account at approximately 2% annually. A savings of approximately $5,000 annually in reminder notices not having to be printed and mailed. A reduction in doubtful accounts of approximately $4,800 as well as reduced collection costs annually. Two additional benefits are the accounting reconciliations for unbilled revenue and power purchased are currently very complex and time consuming. The annual cost for these two reconciliations is approximately, $47,000. The power bill is received monthly for all customers of NPEI, however it is very difficult to reconcile monthly billed Peninsula West customers and a mix of monthly and bi-monthly billed Niagara Falls territory customers. As an approximate total benefit of $111,800

February 11, 2011

annually, the net result is an estimated savings per year of $58,800.

With respect to the timing of converting Niagara Falls bi-monthly customers to monthly, I recommend the billing commence May 1, 2010 for two reasons; first, NPEI's 2010 electricity distribution rates become effective May 1, 2010 and secondly, March and April are historically the lowest consumption months thereby reducing any high dollar impacts to residential customers.

As an example, a customer whose billing period in 2009 is from March 13th to May 13th were billed on June 4th with a due date of June 22nd. Actual reading May 14th to July 14th, were billed on August 11th with a due date of August 27th.

In 2010, the scenario would be as follows; Actual reading for 2 months March 13th to May 13th, billed June 4th, due date June 22nd, estimated reading May 14th to June 14th, billed July 5th, due July 21st, actual reading June 15 to July 13th, billed August 3rd, due August 16th. This customer benefits by having 2 smaller payments on July 21st and August 16th versus one large payment on August 27th as in 2009.

One-time conversion costs for customer communication; public notices and advertising would be incurred in early 2010 and budgeted for in the 2010 operating budget. This amount would be determined and approved by the Board at such time.

If you have any questions, please do not hesitate to contact me at 905-353-6004.

Sincerely,

Suzanne Wilson, VP Finance

ATTACHMENT # 1- Updated RRWF-IRR #1

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2015 Filers

Version 5.00

Utility Name	Niagara Peninsula Energy Inc.
Service Territory	
Assigned EB Number	EB-2014-0096
Name and Title	Suzanne Wilson, VP Finance
Phone Number	905-353-6004
Email Address	suzanne.wilson@npei.ca

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2015 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***

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2015 Filers

Data Input (1)

		Initial Application	(2)			(6)	Per Board Decision	
1	**Rate Base**							
	Gross Fixed Assets (average)	$247,689,793			$ 247,689,793		$247,689,793	
	Accumulated Depreciation (average)	($123,945,922)	(5)		($123,945,922)		($123,945,922)	
	Allowance for Working Capital:							
	Controllable Expenses	$17,041,580		($19,662)	$ 17,021,918		$17,021,918	
	Cost of Power	$136,943,243		$7,262,530.72	$ 144,205,774		$144,205,774	
	Working Capital Rate (%)	13.00%	(9)		13.00%	(9)	13.00%	(9)
2	**Utility Income**							
	Operating Revenues:							
	Distribution Revenue at Current Rates	$28,371,080		$294,112	$28,665,192			
	Distribution Revenue at Proposed Rates	$29,374,853		($61,160)	$29,313,693			
	Other Revenue:							
	Specific Service Charges	$803,285		($0)	$803,285			
	Late Payment Charges	$361,000		$0	$361,000			
	Other Distribution Revenue	$251,187		$6,047	$257,234			
	Other Income and Deductions	$181,003		$0	$181,003			
	Total Revenue Offsets	$1,596,475	(7)	$6,047	$1,602,522			
	Operating Expenses:							
	OM+A Expenses	$16,754,348		($19,662)	$ 16,734,686		$16,734,686	
	Depreciation/Amortization	$4,936,879			$ 4,936,879		$4,936,879	
	Property taxes	$287,232			$ 287,232		$287,232	
	Other expenses							
3	**Taxes/PILs**							
	Taxable Income:							
	Adjustments required to arrive at taxable income	($4,814,861)	(3)		($4,814,861)			
	Utility Income Taxes and Rates:							
	Income taxes (not grossed up)	$34,407			$69,546			
	Income taxes (grossed up)	$43,189			$94,620			
	Federal tax (%)	15.00%			15.00%			
	Provincial tax (%)	5.33%			11.50%			
	Income Tax Credits	($81,003)			($81,003)			
4	**Capitalization/Cost of Capital**							
	Capital Structure:							
	Long-term debt Capitalization Ratio (%)	56.0%			56.0%		56.0%	
	Short-term debt Capitalization Ratio (%)	4.0%	(8)		4.0%	(8)	4.0%	(8)
	Common Equity Capitalization Ratio (%)	40.0%			40.0%		40.0%	
	Prefered Shares Capitalization Ratio (%)							
		100.0%			100.0%		100.0%	
	Cost of Capital							
	Long-term debt Cost Rate (%)	4.28%			4.14%		4.14%	
	Short-term debt Cost Rate (%)	2.11%			2.16%		2.16%	
	Common Equity Cost Rate (%)	9.36%			9.30%		9.30%	
	Prefered Shares Cost Rate (%)	0.00%						

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 colimn 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) Starting with 2013, default Working Capital Allowance factor is 13% (of Cost of Power plus controllable expenses). Alternatively, WCA factor based on lead-lag study or approved WCA factor for another distributor, with supporting rationale.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2015 Filers

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application				Per Board Decision
1	Gross Fixed Assets (average)	(3)	$247,689,793	$ -	$247,689,793	$ -	$247,689,793
2	Accumulated Depreciation (average)	(3)	($123,945,922)	$ -	($123,945,922)	$ -	($123,945,922)
3	Net Fixed Assets (average)	(3)	$123,743,871	$ -	$123,743,871	$ -	$123,743,871
4	Allowance for Working Capital	(1)	$20,018,027	$941,573	$20,959,600	$ -	$20,959,600
5	**Total Rate Base**		$143,761,898	$941,573	$144,703,471	$ -	$144,703,471

(1) Allowance for Working Capital - Derivation

Line No.	Particulars						
6	Controllable Expenses		$17,041,580	($19,662)	$17,021,918	$ -	$17,021,918
7	Cost of Power		$136,943,243	$7,262,531	$144,205,774	$ -	$144,205,774
8	Working Capital Base		$153,984,823	$7,242,869	$161,227,692	$ -	$161,227,692
9	Working Capital Rate %	(2)	13.00%	0.00%	13.00%	0.00%	13.00%
10	Working Capital Allowance		$20,018,027	$941,573	$20,959,600	$ -	$20,959,600

Notes

(2) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2014 cost of service applications is 13%.

(3) Average of opening and closing balances for the year.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2015 Filers

Utility Income

Line No.	Particulars		Initial Application				Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$29,374,853	($61,160)	$29,313,693	$ -	$29,313,693
2	Other Revenue	(1)	$1,596,475	$6,047	$1,602,522	$ -	$1,602,522
3	Total Operating Revenues		$30,971,328	($55,113)	$30,916,215	$ -	$30,916,215
	Operating Expenses:						
4	OM+A Expenses		$16,754,348	($19,662)	$16,734,686	$ -	$16,734,686
5	Depreciation/Amortization		$4,936,879	$ -	$4,936,879	$ -	$4,936,879
6	Property taxes		$287,232	$ -	$287,232	$ -	$287,232
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -		$ -	
9	Subtotal (lines 4 to 8)		$21,978,459	($19,662)	$21,958,797	$ -	$21,958,797
10	Deemed Interest Expense		$3,567,234	($87,405)	$3,479,829	$ -	$3,479,829
11	Total Expenses (lines 9 to 10)		$25,545,693	($107,067)	$25,438,626	$ -	$25,438,626
12	**Utility income before income taxes**		$5,425,635	$51,954	$5,477,589	$ -	$5,477,589
13	Income taxes (grossed-up)		$43,189	$51,431	$94,620	$ -	$94,620
14	**Utility net income**		$5,382,446	$523	$5,382,969	$ -	$5,382,969

Notes

Other Revenues / Revenue Offsets

Note	Particulars	Initial Application				Per Board Decision
(1)	Specific Service Charges	$803,285	($0)	$803,285		$803,285
	Late Payment Charges	$361,000	$ -	$361,000		$361,000
	Other Distribution Revenue	$251,187	$6,047	$257,234		$257,234
	Other Income and Deductions	$181,003	$ -	$181,003		$181,003
	Total Revenue Offsets	$1,596,475	$6,047	$1,602,522	$ -	$1,602,522

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2015 Filers

Taxes/PILs

Line No.	Particulars	Application		Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$5,382,445	$5,382,969	$5,382,969
2	Adjustments required to arrive at taxable utility income	($4,814,861)	($4,814,861)	($4,814,861)
3	Taxable income	$567,584	$568,108	$568,108
	Calculation of Utility income Taxes			
4	Income taxes	$34,407	$69,546	$69,546
6	Total taxes	$34,407	$69,546	$69,546
7	Gross-up of Income Taxes	$8,782	$25,074	$25,074
8	Grossed-up Income Taxes	$43,189	$94,620	$94,620
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$43,189	$94,620	$94,620
10	Other tax Credits	($81,003)	($81,003)	($81,003)
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	5.33%	11.50%	11.50%
13	Total tax rate (%)	20.33%	26.50%	26.50%

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2015 Filers

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$80,506,663	4.28%	$3,445,899
2	Short-term Debt	4.00%	$5,750,476	2.11%	$121,335
3	**Total Debt**	60.00%	$86,257,139	4.14%	$3,567,234
	Equity				
4	Common Equity	40.00%	$57,504,759	9.36%	$5,382,445
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$57,504,759	9.36%	$5,382,445
7	**Total**	100.00%	$143,761,898	6.23%	$8,949,680

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$81,033,944	4.14%	$3,354,805
2	Short-term Debt	4.00%	$5,788,139	2.16%	$125,024
3	**Total Debt**	60.00%	$86,822,083	4.01%	$3,479,829
	Equity				
4	Common Equity	40.00%	$57,881,389	9.30%	$5,382,969
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$57,881,389	9.30%	$5,382,969
7	**Total**	100.00%	$144,703,471	6.12%	$8,862,798

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Per Board Decision			
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$81,033,944	4.14%	$3,354,805
9	Short-term Debt	4.00%	$5,788,139	2.16%	$125,024
10	**Total Debt**	60.00%	$86,822,083	4.01%	$3,479,829
	Equity				
11	Common Equity	40.00%	$57,881,389	9.30%	$5,382,969
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$57,881,389	9.30%	$5,382,969
14	**Total**	100.00%	$144,703,471	6.12%	$8,862,798

Notes

(1) 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 colimn M and Adjustments in column I

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2015 Filers

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	At Current Approved Rates	At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$1,003,772		$648,501		$648,501
2	Distribution Revenue	$28,371,080	$28,371,081	$28,665,192	$28,665,192	$28,665,192	$28,665,192
3	Other Operating Revenue Offsets - net	$1,596,475	$1,596,475	$1,602,522	$1,602,522	$1,602,522	$1,602,522
4	**Total Revenue**	$29,967,555	$30,971,328	$30,267,714	$30,916,215	$30,267,714	$30,916,215
5	Operating Expenses	$21,978,459	$21,978,459	$21,958,797	$21,958,797	$21,958,797	$21,958,797
6	Deemed Interest Expense	$3,567,234	$3,567,234	$3,479,829	$3,479,829	$3,479,829	$3,479,829
8	**Total Cost and Expenses**	$25,545,693	$25,545,693	$25,438,626	$25,438,626	$25,438,626	$25,438,626
9	**Utility Income Before Income Taxes**	$4,421,862	$5,425,635	$4,829,088	$5,477,589	$4,829,088	$5,477,589
10	Tax Adjustments to Accounting Income per 2013 PILs model	($4,814,861)	($4,814,861)	($4,814,861)	($4,814,861)	($4,814,861)	($4,814,861)
11	**Taxable Income**	($392,999)	$610,774	$14,227	$662,728	$14,227	$662,728
12	Income Tax Rate	20.33%	20.33%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	($79,911)	$124,192	$3,770	$175,623	$3,770	$175,623
14	**Income Tax Credits**	($81,003)	($81,003)	($81,003)	($81,003)	($81,003)	($81,003)
15	**Utility Net Income**	$4,582,775	$5,382,446	$4,906,321	$5,382,969	$4,906,321	$5,382,969
16	**Utility Rate Base**	$143,761,898	$143,761,898	$144,703,471	$144,703,471	$144,703,471	$144,703,471
17	Deemed Equity Portion of Rate Base	$57,504,759	$57,504,759	$57,881,389	$57,881,389	$57,881,389	$57,881,389
18	Income/(Equity Portion of Rate Base)	7.97%	9.36%	8.48%	9.30%	8.48%	9.30%
19	Target Return - Equity on Rate Base	9.36%	9.36%	9.30%	9.30%	9.30%	9.30%
20	Deficiency/Sufficiency in Return on Equity	-1.39%	0.00%	-0.82%	0.00%	-0.82%	0.00%
21	Indicated Rate of Return	5.67%	6.23%	5.80%	6.12%	5.80%	6.12%
22	Requested Rate of Return on Rate Base	6.23%	6.23%	6.12%	6.12%	6.12%	6.12%
23	Deficiency/Sufficiency in Rate of Return	-0.56%	0.00%	-0.33%	0.00%	-0.33%	0.00%
24	Target Return on Equity	$5,382,445	$5,382,445	$5,382,969	$5,382,969	$5,382,969	$5,382,969
25	Revenue Deficiency/(Sufficiency)	$799,670	$0	$476,648	($0)	$476,648	($0)
26	**Gross Revenue Deficiency/(Sufficiency)**	$1,003,772 **(1)**		$648,501 **(1)**		$648,501 **(1)**	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2015 Filers

Revenue Requirement

Line No.	Particulars	Application				Per Board Decision	
1	OM&A Expenses	$16,754,348		$16,734,686		$16,734,686	
2	Amortization/Depreciation	$4,936,879		$4,936,879		$4,936,879	
3	Property Taxes	$287,232		$287,232		$287,232	
5	Income Taxes (Grossed up)	$43,189		$94,620		$94,620	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$3,567,234		$3,479,829		$3,479,829	
	Return on Deemed Equity	$5,382,445		$5,382,969		$5,382,969	
8	**Service Revenue Requirement (before Revenues)**	$30,971,328		$30,916,215		$30,916,215	
9	Revenue Offsets	$1,596,475		$1,602,522		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$29,374,853		$29,313,693		$30,916,215	
11	Distribution revenue	$29,374,853		$29,313,693		$29,313,693	
12	Other revenue	$1,596,475		$1,602,522		$1,602,522	
13	**Total revenue**	$30,971,328		$30,916,215		$30,916,215	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$0	(1)	($0)	(1)	($0)	(1)

Notes

(1) Line 11 - Line 8

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2015 Filers

Tracking Form

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.

60 Tracking Rows have been provided below. If you require more, please contact Industry Relations @ IndustryRelations@ontarioenergyboard.ca.

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	$ 8,949,680	6.23%	$ 143,761,898	$ 153,984,823	$ 20,018,027	$ 4,936,879	$ 43,189	$ 16,754,348	$ 30,971,328	$ 1,596,475	$ 29,374,853	$ 1,003,772
1														

ATTACHMENT # 2- Niagara Peninsula Energy Plan document-IRR#3

NPEI Customer Engagement Plan: 2014-2015

Consultation Activities - description, timing, purpose

Provides a detailed customer consultation plan that lays out consultation activities and mechanisms, and the tracking and reporting that will be done to document plan delivery.

ID Consultation Activities	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1) Engagement-Plan Governance Framework																							
1.1) Finalize Engagement Plan							X																
1.2) Draft Engagement-Plan Baseline Report							X																
1.3) Annual Engagement Reporting & Planning Cycle																							
Gather and Group All Feedbacks for Ending Year											X												X
2014 Year-End Report													X										
2015-2016 Customer Engagement Plan														X									
1.4) Quarterly Steering Commitee Meetings	X		X	X	X	X	X	X			X			X			X			X			X
2) Education and Information to Customers																							
2.1) Document Customer Service and IT Systems							X																
2.2) Document Information to Customers on Outages and First Responses							X																
2.3) Document Information to Customers on Capital Improvement Projects & Construction Work							X																
2.4) Document Information to Customer on REG Opportunities, Modalities & Connection							X																
2.5) Document Approach to Providing Access to Energy Data to Customers							X																
2.6) Document Approach to Educating Customers on Energy Bills and Price							X																
2.7) Document CDM Engagement Actions							X																
2.8) Inform Customers and Stakeholders About Energy Storage Activities, then Document It							X																
3) Customer Data Collection and Consultation																							
3.1) Market Characterization Interviews				X	X	X	X																
3.2) Market Characterization Site Visits				X	X	X	X																
3.3) Tracking of Customers' Inquiries, Complaints & Feedbacks																							
Tracking is an on-going operation	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->
NPEI will integrate tracking consultation topics with that of other engagement work				X																			
3.4) Transactional Survey																							
Transactional surveying is an on-going operation					X	X						---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->
NPEI will improve the recording of survey responses, and integration of the consultation topics with that of other engagement work (ongoing)					---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->
3.5) Annual Customer Satisfaction Phone Survey - focus on silent majority (89%)							X																
4) Service-Territory Stakeholders Consultation																							
4.1) Monthly Stakeholder Meetings (a.k.a. Public Utility Commission Meetings)							X																
Stakeholder meetings is a monthly, on-going operation	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->
NPEI will improve the integration and documentation (ongoing progress)								---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->
4.2) Ongoing Consultation with Customers' Technical Service Providers (professional/trades)	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->
5) Participation in Regional Consultation																							
5.1) Consult in Regional Processes																							
Obtain letter from OPA and HONI that no regional process is currently under way								X															
5.2) Consult with Regionally Interconnected Distributors																							

ID	Consultation Activities	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	Send letter to HONI notifying that DSP is being finalized							X																
5.3) Consult on REG Interconnection																								
	Provide Board-prescribed information to HONI and OPA								X															
	Follow up with HONI and OPA								X															
5.4) Consult on REG Investments																								
	Send letter to OPA as prescribed by Board								X															
	Prepare and send a response to OPA letter as required								X															

ATTACHMENT # 3-NPEI Customer Engagement Agendas and presentations-IRR#3

Re:	Meeting Minutes for the second meeting of the Customer-Engagement Steering Committee
Location	In person at NPEI head office – 7447 Pin Oak Drive, Niagara Falls, ON, L2E 6S9
Time:	May 9, 2014, 11:30am to 2:00pm
Attendees:	NPEI: Sue Forcier, Margaret Battista, Brian Wilkie, Suzanne Wilson; ICF Canada: Judy Simon and Erin Tabah (by phone)
Ref:	ICF ref C40042
Version:	May 9, 2014

Agenda

Topics		Timing Approx.
1	Introductions	5 min
2	Comments on the first draft of the Customer Engagement Plan • High-level comments – verbally • Approach to collecting, log, screen and consolidate comments in writing, as needed • Next step to finalize the plan	20 min
3	Idea: use a ICF-NPEI SharePoint Site to manage files. For example: https://sharepoint.icfprojects.ca/NPEI_APnCEngagement/ n.b.: for now, only Sue, Sean, and Katie have access to the link above. • Early feedback on the idea • Go/No-Go with the idea	5 min
4	Review the draft list of consultation topics List_of_Consultation_Topics • Early, high-level feedback • Approach to have it reviewed by all Committee members	10 min

Topics		Timing Approx.
6	Department-by-department progress report • Customer services and IT • Operations • Engineering • Regulatory affairs • CDM	10 min
7	Approach to assembling the Baseline Report in time for the filing • Contributors • Leadership	5 min
9	Wrap-Up • Review task items • Next meeting	5 min

Meeting Minutes

Items 3 and 4 in the agenda were not addressed. There was no update from Operations or Engineering. Action Items are highlighted in yellow.

1. Customer Satisfaction Survey

- Survey to be administered Monday by Utility Pulse, data will be used by Kinectrics to write Chapter 5
- Contains high level questions on how NPEI services customers, including outages, CDM, and how NPEI reaches out to customers
- 400 people out of a possible 8,000 will be canvassed by random phone calls
- Output available at the end of May, formal report to follow two weeks after

2. Comments on the first draft of the Customer Engagement Plan

General Comments and Introduction

- August 29th 2014 remains the deadline for submission. Therefore, all necessary documentation should be submitted by the end of July to meet this deadline.
- The Engagement Plan is expected to be completed by the end of the month.
- Engagement Plan has been designed for 2 years, after which time the market will be reassessed. There is an Annual Report and an initial Baseline Report.

- Once the Engagement Plan is finalized, its implementation costs should be priced out and included in OM&A as well as any costs incurred in development (excluding costs covered by PAB) (Cambridge and North Dumfries is requesting $115k for engagement per year in their 2014 rate application including 2013 - communications manager hired, pre-application meeting with intervenors, customer survey, inviting largest customers to board meeting, website enhancement, policies and procedures creation for engagement, new corporate communications strategy and tactical plan, etc.).
- Margaret has made some changes based on what she has already implemented and submitted a hard copy of her Draft Engagement Plan with her changes to Judy so that changes could be made.
- Due to passage of time and implementation of the plan, Margaret will provide written paragraphs to Judy to replace out of date paragraphs in the Draft Engagement Plan that Margaret has flagged.
- Note that 'VP, Regulatory" throughout the Draft Engagement Plan should be switched to "VP Finance".
- Clarification of section 8 of the Customer Engagement Plan: this plan cuts across departments and documents what everyone will do to meet customer engagement outcomes.
- There are two parts of the Engagement Plan: content and process. The content part includes:
  - Engagement activities across all departments
  - CDM, including CDM consultation:
    - CDM engagement for OPA Province-Wide Programs
    - Engagement being done for the market characterization component of the Achievable Potential work, including customer and supply chain interviews and site visits
    - Change 'roving energy manager' to 'CDM professional'
- The process part of the Engagement Plan includes how NPEI should be organized – steering committee and steering committee coordinator - so that customer engagement is done every year, performance is measured and reviewed, and an annual report on engagement is prepared
  - Quarterly Steering Committee meetings (including implementation plan)
  - Series of reports, including baseline report (one-time) and subsequent annual reports which report on progress and variance from baseline report

Section 3.3 – Regular Stakeholder Meetings and Consultation with Customers' Technical Service Providers

- Signoff needed on draft Engagement Plan from NPEI's Operations and Engineering (i.e., Tom and Dan), indicating that they've acknowledged and agree to commitments made such as holding 'focus groups' (Bryan prefers meetings be done on-line) in October/November 2015 (stakeholder meetings) and tech. service provider consultations.
- Judy and Sue will meet with Tom and Dan to go over relevant parts of Draft Engagement Plan and obtain Tom and Dan sign-off.

Section 3.4 Participation in Consultation with OPA and HONI

- To be done by Tom and Dan, should include documentation of their meetings with Hydro One and OPA
- Note that anything involving smart grids should be tracked as well (Kevin)

3. Baseline Report

- Sue will take the lead in coordinating the preparation of the Baseline Report, which is due by end of June 2014, if possible. The Baseline Report will provide a status report to the end of April 2014.
- The Baseline report is a progress report of what has been done to date in terms of the Engagement Plan, while providing the existing context. It is very high-level and sets the stage for continuous improvement.
- Kinectrics should cross reference the Engagement Plan explicitly in their asset management plan. Kinectrics should take into account the customer survey and baseline report, as well as the ICF report. Cross references of these in Chapter 5 will make Chapter 5 more integrated.
- Section 3.1 write-ups from Engagement Plan – the following sections will be handled by the people indicated below in brackets (to include: high-level description of what tools you have and where to find more information; can cross-reference other documents as needed). The write-ups will go into the Baseline Report:
    - Call Centre Tracking (Margaret)
    - Outages and First Responses (Margaret)
    - Capital Improvement Projects and Construction Work (Dan)
    - REG Opportunities, Programs, Modalities and Connection Procedures (Tom)
    - Approach to Providing Access to Energy Data to Customers (Margaret)
    - Customer Education on Electricity Bills and Price (Margaret)
    - CDM Engagement Actions (Sue)
    - Electricity Storage (Tom)
- Language of CDM section will need to be updated as it predates the directive
    - Should use “CDM professional” instead of “CDM key account manager”, since the consultant does not work directly for NPEI

4. Form C5C (Referenced in Section 2.3.1 of Engagement Plan)

- NPEI will prepare this standardized form to track any consultation activities (events/meetings/interviews etc.) that relate directly to the Engagement Plan
- For some activities, a monthly report may be sufficient (i.e. meetings with customers)
- It was suggested that the language be changed to include various mechanisms to document these events, “including the use of a standardized form where appropriate”.

5. Achievable Potential Study – Data

- Margaret will provide Dave with data by early next week (Monday or Tuesday).
    - Some consumption was initially missing
    - Margaret has added all NAICS codes and now data ties into financials, RRRs
    - Margaret has added missing NAICS codes to the data transfer template, and will send Judy a note on which NAICS codes were added.
- Suzanne will send rate filing data of consumption by rate class to Judy and Sue.

3. Wrap-up

- Next Meeting is scheduled for May 21, 2014.
- Agenda will include discussion of results of customer satisfaction survey and an update on the data plan

Re:	Meeting Agenda for the third meeting of the Customer-Engagement Steering Committee
Location	In person at NPEI head office – 7447 Pin Oak Drive, Niagara Falls, ON, L2E 6S9
Time:	June 20, 2014, 11:30am to 2:00pm
Invitees:	NPEI: Sue Forcier, Margaret Battista, Brian Wilkie, Suzanne Wilson; Dan Sebert; Tom Sielicki; ICF Canada: Judy Simon, and David Shipley, Lacy Caron, Vincent Dufresne (by phone)
Ref:	ICF ref C40042
Version:	June 9, 2014

Agenda

Topics		Timing Approx.
1	Introductions	5 min
2	Status Report on the Customer Engagement Plan • C5C Form • Baseline Report • Next steps to finalize the above	20 min
3	Achievable Potential Draft Summary Report • Presentation of results • Discussion and next steps	15 min
4	Department-by-department progress report related to Engagement • Customer services and IT • Operations • Engineering • Finance • CDM	15 min
9	Wrap-Up • Review task items • Next meeting	5 min

From: Simon, Judy
To: Sue Forcier; Margaret Battista; Tom Sielicki; Dan Sebert; Suzanne Wilson; Brian Wilkie
Cc: Dufresne, Vincent; Williamson, Erin; Fraser, Selena; Shipley, David; Caron, Lacy; Sean Perry; Katie Potts; Sue Forcier @ Samsung
Subject: Steering Committee Status report and next meeting is June 20th, 11:30 - 2:00 p.m
Date: Thursday, June 05, 2014 2:30:31 PM

Dear Steering Committee Members,

Here is an update on progress to date. The next meeting is set for June 20, 2014, at 11:30 am to 2:00 p.m.

We remain on Suzanne's deadline for the COS application filing and this requires completion of the Engagement Plan no later than the end of the month. This cannot be done without the receipt of some feedback still required, as described below.

Achievable Potential Modeling and Market Characterization – draft report on achievable potential to be circulated to Steering Committee today for comment

The Draft achievable potential results show that of the 4 sectors that were of particular interest (hotels, motels; poultry; greenhouses; wineries) for more detailed market characterization research, motels/hotels and greenhouses show the most promise and will be explored in greater detail through the market characterization research. Based on the market characterization work, the achievable potential results will be adjusted and a final achievable potential report will be issued.

In order to complete the market characterization, we kindly request the following individual customer data. This data will ensure that we base the market characterization on accurate customer data. Margaret has refined the customer data such that for each C&I customer there is a corresponding SIC code.

Sorted by SIC code, we need individual customer consumption data (kWh) for 2012 (and 2013 if available) and contact information for the customer (address, phone number, company – wherever available).

Please provide this data by the end of next week.

SIC	Sic Description
721	Accommodation
72111	Hotels (except Casino Hotels) and Motels
72112	Casino Hotels
721110	Hotels (except Casino Hotels) and Motels
721111	Hotels
721114	Motels
1114	Greenhouse, Nursery, and Floriculture Production
111420	Nursery and Floral Cultural
111421	Nursery and Tree Production

111422	Floriculture Production

Customer Engagement Plan – still need some comments to finalize the Plan

Thank you Dan for providing your comments.

To finalize the Engagement Plan, we need:

1) Margaret's new paragraph to replace the outdated information in the Plan
2) Tom's comments

Please provide the above by Friday, June 6th. It is important that the Engagement Plan goes to Kinectrics asap so that they can consider it and conduct any necessary follow-up in the DSP development.

Customer Engagement Baseline Report – detailed outline and write-up direction to come

You will receive a detailed outline of the Baseline Report for each of you to fill in your assigned parts. To assist you in this activity, the material needed will be organized by category and instruction may be provided for certain components to assist you further. In addition, we will populate the outline with material as ICF has collected it to date (material from meeting notes, draft Engagement Plan and NPEI website).

The timing for receiving your write-ups will be very tight due to the need to complete the report by the end of June to give Kinectrics time for incorporation into the DSP and to meet Suzanne's timetable.

Timing of Next Steering Committee Meeting

The next Steering Committee Meeting will be **June 20th, 11:30 – 2:00 p.m.**

Thanks.

Judy

Judy Simon | Principal, ICF Canada | **416.341.6201** | judy.simon@icfi.com | icfi.ca
ICF International | 808-277 Wellington St. W, Toronto, ON. M5V 3E4 | 416.341.0383 (f) | 416.876.1372 (m)

NPEI Achievable Potential Study

Briefing on the Preliminary Results

Prepared for:

Niagara Peninsula Energy Inc.

20 June 2014

Outline of the Presentation

- **Context of the study**
- **Preliminary results**
- **Next steps**

Context for the NPEI AP Study

Purpose of Achievable Potential Study

- **Calculate the conservation achievable potential to assist with the development of the CDM portfolio for new CDM framework**
- **Select key commercial/industrial subsectors that have significant potential savings and have been underrepresented in local CDM program uptake, for market characterization research. The results could serve as a basis for future local programming**
- **Leverage market characterization research interviews to ask more general distribution system planning questions to feed into the Distribution System Plan**

OPA Achievable Potential Study

- **Objective was to estimate achievable potential for electricity savings in Ontario**
- **Savings from codes and standards (C&S) were separated out, to focus on conservation and demand management (CDM) programs**
- **Achievable potential is the fraction of potential savings from economically viable CDM measures that can be captured through utility programs – usually given as a range (e.g. lower to upper)**
- **Economic potential estimate began with output from OPA's End Use Forecaster (EUF) model**
- **Market research in Ontario was used to estimate how much of the economic potential is achievable**

The OPA Achievable Potential Study

- **Objective was to estimate achievable potential for electricity savings in Ontario**
- **Savings from codes and standards (C&S) were separated out, to focus on conservation and demand management (CDM) programs**
- **Achievable potential is the fraction of potential savings from economically viable CDM measures that can be captured through utility programs – usually given as a range (e.g. lower to upper)**
- **Economic potential estimate began with output from OPA's End Use Forecaster (EUF) model**
- **Market research in Ontario was used to estimate how much of the economic potential is achievable**

Need for an NPEI Model

- **OPA results can be subdivided only to the IESO zone: the Niagara zone in this case**
- **OPA results are not targeted to NPEI's mix of customers**
- **What is NPEI's share of the potential?**
  - Not a simple fraction of the Niagara zone, based on load.
  - Scaling by sector and building type produces a fairer share: if NPEI's share of the load is disproportionately residential it is harder to achieve savings
  - An estimate based on the OPA methodology provides better information and insights for the negotiating process.
- **How should NPEI target programs?**
  - Identifying the customer groups, energy end uses, and measures with the most potential will help with program design.

NPEI Model as the First Phase of Market Characterization

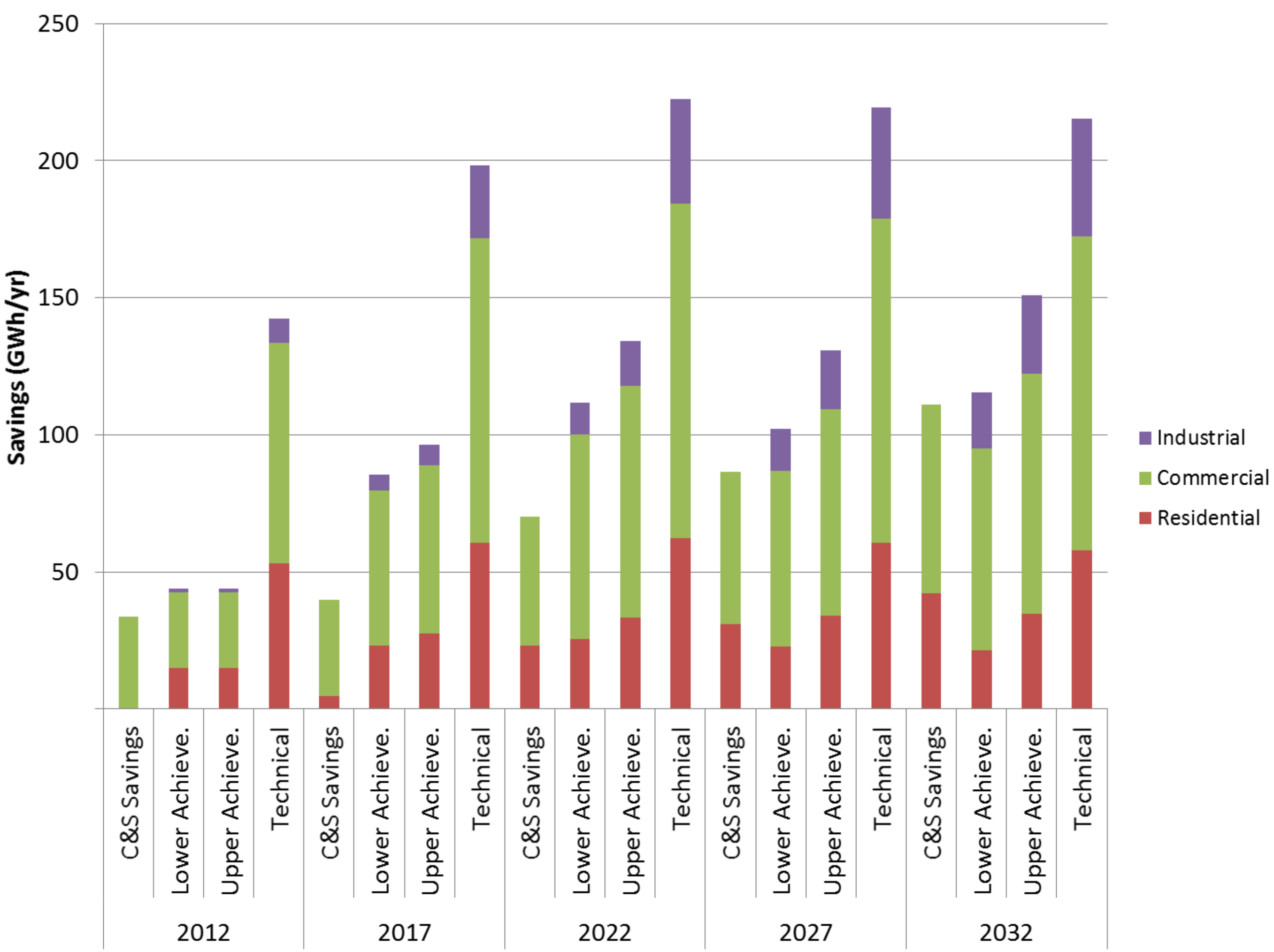
- **The customized model for NPEI:**
  - Confirms the importance of the customer groups NPEI identified for market characterization
  - Provides preliminary estimates of the mix of energy end uses in those customer groups – as a starting point
  - Provides a list of possible CDM measures that may be important
- **The market characterization will feed back into the model and refine the estimates of potential for the targeted customer groups:**
  - Hotels/motels
  - Greenhouses

Preliminary Results

PRELIMINARY RESULTS

Total NPEI Results

NPEI Technical and Achievable Potential by Sector



NPEI Results as Percentage of OPA Totals

NPEI Potential as Percentage of OPA Total

Year/ Potential (Gwh/yr)	Residential	Commercial	Industrial	Total
2012				
C&S Savings	1.2%	1.6%		1.6%
Lower Achieve.	1.2%	1.4%	0.7%	1.3%
Upper Achieve.	1.2%	1.4%	0.7%	1.3%
Technical	1.1%	1.9%	0.6%	1.4%
2017				
C&S Savings	1.0%	1.4%		1.3%
Lower Achieve.	1.1%	1.2%	0.6%	1.1%
Upper Achieve.	1.0%	1.2%	0.6%	1.1%
Technical	0.8%	1.2%	0.6%	1.0%
2022				
C&S Savings	1.1%	1.3%		1.2%
Lower Achieve.	1.0%	1.4%	0.6%	1.1%
Upper Achieve.	0.9%	1.3%	0.6%	1.1%
Technical	0.8%	1.2%	0.6%	0.9%
2027				
C&S Savings	1.0%	1.2%		1.1%
Lower Achieve.	0.9%	1.2%	0.6%	1.0%
Upper Achieve.	0.8%	1.2%	0.6%	1.0%
Technical	0.8%	1.2%	0.6%	0.9%
2032				
C&S Savings	1.0%	1.2%		1.1%
Lower Achieve.	0.9%	1.1%	0.6%	1.0%
Upper Achieve.	0.8%	1.1%	0.6%	0.9%
Technical	0.7%	1.1%	0.6%	0.9%

Residential Potential

Key residential segments:

- **Majority of residential savings are in single family dwellings**

Key residential end uses:

- **Ventilation and circulation**
- **Lighting**
- **Refrigerators**
- **Computers**

Key residential measures:

- **Furnace fans**
- **CFLs and LEDs**
- **Refrigerators**
- **Programmable thermostats**
- **Smart power bars**

Commercial Potential

Key commercial segments:

- Hotel/motel
- Office
- Restaurant
- Retail (including food)

Key commercial end uses:

- Interior, exterior, and architectural lighting
- Fans and pumps
- Computer equipment
- DX cooling

Key commercial measures:

- Next-gen T8 fluorescent
- CFLs and LEDs
- Efficient computer equipment
- Other plug loads (e.g. office eqpt)
- Ventilation motors, ASDs, etc.

Industrial Potential

Key industrial segments:

- Agriculture
- Food and beverage
- Fabricated metals
- Miscellaneous industrial

Key industrial end uses:

- Compressed air
- Motor systems powering pumps
- HVAC
- Process heating

Key industrial measures:

- Impeller trimming
- Motor controls & VSDs
- Compressed air controls
- HVAC controls
- Lighting controls

Investments to Procure Savings

Investments to Procure 2012-2017 Achievable Electricity Savings

Sector	Scenario	2017 Total cumulative implementation costs (million $)	2017 Annual Electricity Savings (GWh/yr.)	2017 Levelized Unit Energy Cost, LUEC (cents/kWh)
Residential	C&S	0	5	0.5
	Lower, excl. C&S	11	23	4.5
	Upper, excl. C&S	20	28	6.4
Commercial	C&S	0	35	0.2
	Lower, excl. C&S	6	57	2.1
	Upper, excl. C&S	8	61	3.1
Industrial	C&S	-	-	0.0
	Lower, excl. C&S	1	6	1.2
	Upper, excl. C&S	2	7	1.5
Total	C&S	0	40	0.2
	Lower, excl. C&S	18	86	2.7
	Upper, excl. C&S	29	96	4.0

Four Targeted Sub-sectors

Achievable Potential Electricity Savings by Milestone Year and Targeted Priority Sub-Sector (GWh/yr.)

	Large Hotel	Other Hotel Motel	Total Hotels % of Commercial	Wineries	Greenhouses	Poultry Operations	Greenhouses & Poultry % of Agricultural	Wineries, Greenhouses & Poultry % of Industrial
2012								
C&S Savings	11.1	0.377	34%					
Lower Achieve.	7.45	0.248	13%	0.066	0.175	0.046	74%	22%
Upper Achieve.	7.45	0.248	13%	0.066	0.175	0.046	74%	22%
2017								
C&S Savings	11.1	0.378	33%					
Lower Achieve.	12.7	0.508	14%	0.310	0.753	0.199	89%	21%
Upper Achieve.	13.6	0.550	15%	0.390	0.945	0.250	93%	21%
2022								
C&S Savings	14.2	0.496	31%					
Lower Achieve.	19.0	0.741	16%	0.652	1.32	0.35	84%	20%
Upper Achieve.	21.4	0.840	17%	0.910	1.86	0.49	88%	20%
2027								
C&S Savings	15.8	0.571	29%					
Lower Achieve.	15.7	0.611	14%	0.864	1.65	0.44	82%	20%
Upper Achieve.	17.9	0.701	14%	1.201	2.52	0.67	84%	21%
2032								
C&S Savings	18.5	0.681	28%					
Lower Achieve.	17.4	0.628	13%	1.247	2.05	0.54	82%	19%
Upper Achieve.	20.0	0.726	13%	1.726	3.40	0.90	82%	21%

Next Steps

NEXT STEPS

Market Characterization

- Market characterization will focus on hotels/motels and greenhouses
- Estimates of end use consumption for these sub-sectors will be improved; e.g., how do greenhouses use electricity differently from overall agricultural sector?
- Adjustments will be made to the potential for specific measures in these sub-sectors
- Additional measures that are pertinent to these sub-sectors may also be identified
- Achievable potential results for the targeted sub-sectors will be adjusted based on these findings

NEXT STEPS

How Can NPEI Use the Results

- **Provide negotiating leverage with OPA in setting NPEI CDM budget and target for 2015-2020**
  - Information on what is achievable and at what cost, using same information base as OPA is using to determine budget and target
  - Information from NPEI achievable potential is more representative of what NPEI can achieve and at what cost - the numbers are based on OPA data but customized, based on actual NPEI customer mix; OPA results are based on Niagara Region IESO zone results
- **Provide good basis for developing CDM portfolio for 2015-2020**
  - Information to assist in targeting the OPA provincial programs to capture more effectively savings based on the measures and subsectors that have the greatest potential for savings in 2015-2020 period
  - Initial basis for targeting specific subsectors and measures for local/regional programming
  - Sound basis to begin to design local and/or regional CDM programs to address particular customer group needs in the greenhouses and hotels/motels subsectors

Questions?

ICF INTERNATIONAL

Meeting Agenda

Re:	Team Follow-Up Meeting
Location	Lync Meeting + Conference call: +1-888-619-1583 code: 249-135-2014
Time:	August 27, 10:00 AM
Invited:	NPEI: Sue Forcier, Sean Perry ICF Canada: Judy Simon, Emily Kirke
Project:	Achievable Potential and Customer Engagement
Ref:	Project Number – C40042
Version:	August 26, 2014

Agenda

Topics		Timing Approx.
1	Status Update	10 min
2	Next Steps	10 min
3	Project Schedule – Timing of: ▪ Draft report submission ▪ Discussion of draft report by ICF ▪ NPEI comments on draft report ▪ Final report submission	10 min
4	Other	5 min

Minutes

1. Status Update

- Genna has completed her market actor interviews for the greenhouse portion of the project
- Emily has a call set up with Jim Bechkos tomorrow
- Emily looking to schedule calls with Joe Salvatore and Graybar
- Sean to try to help set up a call with Joe Salvatore. Emily to send Sean Joe's cell number.
- Mike at Graybar is an excellent person to speak to. Michelle is responsible for smaller accounts; Derek is responsible for larger accounts.

2. Next Steps

- Next steps are for Emily and Genna to work with Dave Shipley to update first pass at achievable potential for hotel, motel and greenhouse sectors.
- Emily and Genna will also be working on the final report in the next few weeks

3. Proposed Schedule

- ICF aiming to submit the draft report to NPEI on September 15th
- NPEI and ICF to discuss the draft report during regular meeting slot on Wednesday, September 17th. Part of the meeting on September 17th will be a policy discussion. We'll do some thinking regarding what the next steps are for NPEI in terms of a marketing strategy and what program concepts should be developed for hotels, motels and greenhouses.
- Deadline for NPEI comments on draft report is September 22nd
- ICF to submit final report to NPEI on September 30th

4. Other

- Genna was wondering about Hydro One's progress to date on greenhouse energy efficiency
- Sean has met with Tom, the Head of Conservation at Hydro One regarding Hydro One's greenhouse energy efficiency work. Hydro One has been in touch with Ron McDonald at the University of Guelph. U of Guelph is doing some cutting edge research and testing of plant growth under different lighting and environmental conditions.
- Hydro One wants to do a pilot on greenhouse LED lighting – NPEI could partner with Hydro One on a project. It is critical to NPEI that the pilot take place at a site in their territory (likely Westbrook)
- One option would be to apply to the conservation fund for an LED project. Another funding option would be to apply to the collaboration fund in partnership with Hydro One
- Sean is hoping to visit the U of Guelph to discuss the latest in LEDs for greenhouses before September 17th (when we'll have our discussion on the draft report). Sean will let Genna know when a meeting has been scheduled and can update her on discussion after the meeting.

ATTACHMENT # 4-Call Centre Calls-IRR#8

2011 Calls

Month	Niagara Falls Customer Service Calls Handled	Niagara Falls Collection Calls Handled	Niagara Falls Billing Calls Handled	Peninsula West Customer Service and Billing Calls	Peninsula West Collection Calls	High Bills handled by phone	Total of all inbound phone queues handled by NPEI	# of Payment Arrangements	# of Misc	Total inquiries (inbound & outbound)
Jan	1667	1493	289	759	539	140	4747	2302	1168	12429
Feb	1942	806	451	746	253	224	4198	1415	939	11303
Mar	2064	1265	429	866	387	234	5011	2017	1124	12672
April	2832	1263	347	2159	527	176	7128	2070	597	14519
May	2182	1630	292	996	421	147	5521	2330	772	13895
June	2873	1154	361	999	328	180	5715	1880	727	14668
July	2323	643	336	1098	146	134	4546	1162	518	11073
August	2212	1217	371	894	392	170	5086	2085	522	13264
Sept	2074	1545	514	754	658	222	5545	2463	489	13747
Oct	2214	1414	585	795	601	272	5532	2196	576	12243
Nov	2083	1470	273	757	519	124	5102	2100	537	14462
Dec	1978	953	208	548	340	87	4027	1494	405	10473
Grand Totals	26444	14853	4456	11371	5111	2110	62158	23514	8374	154748

2012 Calls **Customer Service Quality Indices**

Month	Customer Service Calls Handled	Collection Calls Handled	Billing Calls Handled	High Bills handled by phone	Total Active Customers	Total of all queues (customers calling into the utility)	Total Requests (inbound & outbound)	% of Active Customers calling into utility	# of Inquiry type call	% of incoming calls abandoned within 30s (standard is less than 10% annually)	% of inquiries answered within 30s (standard is 65% annually)
Jan	2,748	1,948	316	119	50,677	5,012	14,420	9.89%	2096	1.00%	70%
Feb	2,442	1,567	272	114	50,838	4,281	11,693	8.42%	1878	0.01%	86%
Mar	2,946	1,814	200	76	50,495	4,960	12,263	9.82%	2021	0.01%	75%
April	2,297	1,793	179	69	50,705	4,269	10,484	8.42%	1657	0.01%	74%
May	2,643	1,683	184	58	50,679	4,510	11,945	8.90%	1849	0.01%	86%
June	2,735	1,647	222	84	50,826	4,604	12,479	9.06%	1942	0.00%	85%
July	2,706	2,470	243	77	50,861	4,271	12,186	8.40%	1804	1.10%	66%
August	2,713	2,023	405	189	50,806	5,141	13,558	10.12%	1806	0.23%	65%
Sept	2,997	2,346	364	138	50,842	6,215	12,483	12.22%	1898	0.25%	68%
Oct	2,992	2,401	418	119	51,145	5,811	13,752	11.36%	2225	0.0005%	93%
Nov	2,940	2,024	319	105	50,919	5,283	14,397	10.38%	2196	0.0060%	86%
Dec	2,154	1,393	251	85	50,962	3,798	9,351	7.45%	1622	0.01%	96%
Grand Totals	32,313	23,109	3,373	1,233		58,155	149,011		22,994	2.62%	79.13%

2013 Calls

Customer Service Quality Indices

Month	Customer Service Calls Handled	Collection Calls Handled	Billing Calls Handled	High Bills handled by phone	Total Active Customers	Total of all queues handled (customers calling into the utility)	Total Requests (inbound & outbound)	% of Active Customers calling into utility	Total qualified incoming calls	# abandoned within 30s	% of qualifying incoming calls abandoned within 30s (standard is less than 10% annually)	#answered within 30s	% of qualifying handled incoming calls answered within 30s (standard is 65% annually)
Jan	2,959	2,565	293	106	51,042	5,817	13,279	11.40%	6130	89	0.01%	5089	87%
Feb	1,961	1,589	234	100	51,363	3,784	9,942	7.37%	3836	29	0.01%	3538	93%
Mar	2,313	1,797	286	108	51,178	4,396	11,627	8.59%	4502	42	0.93%	3870	88%
April	2,675	2,128	254	90	51,154	5,057	11,830	9.89%	5253	57	1.09%	4212	83%
May	2,567	1,845	226	77	51,245	4,638	10,843	9.05%	4761	42	0.88%	4046	87%
June	2,443	1,378	226	85	51,262	4,047	9,886	7.89%	4125	28	0.68%	3746	93%
July	3,833	1,869	263	82	51,244	5,965	13,971	11.64%	6432	149	2.32%	5001	84%
August	2,957	1,935	391	157	51,586	5,283	12,255	10.24%	5477	47	0.86%	4408	83%
Sept	2,760	2,010	374	119	51,717	5,144	12,286	9.95%	5189	45	0.87%	4439	86%
Oct	3,097	2,226	332	125	51,797	5,655	14,198	10.92%	5910	70	1.18%	4468	79%
Nov	2,555	1,737	212	81	51,923	4,504	12,436	8.67%	4628	39	0.84%	3985	88%
Dec	3,821	1,161	237	81	51,689	5,219	10,898	10.10%	6350	221	3.48%	3697	71%
Grand Totals	33,941	22,240	3,328	1,211		59,509	143,451		62,593	858	1.37%	50499	84.86%

2014 Calls

Customer Service Quality Indices

Month	Customer Service Calls Handled	Collection Calls Handled	Billing Calls Handled	High Bills handled by phone	Total Active Customers	Total of all queues handled (customers calling into the utility)	Total Requests (inbound & outbound)	% of Active Customers calling into utility	Total qualified incoming calls	# abandoned within 30s	% of qualifying incoming calls abandoned within 30s (standard is less than 10% annually)	#answered within 30s	% of qualifying handled incoming calls answered within 30s (standard is 65% annually)
Jan	2,612	2,332	298	139	51,957	5,242	13,279	10.09%	5491	63	1.15%	4244	81%
Feb	2,466	2,161	319	134	51,594	4,946	9,942	9.59%	5076	54	1.06%	4199	85%
Mar	2,744	2,234	292	129	52,093	5,270	13,695	10.12%	5419	64	1.18%	4245	81%
April	2,733	2,199	238	85	52,124	5,170	11,837	9.92%	5421	76	1.40%	3807	74%
May	2,643	1,691	183	60	52,152	4,517	9,717	8.66%	4598	47	1.02%	4011	89%
June	2,959	1,414	208	92	52,272	4,581	15,146	8.76%	4651	45	0.97%	4119	90%
July	3,015	1,790	272	107	52,388	5,077	10,567	9.69%	5155	38	0.74%	4626	91%
August	2,767	1,649	386	167	52,380	4,802	9,299	9.17%	4984	58	1.16%	3915	82%
Sept	2,621	1,874	253	109	52,420	4,748	9,862	9.06%	4862	37	0.76%	3979	84%
Oct	3,271	1,998	240	81	52,584	5,509	11,528	10.48%	5714	71	1.24%	4455	81%
Nov								#DIV/0!			#DIV/0!		#DIV/0!
Dec								#DIV/0!			#DIV/0!		#DIV/0!
Grand Totals	27,831	19,342	2,689	1,103		49,862	114,872	0.10	51,371	553	1.07%	41600	83.61%

ATTACHMENT # 5-ICF International documents-IRR#18

ICF Canada - Highlights

ICF Canada (ICF Consulting Canada Inc.) is an ICF International company with staff across Canada and formed on January 1, 2011 by the merger of the Canadian operations of ICF International and Marbek Resource Consultants.

ICF Canada helps Canadian energy enterprises in the power and fuels sectors, as well as energy users to develop, analyze, and implement strategies for a rapidly changing environment. ICF Canada's record of over 2,000 projects successfully completed in more than 20 countries provides tangible evidence of the quality of the firm's expertise and its commitment to service excellence. ICF Canada's support services include CDM/DSM portfolio planning and program design, market research and market characterization, evaluating existing and emerging technologies, and conservation potential reviews (also known as achievable potential studies), as well as substantiating measure assumptions, designing engineering tools, building and using energy models, providing M&V support, and providing CDM engineering support on an as-needed basis.

ICF Canada completed a variety of market research projects for utilities and CDM/DSM program providers across Canada, including the OPA, Ontario LDCs, Union Gas, Enbridge, FortisBC, SaskPower, the Yukon, and Efficiency New Brunswick. Also, through ICF Canada's extensive work with utilities across the country, ICF Canada completed performance and cost assessments of over 100 energy efficient technologies used behind the meter. ICF Canada's in-house database is kept up-to-date with emerging technologies, current costs, and savings. ICF Canada's staff is not just experts on paper; they also have deep practical knowledge on electricity end-uses based on actual experience visiting commercial and industrial buildings.

Over the last 20 years, we have done achievable potential studies and/or related DSM plans for most of the major electric and gas utilities across Canada, including BC Hydro, Fortis BC, the two electric utilities in the Yukon, and the two in Newfoundland and Labrador, Enbridge Gas Distribution and Union Gas. We have done or are currently in the process of completing more than 15 achievable potential studies for Ontario electricity distributors.

Customer Engagement Planning and Implementation

Our achievable potential, CDM/DSM portfolio planning and program design work has typically involved customer and supply chain engagement related to particular markets to assess market barriers and opportunities in order to develop appropriate customer uptake forecasts. For example, for the two electric utilities in Yukon, we completed achievable potential work, the preparation of their DSM Plan, and are working on program delivery. In addition to interviews with supply chain actors, we also spent several weeks across the Yukon in face to face meetings with customers as well as other stakeholders in preparing the DSM Plan. Most recently, we completed an achievable potential study for Ontario for the OPA which involved extensive market characterization work for 6 technology clusters. This work included extensive telephone interviews with supply chain actors in each of the technology clusters, including end users (customers). We have begun work for both electric utilities in Newfoundland and Labrador on assessing their achievable potential. We are currently preparing a joint CDM Plan for Veridian Connections and Whitby Hydro, which involves a customer engagement plan and its implementation, and are in the process of engagement plan implementation.

In our work involving customer engagement, we begin with an engagement plan which we develop in consultation with the utility client. We draw from a range of engagement tools such as customer focus groups, public consultation meetings, face to face, telephone, or on-line interviews and surveys. As necessary, we have used survey houses to assist with surveying. In house at ICF we have the 7th largest marketing and advertising firm in the US and an in-house survey house. In addition, we have purchased Olson Canada, whose staff are experts in using digital media. We draw upon these resources as needed in developing and implementing customer engagement plans. Our firm has been recognized for its excellence in creative work, through the numerous awards we have won on behalf of our utility customers (Please see Appendix A for highlights of some of our awards.).The engagement plan starts with a set of researchable issues we would like to address. Through research and client discussion we determine the appropriate methodology in order to address the researchable issues in an effective manner. Once the plan is approved, we start to implement, and in consultation with the client, may make adjustments, based on field experience and learnings.

For the last two years, we have been doing the lead generation and serving as the client interface as part of the Ontario Power Authority's Energy Efficiency Service Provider Program in two Ontario sectors, healthcare and retail. This work involves direct and ongoing engagement with electric utility customers across Ontario, including lead generation for retrofit programs, assistance with site assessments, energy planning, application preparation, and contractor training.

Customer Engagement Training Related to OEB's Chapter 5 Requirements

Since 2013, ICF with Elenchus deliver a Chapter 5 requirements course in partnership with the MEARIE Group to Ontario LDC professionals. Through this course, we have trained more than 30 professionals in the new distribution system planning requirements from a regulatory and planning perspective. The course includes detailed discussion and a small group and plenary exercise in the development of a customer engagement plan to meet Chapter 5 requirements.

The lead facilitator for the Chapter 5 course was the project manager for the customer engagement work done for NPEI. She has a good understanding of the regulatory and planning context, having been an OEB part time Board member for 10 years. The senior consultant for the NPEI engagement work has also been ICF Canada's lead on market characterization work, which as discussed earlier, is steeped in customer engagement planning and delivery.

Company Profile and History

Founded in 1969 as the Inner City Fund (ICF) to support urban renewal in Washington, DC, ICF International has expanded over the last 43 years to provide a range of consulting services to government and private clients worldwide.

Our work addresses today's most complex management, technology, and policy challenges in four key markets: (1) energy and climate change; (2) environment and infrastructure; (3) health, human services, and social programs; and (4) homeland security and defense. Today, we have revenues approaching $1 Billion and over 4,500 employees in more than 60 offices around the world. Our employees combine their passion for their work with an integrated, end-to-end approach while applying their industry and technical expertise to protect and improve the quality of life.

ICF's end-to-end approach is illustrated in the Exhibit 1.

Exhibit 1 ICF's End-to-End Approach

Much of ICF's work is performed by its energy efficiency practice, which has a long history of successful delivery of energy efficiency programs for utilities. Our firm was involved in some of the first studies carried out after the 1972 oil embargo, and we helped develop and evolve the US national ENERGY STAR and Clean Energy initiatives (as well as several important precursors) from their inception. As energy efficiency has ramped up over the last decade, a growing number of U.S. and Canadian utilities, government agencies and authorities, and private organizations are turning to ICF for their energy efficiency needs. Our services include end-to-end program delivery that ranges from program concept to design and cost-effectiveness analysis; program-filing regulatory support; program roll-out or transition; and program marketing and communications, administration, tracking and reporting, and evaluation.

ICF-designed and -managed energy efficiency projects and programs range from very large, comprehensive portfolios to relatively small, targeted programs that focus on a particular sector (residential, low-income, commercial, small business, agricultural, industrial) and/or specific market segments within a sector (e.g., health care, hospitality, or new homes) or on specific technologies (e.g., lighting, HVAC).

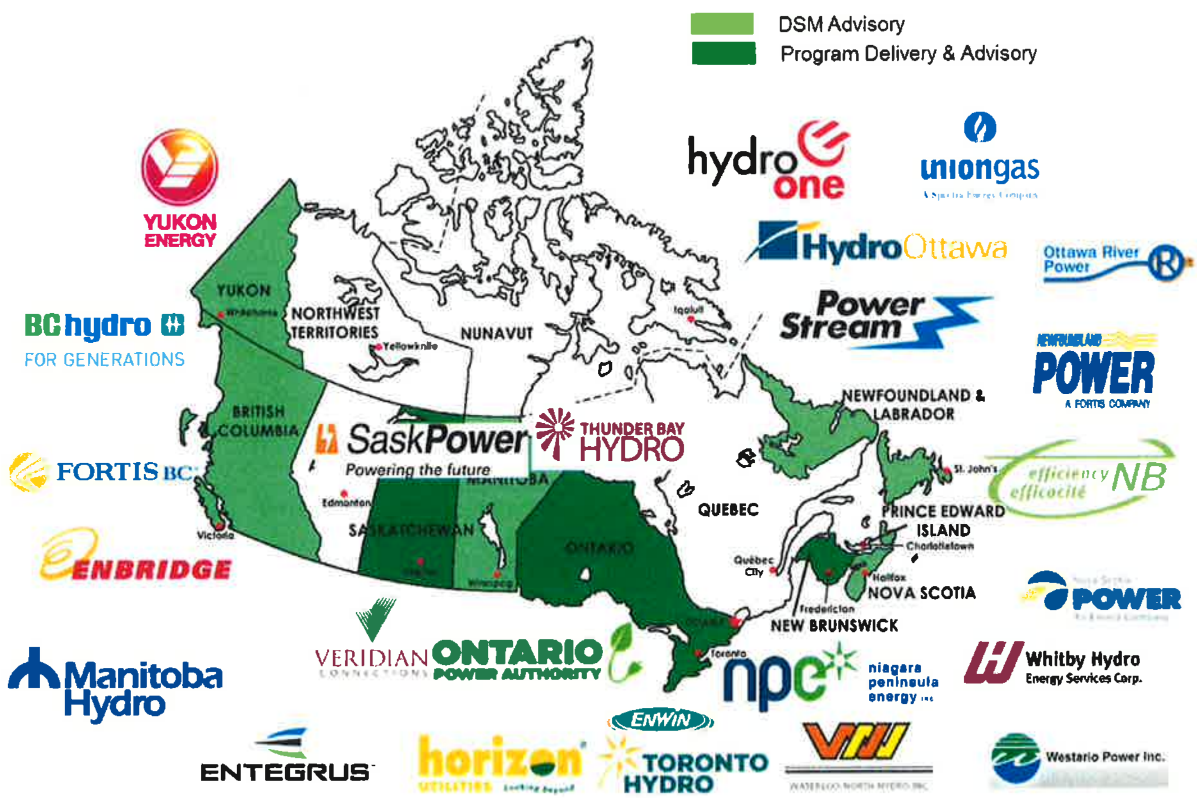
Currently, ICF is implementing projects for a diverse set of utility and energy authorities across the United States and Canada. We currently implement about 125 individual DSM programs in North America, and we've started up seven large portfolios of programs in the last 3 years. ICF's projects for utilities and government clients have consistently been recognized for innovative design and, most importantly, for results. We believe this is because we combine a strong focus on mission success with a fully engaged, consultative approach to program implementation that features accessibility, transparency, clarity, and a dedication to problem solving and continuous improvement. ICF's model is made possible by the breadth and depth of its project team, which includes not only DSM policy, program, and technical field expertise, but also world-class marketing, IT, customer service, and administrative service professionals that are dedicated to the delivery of successful energy efficiency programs.

ICF in Canada

In 2011, ICF expanded its Canadian operations with the acquisition of Marbek Resource Consultants, a well-respected energy and environment advisory services firm, to provide policy, program, technical, and management advisory services in the areas of energy efficiency and CDM/DSM. Paired with ICF's legacy advisory and energy efficiency qualifications, we offer a robust portfolio of services across all of Canada's energy and environmental marketplaces. With more than 30 years of experience in Canada in support of utilities, businesses and government, our Canadian team of over 50 professionals now operates from offices in Toronto, Ottawa, Montreal, Regina, Calgary and Vancouver to best serve our clients' needs.

Across Canada, ICF helps governments, utilities, and private-sector clients to understand the evolving energy landscape and to comply with ever changing environmental regulations and stakeholders. Exhibit 2 below presents some of our Canadian utility clients. At the same time, we help create value for regulators and industry through a rigorous quantitative assessment of the potential impacts and opportunities presented in these policies and markets – see our CDM/DSM services descriptions in the sub-section below. Combined with the DSM program and IRP work we do in the United States, we are easily the leading DSM/IRP firm in North America.

Exhibit 2 Some of ICF's Utility Clients in Canada



ICF in Ontario

ICF has been active on the Ontario electricity scene for over 30 years, serving clients from both our Ottawa and Toronto Offices. Over this time, a lot has changed in the sector, but ICF has stayed at the forefront of advisory services to the utilities by maintaining a broad set of Ontario-specific services that reinforce our staff learning and expertise across the DSM program design and delivery spectrum. Our Ontario clients need not look far to see ICF's analytics and advice at play in influencing and guiding decision-making in the Ontario CDM and DSM landscapes, and in helping our clients meet their needs.

Our CDM and DSM Services

We help utilities and their stakeholders to meet their need for reliable, cost effective power systems through our expert demand-side-energy services. To this end, we serve clients all across the country whether they are in mature markets such as in Ontario, or high-load growth areas such as Saskatchewan, to those with pressing infrastructure challenges such as British Columbia.

We have a proven track record in applying leading-edge technical skills and proprietary modeling, and analysis tools for the following services:

Full-service CDM and DSM program design and implementation: Leveraging our depth of experience with ground-breaking program work like the U.S. Environmental Protection Agency's ENERGY STAR® initiative, we work with our clients to design and implement award-winning demand-side management program solutions and portfolio planning services. These programs draw from our knowledge of both technology and behavior to reduce energy consumption among commercial, industrial, and residential end users. Our program solutions benefit our clients by employing several hallmark service features:

- Sophisticated program portfolio planning models that bring into focus technologies, market effects and cost effectiveness, to clarify program planning decisions and support regulatory submissions.
- Rigorous market characterization research and analysis methodologies to support the development of programs that truly overcome market defects and barriers.
- Detailed and disciplined Program Implementation Planning services to pre-condition programs for success before the launch.
- High-quality direct account management and engagement services employing state of the art CRM and document management Systems such as MS Dynamics and MS Sharepoint.

Load forecasting: We create sophisticated forecasts of energy loads for our utility clients by applying our knowledge of energy use patterns, energy efficiency technology development, and upcoming codes and standards. Our proprietary Sector End-Use Forecasting (SEEF) modeling platform can:

- Ground-truth load forecasts with a detailed end-use based forecast built from the bottom-up;
- Generate multiple forecasts incorporating a range of different economic conditions (economic growth, energy prices, regulation, or competition), to explore the full range of potential business environments,
- Examine trends in energy use for specific end uses in specific customer groups, and
- Model possible impacts of proposed regulatory changes.

Conservation potential: We have emerged as Canada's undisputed leader in helping energy utilities build realistic and defensible forecasts of the achievable savings potential in their service territories. These studies involve the analysis of energy trends and the feasibility of a wide range of energy efficiency options. Our in-house spreadsheet-based macro model, Sector Energy End-use Model (SEEM), can:

- Provide a profile of baseline energy use and reference forecast energy consumption
- Estimate the impact of applying a wide array energy saving measures. Scenarios that are typically considered include technical potential, economic potential, and achievable potential.
- Provide total energy use by service region, building sub sector and end use
- Estimate the demand impacts of the energy-efficiency measures
- Export results to a user-friendly, menu-driven data delivery module called Data Manager that permits fast and flexible presentation of results at the level of disaggregation desired.

Facility energy management: Our program designs are informed by the work we do in the field. We help commercial and industrial facility owners and managers to more effectively manage energy across their building portfolios, and to help industries to leverage energy management to competitive advantage. Our services include:

- Facility performance assessments and establishment of key performance indicators.
- Identification of opportunities and best practices to improve energy efficiency.
- Development of action plans
- Assessing performance improvement on regular basis and establishing a cycle of continuous improvement.

The information and skills that we garner in the "real world" of direct facility energy management continuously informs our DSM measure development, our understanding of market barriers and our network of trade allies.

Company Experience

ICF has extensive experience designing and managing both large and small portfolios of electricity and natural gas programs – designing each program for particular customer segments based upon customer needs, while seeking to harmonize trade ally networks, incentives, marketing efforts, and IT systems. We have launched a number of high-profile portfolios of programs in recent years. ICF ensures that our customers benefit from the latest tools and technologies, and we incorporate the most up-to-date information regarding program operations into our designs.

Relevant Ontario Experience - Sample Projects

2015-2020 CDM Plan Development, Veridian Connections and Whitby Hydro (October 2015 – Ongoing). Veridian Connections and Whitby Hydro have jointly hired ICF to develop their CDM plans for 2015 – 2020. It is anticipated that this plan will be a joint submission of the two utilities. The project entails several phases including: internal consultation and review of the existing portfolio of programs; external stakeholder engagement activities (Region, Municipalities, Trade-allies/Channel Partners, Various Utility Customer Classes); Preliminary program portfolio development; Business planning for financial models and resource needs; and finally, final CDM Plan Development using the model and templates prescribed by OPA.

Electric Vehicle Load-Shifting Pilot Program, Niagara Peninsula Energy Inc., (March 2014 – October 31, 2014). ICF was retained by Niagara Peninsula Energy Inc. (NPEI) to develop a program concept and business case for funding of an electric vehicle load-shifting pilot program through the Ontario Power Authority's Conservation Fund. With approval from the Conservation Fund secured, ICF developed a detailed program design and implementation plan. The project involves the load shifting of the battery charging of non-road electric vehicles to off-peak hours in industrial facilities (forklifts, pallet trucks) and of golf carts in golf courses. The pilot involves two large golf courses, a large greenhouse and a manufacturer. Timers and additional wiring as necessary were installed free of charge in each facility to enable the charging of the vehicle batteries to take place after 7:00 p.m. An M&V protocol, in conformity with OPA M&V protocols, was designed and implemented at each facility in order to properly measure the base case and the savings achieved from the load shifting.

In carrying out the project, extensive market characterization work was necessary to assess the market potential for a provincial rollout of the program. This included face to face and telephone interviews with customers as well as telephone surveys, and an on-line customer survey. The completed project included a final report which documents the pilot program design and results. It includes recommendations related to a provincial program rollout, a short case study of each facility, and an easy to use guide for facility owners and operators for setting up a load shifting program for non-road electric vehicles in similar facilities. ICF was the project manager for the pilot delivery. The pilot ran from March 1 to September 30, 2014 and the final report was completed by October 30, 2014.

Market Characterization and Technology Studies

Program portfolio design requires an in-depth understanding of the local markets and their inherent barriers that prevent broader adoption of efficiency measures. ICF has become a market leader in leading market research studies and jurisdictional scans to provide utilities with up-to-date information on market conditions. This allows programs to be tuned towards the markets and barriers that they are intended to address. This in turn ensures programs are more cost-effective by increasing uptake.

Our Ontario market characterization work holds a key place in the portfolio design process by providing our clients with a deep understanding of the technical and market issues at play in their respective service territories. Through our market studies, our clients come to understand the market structure, product distribution system and players, market actors and their associated issues and information barriers. These allow for programs to be more relevant to the jurisdiction in question, and more adaptive to the need of the participants in a given market segment. Our technology studies focus on understanding the energy savings possible through various technologies and their overall cost and replacement profiles, as well as market issues specific to those technologies. Taken together, this direct Ontario experience, combined with similar experience in other jurisdictions, informs better energy savings measure selection, improved budgeting and cost effectiveness modeling, and better overall program take-to-market approaches. This results in more cost-effective and efficient programs for our clients.

Details of some of our work in this area are provided below:

Market Characterization of the Greenhouse and Hotel/Motel Sectors in the Niagara Peninsula Energy Inc. Service Territory, Niagara Peninsula Energy Inc. (NPEI) (March 2014 to October 31, 2014). ICF was retained by NPEI to customize, based on NPEI's customer consumption data, the results of the achievable potential study for 2012-2032 that ICF had previously completed for the OPA. The results of that work revealed two key subsectors with significant achievable potential within NPEI's territory (greenhouses and hotels/motels), which have not been well-addressed in current conservation and demand management (CDM) programming. In order to better understand these subsectors to enhance customer uptake and energy savings through NPEI's CDM, NPEI asked ICF to conduct a detailed market characterization of these two subsectors. This work was accomplished both through site visits and interviews as well as the review of available customer audits carried out through CDM. This process provided NPEI with a far richer representation of the facility types, equipment used and potential energy savings within their territory. Based on the results of this work, ICF made adjustments to the customized achievable potential modeling to take into account the learnings from the market characterization work. The final report contains the final achievable potential results, the findings from the market characterization work, and recommendations to increase uptake by greenhouses and hotels/motels in existing OPA CDM programming.

Market Overview for the Commercial Refrigeration Market, Lighting Controls Market, Variable Speed Drives Market, and Compressors Market in Ontario, Ontario Power Authority (2013). OPA contracted ICF to develop a market overview for four key CDM end uses:

- Refrigeration – Commercial and institutional
- Lighting Controls – Commercial, institutional and industrial
- Variable Frequency Drive (VFD) – Commercial, institutional and industrial
- Compressors – Industrial

The results of our work are being used by the OPA to develop channel-specific strategies for each of these high-impact end uses. These strategies will assist LDCs in achieving their targets by unlocking the high potential for savings within the channels. Our approach was to work closely with the OPA to produce lean, high-value upstream market research work that meets the objectives in thirty business days. The project involved quickly mobilizing a skilled and efficient core project team, supported by a pool of seasoned sector and technology subject matter experts. The team ramped up quickly, and drafted concise, representative and insightful market reports that OPA found extremely useful.

Early Replacement Furnace Program Assessment, Union Gas (2012-2013). This project characterized the early replacement of residential furnaces as a potential conservation measure. More specifically, the project: determined that the use of a Weibull failure distribution, as used by the US Department of Energy, is a solid method of determining the remaining life of older Canadian residential furnaces; provided the technical and marketing information needed to estimate the potential for a prescriptive or quasi-prescriptive residential furnace early replacement program; and assessed whether such a program would help achieve Union Gas's DSM objectives.

Market Assessment of High Efficiency Commercial Clothes Washers, Union Gas (2010). The scope of this analysis included estimating energy use for existing commercial washers, estimating installed costs and savings resulting from upgrading to high efficiency models, and determining the market opportunity in Union Gas territory across all relevant market segments. Segments included multi-family residential, hospitality, long term health and Laundromats. In addition, the study focused on the determination of potential natural gas, electricity and water savings by market segment and upgrade case.

High-Efficiency Rooftop Units, Union Gas (2009). The objective of this study was to research and assess high-efficiency rooftop units and develop energy saving measures that will be used by Union to inform demand-side management (DSM) program planning. The scope included packaged indirect-fired rooftop units in three application categories: heating and cooling; heating only; and make-up air. The approach involved researching and profiling rooftop unit technologies, equipment, and markets; modeling energy savings impacts in representative building archetypes; and completing a financial analysis of energy saving opportunities. The savings were modeled using two modeling platforms: eQUEST and ICF's CEEAM energy simulation programs. Overall, the study confirmed the existence of cost-effective energy saving measures in all three equipment categories, and serving all commercial sub-sectors.

Achievable Potential Studies

Conservation potential studies (e.g. achievable potential studies) are a critical first step in CDM portfolio design. These studies serve to bridge the gap between long-term energy planning and CDM program planning. Through our studies, we have developed an unparalleled ability to identify and prioritize market segments and sectors, which has allowed us to direct utilities towards the most viable and lucrative market segments in which to develop programs.

ICF is the undisputed leader in developing the achievable potential for CDM in Ontario. We've worked with the OPA and the gas utilities for the last decade to quantify the potential for energy savings in the province. In doing so, we've established a very deep and fundamental understanding of the various moving parts that inform good program design. This includes the inventory of the building stock and its associated end-use equipment breakdown. Our experience has given us a comprehensive database of energy savings measures and their associated financial performance that our clients benefit from. As well, we have an in-depth understanding of program and measure financial performance modeling and scenario development. All of these serve to inform prioritization of programs for our Ontario clients and deliver more cost-effective programs that deliver savings.

Ontario Achievable Potential 2015-2020, Ontario Power Authority (2013-2014). ICF worked with the OPA to develop estimates of achievable potential for CDM in Ontario, to support OPA's planning of CDM programs. ICF used the technical potential output from existing OPA load forecasting models to develop initial estimates of achievable potential by sector, sub-sector, milestone year, and measure. These results were used to target a subset of measures for detailed investigation through market characterization studies in 6 technology clusters. Research into the customers and supply chain for these measures through interviews of actors across the supply chain including end users provided insights to guide estimates of uptake under different program scenarios. The results of this market characterization were used to develop more detailed estimates of achievable conservation potential by measure, milestone year, and different program options, focusing on both the 2015-2020 timeframe and the longer term forecast to 2032. In addition, the achievable potential results were adjusted based on the Ontario Power Authority's forecast of the impacts of codes and standards.

Achievable Potential Studies for Ontario LDCs (2014 – to present). Based on the OPA Achievable Potential Study results, ICF has developed a tool for customizing the results to individual local distribution companies. The tool is developed by tailoring a version of the OPA Achievable Potential model to the individual LDC's service territory, by scaling the results for each building type and IESO zone to the size of the LDC's customer base in that building type and zone. The tool consists of four Excel workbooks that provide results at the full level of granularity, down to estimated potential for individual measures in the different building types. A brief report summarizes the overall results. To date, ICF has completed or is the process of completing projects for more than 15 LDCs.

Ontario 20-year Load Forecast & Conservation Potential Assessment. Ontario Power Authority and Cadmus (2009). ICF and the SeeLine Group provided input assumptions for a 20-year electric energy and demand model developed for OPA by The Cadmus Group. The End Use Forecaster model provided an electric energy and demand load forecast and an associated conservation potential assessment for the Province of Ontario. The electricity load forecast and the conservation potential assessment were based on a detailed end use approach that represents the most comprehensive level of detail ever undertaken in Ontario.

DSM Potential Review - Update 2011. Union Gas (2011). Following completion of Union Gas' earlier DSM Potential study in 2009, ICF updated the study's results in response to the significant changes to the economy, including lower natural gas supply prices. The updated study results provided: detailed end use base year profiles calibrated to actual sales data; technology profiles deriving the economic and financial performance of the DSM actions; a business-as-usual forecast for the base case and estimates of economic and achievable potential cost-effective DSM actions. The study results are supporting Union's current regulatory submissions and the development of multi-year DSM targets.

Natural Gas DSM Potential Update – 2008, Enbridge Gas (2009). ICF updated Enbridge's previous (2004) DSM Potential study, which was also conducted by ICF. The study outputs consisted of an updated set of DSM forecasts for each of the three sectors included in the study (residential, commercial and industrial), together with an updated set of energy technology profiles that address each combination of sector and end use. The study outputs included a Base Year Forecast, which incorporated the effects of natural conservation, together with Technical, Economic and Achievable Forecasts and estimates of savings potential. The study also reviewed a number of emerging technologies that may influence future opportunities. The final study reports provide a foundation that Enbridge can use on an ongoing basis to inform the setting of annual DSM targets and budgets, the development of a long range DSM strategy, and the design and development of DSM programs.

Program Delivery Projects

ICF firmly believes that our program and portfolio designs are made much more relevant by our direct involvement in program delivery. Program delivery places ICF into participant-facing roles, and allows us to experience first-hand the many program delivery challenges that are experienced by our utility clients. Being program implementers causes us to become better program designers. Our clients benefit directly from all of the lessons learned both directly in the Ontario context, as well as through our experience in other jurisdictions.

Energy Efficiency Service Provider for the Retail Sector, Ontario Power Authority (February 2013-present). ICF is working with the Retail Council of Canada to deliver conservation demand management services to the retail sector in Ontario through an OPA-contracted and –funded initiative. Through the EESP (Energy Efficiency Service Provider), services are provided to the end user at no cost. The scope of work for each retail customer is customized to the participant, to meet their specific needs. ICF has engaged with various retailers and is providing assistance with developing business cases for energy efficiency, technology assessments, measurements and verification and energy performance benchmarking. ICF is also assisting with the development of webinars, monthly newsletters, a website with tools and resources, as well as providing guidance to retailers on how to access electric utility incentives. The initiative is designed to reduce retailers' real estate portfolio costs and help achieve environmental and sustainability goals, while contributing to the overall demand reduction in the province of Ontario. To-date the project has identified over 7MW of projects, which are being moved along by the account managers.

Canadian Coalition for Green Health Care (CCGHC) – Energy Efficiency Service Provider Initiative CCGHC – Ontario Power Authority Host. (2013 – Present). ICF, in partnership with The Canadian Coalition for Green Health Care, is planning and delivering a range of cost-effective energy management services to the Healthcare Sector in Ontario. The Initiative's goal is to accelerate CDM activities within the sector through the development, coordination and implementation of energy efficiency projects.

Technical Review Services for Commercial & Institutional saveONenergy Initiatives. Oakville Hydro (2011), (2011), Powerstream (2012 - Present), Enwin (2012 - Present), Hydro Ottawa (2011-Present), Hydro One (2011), Westario Power (2011-2012), Ottawa River Power Corporation (2011-2012), various other LDCs as a subcontractor to Enbridge Gas Distribution (2012 - 2014). ICF provides CDM program implementation services to a number of LDCs, delivering the Commercial & Institutional saveONenergy Initiatives. ICF services span the saveONenergy Retrofit, Energy Audit, and New Construction initiatives. Depending on client needs, ICF reviews prescriptive, engineered and custom applications, energy audit applications, reviews measurement and verification (M&V) plans, conducts pre- and post-retrofit QA/QC site visits, and provides client liaison services.

Exhibit 3 Some of ICF's Program Design and Delivery in Ontario

<table>
<tr><th>Client</th><th>Sector</th><th>Program</th><th>Role</th><th>Year(s)</th><th>Results (kW/kWhs/GJ)</th></tr>
<tr><td rowspan="3">Retail Council of Canada & Ontario Power Authority</td><td rowspan="3">Business – Retail</td><td rowspan="3">Retail Energy Bright</td><td rowspan="3">Program Manager</td><td rowspan="3">2013-Present</td><td>Over a period of 18 months, built pipeline up to present size of 7 MW (45 GWh) across 91 distinct projects.</td></tr>
<tr><td>Measures including lighting, HVAC, DCV, and both incented and non-incented projects.</td></tr>
<tr><td>Delivered multiple multi-site head office applications.</td></tr>
<tr><td rowspan="3">Canadian Coalition for Green Healthcare & Ontario Power Authority</td><td rowspan="3">Institutional – Healthcare</td><td rowspan="3">Healthcare Energy Leaders of Ontario</td><td rowspan="3">Program Manager</td><td rowspan="3">2013-Present</td><td>Over a period of 12 months, built the pipeline up to present size of 13.7 MW (103 GWh).</td></tr>
<tr><td>Measures including HVAC, Lighting, Cogeneration and whole building energy programs.</td></tr>
<tr><td>Delivered multiple Energy Management Plan training workshops.</td></tr>
<tr><td rowspan="2">Various – Ontario LDCs</td><td rowspan="2">Commercial Retrofit and New Construction</td><td rowspan="2">Energy Retrofit Incentive Initiative, High-Performance New Construction Initiative</td><td rowspan="2">Technical Review Support</td><td rowspan="2">2010-Present</td><td>ERII/Retrofit since 2008: 357 applications received. Total savings of 6.1MW and 27.5 GWh. Total incentive payment recommendations of $4.8M.</td></tr>
<tr><td>HPNC: 133 applications received. Total savings of 27 MW and 11.2 GWh. Total incentive payment recommendations of $1.3M.</td></tr>
<tr><td>Toronto Hydro</td><td>Commercial and Industrial</td><td>Energy Retrofit Incentive Initiative,</td><td>Project Identification and Audit Support</td><td>2014 – Present</td><td>Over a period of 8 months have completed over 40 assessments of mid sized commercial and industrial facilities. To date, these assessments have identified 1.5 MW (8.7 GWh) of savings. The Assessments are leading to further project development and application assistance.</td></tr>
</table>

Professional Development Course Design and Delivery

ICF has been a leader in developing and delivering professional development courses for the Ontario context. Our courses are well researched, and represent the state-of the-art of best industry practice. Furthermore, our courses also seek to inform LDC's and the broader industry of the changing regulatory context. Our clients benefit from the in-depth knowledge that our staff gain in developing and delivering these training courses. We apply the content of each course in our day-to-day handling of issues, ensuring that our clients have the most up-to-date and relevant information in all of our assignments.

Of particular relevance to this assignment is our role in partnership with the MEARIE group, in educating Ontario LDCs on the intricacies of the 2015-2020 CDM framework cost effectiveness and program design requirements.

Ontario CDM Professional Development Course Design and Delivery. MEARIE (2013 – Present). In partnership with the MEARIE Group, ICF developed and delivered a number of courses as part of new CDM course program. Components of this program included:

- *How to Design a Successful Board-Approved Program.* Design and delivery of a one-day course on how to prepare a successful application to the Ontario Energy Board for a Board-Approved Program. The course was based on the PowerStream Board CDM program application as well as past Board proceedings related to CDM program approvals of Toronto Hydro and Hydro One. This course was delivered twice in 2013-2014.

- *Chapter 5 Requirements.* This is a one day regulatory and policy course targeted at LDC accounting, regulatory, finance and CDM professionals to provide training on the Ontario Energy Board's requirements for distribution system planning and plans to be filed as part of the utility rate case. It deals with all policy aspects of the requirements, including customer engagement, the CDM components, and how to integrate these requirements into distribution system planning and CDM planning. This course has been delivered three times in 2013-2014 and additional courses are planned for 2015.

- *CDM Economics.* ICF is designed and delivered a one-day CDM economics course for CDM utility professionals in London, Ontario in October (members of the EDA SW Ontario chapter), and in Toronto in November2014. Two course events are planned for 2015 for CDM utility professionals. The course will cover cost-benefit analysis, program budgeting, and factors to consider in opting for a P4P or FCR program approach, and in determining the type and level of program outsourcing.

- *CDM Account Management.* ICF is designed and delivered a two-day CDM account management course in Toronto in November of 2014 aimed at CDM utility professionals. The course will focus on how to assist LDC customers in preparing a business case for energy retrofits, lead generation and management, and other aspects of program delivery. The course is planned to be offered twice in 2015.

- *CDM Planning and Program Design.* ICF is designed and delivered a one-day conservation and demand management in Toronto in November of 2014 for CDM utility professionals. The course focused on how to prepare a successful CDM portfolio including program screening and design approaches, risk assessment and portfolio optimization. The course is planned to be offered twice in 2015.

CONSERVATION POTENTIAL STUDIES

Within the past 7 years, ICF has performed major provincial conservation potential studies for:

- BC Hydro
- FortisBC
- SaskPower
- Yukon Energy
- Newfoundland & Labrador

These successful projects have served to inform each utility about the savings potential associated within each market sector, and accordingly, what program budgets should be set at in order to achieve this potential.

Professional Development Course on the Principles: Applications and Analysis of Conservation and Demand Management, Ontario Power Authority (OPA) 2010-2011. ICF was selected to design, develop, pilot test and deliver professional development content for OPA and Ontario Local Distribution Company (LDC) staff. The primary goal of the course is to continue to build organizational capabilities, and for the target audience to improve its ability to provide appropriate, sufficient and affective support to external conservation partners. The primary objectives of the professional development course are to: (i) Enhance the skills and knowledge of existing Conservation Staff with respect to the principles, applications and analysis of CDM; (ii) Provide an effective, consistent and replicable approach for introducing new staff (either to OPA or to Division) to the principles, applications and analysis of CDM. The completed course consists of three separate but complementary courses: a CDM Fundamentals course aimed at new and Supporting CDM Staff, an Applied CDM course offering 4 days of in-depth CDM training aimed at program staff, and a 1 day Strategic Leaders Forum aimed at Program leaders in Ontario.

CDM/DSM Program Work Outside of Ontario

In addition to our Ontario-specific program experience, ICF has successfully completed dozens of projects related to the planning and implementation of CDM/DSM programs outside of the province. We believe that this experience is relevant as it demonstrates our depth of experience in the program portfolio field, which we use to inform our work in Ontario. Furthermore, the methodologies used in these projects (such as market studies and cost-effectiveness testing) are directly applicable to Ontario.

As in the previous section, our work outside Ontario can be divided into several categories:

- *Conservation Program Planning and Studies*: ICF has done extensive work across Canada, and is the leading provider of CDM potential and program planning services. We have undertaken such work for BC Hydro, Fortis BC, Yukon Electric and Yukon Energy, and SaskPower.
- *CDM Market and Technology Studies*: Outside of Ontario we have worked extensively for FortisBC (gas utility) and provided detailed market studies that have led to improved programs.
- *Portfolio Planning and Program Implementation*: ICF delivers more than 125 programs on behalf of 40 utilities across the US. We have prepared more than 40 DSM plan for utilities in Canada and the US. In addition, ICF Canada is delivering the industrial portfolio of DSM programs for SaskPower and we have worked extensively on DSM Plans and Conservation Potential Reviews (CPRs) for BC Hydro, FortisBC, and the Yukon utilities in the last few years. Furthermore, we have DSM experience working with Newfoundland and Labrador utilities, Efficiency New Brunswick and Nova Scotia Department of Energy.

The following table presents just some of our program Design and Implementation achievements on behalf of our clients:

Exhibit 4 Some of ICF's Program Design and Delivery Achievements in Canada

Client	Sector	Program	Role	Year(s)	Results (kW/kWhs/GJ)
Efficiency NB	Industrial	Large Industrial Program	Turnkey Program Manager/Transition to Program Support. (Results include time under management by ICF's Colin Murray while employed at Efficiency NB)	2009-2012	26 of 30 Industries participating $94 million in capital $25 million in savings 2451 TJ annual savings 168,000 annual tones CO2 saved
Efficiency NB	Industrial	Small and Medium Industrial Program	Program Manager/ Energy Advisor (Results include time under management by ICF's Colin Murray while employed at Efficiency NB)	2010-2012	34 of targeted 80 Industries participating 30.2 TJ annual savings 2500 annual tones CO2 saved
SaskPower	Industrial	Industrial Energy Optimization Program	Turnkey Program Manager/Transition to Program Support	2012-present	25 of 30 Industries participating 20 MW of projects being developed 1.5 MW of completed and verified projects
SaskPower	Commercial	Commercial Lighting Program	Program Manager/Transition to Application Processing Management	2012-present	1900 applications approved 110,000 lighting measures approved $2.5M incentives paid 4MW of completed and verified projects
SaskPower	Institutional – Municipal	Municipal Ice Rink Program	Program Manager/ Transition to Program Support	2012-present	65 Customer service Energy Audits Performed and Benchmarked

Company References

This section contains 3 references for ICF.

Reference #1			
Company Name:	Toronto Hydro	Approx. Size ($$ Rev):	~$150K (Project size)
Industry Segment:	Electric utility	Where Located:	Ontario
Contact Person:	Mike Marchant	Contact's Title:	Director, Customer Data and Engineering Services
Contact's Phone #:	416-542-3361		
Brief Description of work performed:			
Local Demand Response Toronto Hydro retained ICF International to develop financial models and business analysis to explore the potential for localized demand response (DR) initiatives that specifically target areas of high system constraint in Toronto's service territory. The resulting model was named "DR Challenger". The DR Challenger can also so do regular CDM cost-effectiveness tests such as the TRC, PAC and LUEC. Mike Marchant gave ICF permission to state that: "Toronto Hydro finds the DR Challenger useful and easy enough that they are using it for early CDM cost-effectiveness calculation scenarios before formalizing with the OPA tool."			

Reference #2			
Company Name:	Niagara Peninsula Energy	Approx. Size ($$ Rev):	~$360k (Project size)
Industry Segment:	Electric utility	Where Located:	Ontario
Contact Person:	Sue Forcier	Contact's Title:	Chief Conservation Officer
Contact's Phone #:	905-356-2681 x6001		
Brief Description of work performed:			
2013-2014 – Design and delivery of an EV load shifting pilot for shifting the charging of electric battery-powered off-road vehicles (forklifts, pallet trucks) used in industrial and commercial facilities and golf carts in golf courses to off-peak hours, funded by the OPA's Conservation Fund. Work is ongoing and scheduled to be completed at the end of October 2014. 2014 – Conduct of a customized achievable potential study based on OPA's achievable potential study completed by ICF, which will be adjusted based on detailed market characterization work in two business subsectors. Work also involves the development of a 2-yr Customer Engagement Plan to comply with OEB customer engagement requirements and a Baseline Report which documents engagement activities as a result of the engagement plan in 2014. Work is ongoing and scheduled to be completed at the end of October 2014.			

Reference #3			
Company Name:	FortisBC	Approx. Size ($$ Rev):	~$200,000 (Project Size)
Industry Segment:	Electric and Natural Gas Utility	Where Located:	British Columbia
Contact Person:	Colin Norman	Contact's Title :	Program Manager, Portfolio Projects, Energy Efficiency & Conservation
Contact's Phone #:	604-592-7513		
Brief Description of work performed:			

2012-2013 - Following the successful preparation of FortisBC's 2011 DSM submission to the BC Utility Commission, ICF prepared the utility's 2014-2018 DSM Plan submission. As in the preceding case, we worked in close collaboration with the FortisBC program managers to identify the necessary inputs into the Plan. ICF also carried out all of the required program cost-benefit analysis and prepared a summary report to document the results. With both DSM plans, ICF provided timely support to FortisBC in its submission of responses to interrogatories (IRs) as well.

CVs of the Report Authors

Judy Simon **ICF International**
Principal

EDUCATION

2011-12 Mini-MBA (Advanced Management Course) McGill University Executive Institute, in progress (Module 1 completed)

1980 Master of Environmental Design (Environmental Science), University of Calgary

1977 Bachelor of Science, University Scholar, Great Distinction, McGill University

EXPERIENCE OVERVIEW

Judy Simon has over 30 years of experience related to Ontario conservation frameworks, policy, programming and markets and CDM training. This has included work on preparing CDM plans, designing and delivering CDM programs, work on carrying out achievable potential studies to assist the OPA and LDCs to set CDM targets and plan CDM portfolios, and the design and delivery of a suite of CDM courses through the MEARIE Group, and managing more than 100 related projects.

Judy was a senior advisor to the OPA on the development of the first generation CDM framework, and has advised more than 40 Ontario LDCs in the design of their CDM programs and plans. Most recently, Judy was the project manager for the Achievable Potential Study for the Ontario Power Authority, which included the generation of achievable potential by sector, market segment and end-use. She was also the project manager for the work done for NPEI related to achievable potential, market characterization and customer engagement.

Judy has a strong understanding of Ontario's regulatory framework for both electric and natural gas utilities in Ontario. As a part time Ontario Energy Board member for ten years, Judy was involved in more than 100 proceedings, which included policy proceedings related to stakeholder consultation and engagement, and was the lead Board member in the development of enhanced versions of the Environmental Guidelines for the Location, Construction and Operation of Hydrocarbon Pipelines and Facilities in Ontario during her tenure. In her role as manager in charge of all energy and waste management approvals under the Environmental Assessment Act for the Ministry of the Environment, she was responsible for the development and implementation of the Ministry's Pre-Submission Consultation Guidelines with directly and indirectly affected stakeholders.

Judy is a leading facilitator of energy planning and policy work, having facilitated numerous CDM/DSM related workshops/seminars for LDCs, the OEB, and other organizations. Most recently she did facilitation for CDM planning and customer engagement with NPEI, facilitating an internal working group of utility vice presidents and the CEO on CDM and customer engagement matters related to the development of the utility's distribution system plan. Judy is the lead facilitator and designer of the MEARIE Group's Chapter 5 Requirements Course for LDC professionals in Ontario.

PROJECT EXPERIENCE

ICF International, Principal
Responsible for and provide services in:

- Energy planning and policy analysis
- Planning, portfolio analysis and program design
- Energy regulatory approvals related to rates and CDM/DSM
- Stakeholder engagement, facilitation and partnership building
- Training in CDM/DSM, distribution system planning and associated regulatory matters

Elenchus, Principal, Economic Regulation and Conservation
Responsible for and provided services in:
- Management of Elenchus economic regulation and policy staff
- Business development and corporate planning
- Management in energy and water conservation, and environmental sustainability
- Stakeholder engagement, partnership building and training in regulatory utility affairs
- Program evaluation, measurement and verification

IndEco Strategic Consulting Inc., Vice President
Responsible for and provided services in:
- Program design and delivery, monitoring and evaluation related to demand-side management and conservation and demand management for energy and water
- Preparation of comprehensive, sustainability, energy and water management plans
- Business development, market assessment
- Marketing and promotions
- Stakeholder and channels management
- Facilitation, education, training and awareness
- Company executive for the above

Ontario Energy Board, Board Member (part-time)
Ms. Simon was involved in more than 150 files including rates cases, franchise approvals, leave to construct applications, and policy hearings related to demand-side management, gas pipeline approvals, corporate mergers and other matters. Ms. Simon was appointed to the Board as the Board members' leading authority on energy efficiency, public consultation and environmental matters.

Ontario Ministry of Industry, Trade and Technology, Manager, Technology Policy
Ms. Simon was responsible for managing the Technology Centres and for the development of technology policy related to the energy and environmental sectors. Ms. Simon coordinated the preparation of the Cabinet Subcommittee's report on free trade, which was tabled in the Legislature.

Ontario Ministry of Environment, Manager, Environmental Assessment Branch
Ms. Simon was responsible for all the waste and energy approvals under the Environmental Assessment Act (EA Act) and for the development of all EA programmatic policies. This included responsibility for more than 100 energy (electricity transmission and generation) and waste EAs. Ms. Simon was senior advisor to legal counsel on the major Ontario Hydro eastern Ontario and southwestern Ontario transmission system expansions before the Joint Board (Joint Panel of Ontario Municipal Board and Environmental Assessment Board), and one related judicial review proceeding before the Ontario Divisional Court. Ms. Simon was also an expert witness for the Ministry in the southwestern Ontario hearing.

Ontario Ministry of Environment, Environmental Planner, Environmental Assessment Branch
Ms. Simon was responsible for the coordination and preparation of government reviews for waste, energy, transportation and sewage and water related environmental assessments under the Environmental Assessment Act.

Ontario Ministry of Energy, Energy Planner, Conservation and Renewable Energy Group
Ms. Simon was responsible for the preparation of a government discussion paper on district energy and for providing policy advice on municipal energy matters and renewable energy approvals.

Nova, an Alberta Corporation, Energy Researcher, Algas Resources
Ms. Simon was responsible for the preparation of a feasibility assessment of a pilot anaerobic digester on livestock operations in southern Alberta. Nova (then Alberta Gas Trunkline) funded Ms. Simon's master's thesis, which involved developing a technology assessment model, which was then applied to a feasibility analysis of methanol and ethanol as transition transportation fuels, with natural gas as a feedstock.

SELECTED PROJECTS

Frameworks and Planning

Veridian Connections and Whitby Hydro. Prepare separate and a joint CDM Plan based on the new 2015-2020 framework. Work includes extensive customer engagement, portfolio planning and risk assessment, program design and the development of program implementation strategies. Work is ongoing. Project Manager.

Niagara Peninsula Energy (NPEI) Inc. Prepared an energy conservation achievable potential study for NPEI based on the OPA's provincial achievable potential results (by sector, market sector and end use, including TRC, PAC and LUEC results) customized to the NPEI service territory based on NPEI customer data and a market characterization of key commercial and industrial market segments in the service territory. Conducted market characterization work in the hotel/motel and greenhouse sectors, and adjusted the achievable potential results. Project Manager.

Ontario LDCs. Prepared or in the process of completing an Achievable Potential Study for more than 15 Ontario LDCs. Account executive.

Ontario Power Authority (OPA). Prepared an Achievable Potential Study for 2012-2032 for the residential, commercial, institutional and industrial sectors based on end-use modeling and a detailed market characterization analysis from research and interviews. Results were by sector, subsector and end use and included supply curves, codes and standards, as well as cost-effectiveness test results (TRC, PAC, LUEC). The work involved extensive market characterization in 6 technology clusters, the results of which were used to adjust the achievable potential results. Project manager.

30 local Ontario electricity distributors. Assisted these electricity distributors to develop program plans, CDM budgets, and resource plans for approval by the OPA for the delivery of residential, commercial and industrial conservation and demand management plans. Senior project manager.

10 local Ontario electricity distributors. Assisted these distributors in the preparation of conservation and demand management plans, which included the design of their portfolio of CDM programs, and approval of these plans by the Ontario Energy Board. Senior project manager.

Yukon Energy. Provided assistance in the preparation of a Compliance Filing related to the approval of the joint Yukon Electrical-Yukon Energy CDM Plan, which involves the review of the avoided costs, Total Resource Cost Test, Program Administrator Cost Test and Rate Impact Measure Test for all the approved programs in the DSM portfolio, as well as a calculation of the portfolio cost-effectiveness. Based on the review and recalculation of the costs based on the Yukon Utilities Board required proration, implications on program design and delivery were identified and assessed, including improvements to program measures and delivery strategies to address new budget restrictions. Project manager.

Yukon Electrical Company Ltd. Provided assistance in responding to interrogatories and in the development of reply argument before the Yukon Utilities Board regarding the approval of YECL's DSM Plan in its most recent General Rates Case (2013-2015). This included strategic advice and assistance with responses to cross-examination at the oral hearing related to the methodology for calculating avoided cots and the cost-effectiveness tests (TRC, PAC, RIM). Senior advisor.

Ontario Energy Board. Facilitated the development of the short-term regulatory framework for low-income natural gas demand-side management through the facilitation of a multi-stakeholder working group set up by the Board. Prepared a report that documents the framework and consensus reached. Project manager and lead facilitator. ☐

Ontario Energy Board. Facilitated the development of the framework for the Board's emergency low-income energy financial assistance program through the facilitation of a multi-stakeholder working group set up by the Board. The result of this work was documented in a report to the Board. Project manager and lead facilitator.

Enbridge Gas Distribution. Prepared a review of the OEB Demand Side Management (DSM) Guidelines for Natural Gas Distributors. Project manager and lead author.

Ontario Power Authority. Provided advice on the establishment of the first CDM framework for LDCs (2007-2011). Project Manager.

CDM/DSM Program Design

Welland Hydro. Design of a whole-house residential pilot program including the business case for approval of pilot delivery under the Conservation Fund. Work is ongoing. Account executive.

Niagara Peninsula Energy Inc. Designed and delivered of a commercial and industrial load displacement program for charging electric vehicles (e.g. golf carts, forklifts) funded by the OPA's Conservation Fund. Account executive.

MEARIE Group (Electricity Distributors Association). Designed and delivered a one-day training course on portfolio planning and program design for LDC professionals in the new CDM framework (2015-2020). Lead trainer and program designer.

MEARIE Group. Designed and delivered a one-day training course on CDM economics for LDC professionals in the new CDM framework (2015-2020). Trainer and program designer.

MEARIE Group. Designed and led a one-day training course (2 sessions) for utility DSM professionals on how to prepare a successful program design and application for Ontario Energy Board approval for electricity distribution conservation professionals. Project manager and lead trainer.

Nelson Hydro. Prepared a detailed program design for an on-bill financing program for residential retrofits and an examination of the integration of water conservation into the program design. It also included an examination of PACE opportunities. The program was the first of its kind in British Columbia and launched in March 2012. Senior manager and lead author.

Office of Energy Efficiency, NRCan. Prepared a concept paper regarding on-bill financing of residential homeowner retrofits, which included an examination of 5 case studies of innovative continental programs and related legislation. Senior manager and principal author.

Office of Energy Efficiency, NRCan. Prepared a discussion paper on business models for district energy in Canada. Senior manager and lead author.

Office of Climate Change. Government of Newfoundland and Labrador. Research on all electricity distributor conservation and demand management programs across Canada, with a focus on commercial, institutional and industrial programs. Screening of detailed program investigations in British Columbia, Ontario, Quebec and New Brunswick followed by a selection of 6-8 of these programs for more detailed analysis, to assist the government in developing a portfolio of conservation and demand management programs for the province. Senior project manager.

Toronto Atmospheric Fund. Developed a municipal lighting program design for Toronto Atmospheric Fund. Work involved review of energy forecasts and needs in the Greater Toronto Area (GTA), survey of existing municipal and LDC lighting programs in the GTA, evaluation of measures (including TRC calculations), and preparation of written descriptions. Senior project manager.

CDM Program Delivery

Peterborough Distribution Inc. Worked on delivery of all of the customer service, marketing and sales, and regulatory reporting aspects of all of the business energy conservation programs (commercial, institutional, and industrial) of the local electricity distributor. Senior manager.

Brant County Power. Worked on delivery of all of the customer service, market and sales, and regulatory reporting aspects of all of the business energy conservation programs (commercial, institutional, and industrial) of the local electricity distributor. Senior manager.

Hydro One. Delivered the small commercial direct install program to over 2000 customers (2008). Senior manager.

Barrie Hydro. Delivered the 2007 and 2008 Electricity Retrofit (ERIP) Incentive Program, targeted at all business customers. Delivered the marketing and promotion related to 2008 Great Refrigerator Roundup (GRR), peaksaver, Summer Savings residential programs. Delivered the 2008 small commercial lighting direct install program. Senior project manager.

Peterborough Distribution Inc. Delivered the 2007 ERIP and project management for Summer Savings, peakSaver, and GRRR. Senior project manager.

NEPA group (11 local electricity distributors, municipal and investor owned). Delivery of turnkey 2007 ERIP for each utility. Project manager.

Program/Portfolio Evaluation

Natural Resources Canada (NRCan), Office of Energy Efficiency. Facilitated strategic planning sessions with the ecoEnergy program staff across programs and functional areas to facilitate the development of program evaluation plans for 9 programs. Facilitator and advisor.

Ontario Power Authority (OPA). Prepared an evaluation of Veridian and PowerStream peaksaver Neighbour Referral custom programs. Senior advisor.

University Health Network. Prepared process and impact evaluations of program results of the social marketing, employee engagement, and operator training programs related to energy conservation regarding the implementation of Thermostats, Lights and Controls energy management program. Senior manager.

Canadian Gas Association. Identified and documented DSM best practices for monitoring and evaluation in Canadian gas utilities. Project manager.

Enbridge Gas Distribution. Advised on improvements to its DSM regulatory framework including budget and target setting, stakeholder input, monitoring, evaluation and reporting. Project manager.

Enbridge Gas Distribution. Advised on improvements to its DSM incentive. Project manager.

Enbridge Gas Distribution. Prepared a review of the OEB report Measures and Assumptions for Demand Side Management (DSM) Planning. Project manager.

OPA, Milton Hydro, Toronto Hydro, Toronto Catholic District School Board, Halton District School Board, Halton Catholic District School Board. Prepared an impact and process evaluation of the Energy Drill Schools Pilot Program, a behavioural demand response program based on the 'fire drill' model for DR events (e.g. smog days, peak demand). Senior project manager.

York Region. Oversaw the annual process evaluations for York Region's residential toilet rebate program, rain barrel sales program, and commercial kitchen spray valve program. Senior manager and quality assurance officer.

Best Practices

Canadian Gas Association and Canadian Electricity Association. Designed and facilitated a seminar session on best practices in DSM/CDM and prepared a report which documented the results – issues, lessons learned – from the series of 4 workshops held across Canada. Project manager and lead facilitator.

Canadian Gas Association. Prepared 2010 update and 2009 update to the original report on DSM best practices report (2006). Also prepared the original report. Project manager.

Enbridge Gas Distribution. Identified and documented best practices regarding DSM incentive mechanisms in North American Gas utilities. Project manager.

York Region. Identified and documented best practices related to municipally run water conservation programs in North America for the residential, multi-residential and ICI sectors for 2009, 2010 and 2011. Senior project manager.

Research and Analysis Related to DSM/CDM Programs and Policies

Canadian Gas Association. Prepared a profile of gas DSM across Canada from 1995-2012, and conducted research and analysis on various gas DSM issues, Senior advisor.

Canadian Gas Association. Identified and assessed load reduction trends in Canadian natural gas distributors across the country and identified rate design options for addressing this situation. Project manager.

Independent Electricity System Operator (IESO). Developed a profile of the hospital and long-term care sector related to energy use and their educational needs related to energy management, with a focus on educational needs to the switch from the regulated price plan to the wholesale market. Senior project manager.

Enbridge Gas Distribution. Advised on customer care policy related to sub-metering companies. Project manager.

Low-Income Energy Matters

Low-income Energy Network (LIEN). Consultant to LIEN for several years, advising and assisting in the preparation of submissions on low-income customer care/customer protections, rates matters, arrears management, and DSM/CDM before the Ontario Energy Board. Lead consultant.

Housing Services Corporation (formerly Social Housing Services Corporation - SHSC). Consultant to SHSC for several years, advising and assisting in the preparation of submissions on low-income customer care/customer protections, sub-metering and other rates issues, and DSM/CDM. Lead consultant.

Ontario Power Authority (OPA). Developed program concepts and initial program design for a multi-family energy conservation program, which included social and affordable housing. Senior manager.

Enbridge Gas Distribution. Benchmarked customer care programs (e.g. disconnection/ reconnection, equal billing arrears management), including those for seniors and hardship customers compared with other Canadian and US utilities and jurisdictions. Made recommendations on improvements to programs and linkages to DSM programs. Project manager.

Enbridge Gas Distribution. Advised on DSM policies, regulatory treatment of DSM, low-income programs and other matters in the 2006 generic gas DSM hearing and on Enbridge's 3-year DSM plan. Project manager.

BC Hydro. Provided strategic planning advice on the development of a framework to provide a comprehensive array of services, specifically targeted at low-income customers, including DSM, bill and arrears management, and bill assistance. Senior advisor.

Brantford Power. Designed and trained the delivery agents to deliver the award-winning Conserving Homes Program (also funded by Ontario Ministry of Energy). The program became the blueprint for the OPA's and the Ontario natural gas' low-income DSM programs (e.g. basic and deep measures, pre-and post-assessments, free measures and direct install, participant education). Project manager.

APPEARANCES

2013 Yukon Utilities Board, expert witness on behalf of Yukon Electrical Company Ltd. regarding approval of the 5-yr DSM Plan in their General Rates Case Proceeding
2008 – 2010 Ontario Energy Board, expert, on behalf of Social Housing Services Corporation/GLOBE on sub-metering, electricity customer service rules, regulated price plan and DSM/CDM
2005 Ontario Energy Board, expert, on behalf of Low-Income Energy Network regarding conservation and demand management policies and programs, regulated price plan and other matters
2005 Ontario Energy Board, expert witness, on behalf of Milton Hydro regarding the approval of its 2005 Conservation and Demand Management Plan
2005 Ontario Energy Board, expert witness, on behalf of Brantford Power regarding the approval of its 2005 Conservation and Demand Management Plan
2004 Ontario Energy Board, expert, on behalf of Canadian Energy Efficiency Alliance, regarding regulatory framework for electricity conservation that promotes productivity and energy efficiency
2002 Ontario Energy Board, expert witness, on behalf of Enbridge Gas Distribution Inc. in their 2003 rates case, regarding appropriate incentive mechanisms, cost recovery and regulatory framework for DSM
1985 Joint Board, expert witness, on behalf of Ontario Ministry of the Environment, related to Ontario Hydro's Southwestern Ontario Transmission System Plan EA approval regarding environmental issues associated with pipeline construction and maintenance and EA policy matters

ADVISORY COMMITTEES/BOARDS

May 2012- Sept. 2012	Past Chair, Board of Directors, Clean Air Partnership, City of Toronto
Apr. 2009 – May 2012	Chair, Board of Directors, Clean Air Partnership, City of Toronto
Apr. 2008 – present	Member, Grants Committee, Toronto Atmospheric Fund (TAF)
Jan. 2006 – present	Member Board of Directors, Clean Air Partnership
Jan. 2005 – July 2006	Member, City of Toronto's Environment Roundtable
Oct. 2002 – Mar. 2006	Member, Grants and Loans Committee, TAF
April 1999 – 2002	Vice President, Environment, Provincial Council of Women
Dec.1996 – Mar. 2008	President, Board of Directors, Canadian Environmental Law Association (CELA)
Apr. 1994 – Mar. 2008	Member, Board of Directors, CELA
May 1992 – May 2002	Member, National Association of Regulatory Utility Commissioners
Sept.1990 – Dec. 2001	Member, Environmental Advisory Panel to the President, Ontario Hydro

AWARDS

1981	Commendation, Mayor, City of Toronto, for work on Toronto Recycling Action Committee
1980	Natural Sciences and Engineering Doctoral Scholarship (awarded, not accepted)
1977-80	Natural Sciences and Engineering Post-graduate Scholarship
1972-77	McGill University Scholarship
1972-77	Steinberg Canada Scholarship

EMPLOYMENT HISTORY

ICF International	Principal	June 2013-present
Elenchus Research Associates	Principal, Economic Regulation & Conservation	2011 – 2012
IndEco Strategic Consulting Inc.	Vice President	1994 – 2011
Ontario Energy Board	Board Member (part-time)	1992 – 2002
Judy Simon	President	1989 – 1994
Ontario Ministry of Industry, Trade and Technology	Manager, Technology Policy Branch	1987 – 1988
Ontario Ministry of Environment	Manager, Environmental Assessment Branch	1982 – 1987
Ontario Ministry of Environment	Environmental Planner, Environmental Assessment Branch	1981 – 1982
Ontario Ministry of Energy	Energy Planner, Conservation and Renewable Energy Group	1980 – 1981
Nova, an Alberta Corporation	Energy Researcher, Algas Resources	1978 – 1980

Vincent Dufresne, Eng. [QC], CEM, CMVP

ICF International

Manager

EDUCATION

B.A. *cum laude*, Mechanical Engineering, École Polytechnique de Montréal, Montréal, Québec, Canada, 2005

CERTIFICATIONS AND TRAINING

Certified Energy Manager (CEM), Association of Energy Engineers, 2010
Certified Measurement and Verification Professional (CMVP), Association of Energy Engineers, 2009
Engineer, Ordre des Ingénieurs du Québec, 2007 – Equivalent to P. Eng. in the rest of North America.
Compressed Air Challenge Fundamentals, 2012

EXPERIENCE OVERVIEW

Vincent Dufresne is an energy efficiency practitioner with nine years of experience in the field. As a consultant, Mr. Dufresne specializes in energy efficiency/demand-side management (DSM) program & policy; program design & planning; market characterization and research; market potential review; and program evaluation, measurement and verification (EM&V). He has worked on programs mostly in the industrial, municipal, institutional and commercial sectors (buildings). He thrives on making DSM programs strike the right balance between market transformation and resource acquisition in order to achieve quick results with long-term impacts.

In addition to his DSM program skills, Mr. Dufresne also possesses a strong technical background in energy engineering and energy auditing that informs to his program expertise. Mr. Dufresne is respected for his strong analytical skills, his capacity to absorb and synthesize large amount of academic and empirical information, the superior approach to solving problems he puts forward and his excellent writing and presentations skills.

Mr. Dufresne has done business with the Ontario Power Authority, Union Gas, Toronto Hydro, SaskPower, Hydro-Québec, Yukon Energy & Yukon Electrical, CANMET, Office of Energy Efficiency, Natural Resources Canada, and the Canadian International Development Agency, as well as the World Bank, the Inter-American Development Bank, the International Finance Corporation, and several governmental organizations overseas. Mr. Dufresne has worked in Quebec, Ontario, British Columbia, Saskatchewan, and Yukon, and also in India, Indonesia, Jordan, Tunisia, Chile, Uruguay, Nicaragua, Honduras, Costa Rica, El Salvador, Ecuador, Mexico, and the Dominican Republic. He participated in projects in multiple other countries such as Brazil, Argentina, Russia, Turkey, Lebanon, and Jamaica.

He is a registered engineer in the Province of Quebec, Canada, a certified measurement verification professional (CMVP), and a certified energy manager (CEM). He is fluent in Spanish and French.

PROJECT EXPERIENCE

DSM/CDM and Energy Conservation Programs

Healthcare-Sector Energy Efficiency Service Provider (EESP), Canadian Coalition for Green Healthcare (CCGHC) with funding from the Ontario Power Authority (2013 – in progress). ICF International is working with the CCGHC to deliver CDM to the healthcare sector in Ontario through an OPA-contracted and –funded EESP. Mr. Dufresne was a key advisor involved in the planning phase of the program. He supported the project manager in planning the research and in the sector and channel consultation. He also supported the project manager with analyzing the market data, and laying out the energy efficiency service-provider plan (that is: the actual design of the program), as well as the marketing, outreach and communications plan. He contributed to the evaluation, measurement and verification plan, and will make sure that the design is evaluable.

Retail-Sector Energy Efficiency Service Provider (EESP), Retail Council of Canada (RCC) with funding from the Ontario Power Authority (2013 – in progress). The retail-sector EESP project was similar to the health-care sector EESP project (above), and Mr. Dufresne's responsibilities were the same.

The Investigation of Demand Response Program Concepts for Business Customers. Ontario Power Authority (in progress). ICF International is assisting Freeman, Sullivan & Co. in carrying out an investigation of demand response (DR) program concepts for business customers on behalf of the Ontario Power Authority (OPA). This investigation will define the next generation of DR programs and help evolve OPA's existing DR products into more useful resources. We are part of a uniquely qualified team with an unparalleled understanding of Ontario's electricity system, the OPA's planning context and evolving system operator needs. The team is very familiar with Ontario customers and DR programs, highly experienced with the latest innovations, pilots and programs aimed at providing operators with flexible resources. Mr. Dufresne is in charge of the stakeholders' consultations and focus groups.

Local Demand Response Valuation and Financial Analysis, Toronto Hydro-Electric System (2013 – in progress). Toronto Hydro retained ICF International to develop financial models and business analysis to explore the potential for localized demand response (DR) initiatives that specifically target areas of high system constraint in Toronto's service territory. Mr. Dufresne is the project manager and the lead developer. The models developed will present the potential for DR alternatives to defer such investments and to build the business cases f to support this approach, from the perspective of Toronto Hydro, that of the participating ratepayers, of all ratepayers and of the province as a whole.

DSM Program Design for the Commercial Lighting Sector and the Building Retrocommissioning Sector in Saskatchewan, SaskPower, 2011-2013. Mr. Dufresne was involved in the development of a commercial and institutional DSM program in the province of Saskatchewan, Canada. SaskPower contracted ICF International to conduct a market characterization of the commercial sector, design and develop a DSM program, and launch and operate the program during a three-year period. SaskPower and ICF International decided to focus resources and attention on two sub-sectors: commercial lighting, and commercial building recommissioning. ICF International completed the program development, rolled out the program, and is currently operating it on behalf of SaskPower. Mr. Dufresne established the methodology; acted as a deputy project manager; supervised a team of market researchers; conducted interviews, surveys and literature reviews; supervised a Delphi Panel; analysed the market data; suggested program concepts; laid out participation processes and eligibility criteria; sized the incentives, made impact projections, developed the budget and computed the cost-effectiveness tests; created logic models and program theories; and drafted most of the design-stage reports.

Municipal Ice Rink DSM Program Delivery Services. SaskPower, 2012-2013. Mr. Dufresne led the design of a DSM program targeting the municipal ice rink sector of Saskatchewan. ICF International was retained to design, launch and operate the program in fast-track mode. SaskPower had been working with the municipal ice rink sector for years at the time, and ICF International tapped into this knowledge and experience to design a project that was adapted to Saskatchewan and effective at delivering results and savings. Mr. Dufresne coordinated the direct engagement with town recreational directors, ice rink operators and the DSM program design efforts. Mr. Dufresne suggested innovative and effective approaches to deliver a walk-through energy efficiency audit campaign in the ice rinks.

DSM Program Design for the Large-industry Sector in Saskatchewan, SaskPower, 2011-2013. Mr. Dufresne was involved in the development of an industrial DSM program in the province of Saskatchewan, Canada. SaskPower, the local government-owned utility, contracted ICF International to conduct an industry consultation and research the market, design and develop a DSM program, and launch and operate the program during a three-year period. ICF International completed the program development, rolled out the program and is operating it on behalf of SaskPower. Mr. Dufresne established the methodology; acted as a deputy project manager; conducted interviews, industry consultation activities and literature reviews; supervised a Delphi Panel; compiled and analysed the market data; suggested program concepts; laid out participation processes and eligibility criteria; sized the incentives, made impact projections, developed the budget and computed the cost-effectiveness tests; created a logic model and a program theory; and drafted reports.

Small and Medium Industrial DSM Program Design. SaskPower, 2012. Mr. Dufresne led the design of a DSM program targeting the small and medium industrial sector of Saskatchewan, Canada. The program was to pursue energy conservation opportunities that are significant in potential in the sub-sector; and that are highly replicable. Mr. Dufresne led a literature review and a jurisdictional scan, a channel and sector consultation, the writing of a program design concept note, the modeling of the program to check the cost-effectiveness, and the development of an implementation plan.

<u>DSM Program Design for the Residential, the Commercial and the Institutional Sectors in Yukon, Yukon Energy Corporation and Yukon Electrical Company Limited, 2011-2013</u>. Mr. Dufresne was involved in the design of a residential and a commercial DSM program portfolio in the Yukon, Canada. Yukon Energy Corporation and Yukon Electrical Company Limited (YEC/YECL), and the local utilities anticipate creating a portfolio of programs in the residential and commercial sectors. ICF International conducted a market potential review, next a characterization of the residential and commercial markets, and then designed DSM programs, prepared a design document, drafted a program implementation plan and an evaluation, measurement and verification plan that will be the base for the filing of the DSM program portfolio to the Yukon Utility Board. Mr. Dufresne supervised a team of market researchers; conducted interviews, surveys and literature reviews; compiled and analysed the market data; facilitated the DSM strategic discussions and planning; carried out the budgeting, impact projections and cost-effectiveness modeling; and drafted the DSM portfolio design document, the program implementation plan and the evaluation, measurement and verification plan.

<u>Design of an Institutional Building Energy Conservation Program in Jordan, German Development Bank (KfW, German acronym), 2010.</u> While employed at Econoler, Mr. Dufresne led the preliminary design of an energy conservation program in Jordan. The KfW intended to lend approximately $30 million to the Government of the Hashemite Kingdom of Jordan to implement an energy efficient retrofit project in government-owned buildings: e.g. hospitals, schools, ministry headquarters, and office buildings. Mr. Dufresne established the methodology and the implementation plan, managed the project, conducted site visits, interviews and literature reviews, identified potential energy conservation measures to be implemented, identified and characterized the market actors, suggested a program concept and approach, drafted a program logic model, and commented on implementation implications.

<u>Demand-Side Management Professional Development Course, Ontario Power Authority (OPA), 2010-2011.</u> Mr. Dufresne participated in the development of a professional development course on demand-side management program design, implementation and evaluation for the staff of the OPA, and Ontarian Local Distribution Companies. Mr. Dufresne was a key expert of the team. He worked on the design of the learning framework, the research and literature review, the brainstorming, the development of the slide decks, speakers notes and activities, and the pilot delivery.

<u>Global Environment Facility Industrial Energy Efficiency Program in Chile, Inter-American Development Bank (IDB), 2009.</u> While employed at Econoler, Mr. Dufresne designed a large-scale energy efficiency program to increase the market penetration of energy services in Chile. The program was to be co-funded by the Global Environment Facility (GEF). GEF would contribute $8 million. The program included: training for energy efficiency consultants, training for plant workers, pilot projects, measurement and verifications activities, communication activities and an energy conservation partial guarantee fund. The total budget for the program including co-financing was approximately $40 million. Mr. Dufresne developed the methodology and implementation plan, managed the program design budget, collected the data, and conducted interviews. He carried out a market analysis, wrote the concept notes, and computed the program cost-effectiveness and the greenhouse gases abatement.

<u>Energy Audits Program, Inter-american Investment Corporation (IIC), 2008-2009.</u> While employed at Econoler, Mr. Dufresne designed and managed a ten-energy audit program in four countries in Central America: Costa-Rica, El Salvador, Nicaragua and Honduras. The project was financially supported by the Republic of Korea through the Korea-IIC Small and Medium Enterprise Development Trust Fund. The audits were conducted in the commercial and industrial sectors. Mr. Dufresne recruited and contracted local experts, conducted walk-through audits locally, trained the local energy engineers, provided advice, provided energy savings modelling methods, performed extensive quality control of the reports, compiled the market data generated by the energy audits, and wrote a final report.

<u>Central America GREENPYME Energy Efficiency Program, Inter-american Investment Corporation (IIC), 2009-2010.</u> While employed at Econoler, Mr. Dufresne designed and managed a 26-energy audit program in Belize and Jamaica in the commercial and industrial sectors. Mr. Dufresne recruited and contracted local experts, established a program participation process and procedures, supervised the conduct of the analysis, calculations, editing, quality control and delivery of reports, compiled the data from the 26 audits, and managed the delivery of a workshop on the findings of the 26 audits.

Industrial Energy Management Program Design, Quebec Ministry of Natural Resources and Wildlife (MRNF, acronym in French) formerly known as Energy Efficiency Agency (AÉÉ, acronym in French), 2008. While employed at Econoler, Mr. Dufresne participated in the design of an energy efficiency program to increase the market penetration of good energy management practices in the industrial sector of the province of Quebec. Mr. Dufresne established savings projections, estimated budgets, and computed all of the standard program cost-effectiveness tests: i.e. the total resource cost, rate impact measure, participant, and program administrator tests.

Energy Efficiency for Caribbean Water and Sanitation Companies, Inter-american Development Bank (IDB) 2009-2010. While employed at Econoler, Mr. Dufresne participated in an energy efficiency audit program at water utility facilities in six Caribbean countries: Barbados, Bahamas, Guyana, Haiti, Jamaica, Suriname, and Trinidad and Tobago. Mr. Dufresne established the methodology and implementation plan, created the team, recruited local experts, and negotiated with the sub-contractors.

Demand-Side Management Support to Argentine Utilities, Energy Secretariat of the Argentine Republic (SENER) with World Bank funding, 2006-2007. While employed at Econoler, Mr. Dufresne worked on the design of eight utility-based demand-side management programs in Buenos Aires, Cordoba and Santa Fe, Argentina. The local electricity distribution companies that benefited from the support were: EDENOR, EDESUR, EPEC Córdoba, and EPE Santa Fe. Mr. Dufresne was a key expert for the first half of the assignment and then was the project manager for the other half. Mr. Dufresne established program savings projections, program budget, and program cost-effectiveness. He developed early program designs, established the program logic models and management-by-objective frameworks, and drafted the program briefs and the final report.

Energy Efficiency in the Agricultural Pumping in India, Canadian International Development Agency (CIDA), 2006-2007. While employed at Econoler, Mr. Dufresne was involved in the design of an energy conservation program in the agricultural pumping sector in the state of Madhya Pradesh, India. Mr. Dufresne did a literature review, conducted interviews with key stakeholders including supply-side actors, end-users, and local electricity distribution companies. He visited sites, developed early program designs, and suggested operational mechanisms.

Romanian Energy Efficiency and Renewable Energy Credit Line, European Bank for Reconstruction and Development (EBRD), 2005. While employed at Econoler, Mr. Dufresne participated in a market study for the creation a €50m credit line for energy efficiency and renewable energy projects in Romania. Mr. Dufresne designed a survey, sent the survey by email or fax to 500 Romanian industrial companies, received and compiled the responses, processed the data, conducted a market analysis, drew conclusions, and drafted the final report.

Market Characterization, Technology Assessment and Conservation Potential Studies

Market Overviews – Lighting Controls, Commercial Refrigeration, Industrial Compressors and Variable Frequency Drives. Ontario Power Authority (2013). The OPA retained ICF International to develop concise and insightful market overviews for the aforementioned electricity end-uses. Mr. Dufresne was the project manager and lead methodologist. These market overviews were intended to be scans of the on the base of which further actions such as pilot projects, customer and channel partner engagement, and/or further research and market consultation could be undertaken; they included technology and market characterization, as well as an assessment of the achievable energy conservation potential. The OPA needed the work to be done on a very short timeline, within a month; this definitely was out-of-the-ordinary and challenging. Mr Dufresne and his team were able to serve that need. Mr. Dufresne supervised the team of researchers and made a significant contribution to the final reports.

Ontario Achievable Potential 2015-2020. Ontario Power Authority (2013-2014). ICF International worked with the OPA to develop estimates of achievable potential for CDM in Ontario and to support OPA's planning of CDM programs. The project's timeframe was driven by the timing of the next round of CDM planning taking place in early 2013. Mr. Dufresne was main methodologist and a key expert partaking in the second phase of the study: market characterization. The team selected six clusters of energy conservation measures of interest and produce a review of the market structure, the actors, the hurdles, barriers, and the drivers for each these clusters. Mr. Dufresne led the development of the methodology, the research, workshops and interviews with key market actors. He supervised the drafting of the reports, and worked with the conservation potential experts to feed back the market intelligence in the OPA load forecasting model.

Pre-Feasibility Study – Condensing Unit & Infrared Radiant Tube Heating. FortisBC. (2013) Through this study, FortisBC sought to characterize the technology and the market of two innovative gas-fired heating devices: condensing unit heaters and infrared radiant tube heaters. These may be used to replace existing warehouse space heating systems. The study comprised an assessment of the market opportunity, technical characteristics, and projected energy savings. The results were to be used by FortisBC to inform the feasibility of launching an incentive program targeted at the warehouse sector in BC. Mr. Dufresne was the lead methodologist; he supervised the research team, carried out a significant portion of the research and analysis work, and drafted large parts of the final report.

Energy Efficiency and Renewable Energy Market Research in Chile, Chilean Energy Efficiency Agency (AChEE, Spanish acronym) formerly known as the National Energy Efficiency Program (PPEE, Spanish acronym) 2010-2011. While employed at Econoler, Mr. Dufresne led an energy efficiency market potential study and market characterization studies in Chile. Mr. Dufresne was the project manager during most of the duration of the project. Mr. Dufresne managed the budget, recruited, contracted, trained and supervised local experts. He conducted a literature review, performed an analysis, wrote reports, and ensured a smooth transition to the next project manager.

Energy Efficiency and Renewable Energy Market Research in Brazil, International Finance Corporation, 2010. While employed at Econoler, Mr Dufresne led the implementation of an energy efficiency market potential study and market characterization study in Brazil. Mr. Dufresne was the project manager during half of the duration of the project. Mr. Dufresne recruited, contracted and supervised local experts, conducted a literature review, performed analysis, drafted reports, and ensured a smooth transition to the next project manager.

Program Evaluation
Which Involves Research and Stakeholder Engagements for Process Evaluation or Attribution Purposes

PADIGE Attribution Study, Hydro-Québec, 2011. Mr. Dufresne led the implementation of an attribution study of the "Analysis and industrial demonstration program for large enterprises" (PADIGE, acronym in French) for the years 2005 to 2010. The PADIGE is an industrial energy efficiency audit program. The PADIGE-financed energy audits helped large industrial enterprises to identify many cost-effective capital-intensive energy conservation measures, as well as low-cost/no-cost energy conservation measures. Hydro-Québec contracted ICF International to test the causality between the savings yielded by the implementation of the low-cost/no-cost measures and the PADIGE program. Mr. Dufresne established the methodology and work plan, carried out an attribution best practices review, participated in the creation of a survey questionnaire and of an attribution algorithm, used an online survey platform to collect data, and drafted the final report.

Impact Evaluation of LED Roadway Lighting Program, Natural Resources Canada, (2012). Natural Resources Canada retained ICF International to conduct an impact evaluation of its LED Roadway lighting program. Mr. Dufresne adapted and finalized the impact evaluation portion of the evaluation, measurement and verification plan that had been laid out by a teammate, he developed an action plan, mobilized the research staff, laid out the interview guides, supervised the data collection, carried out an analysis of the data, executed an attribution study, and drafted the final report.

Development of Two Program Evaluation, Measurement and Verification Plans, Toronto Hydro Electric System (THES), 2011. Mr. Dufresne developed a draft evaluation, measurement and verification plan for two new demand-side management programs that THES was planning to launch in 2012. The two programs were: a monitoring and targeting (energy management information system) program for large and medium commercial buildings, and a communication and outreach program aimed at the minorities and ethnic communities of Toronto. THES has the obligation to file a draft evaluation plan with the Ontario Energy Board for each of the demand-side management programs that they seek approval for. The evaluation plans had to be compliant with the Ontario Power Authority (OPA) Evaluation, Measurement and Verification Protocols and Requirements, and had to be structured and formatted based on the OPA evaluation plan template. Mr. Dufresne collected data from the THES program design team, drafted the program logic and program theory, suggested a management-by-objective framework, established the evaluation approach, suggested data collections and analysis methods, populated the OPA evaluation plan template, and provided tips and additional advice to THES.

Development of Seven Program Evaluation, Measurement and Verification Plans, Union Gas, 2011. Mr. Dufresne led the development of draft evaluation, measurement and verification plans for seven demand-side management programs that Union Gas was planning to implement in 2012. The seven programs were: a low-income program, a residential program, a commercial/industrial prescriptive program, a commercial/industrial custom program, a large industrial program, a residential market transformation program and a commercial/industrial market transformation program. Union Gas has the obligation to file a draft evaluation plan with the Ontario Energy Board for each of the demand-side management programs that they seek approval for. The evaluation plans had to be compliant with the Ontario Power Authority (OPA) Evaluation, Measurement and Verification Protocols and Requirements, and had to be structured and formatted based on the OPA evaluation plan template. Mr. Dufresne established the project implementation plan, managed the project, created a first evaluation plan for the low-income program, recruited and contracted sub-contractors, and trained the project team.

Multifamily Buildings Program Evaluation: Ontario Power Authority (OPA). 2009-2011. Over the last three years ICF International has extensively contributed to the gross impact analysis for the OPA's Multifamily Buildings Program evaluation. This is a three year, three-phase evaluation project. Mr. Dufresne has been conducting desk-top and post-retrofit site visit evaluation activities.

ERII Program Application Review, Various Local Ontarian Distribution Companies including Ottawa Hydro, Hydro One and Oshawa PUC, 2010 to present. Mr. Dufresne reviewed prescriptive and custom incentive program applications of the Ontario Power Authority's Electricity Retrofit Incentive Initiative Program (ERII), formerly known as Electricity Retrofit Incentive Initiative Program (ERIP).

Development of a monitoring, measurement and verification and reporting toolkit, Quebec Ministry of Natural Resources and Wildlife (MRNF, acronym in French) formerly known as Energy Efficiency Agency (AÉÉ, acronym in French), 2006-2007. While employed at Econoler, Mr. Dufresne designed a measurement and verification method and a set of tools that the AÉÉ provided to Quebec provincial government building managers and operators. The materials were used as job aids by building managers to monitor the progress toward achieving the provincial government energy savings goal. Mr. Dufresne managed the project, wrote the specifications of the method and tools, developed the tools on an Excel and Visual Basic for Application platform, drafted the user manual, test-drove the tools, and presented it to the client. The tools enabled the building managers and operators to assess the avoided energy use in facilities and transports. The method was based on a whole-building methodological approach. Results were adjusted based on weather data. Aesthetics and ergonomics were major design factors.

ecoEnergy Retrofit Project Verification, Natural Resources Canada (NRCan), 2010-2011. Mr. Dufresne worked on the post-retrofit auditing of NRCan's ecoEnergy Retrofit – Small and Medium Organizations Program (previously known as the Energy Retrofit Assistance Program). Mr. Dufresne conducted site visits, and implemented performance measurement and verification analysis. Buildings were all schools or hospitals. They were located in Montreal, Quebec City, Sorel-Tracy, Hudson, Vaudreuil-Dorion, and Blanc-Sablon in the Province of Quebec.

Communication and Facilitation

How to Prepare a Successful Board-Approved DSM Program, The MEARIE Group, 2013. Mr. Dufresne developed the course materials and was the co-facilitators of two one-day workshops on DSM program design and how to file and get the design approved by the Ontario Energy Board. The course was presented in person to audiences of local distribution company staff involved in the planning and delivery of DSM programs.

International RETScreen Workshops, Various Clients, 2006-2010. While employed at Econoler, Mr. Dufresne facilitated seven workshops on energy efficiency and renewable energy based on the RETScreen software: once in Washington DC, twice in Mexico, twice in Chile, once in the Dominican Republic, and once in Tunisia. The clients included: the World Bank, CanmetENERGY, Fundación Chile, and Foreign Affairs and International Trade Canada. RETScreen is a world-known clean energy project modeling and project evaluation software. The clean technologies that can be modelled using RETScreen include: solar water heating, small hydro, wind turbines, cogeneration and trigeneration, photovoltaic, biomass heating, landfill gas valorization, and passive heating, as well as numerous energy conservation measures. Mr. Dufresne tailored the training materials to the needs of the audience, prepared the training sessions, facilitated the workshops, and wrote short final reports.

Translation of RETScreen into 34 Languages, CanmetENERGY, 2008-2009. CanmetENERGY retained Econoler to translate the RETScreen Software into 34 languages. While employed at Econoler, Mr. Dufresne managed and supervised the translation and proofreading of the software in 8 languages out of 34, and he also supervised the translation of software updates into 16 languages. RETScreen is a world-known clean energy project modeling and evaluation software. The technologies that can be modelled using RETScreen include: solar water heating, small hydro plants, wind turbines, cogeneration and trigeneration plants, photovoltaic projects, biomass projects, landfill gas valorization projects, passive heating, as well as numerous energy conservation measures. Mr. Dufresne recruited and contracted translators and proofreaders, answered all technical questions from the sub-contractors, ensured compliance with the project calendar, carried out certain quality control tasks, and supervised the payment of the multiple sub-contractors that were involved.

International Dollars to $ense Workshops, Office of Energy Efficiency of the Ministry of Natural Resources Canada (NRCan), 2005-2009. While employed at Econoler, Mr. Dufresne presented a two-day version of the "Dollars to $ense" workshop four times: three times in Mexico and once in Chile. The "Dollars to $ense" workshop is a highly interactive and engaging course developed by NRCan to teach workers (e.g. plant or building operators) and junior energy engineers the basics of energy management. Mr. Dufresne presented two modules of the course, namely: "Spot the [Energy Conservation] Opportunity", and "Energy Master Plan". Mr. Dufresne managed the contract with NRCan, recruited and contracted Spanish-speaking co-facilitators, adapted the training materials, co-facilitated the lectures, group discussions, demonstrations and activities, gathered feedback from the attendance, and wrote short final reports.

Booklets for Energy Efficiency Practitioners, Inter-american Development Bank (IADB), 2009-2010. While employed at Econoler, Mr. Dufresne was the project manager and the main copywriter of capacity-building booklets aimed at the energy efficiency practitioners of Latin America and the Caribbean and of the IADB. Mr. Dufresne prepared the work plan, participated in the data collection, the literature review and a few interviews, drafted a preliminary version of the reports, discussed preliminary results with IADB staff, and participated in the final editing of the English version of the booklets. Eight booklets were drafted and edited. The topics covered in the booklets are: rationale for energy efficiency intervention in the markets, energy efficiency programs, institutional framework, capacity building needs and solutions, standards and labeling, measurement and verification, energy efficiency financing and ESCOs & energy performance contracting. The booklets were concise and audience-sensitive. All booklets were translated into Spanish before being published. (See Publications).

SELECTED PUBLICATIONS AND PRESENTATIONS

Dufresne Vincent, Langlois, Couture-Roy, Flamand, Nour. *Guía A: Programas de financiamiento de eficiencia energética: Conceptos básicos* [English translation: Guidebook A – Fundamentals of energy efficiency financing programs]; edited by Inter-American Development Bank. Washington DC. September 2012 [ONLINE] as seen on April 2013, URL: http://idbdocs.iadb.org/wsdocs/getdocument.aspx?docnum=37123162

Biaou Léon, Langlois, Chabchoub (Dufresne was a ghost writer). *Guía B – Justificación de la intervención del gobierno en el mercado de eficiencia energética* [English translation: Guidebook B – Rational for government energy efficiency market interventions]; Edited by Inter-American Development Bank. Washington DC. December 2012. [ONLINE] as seen on April 2013, URL: http://idbdocs.iadb.org/wsdocs/getdocument.aspx?docnum=37344984

Dufresne Vincent. Understanding the Minds of the Decision Makers in Industry: Drivers and Hurdles to Implementing Low-cost/Low-payback Conservation Measures; Presented at the summer congress of the Association of Energy Services Professionals. Toronto, Canada. July 2012.

PROFESSIONAL AFFILIATIONS

Association of Energy Service Professionals
Association of Energy Engineers
Ordre des Ingénieurs du Québec (i.e., College of Engineers)

SECURITY CLEARANCES

Clearance Level: Level II (Secret) – Government of Canada

LANGUAGES

French: fluent in speaking, fluent in writing (mother tongue)
Spanish: fluent in speaking, fluent in writing

EMPLOYMENT HISTORY

ICF International	Manager	2013-present
ICF International	Senior Associate	2010-2013
Econoler	Project Manager	2004-2010

Appendix A ICF Awards

ICF INTERNATIONAL

Award Winning Program Delivery – North America

Winning Client	Award
Baltimore Gas & Electric	▪ ENERGY STAR® Partner of the Year – Sustained Excellence (2013, 2014) ▪ ENERGY STAR® Partner of the Year (2011-2014) ▪ ENERGY STAR® New Homes – Leadership in Housing Award (2010-2014) ▪ AESP Honorable Mention for Outstanding Achievement in Marketing Communications (2010) ▪ Platts Energy Efficiency Program of the Year (Energy Supplier) (2010) ▪ Finalist in the Energy Efficiency/Demand Response Category with POWERGRID International Magazine & PennWell Corp (2012)
Efficiency New Brunswick	▪ Alliance to Save Energy International Star (i-Star) award 2010, Large Industry Energy Efficiency Program
EPA ENERGY STAR Homes Team	▪ Bronze Medal- development and implementation of New Homes program 'Version 3' requirements (2012)
AEP Texas	▪ ENERGY STAR® Partner of the Year (2011)
CenterPoint Energy	▪ ENERGY STAR® Sustained Excellence (2010, 2012)
Consumers Energy	▪ ENERGY STAR® Partner of the Year 2012
DTE Energy	▪ ENERGY STAR® Special Recognition (2011) ▪ Platts Energy Efficiency Program of the Year Finalist (2010)
Entergy Texas	▪ ENERGY STAR® Special Recognition (2010) ▪ Partner of the Year (2012)
Environmental Defense Fund and the Mayor's Office of Long-term Planning and Sustainability, New York	▪ New York City Clean Heat Program-Prize for Public Service Innovation (2013)
Joint Management Committee (Massachusetts)	▪ ENERGY STAR® Partner of the Year Recognition (2007-2009) ▪ ENERGY STAR® Sustained Excellence in Program Management (2010-2012) ▪ ENERGY STAR® Leadership in Housing 2010-2012 ▪ EPA Regional 1 Sustained Excellence Award for Program Management (2012)
National Grid	▪ Platts Energy Efficiency Program of the Year Finalist (2010)
NYSERDA	▪ American Council for an Energy-Efficient Economy (ACEEE) – Exemplary Program (2007)
Oncor	▪ ENERGY STAR® Sustained Excellence (2006-2009, 2012)
PECO	▪ ENERGY STAR® Partner of the Year (2012)
Pepco	▪ Platts 2012 Global Energy Award of Excellence in the Energy Stewardship Category (for EmPOWER Maryland Programs) ▪ ENERGY STAR® Partner of the Year (2014)
Delmarva Power and Light	▪ ENERGY STAR® Partner of the Year (2014)
Public Service Company of New Mexico	▪ ENERGY STAR® Sustained Excellence (2012)
Public Service Company of Oklahoma	▪ ENERGY STAR® Partner of the Year (2010)
Southern California Edison	▪ ENERGY STAR Partner of the Year – Sustained Excellence (2014)
South Carolina Electric and Gas	▪ ENERGY STAR® Partner of the Year (2013,2014)
Southern Maryland Electric Cooperative	▪ ENERGY STAR® Partner of the Year (2012, 2013, 2014)

Sample of Creative Awards

Communicator Awards of Excellence

- BGE Digital Billboards
- California Energy Commission Brochure
- Delaware Time to Re-think, Teens & Drink Video
- EPA Green Infrastructure Publication
- EPA Schools Chemical Cleanout Annual Report
- EPA Sustainable Skylines Brochure
- MEPI U.S.-Saudi Women's Forum on Social Entrepreneurship Short Video
- NHMRC Love Through the Ages TV PSA

Communicator Awards of Distinction

- BGE Bragging Lights TV Spot
- BGE Bus Shelter Ad
- BGE Feeling Great TV Spot
- BGE Monthly Email Advertising
- BGE Postcard Marketing
- DoD Department of the Navy Annual Report
- DoD Tobacco Cessation Integrated Campaign
- DoD Tobacco Cessation Web Site
- DOJ Human Trafficking Conference Materials
- EPA GreenScapes Fillable Online Form
- EPA RCC Update Annual Report
- EPA Smart Growth Annual Report
- HHS Hope Through Prevention Poster
- HHS OFA TTA Logo
- ICF Charity Auction Poster
- LRI ICCA Global Research Strategy Brochure
- NHMRC The Conversation Video
- NRFC Integrated Campaign
- NRFC Spotlight on Dads Web Banner
- U.S. Air Force Energy Awareness Logo
- WE Way to Save Integrated Campaign

MEMORANDUM

To: Sue Forcier

From: Judy Simon

Date: 30 December, 2013

Re: CDM-2014 Rate Filing Opportunity: CDM Achievable Potential and Customer Engagement

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Sue,

Further to our meeting of December 3, 2013 with Brian Wilkie, I have prepared the following memo which describes the opportunity to fund CDM and customer engagement work through CDM Program Administration (PAB) dollars that can also contribute to Niagara Peninsula Energy's upcoming 2014 CoS rate filing, in particular the preparation of the Distribution System Plan.

The memo includes four opportunities to use PAB dollars, in whole or in part, to fund the proposed budget for the work. The first two opportunities, *CDM Achievable Potential,* and *CDM Market-Adjusted Achievable Potential*, are mutually exclusive; the latter being more tailored to the specific markets and customers in NPEI service territory. The third opportunity, *Customer Engagement Plan*, and fourth opportunity, *Achievable Potential Training for Customer Engagement*, are independent and can be selected with either the first or second opportunity.

CDM and 2014 Rate Filing: Joint Opportunity

In October of 2012, the Ontario Energy Board (OEB), set new policy for distribution system network planning in Ontario, requiring electricity distributors to take a comprehensive and integrated approach to planning. The OEB put forth how distributors are to accomplish this planning in a recently released Board Report (*Filing Requirements for Electricity Transmission and Distribution Applications Chapter 5 Consolidated Distribution System Plan Filing Requirements*, March 28, 2013), which describes in detail how the distributor is expected to prepare the Distribution System Plan (DSP) and what the plan is to contain.

In particular, electricity distributors are required to meet the OEB Customer Focus Outcome by demonstrating that the distributor has responded to identified customer preferences (e.g. CDM, distributed generation, load management). Customer engagement is essential to achieving the Customer Focus Outcome. Distributors need to know which services customers value. These new requirements open the door for the distributor to do research related to CDM to understand customer needs and preferences and identify CDM services that customers value. Since the DSP must serve present and future customers, this provides support for identifying current CDM needs/opportunities and forecasting future ones.

ICF Marbek is close to completion (data expected to be available end of January 2014) of an Achievable Potential Study at the provincial level for the Ontario Power Authority, which provides a 20 year CDM forecast - a base case, technical and achievable potential forecasts, broken down by sector (residential, commercial/institutional, and industrial). The forecasts are based on building types and energy end uses and provide the energy savings potential (kWh). The model could be scaled to the IESO zone level and to the service territory of individual distributors. The model at the distributor level could be used to identify key CDM opportunities in 2014, and for the next 5 years, and form a sound basis for program design of distributor-designed CDM programs.

Because the model would be useful for 2014 CDM delivery, it could be funded through the PAB budget. It could also be useful for customer engagement related to the 2014 CoS rate filing. At minimum, the model could be used as a starting point or touchstone for customer engagement on CDM needs and opportunities (Opportunity 1). It could also generate and incorporate customer preferences/needs if a more tailored model is developed (Opportunity 2); the process and results of this incorporation would form part of the customer engagement component of the 2014 rate filing.

Opportunity 1: CDM Achievable Potential Based on Provincial Data

Description – Provide NPEI with a 20-year base case, technical and achievable potential forecast (kWh) based on scaling the OPA provincial Achievable Potential (kWh) to the NPEI service territory, using customer data provided by NPEI to adjust the overall mix of building types from the provincial level to the NPEI service territory.
Budget - $42,000

Opportunity 2: Market- Adjusted CDM Achievable Potential in NPEI Service Territory

Description – Adjust the NPEI 20-year achievable potential forecast derived from the OPA provincial achievable potential forecast based on CI customer, market player and supplier interviews (focus on industrial), site visits to key industrial facilities (winery, poultry operation, greenhouse), and research on relevant CI subsector energy profiles, to represent more accurately NPEI service territory markets and customers, resulting in an improved description of the energy use and savings opportunities, focusing on those building types that are most likely to be different than those of other parts of the province. The top 3-5 market segment/customer opportunities for CDM will be identified for 2014 and beyond.
Budget - $115,000 (includes Opportunity 1 and 2)

Opportunity 3: Customer Engagement Plan

Description – Prepare a 5-year high level strategy for customer engagement for distribution system planning and a 2-year (2014-15) customer engagement plan based on a facilitated planning session of senior interdepartmental representatives of NPEI involved in capital planning, distribution systems operations and maintenance, smart grid, renewables connection, CDM, customer data access, and customer engagement (and other as determined by NPEI).
Budget -$22,500

Opportunity 4: Achievable Potential Training for Customer Engagement

Description – Prepare a slide presentation on NPEI's CDM achievable potential and provide a short training webinar (30-45 minutes) for NPEI staff on technical and achievable potential.
Budget - $5,000

Proposal – Customer Engagement Baseline Report

Re: New Work: Baseline Report & Chapter-5 Consultation Form
CDM-2014 Rate Filing Opportunity: CDM Achievable Potential and Customer Engagement

From: Judy Simon, ICF Canada, Toronto Office

To: Sue Forcier, Niagara Peninsula Energy Inc.

Date: May 29, 2014

Sue,

Further to our recent discussions, the purpose of this proposal is to provide a high level outline of the next steps in developing a Customer Engagement Baseline Report for 2014 and to provide a related Work Plan and Budget.

Upon your approval, which you can provide with a confirmation email to me that indicates that we can proceed on the basis of this memo, this work would be added on to the existing agreement we have on carrying out a CDM Achievable Potential study and developing a Customer Engagement Plan for NPEI's 2014 Rate Filing.

Background

In October of 2012, the Ontario Energy Board (OEB), set new policy for distribution system network planning in Ontario, requiring electricity distributors to take a comprehensive and integrated approach to planning. In particular, electricity distributors are required to meet the OEB Customer Focus Outcome by demonstrating that the distributor has responded to identified customer preferences (e.g. CDM, distributed generation, load management). Customer engagement is essential to achieving the Customer Focus Outcome. Distributors need to know which services NPEI's customers value.

ICF has been supporting NPEI with planning the customer engagement work, and guidance on how to demonstrate compliance with Board requirements, and how to make and show progress with regard to customer engagement. The outcome of our work to date has been a document that will be filed with the OEB as part of NPEI's rate filing in August: the Customer Engagement Plan. There are two task items that were laid out in the Customer Engagement Plan and that NPEI is seeking further support from ICF: the creation of a Customer Engagement Baseline Report, and the creation of a Chapter-5 Compliance Form (C5C Form), which will be used to facilitate documentation for the

Baseline Report and the subsequent annual reports on progress related to the implementation of the Customer Engagement Plan.

Proposed Services and Deliverables

Under the direction of NPEI's Customer Engagement Steering Committee Coordinator, ICF will coordinate the preparation of the Baseline Report and the C5C Form, in collaboration with NPEI's Customer Engagement Steering Committee. We appreciate how time critical the development of this document is given the timetable for the August rate filing.

The Baseline Report will contain a comprehensive description of all customer education, information and technical assistance, inquiries, comments and complaints monitoring as well as surveying and direct engagement, done to the end of April 2014. The report will be sensitive to and reflect compliance with Board's requirement when applicable. In February and March, ICF developed an early outline of the Baseline Report as well as a preliminary list of specific information items to be included in the Report. We delivered this to NPEI along with the Draft Customer Engagement Plan. It will be our starting point.

The C5C Form will be a standard consultation activity form, which will be used by NPEI staff to document consultation activities that result directly from the Customer Engagement Plan in a manner that will address specific and explicit Board requirements. Details about the C5C Form were provided to NPEI in March along with the Draft Customer Engagement Plan, and this will be our starting point.

Work Plan

The following provides a suggested work plan to meet the above listed requirements. We plan to do the work in five task areas:

1) Inception:
    a) Revisit/Validate the Baseline Report outline and list of information items with Sue Forcier.
    b) Built lists of information items that are specific to each Committee Member to provide a starting point for Committee members.
    c) Prepare a template for Committee members to fill out regarding the tools and methodologies they use to support the customer engagement
    d) Prepare a template for Committee members to fill out to describe the engagement activities that have taken place under their purview related to the Engagement Plan to the end of April 2014
    e) Draft and then send an introductory memo for Sue Forcier to send to the Committee Members to explain the process, the need to fill out the templates and that the template information will go directly into the Baseline Report. The memo will also kindly stress the importance of responding to ICF team members in a timely manner.
    f) Develop a draft of the C5C Form.
2) Follow up call with each Committee member to obtain clarifications/additions to the information provided in the templates each filled out:
    a) Follow up after reviewing the material provided in the templates, and schedule a call (up to 30 minutes) to seek clarifications/additional details, as needed

3) Completion of the C5C Form:

    a) Obtain written comment on the draft C5C Form from Committee Members
    b) Revise and finalize the C5C Form.

4) Completion of the Baseline Report:

    a) Circulate the Draft Report for review by each Committee Member. Committee members will provide written comments to the Steering Committee Coordinator and ICF will address the comments received.
    b) ICF may call the commenter as needed to seek clarifications to ensure understanding of the feedback before addressing the comment in the final report.
    c) ICF will finalize the Baseline Report by integrating the comments into the draft report.

ICF's team will be diligent, goal-oriented, nimble and to-the-point in our requests to the Committee Members, but nevertheless we wish to respectfully highlight that the success of our work will depend on the availability and collaboration of the members of the Customer Engagement Committee

We built a project team that is sufficiently large to deliver all of the consultation work required in a short timeframe. The team is comprised of:

- Judy Simon – Project Manager
- Vincent Dufresne – Deputy Project Manager, and Consultation Methodologist
- Selena Frazer – Analyst, Researcher & Writer
- Erin Williamson – Analyst, Researcher & Writer
- Genna Woolston – Analyst, Researcher & Writer

Selena, Erin and Genna are new to our work with NPEI. All three hold a relevant Master's Degree and possess excellent research, technical and analytical skills. They have seven, six and four years of experience, respectively, in the sustainable energy sector with exposure to stakeholder engagement, research, and business-to-business interviewing. We can provide resumés upon request.

Timeline and Budget

The completion of the work plan will be carried out according to the following timeline:

- Provision of Task Lists and Templates to Steering Committee — June 6
- Provision of Draft C5C Form for review by Steering Committee — June 6
- Completion of Templates by Steering Committee — June 14
- Comments on C5C Form by Steering Committee — June 14
- Follow up calls to Steering Committee — June 18
- Draft Baseline Report circulated for review to Steering Committee — June 21
- Comments from Steering Committee — June 25
- Follow up calls to Steering Committee — June 27
- Final Baseline Report — June 30

Given the importance of this report and the tight timetable, ICF expects that NPEI Steering Committee members will make themselves available for any short phone calls needed to follow up on their comments and will provide feedback in a timely manner (within 2-3 days). If these expectations are not met, ICF will not be able to meet the deliverable due dates for this project.

We estimate the total cost to complete this work plan at $10,000 plus HST. We will invoice at the end of June for the full amount.

Thank you very much for this opportunity to provide you with additional support related to your 2014 COS filing. The team looks forward to getting started and working with you and the Steering Committee on this important work.

Sincerely,

Judy Simon

Judy Simon

Principal at ICF Canada

ATTACHMENT # 6-Harris license agreement and Utilismart agreement-IRR#26

N. Harris Computer Systems

License Agreement

LICENSE AGREEMENT by and between N. Harris Computer Systems ("Harris"), having offices at #400 –1 Antares Drive, Ottawa, ON K2E 8C4 and Niagara Falls Hydro ("Customer"), having offices at 7447 Pin Oak Drive, Niagara Falls ON Canada L2E 6S9, is made and entered into as of the_____________________day of __________________, 2005. As of January 1, 2006, Customer name ~~will change from Niagara Falls Hydro to Serv Co.~~may change.

1. DEFINITIONS. For purposes of this Agreement:

1.1. **"Program"** means the software application(s) set in the License Supplement or otherwise made available by Harris for use by the Licensee as a part of this agreement.

1.2. **"Territory"** "Territory" means the United States of America and Canada.

1.3. **"Customer"** "Customer" means a person or entity located in the Territory who/which is receiving a Service from Licensee or an Affiliate and for which Licensee generates a bill or a billing transaction using the Licensed Software.

1.4. **"Account"** shall mean each active discrete billing unit, also referred to as an active unique account. The term "Accounts" applies only to Programs which are part of Harris Utilities.

1.5. **"Services"** means billing and related services for consumers of electric, gas, water, sewer, solid waste, recycling, storm drainage, and all other services for which the Licensed Software can be utilized.

1.6. **"Documentation"** means user guides, operating manuals, and specifications, whether in print or machine readable media, in effect as of the date of shipment

1.7. **"Use"** means to load, execute, employ, utilize, store or display the Program

1.8. **"Affiliates"** means any entity controlling, controlled by, or under common control with Licensee

1.9. **"Server"** means one or more interconnected computer hardware systems configured to run the Program(s)

1.10. **"User"** Unless specified as "Named User" User means the number of users licensed to use the Program(s) concurrently.

1.11. **"Named User"** means an individual or non-human operated device authorized to access and use the Program(s), regardless of whether the individual is actively using the Program(s) at any given time.

1.12. **"Consolidated Billing Services"** means the inclusion in a single bill of both the Services provided by Licensee as well as additional Services provided to that same Customer by a third party who has authorized Licensee to bill for their Services.

1.13. **"TRACKER"** means Software Action Notice and is a number assigned by Harris as a unique identifier for a specific piece of software development (not to be confused with a "case" or an "issue", which may or may not become a TRACKER).

1.14. **"Live Operation"** means the first use of a module, in whole or in part, in Licensee's normal business operations.

2. LICENSE.

2.1. For each Program listed in Appendix "~~A~~B" - Cost Proposal and as amended from time to time by way of an additional Supplement to be attached as an Appendix to this Agreement, Harris grants to Licensee a perpetual, non-exclusive, non-transferable license to Use and allow its Affiliates (for so long as they are Affiliates) to Use, the Program solely for its and its Affiliates internal purposes on the Hardware and Operating System Software at the Site. Licensee shall ensure that its Affiliates comply with the terms of this Agreement and will be liable for any breach by any Affiliate. Licensee may delegate authority to execute Supplements to any Affiliate.

2.2. The Program may be transferred temporarily to a backup computer. The Program may also be transferred to computer hardware or used with an operating system, other than the specified Hardware or Operating System Software, subject to Harris's transfer policies and fees then in effect. Licensee may make a reasonable number of copies of the Program exclusively for testing, disaster recovery, inactive back-up or archival purposes. Copying or Use of the Program or Documentation other than as expressly authorized by this Agreement is not permitted.

2.3. ~~As soon as practicable~~30 days after signing the Agreement, Harris shall deliver the Program and Documentation to the Site. One (1) copy of each Program per Server and one (1) copy of Documentation shall be delivered to Licensee. Licensee may make and Use additional copies of Programs and machine readable Documentation for the number of users specified on the applicable Supplement.

2.4 The embedded development and run-time version of the Database, if any as set in Appendix "B~~A~~" and as amended from time to time, is limited to Use with, and modification of, licensed Harris Programs and tools only. Licensee's right to Use the embedded development and run-time version of the Database is limited to Use in conjunction with licensed Harris Programs, unless Use is required for purposes of systems administration. Licensee is prohibited from timesharing, service bureau, subscription service, or rental use of the Database programs and the publication of any results of benchmark tests run on the Database. ~~In the event Licensee desires to Use the Database for any other purpose, Licensee shall obtain a full use license.~~ Except to the extend permitted by applicable laws, Database provider accepts no liability for any damages, whether direct, indirect, incidental, or consequential, arising from the use of the Database programs nor will Database provider perform any obligations not previously agreed to between Harris and Database provider.

2.5 The Use of any third-party product delivered to Licensee by Harris that is not in a sealed package containing a "shrink wrap" license or any products delivered to Licensee by Harris not containing a "click wrap" license, shall be governed by the terms of this Agreement. The Use of any third-party product delivered to Licensee by Harris in a sealed package containing a "shrink wrap" license shall be governed by the terms of the license agreement contained within the sealed package. The Use of any third-party product delivered to Licensee by Harris containing a "click wrap" license shall be governed by the terms of that license agreement. Notwithstanding any terms and conditions set forth in this Agreement, Harris shall have no responsibility for such Programs, and all problem resolution and support for such Programs shall be obtained by Licensee from the applicable vendor, except as explicitly specified in the Cost Proposal attached for reference hereto as Appendix "A". Unless specified otherwise herein, Licensee's Use of any third-party product is intended to be run-time and is not a full-use license. If, for any reason more licenses are required for system operation, Licensee is responsible for any additional costs associated with obtaining those additional licenses, the costs associated with applicable integration fees and annual support and maintenance fees. Changes made by Third Parties in their pricing policies shall be the responsibility of Licensee.

3. SUPPORT, MAINTENANCE AND TESTING.

3.1 Support will be provided during normal business hours (~~6~~8 AM through ~~6~~8 PM ~~PST~~EST/~~PDT~~EDT, Monday through Friday, excepting normally recognized holidays). Harris offers other hours of support which require payment of a higher fee. Licensee can elect to modify the hours of support by payment of the then current fee for the additional hours of support.

3.2 Maintenance entitles Licensee to have access to Harris's electronic support facilities and to receive all error correction releases and/or performance enhancement releases of the Programs not separately marketed by Harris. The license granted to Licensee under Section 2 shall extend to each update, correction and enhancement release received from Harris. Support entitles Licensee's employees to telephone Harris's Helpline and to have access to Harris's electronic support facilities.

3.3. Licensee shall have 30 days from the date of first use in live operation (the initial testing period) to perform reasonable tests to verify that there are no material deficiencies in the Program(s). In the event that a Program is found to contain material deficiencies, Licensee shall notify Harris in writing, specifying the nature of the deficiencies. Harris shall have thirty (30) days to correct the deficiencies. Harris shall notify Licensee in writing when the deficiencies have been corrected and the provisions of this paragraph shall again apply. A Program shall be deemed to be accepted upon the expiry of the initial testing period or of any repeat testing period, if no notice of a material deficiency has been delivered by Licensee to Harris during such period(s). The repeat testing period will be thirty (30) days or the remainder of the testing period, whichever is longer. If after two retests, the Program is found to continue to possess material deficiencies, Licensee may invoke the remedy provided in the Warranty.

3.4. For so long as Licensee remains current on all required maintenance payments, Harris will, as part of its maintenance and support obligations, provide problem diagnosis for the Programs and will supply corrections for such problems. Upon receipt of notice from Licensee of nonconformance between the Programs and Documentation, Harris shall correct the problem in accordance with the Agreement. Any corrections to the Programs will be made to all supported versions or releases of the Programs. Harris will perform these services in a timely manner consistent with the urgency of the situation. The following general guidelines will be followed:

a) Priority 0: Critical System Down or Imminently Down. Where a supported version of the software is currently suffering from a deficiency resulting in a critical system failure and where the supported version of the software is currently suffering from a deficiency that will result in a critical system failure before the next Service Pack release. Harris development staff will evaluate the TRACKER within one (1) business day of the TRACKER'S creation and an estimated of the resolution timeframe provided to Licensee via Harris Support when determined. Development resources will be assigned immediately to fix and provide a Patch release as soon as possible. A critical system failure is defined as anything that causes:

   i) A critical process to be inoperable;

   ii) A critical calculation to be incorrect;

   iii) Data to be corrupted by the system;

   iv) A critical output to be displayed incorrectly;

b) Priority 1: System Down or Imminently Down. Where a supported version of the software is suffering from a deficiency which is resulting in a system failure for which:

   i) The solution can wait for inclusion in a Service Pack release;

   ii) Requiring the customer to upgrade to the next Enhancement Release is unreasonable (e.g. updates to statutes);

   iii) A workaround does not exist.

   Harris development staff will evaluate the TRACKER within two (2) business days of the TRACKER's creation and schedule the delivery date/Service Pack version number within five (5) business days. The schedule date will be provided to Licensee via Harris Support. Harris Support will work with both Licensee and Harris Development to determine a mutually acceptable delivery timeframe.

c) Priority 2: Unplanned Deliverable. Priority 2 status is reserved for circumstances where the under development version of the software needs to be modified to accommodate a request that cannot wait for release in a future version of the software, but for which the luxury of scheduling exists:

   i) Software deficiency corrections where the current workaround is unduly cumbersome;

   ii) Software deficiency corrections where failure to correct the issue before the next Enhancement release will result in a Priority 1 situation.

   The TRACKER will be evaluated by Harris staff and scheduled into the current development cycle within ten (10) business days. If for timing issues it is not possible to schedule the Priority 2 Modification into the current development cycle, Licensee will be notified into which release it has been scheduled. Licensee will be required to upgrade to the upcoming Enhancement Release in order to receive Priority 2 Enhancements.

d) Priority 3: Planned Delivery. Priority 3 status is reserved for any software Enhancement or Fix where the luxury of planning and scheduling exists:

   i) The TRACKER will be evaluated by Harris staff and either scheduled into future software release or rejected within sixty (60) days of receipt. Licensee will be required to upgrade the version of their software in order to receive a Priority 3 Enhancement.

3.5 Harris shall have no obligation to Support or Maintain the Program for Use on any computer system other than the Hardware and Operating System Software or in the event Licensee modifies the Program or data generated by the Program other than as provided in the Documentation. Harris shall use commercially reasonable efforts to modify any version of the Program to run with new versions or releases of the Operating System Software or Hardware. If Licensee purchases Maintenance from Harris for any Programs for Use on specific Hardware or in a specific network, Licensee must purchase Maintenance from Harris for all functionally related Programs licensed from Harris for Use on such hardware or network.

3.6. Harris offers Licensee the option of having the source code to the Program placed in escrow at the fees and terms set out in the attached Appendix "~~B~~D" - Escrow Services Agreement. Upon Licensee's acceptance of the Program and completion of each major release of the Program(s) but not less often than annually, Harris shall deliver one copy of any Harris source code for the Program to Harris's then current escrow agent. The appropriate annual escrow fees shall apply and are subject to change.

4. PAYMENT TERMS

4.1 Subject to 4.2 hereof, all fees incurred pursuant to this Agreement including Appendix "A" and any Supplement added thereto from time to time shall be paid within thirty (30) days after the invoice date. Licensee shall pay all applicable shipping charges and taxes, exclusive of Harris's income and corporate franchise taxes. Licensee shall reimburse Harris for all reasonable travel and living expenses incurred by Harris in rendering all services. After notice, past due amounts owing from Licensee shall bear interest at the rate of 1% per month. Licensee shall reimburse Harris for all reasonable costs incurred (including reasonable attorneys' fees) in collecting past due amounts owed by Licensee. Licensee shall pay license fees per the payment terms specified in Appendix "A". All payments shall be in ~~United States~~Canadian Dollars. The payment of Fees for Third Party Programs, including maintenance and support (if any) shall be 100% upon execution of this Agreement.

4.2 In accordance to the agreed upon payment terms defined in Appendix A, ~~a~~Annual fees for Support and Maintenance on licensed Harris Programs are due upon Licensee using Harris Programs, in whole or in part, in Live operations, but not later than ninety days after final data conversion. Upon payment of all new Support and Maintenance Fees, as well as any outstanding Support and Maintenance Fees, if any, Licensee may renew Support and Maintenance on an annual basis. Harris reserves the right to suspend Support and Maintenance for the Program(s) should any undisputed amounts owing to Harris pursuant to this Agreement, remain unpaid thirty (30) days into the Support and Maintenance period for which the fees are due.

5. CONFIDENTIALITY AND PROPRIETARY RIGHTS.

5.1 Each party shall hold Confidential Information of the other in confidence. "Confidential Information" includes without limitation the terms of this Agreement, the Program(s) and all Documentation, and all methods or concepts utilized therein, plus all information identified by the disclosing party as proprietary or confidential. All Confidential Information shall remain the sole property of the disclosing party. Upon execution of a non-disclosure agreement satisfactory to Harris, third parties may have access to Confidential Information solely for the purpose of providing services to Licensee. Information will not be considered to be Confidential Information if (i) available to the public other than by a breach of this Agreement; (ii) rightfully received from a third party not in breach of any obligation of confidentiality; (iii) independently developed by a party without access to Confidential Information of the other; (iv) known to the recipient at the time of disclosure; (v) produced in compliance with applicable law or a court order, provided the other party is given notice and opportunity to intervene; or (vi) it does not constitute a trade secret and more tha~~nt~~ five (5) years have elapsed from the date of disclosure.

5.2. All Programs and Documentation, and any modifications or copies thereof, are proprietary and protected by copyright and/or trade secret law and no ownership rights are transferred by this Agreement. All proprietary notices incorporated in, marked on, or affixed to a Program or other Confidential Information by Harris or its suppliers shall be duplicated by Licensee on all copies of all or any part of the Program and shall not be altered, removed or obliterated. Licensee shall not reverse engineer, reverse assemble or reverse compile any Program or part thereof. Licensee may modify the Programs to the extent and in the manner described in the Documentation for the Program(s).

6. WARRANTY.

6.1. Harris warrants that each Program licensed to Licensee will operate substantially in conformance with the Documentation for such Program for a period of one year from either the date of the License Supplement of such Program or completion of the Testing phase more particularly described in ~~the Statement of Work~~Appendix B - Cost Proposal. ~~attached to the Installation Services Agreement to be entered into between the parties, whichever shall occur first.~~

6.2. Harris warrants that the media on which the Program is delivered will be free of defects in material and workmanship for a period of ninety (90) calendar days following the date of shipment.

6.3. Licensee's sole and exclusive remedy for breach of either of the foregoing warranties shall be replacement of the defective materials licensed on a Supplement. Such a remedy is available only if Harris is notified within the applicable Warranty Period and is provided a reasonable opportunity to cure such breach.

6.4. NO OTHER WARRANTY, EXPRESS OR IMPLIED, IS MADE WITH RESPECT TO THE PROGRAM, DOCUMENTATION OR SERVICES TO BE SUPPLIED BY HARRIS, INCLUDING WITHOUT LIMITATION ANY IMPLIED WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE.

7. INFRINGEMENT INDEMNITY.

Harris shall indemnify, defend, or, at its sole option, settle any claim or suit against Licensee if such suit or claim is based ~~solely~~ on the basis of a patent, trademark, copyright or trade secret infringement by the Program or Use thereof provided Harris has sole control of such defense and/or settlement and Licensee promptly notifies Harris and gives Harris all related information known to Licensee. In the event that a competent court adjudicates that the Program or any part of it does infringe a third party's patent, trademark, copyright or trade secret, or in the event that Licensee is enjoined from using the Program or any part of it, Harris shall, at its expense and option, do one of the following things:

a) procure for Licensee the right to Use the Program or the affected part thereof; or

b) replace the Program or affected part thereof with other suitable programs acceptable to the Customer; or

c) modify the Program or affected part thereof to make it non-infringing; or

d) if none of the foregoing remedies are commercially feasible, refund the aggregate payments paid by Licensee for the Program or the affected part thereof, less reasonable amortization for Use.

Harris shall have no obligations under this Section 7 with respect to any claim to the extent it is based upon (i) the Use of any version of the Program other than a current, unaltered release of the Program, if such infringement would have been avoided by the Use of a current, unaltered release; (ii) the combination, operation, or Use of the Program with software or hardware other than as specified by Harris, if such infringement would have been avoided in the absence of such combination, operation or Use; or (iii) the Use of the Program on or in connection with a computer system other than the Hardware and the Operating System Software. ~~Moreover, to the extent that Harris is named in any suit or claim and to the extent that that suit or claim is based upon any of the events stated in this paragraph of Section 7, Licensee shall indemnify and hold Harris harmless from all damages and costs (including all Harris's attorney fees) related to such suit or claim.~~ Harris consent is not to be held unreasonably.

8. ~~LIMITATION OF LIABILITY.~~

~~Except as provided in Section 7 and subject to Subsection 6.3, Harris's total liability, including but not limited to liability arising out of, resulting from or in any way related to contract, tort, breach of warranty, intellectual property infringement or otherwise, shall not in any event exceed the total fees paid by Licensee with respect to the affected Program. Neither Harris nor its licensors shall be liable for loss of profits, indirect, special, incidental, or consequential damages.~~

~~9.~~ ~~A~~ARBITRATION

In the event of any dispute, controversy or claim arising under, out of or relating to this Agreement and any subsequent amendments of this Agreement, including, without limitation, its formation, validity, binding effect, interpretation, performance, breach or termination, as well as non-contractual claims, the following procedures shall apply:

9.1. The parties shall first attempt to settle such dispute or controversy by negotiation.

9.2. In the event such dispute or controversy cannot be resolved successfully by negotiation after sixty (60) days, the dispute or controversy shall be submitted to final and binding arbitration in accordance with the World Intellectual Property Organization ("WIPO") Expedited Arbitration Rules. The arbitrator(s) shall be selected and agreed on by both parties. If the parties are unsuccessful at selecting mutually agreed upon arbitrator(s), then one will be appointed to them by WIPO. The arbitrator(s) selected shall be familiar with computer programming techniques and software system development projects, as well as the protection of trade secrets and confidential information related thereto and shall be neutral, impartial and independent. Each party shall initially bear its own costs and legal fees associated with such arbitration and the parties shall split the cost of the arbitrator(s) and any WIPO registration fees. The prevailing party in any such arbitration shall be entitled to recover from the other party the reasonable attorneys' fees, costs and expenses incurred by such prevailing party in connection with such arbitration. The decision of the arbitrator(s) shall be final and may be sued on or enforced by the party in whose favor it runs in any court of competent jurisdiction at the option of the successful party. The rights and obligations of the parties to arbitrate any dispute relating to the interpretation or performance of this Agreement or the grounds for the termination thereof, shall survive the expiration or termination of this

Agreement for any reason. The arbitrator(s) shall be empowered to award specific performance, injunctive relief and other equitable remedies as well as damages, but shall not be empowered to award punitive or exemplary damages or award any damages in excess of any limitations set forth in this Agreement.

~~10.~~9. TERM, TERMINATION, EFFECT OF TERMINATION

~~10~~9.1. This Agreement including Appendix "A"- License Supplement shall be effective from the date set forth above and shall remain in effect unless otherwise terminated in accordance with the terms of this Agreement. Any amending supplement shall be effective from the date set forth in that supplement and will automatically terminate upon termination of this License Agreement.

~~10~~9.2. The license granted in this Agreement and any subsequent supplement may be terminated by Harris immediately, at its sole discretion, if Licensee chooses to replace the Harris Programs with products procured through a party other than Harris. In such event, Harris may also, at its sole discretion, terminate (i) the maintenance and support obligations set out in Section 3; and (ii) the provision of escrow services described in subsection 3.6 (including any relevant Escrow Agreement signed between the parties), of this Agreement. Notwithstanding the foregoing, if prior to transition to the replacement programs or system Licensee chooses to continue using the Programs and the support services of Harris, Licensee shall continue to pay Harris support fees, on a time and material basis at the then current rate. Upon transition to its replacement system, Licensee agrees to (i) purge from its system all Programs, whether or not modified and incorporated into other materials; (ii) destroy or return the Programs and Documentation to Harris together with a written certification by an authorized signing officer of Licensee that Licensee has taken this action; (iii) and pay all outstanding invoices forthwith.

~~10~~9.3. Either party may terminate this Agreement or any license granted under this Agreement or an applicable supplement: (1) on thirty (30) days written notice for material breach, unless the breach is cured within the thirty (30) day notice period; or (2) immediately, if the other party shall (i) cease to conduct business in the normal course, (ii) make a general assignment for the benefit of creditors, (iii) suffer or permit the appointment of a receiver for its business or assets, (iv) or shall avail itself of or become subject to any proceeding under the Bankruptcy Laws or any other statute of any jurisdiction relating to insolvency or the protection of creditors.

~~10~~9.4. Upon termination under Subsection 10.3 for breach by Licensee, Licensee shall immediately (1) pay all fees incurred and any outstanding invoices for the Programs or Services rendered by Harris prior to date of termination; and (2) cease Using the Program and Documentation, remove the Program from its system and return the Program and Documentation to Harris. Licensee shall also provide to Harris within thirty (30) days of termination written certification by a duly authorized signing officer of Licensee that all copies of the Program and Documentation, whether or not modified or incorporated into other materials, have been destroyed or returned to Harris. In the event of termination under this Subsection 10.4, Harris at its sole option may immediately terminate (i) the maintenance and support obligations set out in Section 3; and (ii) the provision of escrow services described in Subsection 3.6 (including any relevant Escrow Agreement signed between the parties), of this Agreement.

~~10~~9.5. Each party's obligations under Section 5 hereof are of a unique character and each party agrees that any breach of this Agreement may result in irreparable and continuing damage to the other party for which there may be no adequate remedy in damages. In the event of breach of Section 5, the damaged party will be entitled to injunctive relief and/or a decree for specific performance and such further relief as may be proper. Neither party's right to pursue any other remedies available to it shall be in any way limited or impaired by any termination of this Agreement.

~~10~~9.6. The parties' rights and obligations under Sections 5, 7, 8, 9 and 12 hereof shall survive termination of this Agreement or any license granted under this Agreement.

~~10~~9.7. All notices relating to termination or default under this Agreement shall be in writing and delivered by overnight delivery service or certified mail, return receipt requested, to the address specified above. Either party may change its address by providing notice in accordance with this Section.

~~11.~~10. GENERAL.

10~~1~~.1. Neither this Agreement nor any license hereunder may be assigned (whether by operation of law or otherwise) by either party without the other party's prior written consent. In the event that Licensee and/or one or more Affiliates, if any, is reorganized such that the Affiliate(s) and/or a portion of the Licensee is no longer qualified for Use, Licensee may request assignment, which shall not be unreasonably withheld. Any fees for additional users or accounts shall be paid to Harris.

~~11~~10.2. From time to time, Harris may request Licensee to provide a certification to the effect that actual Use of the Program is in compliance with the terms of this Agreement as amended in writing from time to time. In addition, Harris may, upon reasonable notice, perform an audit to determine compliance with the terms of this Agreement. Audits will be made no more than once in any twelve (12) month period, and, if conducted, will occur at or around the end of each Maintenance Contract Year. If the number of accounts, copies or users is found to be greater than that specified in the License Supplement or the computer system on which the Program is in use differs from the Hardware and Operating System Software specified on any Agreement, Harris shall have the right to charge Licensee the applicable current list prices therefore. If the resulting adjustment to the license fees owing by Licensee are greater than 5% of the license fees previously paid by Licensee to Harris, Harris may also charge Licensee the reasonable expenses associated with such audit.

~~11~~10.3. This Agreement is subject to any governmental laws, orders or other restrictions on the export of Programs and related information and Documentation that may be imposed by governmental authorities.

~~11~~10.4. Any provision of this Agreement which is prohibited by law or is unenforceable will be ineffective only to the extent of such prohibition or unenforceability without invalidating the remaining provisions hereof.

~~11~~10.5. Subject to the limitations herein before expressed, this Agreement will enure to the benefit of and be binding upon the parties and their respective successors and assigns.

~~11~~10.6. This Agreement, together with ~~the License Supplement~~Appendix "A" and "B" ~~provided in Appendix "A"~~, the exhibits and addenda, if any, attached hereto, constitutes the entire agreement of the parties and supersedes all previous and contemporaneous communication, representations, understandings or agreements related to the subject matter hereof. This Agreement may be modified only in a writing signed by both parties. Licensee may issue a purchase order in lieu of a Supplement, if confirmed by a Harris invoice or other Harris confirming document. Pre-printed terms and conditions on or attached to any such purchase order shall be of no force or effect. In the event of inconsistencies or conflicts in the terms and conditions of any portions of the entire agreement the order of priority shall be; (i) this License Agreement, (ii) License Supplement(s) appended to this Agreement and any addendums thereto, (iii) Services Agreement(s) entered into between the parties and associated Statement(s) of Work and Change Orders (if any) and any addendums thereto, (iv) the SNAP Report (if any) when approved, and (v) Harris's response to Licensee's RFP (if any).

~~11.7 Additional Billing Rights. For so long as both this Agreement and the License Supplement contained in Appendix "A" attached for reference hereto remain in full force and effect, and provided that Licensee is not in default with respect to any payment obligations under either this Agreement or under any Agreement for Services between the parties, Harris hereby grants Licensee the right to provide Consolidated Billing Services to its Customers. Such Consolidated Billing Services may only be provided to Customer of Licensee located in the Territory. The aggregate number of Customers, including those Customers for whom a Consolidated Bill is generated, may not exceed the maximum Account limitation identified in Appendix "A", unless otherwise authorized in an amendment hereto.~~

1~~2~~1. NON-SOLICITATION.

Parties agree that during the term of this Agreement, and for a period of two (2) years thereafter, they will not, without the express prior written consent, directly or indirectly, solicit any person for employment, who is currently employed by the other party. In addition, any person who has been previously employed by either party shall be prohibited from servicing or providing consultation within the scope of work contemplated by this Agreement for a minimum of two (2) year after their current employment.

~~13.~~12. MARKETING.
Licensee agrees that during the term of this Agreement, Harris may publicly refer to Licensee, orally and in writing, as a client of Harris. Any other reference to Licensee by Harris requires the written consent of Licensee.

14~~3~~. GEOGRAPHIC TERRITORIES.
Use of the Programs shall not extend beyond the boundaries of the United States of America and Canada.

1~~5~~4. GOVERNING LAW.
The Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be duly executed as of the date set forth above.

NIAGARA FALLS HYDRO, INC.~~O~~	N. HARRIS COMPUTER SYSTEMS
By: Suzanne Wilson	By:
Name Printed: Suzanne Wilson	Name Printed: Jeff Bender
Title: Director of Finance	Title: CEO
June 30, 2005	

2.3 Delivery of Escrow Materials: "Escrow Materials" is defined as a sealed package containing a copy of the Program's source code on Harris supported electronic medium in the format and system environment used by Harris and Customer in its own operation to generate object code, together with a copy of the existing systems documentation developed for the Programs and the specifications for the operating environment and software tools required to make effective use of the source materials. Escrow Materials will be shipped within ten (10) days of the initial payment of the Annual Fees to Harris' then current Escrow Agent, DSI Technology Escrow Services, having an address at 2100 Norcross Parkway, Suite 150, Norcross, GA, 30071. Subsequently, provided Customer has maintained payment of the Support and Maintenance fees and Escrow Services Annual Fees, the existing Escrow Materials will be exchanged for a replacement set comprising the then-current source and documentation and shall again be placed with Harris' then current Escrow Agent, such exchange occurring as soon as practical following the shipment of a new release of the Programs.

2.4 Access to Escrow Materials: Escrow Materials shall remain in a sealed package and shall be held, in trust, by Harris' Escrow Agent. Customer shall be entitled to verify with the Escrow Agent that the Escrow Materials (namely the sealed package containing the then current source code) have been placed with Harris' Escrow Agent. However, Customer shall not be entitled to access the Escrow Materials unless and until one of the following events occur:

a) Harris is unwilling or unable to complete modifications to the programs which are required to allow Customer to comply with regulatory or legal requirements which are beyond the control of Customer; or

b) Harris takes advantage of the insolvency laws of any jurisdiction; or

c) Harris makes an assignment in bankruptcy or is adjudicated as bankrupt and Canadianize to the Bankruptcy and Insolvency Act of Canada; or

d) Harris makes a general assignment for the benefit of its creditors; or

e) Harris has a receiver, administrator or manager of its property, assets or undertakings appointed in such circumstances as would adversely affect the continuing use by Customer of the Software specified in the License Supplement; or

f) Harris is ordered by any Court of competent jurisdiction to be wound up; or

g) Harris becomes insolvent; or

h) Harris ceases doing business as a going concern.

2.5 Warranties of Harris: Provided Customer complies with the terms of the License Agreement and all Supplements and Addendums thereto and pays the agreed Support and Maintenance fees, Harris will, to the extent that it is still supplying such services to other customers, warrant that the Escrow Materials and replacement Escrow Materials delivered under this Agreement will be complete, accurately reflect the most current version of the source code of the Programs used by Customer, incorporate all changes made to the Programs or the source code thereof from the previous time the Escrow Materials were delivered to Harris' Escrow Agent under this Agreement, and contain no passwords or other devices that would prevent or prohibit the use of the Escrow Materials at any time should an event in s.2(4) occur.

2.6 Harris' Intellectual Property: Customer acknowledges that the Escrow Materials are and shall remain solely Harris' property (tangible and intellectual). Customer furthermore acknowledges that any breach or violation of this Agreement would cause Harris irreparable harm and that legal remedies, in themselves, may not adequately remedy such breach or violation. Harris, therefore shall be entitled to pursue, in addition to any legal remedy available to it, all equitable remedies (including injunctive relief and specific performance). Customer hereby warrants that it shall not attempt to access, except pursuant to the provisions of this Agreement, the Escrow Materials and replacement Escrow Materials delivered under this Agreement to Harris' Escrow Agent. Even in the event of access to the Escrow Materials by Customer pursuant to s.2(4), Customer acknowledges that it shall only be entitled to use the source code and documentation in the same manner in which Customer is permitted to use the object code of the Programs as specified in the License, with the additional license to modify the source code and convert it to executable object code. In particular, without restricting the generality of the foregoing, the release, modification, enhancement, or alteration of the Escrow Materials does not alter Harris' complete and sole ownership of all property rights in the Programs and Customer shall sign all written instruments to this effect if required by Harris or an agent acting on behalf of Harris. Customer furthermore acknowledges that any resultant modification or enhancement to the Escrow Materials shall become Harris' intellectual property and Customer shall sign all written instruments to this effect.

SECTION 3: PAYMENT

3.1 Excepting the initial invoice that is due upon execution of this Agreement, all fees shall be paid within thirty (30) days after receipt of the invoice. Customer shall pay all applicable shipping charges and taxes, exclusive of Harris' income and corporate franchise taxes. If any invoice is not paid within thirty (30) days, Customer shall pay a late payment charge of 1% per month on the unpaid amount, together with the amount of the original invoice. Customer shall reimburse Harris for all reasonable costs incurred (including reasonable attorneys' fees) in collecting past due amounts owed by Customer.

SECTION 4: TERMINATION AND DEFAULT

4.1 Termination: At Customer's option, this Agreement may be terminated by providing notice in writing to Harris at least thirty (30) days prior to an annual Escrow Services renewal date. Upon termination, Harris' Escrow Agent shall return all Escrow Materials to Harris and any and all rights enjoyed by Customer hereunder shall automatically and immediately terminate.

HARRIS

Harris Computer Systems

Appendix D - Escrow Services Agreement

SERVICES AGREEMENT by and between Harris Computer Systems ("Harris"), having offices at #400 –1 Antares Drive, Ottawa, ON K2E 8C4 and Niagara Falls Hydro ("Customer"), having offices at 7447 Pin Oak Drive, Niagara Falls ON Canada L2E 6S9, is made and entered into as of the__________________day of__________________, 2005. As of January 1, 2006, Customer name may change.

PREAMBLE

WHEREAS:

a) Harris owns or has the right to license certain Software ("Programs"); and

b) Harris provides software escrow services ("Escrow Services") to its licensees as defined in Appendix "B" to the License Agreement entered into between the parties hereto, such License Agreement dated for reference the 30th day of June, 2005, and is willing to provide such services to Customer on the terms and conditions specified in this Agreement; and

c) Customer has licensed the Software ("Programs") specified in the License Supplement: and

d) The initial Support and Maintenance period specified in the License Supplement has not expired or the Customer has made timely renewal payments;

THEREFORE in consideration of the premises and of the mutual covenants herein set forth, the parties agree as follows:

PROGRAMS	ANNUAL FEES	UPDATE FEES
North Star	$1500 CAD	$500 CAD
TOTALS	$1500 CAD	$500 CAD

SECTION 1: HARRIS PROGRAMS

1.1 "Program" means the software application(s) set in the License Supplement or otherwise made available by Harris or use by the Licensee as a part of this Agreement.

SECTION 2: ESCROW SERVICES

2.1 Term: Escrow Services will commence on the date of execution of this Agreement and will continue as long as the Customer is covered by Support and Maintenance pursuant to the License Agreement and any Support and Maintenance Service Agreement entered into between the parties and so long as the Customer has paid the applicable Escrow Service Fees. Escrow Services will terminate automatically upon the termination of the License Agreement or of an applicable License Supplement, Service Agreement, or upon non-payment of Support and Maintenance fees or Escrow Services Fees.

2.2 Charges: The fee for the first delivery of the Escrow Materials will be the Annual Fee. Subsequently, the Annual Fee will be billed as a supplementary charge to the Support and Maintenance fees under the same payment terms. Should Customer request Escrow Materials outside the normal release update cycle, the Update Fee will apply.

4.2 Remedy of Default: This Agreement may be terminated by either party if the other fails to perform or comply with any provision of this Agreement, provided that a party intending to terminate under this provision will provide written notice of the applicable default to the defaulting party, and termination based thereon will only be effected if the defaulting party fails to rectify the specified default within sixty (60) days after receipt of such notice. Upon the occurrence of an Event of Default by Harris and failure by Harris to remedy, if Customer elects not to terminate this Agreement, then the Customer shall be entitled to have access to the Escrow Materials currently in Harris' Escrow Agent's possession, or the most current version of the code, and the Escrow Materials will, subject to the provisions of s. 2(6) hereof, be released from the escrow restrictions forthwith.

SECTION 5: GENERAL PROVISIONS

5.1 Assignment: Neither party hereto shall be entitled to assign that party's rights and obligations under this Agreement without the express written agreement of the other party, such agreement not to be unreasonably withheld.

5.2 Severability: Any provision of this Agreement which is prohibited by law or is unenforceable will be ineffective only to the extent of such prohibition or unenforceability without invalidating the remaining provisions hereof.

5.3 Enurement: This Agreement will enure to the benefit of and be binding upon the parties and their respective successors and assigns.

5.4 Modification: This Agreement may not be modified except in writing by an authorized signatory of each party.

5.5 Non-Solicitation: The parties agree that during the term of this Agreement, and for a period of two (2) years thereafter, they will not, without the express prior written consent, directly or indirectly, solicit any person for employment, who is currently employed by the other party. In addition, any person who has been previously employed by either party, shall be prohibited from servicing or providing consultation within the scope of work contemplated by this Agreement for a minimum of two (2) year after their current employment.

5.6 Marketing: Customer agrees that Harris may publicly refer to Customer orally and in writing as a client of Harris. Any other reference to Customer by Harris requires the written consent of Customer.

5.7 Notification: All notices under this Agreement shall be in writing and delivered by overnight delivery service or certified mail, return receipt requested, to the address specified above. Either party may change its address by providing notice in accordance with this Section.

5.8. Governing Law: The Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario. This Agreement shall attorn to the jurisdiction of a competent court within a mutually agreed upon county in the Province of Ontario.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be duly executed as of the date set forth above.

NIAGARA FALLS HYDRO, INC.	**N. HARRIS COMPUTER SYSTEMS**
By: Suzanne Wilson	By:
Name Printed: Suzanne Wilson	Name Printed:
Title: Director of Finance	Title:
June 30, 2005	

utilismart™ CORPORATION

utilismart™ Customer Agreement **Contract No: NPE-01-SM-010109**
Contract Period Start Date (for Initial Term): January 1, 2009.

To: **Niagara Peninsula Energy Inc. (hereinafter referred to as the "Customer")**
Address: **7447 Pin Oak Drive**
Niagara Falls, ON L2E 6S9

This utilismart™ Customer Agreement (the "Agreement") sets out the terms and conditions under which Utilismart Corporation, having offices at 2386 Main Street, London, Ontario (hereinafter referred to as the "Company"), will make available the Services (as defined below) to the Customer. When signed by both parties, this agreement supersedes and replaces the agreement between Enerconnect Inc. and Niagara Falls Hydro Inc. dated April 3, 2007 and between Enerconnect Inc. and Peninsula West Utilities Ltd. dated April 28, 2004, once the Contract Period begins.

1. SCOPE OF SERVICES.

(a) The Customer will purchase and the Company will perform the utilis**mart**™ SETTLEMENT MANAGER Services described in Attachments 1 and 2 to this Agreement (the "Services").

(b) The Company warrants the Services are in compliance with the Ontario Independent Electricity System Operator ("IESO") rules (the "Rules") and Ontario Energy Board Standards (the "Standards") as of the date of this Agreement and will be maintained in such compliance during the term of this Agreement.

(c) The Company may modify at its discretion, the manner in which the Services are provided to the Customer during the Initial Term or Renewal Term (as each term is defined in Section 18 and sometimes collectively referred to herein as the "Term") provided that such modifications are not Material Alterations and that the Services remain in compliance with the Rules and Standards. The Company shall obtain the written consent of the Customer in the event that such modifications are Material Alterations (said consent will not be unreasonably withheld). The parties agree that for the purposes of this Agreement a Material Alteration will mean a change in the Services that would reasonably be expected to have a significant negative effect on the value or nature of the Services to the Customer or the commercial viability of this Agreement to either party.

(d) Notwithstanding the terms of Section 1(c) and Section 18, should there be a change in the Rules and Standards which necessitate a Material Alteration in the Services, the Company agrees to undertake such change at no cost to the Customer, or if unable to make such change and the parties are unable to negotiate a mutually agreeable alternative, to give the Customer no less than 3 months written notice of the Company's decision to terminate this Agreement.

2. THE AGREEMENT. All Attachments to this Agreement shall be deemed to be part of this Agreement. In the event of a conflict between Attachment 1 and Attachment 2, Attachment 1 shall be read in priority to Attachment 2.

3. PAYMENT. To purchase the Services, the Customer shall pay the Company the fees as set out in and in accordance with Attachment 1. The Customer shall pay all sales and goods and services taxes, duties and levies, any related interest and penalties and all similar charges, however designated, imposed or based upon the provision or use of the Services provided under this Agreement (excluding taxes based on the Company's net income), and any additional amounts necessary to ensure that the net amounts received by the Company after all withholdings or payments equal the amount to which the Company otherwise would have been entitled to, absent such charges or taxes. Such charges or taxes shall be separately itemized on the Customer's bill. Monthly invoices shall be sent to the Customer while the Services are being provided, unless a different payment schedule is agreed to and set forth in the Schedule of Charges. Invoices are payable to the Company thirty (30) days from the date of invoice. Interest charges will be added to any past due amounts at the rate of 1.5% per month.

4. NOTICES. Any notice, report, request or demand shall be made to the receiving party's designated representative, either by delivery in person or by facsimile followed by a paper copy sent by first-class mail. No notice shall be effective until received by the party to whom it is addressed, to the applicable address set out above. Addresses may be changed by written notice.

5. CHANGES. The Customer may request changes in the Services at any time or a change may be required due to changes in the Rules or Standards that is not a Material Alteration. In such case a change order must be confirmed in writing, approved by the Company and signed by both parties. Once executed, such change orders will form part of this Agreement. A reasonable adjustment to the due date and/or Schedule of Charges shall be made if any such change affects the time of performance or the cost of the Services to be provided under this Agreement.

6. LIMITATION OF WARRANTIES. The provision of Services under this Agreement shall proceed with diligence and shall be executed with ordinarily acceptable practices in the field to which the Services pertain, as well as any standards set forth in Attachments 1 and 2. Except as set forth in this Section, the Company and its affiliates, subcontractors and agents make no warranties with respect to the services, express or implied, and specifically disclaim any warranty of merchant ability or fitness for a particular purpose. Whereas the Company must rely on the accuracy of third party metering devices and data provided to it by third parties in order to provide the Services, the Company does not warrant the accuracy, completeness or currency of any data collected on behalf of the Customer and stored in the Company's database.

7. CONFIDENTIAL INFORMATION. Each party agrees that it shall not disclose, either during the Term or after the expiration or termination of this Agreement, to any unaffiliated third party any proprietary information of the other party, including, without limitation, information concerning trade secrets, methods, processes or procedures or any other confidential business or technical information or customer data ("Confidential Information"), which it learns during the course of its performance of this Agreement, without the prior written consent of the other party, except to the extent that any such Confidential Information: (i) is in the public domain; (ii) is independently developed by the receiving party; (iii) is already in the possession of such party prior to disclosure by the other party; (iv) is rightfully received from a third party not under a confidentiality obligation to the other party; or (v) is legally required to be disclosed by the receiving party. Either party may disclose Confidential Information to its sub-contractors, agents or advisors on a need-to-know basis, provided it first obtains an appropriate non-disclosure agreement therefrom.

8. INTELLECTUAL PROPERTY RIGHTS.

   (a) <u>Customer Proprietary Information</u>. The Company acknowledges and agrees that it shall have no right, title, claim, interest, security interest or lien ("Interest") in any specifications, designs, plans, drawings, data, software, computer systems, prototypes or other technical or business information ("Proprietary Information") and disclosed to the Company by or on behalf of the Customer in connection with this Agreement ("Customer Proprietary Information"), regardless of whether any such information constitutes a trade secret or is competitively sensitive, or in any Proprietary Rights (as defined below) with respect thereto, and disclaims any such Interest in any of the Customer Proprietary Information or such Proprietary Rights. The Customer hereby grants or shall grant to The Company a personal, non-exclusive, non-transferable, royalty-free license (without the right to sublicense, except to affiliates) during the Term, to use, execute, reproduce, display, perform and copy such Customer Proprietary Information (including the right to provide such information to subcontractors) for the sole purpose of performing the Services and only to the extent necessary to do so. As used in this Agreement, "Proprietary Rights" means, with respect to any item, all trade secret, copyright, patent, trademark, service mark, certification mark, trade dress or other intellectual property or proprietary rights in all countries related to such item or any part thereof, any extensions or renewals of the foregoing, and any registrations, patents or applications with respect to the foregoing.

   (b) <u>The Company Proprietary Information</u>. The Customer acknowledges and agrees that it shall have no Interests in any Proprietary Information disclosed to the Customer by or on behalf of the Company in connection with this Agreement ("The Company Proprietary Information"), regardless of whether any such information constitutes a trade secret or is competitively sensitive, or in any Proprietary Rights with respect thereto, and disclaims any such Interest that it might otherwise have in any of the Company Proprietary Information or such Proprietary Rights. Where necessary for the proper performance of the Services under this Agreement, the Company will grant to the Customer a personal, non-exclusive, non-transferable, royalty-free license (without the right to sublicense, except to affiliates) during the Term, to use, execute, display, perform and copy any such Company Proprietary Information for use solely in connection with Customer's receipt of the Services.

(c) Restrictions. Notwithstanding the terms of the preceding section, the Customer shall not reproduce, copy, amend, modify, merge or reverse engineer all or any portion of any software resident on the Host System (as defined below), or attempt to do any of the foregoing. In this Agreement, "Host System" means the hardware, main processing modules of the Utilismart database and/or other related software licensed, leased or owned and operated by the Company and/or the Company's approved agents, subcontractors and suppliers, to provide Services to the Customer.

9. ACCESS. As part of the Services, the Company shall provide the Customer with two (2) usernames/ passwords for access to Customer data for each physical meter point registered. The Company shall provide any additional usernames/passwords at an additional cost.

10. TRADE NAMES. Neither party shall use the other party's trade name, trade-marks or logos, in any way, without the prior written consent of the other party, which consent may be withheld within such party's reasonable discretion, except that the Company may include the Customer's name in the Company's customer lists.

11. LIMITATIONS OF LIABILITY.

(a) The Company shall not be liable to the Customer for any special, indirect, incidental, consequential or punitive damages of any character, including but not limited to loss of use, loss of profit, past and future, additional out-of-pocket expenses incurred by the Customer, or other claims resulting from, arising out of, in connection with or in anyway incidental to any act or omission of the Company related to the provisions of this Agreement, including without limitation, claims of third parties.

(b) TO THE EXTENT PERMITTED BY LAW, THE LIABILITY OF THE COMPANY TO THE CUSTOMER FOR ANY REASON AND UPON ANY CAUSE OF ACTION WHATSOEVER, WHETHER IN CONTRACT OR TORT, SHALL BE LIMITED TO FEES PAYABLE BY THE CUSTOMER UNDER THIS AGREEMENT IN RESPECT OF THE SERVICES IN THE MONTH IN WHICH THE CAUSE OF ACTION AROSE.

(c) The Company shall not be liable for any costs, losses, damages, legal costs and expenses, liability, claims and demands resulting from or arising in connection with any use of the Customer's usernames or passwords. The Customer is solely responsible for ensuring that the usernames and passwords are kept confidential. The Customer agrees that under no circumstances shall the Company be held responsible or liable for situations where the data stored or communicated through the Company's website interface are accessed by third parties through illegal or illicit means, including situations where such data is accessed through the exploitation of security gaps, weaknesses or flaws, if unknown to the Company at the time, which may exist in the Host System (as defined herein). The Company simply stores and facilitates the transmission of private electronic communications. Electronic communications on the Company's Host System are private, and only under situations where explicitly required or allowed by law will such communications be accessed, intercepted, disclosed, or used without the consent of at least one of the parties to the communication.

12. INDEMNIFICATION. The Company and the Customer shall indemnify each other and their respective Affiliates as defined in Section 14, employees, subcontractors and agents against all losses resulting from injury or death of any person (including their respective employees, subcontractors or agents) or loss or damage to any tangible, real or personal property to the extent that such loss was proximately caused by gross negligence or willful misconduct of any person for whose conduct the indemnitor is responsible and which arises from the provision or receipt of the Services. The Customer shall indemnify the Company against all other claims from any third party, relating to the Company's provision of Services.

13. FORCE MAJEURE. Neither party shall be liable to the other party for any loss, damage, delay or failure of performance resulting directly or indirectly from any cause which is beyond its reasonable control, including (without limitation) acts of God, riots, civil disturbances, wars, states of belligerency, acts of the public enemy, strikes, work stoppages, power or utility failures, extraordinary traffic conditions, changes in laws or regulations, or the acts or omissions of any governmental authority. Under

such circumstances, the parties shall engage in good faith negotiations to arrange achievement of this Agreement's purposes through alternative methods.

14. ASSIGNMENT. Neither party may assign this Agreement without the other's written consent (which shall not be unreasonably withheld); provided, however, that the Company may without consent assign this Agreement in whole or in part to a Company Affiliate or Related Company. Affiliate means any partnership, corporation or other form of enterprise Controlled (as the term is defined in the following sentence) by, Controlling, and/or under common Control with, one of the parties. "Control" means the ownership, directly or indirectly, of greater than fifty percent (50%) of the voting securities of the entity in respect of which such determination is being made and the power to direct or cause the direction of the management and operating policies of such entity. A Related Company is a partnership or corporation in which the Company or an Affiliate directly owns not less than thirty percent (30%) of the voting securities of such entity.

15. SUBCONTRACTING. The Company may subcontract all or any portion of the Services to be performed by it under this Agreement, but shall retain responsibility for the Services subcontracted.

16. INDEPENDENT CONTRACTOR. Other than as expressly set forth herein, the Company and its subcontractors are independent contractors for all purposes and at all times for the work performed under this Agreement.

17. THIRD PARTY BENEFICIARY RIGHTS. No provision of this Agreement shall in any way inure to the benefit of any third person (including the public at large) so as to constitute any such person a third-party beneficiary of the Agreement or any of the terms hereof, or otherwise give rise to any cause of action in any person not a party hereto except to the extent as may be provided for in this Agreement.

18. TERM AND TERMINATION.

(a) The term of this Agreement shall be as shown in the signature section, commencing on the date hereof (the "Initial Term"). After the end of the Initial Term, the Agreement shall be renewed for successive 1 year terms (each a "Renewal Term"), unless terminated prior to the end of any Renewal Term, as the case may be.

(b) If there has been a breach or default by either party (the "Defaulting Party"), then the other party may terminate this Agreement after giving the Defaulting Party notice, in accordance with the provisions of this Agreement, of the breach or default and 30 business days to remedy the same, or in the case of any breach or default which cannot be reasonably remedied within 30 business days, such period as may reasonably be required to expeditiously remedy the breach or default. If the Customer is in default, a Termination Payment will be due and payable to the Company within 30 days of the termination of this Agreement. The Termination Payment will equal 50% of the remaining Agreement fees, based on the then current Monthly Fees as calculated in accordance with the terms outlined in Attachment 1.

(c) If neither party is in default, this Agreement may be terminated by the Company or the Customer upon providing 180 days prior written Notice to the other party. If this Agreement is terminated by the Customer more than 180 days prior to the end of the Initial or Renewal Term, then the Termination Payment will be due within 30 days of termination by the Customer. If this agreement is terminated by the Company and neither party is in default, the Company will provide the Customer with service until the end of the 180 day period and the Customer shall remain liable for any fees incurred according to the terms of Attachment 1 of this Customer Agreement.

(d) For the purposes of this Agreement a breach or default will include the following:
   (i) A violation of any term of this Agreement;
   (ii) The failure to make, when due, any payment required pursuant to this Agreement if such failure is not remedied within 10 business days after written notice is provided

19. DISPUTE RESOLUTION. If any dispute, difference or question shall arise between the parties concerning the construction, meaning or effect of this Agreement or anything herein contained or the rights or liabilities of any of them that cannot be mutually resolved between the parties within 30 days, then every such dispute, difference or question shall be referred to a single arbitrator, chosen unanimously by the parties. In the event that the parties cannot agree on a person to act as a single arbitrator, a single arbitrator shall be appointed in accordance with the provisions of the *Arbitration Act Ontario*. The determination made by the arbitrator shall be binding upon the parties

hereto, and their administrators, successors and assigns, as the case may be. The cost of the arbitration, excluding a party's legal fees and disbursements, shall, unless otherwise ordered by the arbitrator, be borne equally by the parties.

20. GENERAL.

(a) Any change to this Agreement (including its attachments) must be in writing and signed by both parties.

(b) Failure to enforce any right or remedy available under this Agreement will not be construed to be a waiver of the right or remedy.

(c) Any arbitration or legal action either party brings against the other party with respect to this Agreement must begin within one (1) year after the cause of action arises.

(d) Should any provision of this Agreement be held to be void or unenforceable, the remaining provisions shall remain in full force and effect, to be read and construed as if the void or unenforceable provisions were originally deleted.

(e) This Agreement shall be construed in accordance with and governed by the laws of the Province of Ontario and the laws of Canada applicable therein, without regard to conflicts of laws. The parties shall attorn to the exclusive jurisdiction of the courts of the Province of Ontario.

(f) This is the entire agreement between the parties with respect to the Services provided hereunder and supersedes all prior agreements, proposals, communications and understandings, whether written or oral.

(g) Unless otherwise expressly stated, all amounts in this Agreement are in the lawful currency of Canada.

(h) Sections 3, 6, 7, 8, 10, 11, 12, 13, 14, 17, 18 and 19 shall survive the expiration or termination of this Agreement.

(i) This Agreement may be executed in any number of counterparts, each of which shall be deemed an original and all of which together shall constitute one and the same instrument. A photocopy or facsimile copy of this Agreement bearing the signature of each party, in a single document or as counterparts, thereof, shall be deemed an original execution version of this Agreement.

(j) The Customer hereby jointly and severally agrees to indemnify and save the Company harmless from and against any and all claims, demands, actions, causes of action, damages, losses, deficiencies, costs, liabilities and expenses which may be made or brought against the Company or which the Company may suffer or incur as a result of, in respect of or arising out of any non-performance or non-fulfillment of any obligation of the Customer as set out in the Agreement.

(k) The Customer hereby authorizes Utilismart Corporation to use the Customer's company information as required for the services as described in this contract and in Utilismart Corporation's Client Privacy Policy, a copy of which is available upon request.

(l) Time is of the essence of this Agreement.

Dated this 30th Day of September, 2008

For
Utilismart Corporation

By: ______________________
Name: Ian J. Cameron
Title: General Manager

For
Niagara Peninsula Energy Inc.

Initial Term: three (3) years

By: ______________________
Name: Brian Wilkie
Title: President and CEO

Attachment 1 – Purchased Services/Schedule of Charges

NPE-01-SM-010109

GENERAL

This Attachment 1, Purchased Services / Schedule of Charges, is an attachment to the utili**smart**™ Customer Agreement, (the "Agreement") between **Niagara Peninsula Energy Inc.** (hereinafter referred to as the "Customer") and **Utilismart Corporation** (hereinafter referred to as the "Company").

The Services provided by the Company consist of operating a data collection and data storage system and providing access to the utili**smart**™ web-based presentation software and the Host System. Access to the Services is attained through the utili**smart**™ web interface program, which is run from the Customer's PC workstation.

A schedule of services purchased and charges to be paid is detailed below, any additional meter points added to the service will be included at the fees listed below. Fees for new metering points will be charged based upon this schedule and will commence on the date the web presentation is made available to the Customer and extend for the duration of this contract.

SCHEDULE OF SERVICES PURCHASED AND CHARGES

Monthly Services and Charges for all services outlined in Attachment 1 and Attachment 2

Settlement Manager Service (all services outlined in Attachment 1 and 2) For up to 425 Metering Points (any combination of IESO and retail Meter Points)	
Term	**Price per month***
1 Year	$17,400
2 Year	$17,400
3 Year	$16,500
4 or 5 Year	$16,500 for 1st 3 years, then: years 4 and 5 will use the 3 year price adjusted by the Ontario All-items CPI value for the 12 month period preceding the start date of years 4 and 5 as applicable
Additional Meter Points over 425	$35/Meter-Point/month Includes meter reading and settlement services.

Item	Description of Services Purchased
SM 1 Services include:	-Daily wholesale and retail interval meter data collection -Daily validating, editing and estimating of meter data -Daily collection of HOEP pricing (when available) -Daily processing of information and posting to secure web application -Daily email notification of meter data gaps or inconsistencies for wholesale meter points -Daily calculation of NSLS and Average Weighted Price presented in web application -Collection and presentation of IESO settlement statements - on the IESO scheduled basis -Independent calculation of total loss factor, including fixed and complex losses -Comparison of wholesale meter data readings with the IESO readings – and formally disagree with errors for such comparisons, as applicable - Management of Notices of Disagreement (NoDs) -Customer access to energy usage and cost information via a secure web application -Customer support via call centre for full product/service application support -Downloadable CIS billing determinants file for NSLS and Retail Interval Meters -Hourly pricing and hourly kWh for interval metered points -Web application accessible 24 hours/day – 7 days/week -Validation of charges 101, 650, 651 and 652

Initial Set-up Services and Charges

utilismart™ One Time Charges* (See Notes) Total		
Set-Up Fees The Basic Set up Fee is to be billed upon completion of the set-up of the points. One Time Set Up fee includes: • Set up and mapping of meter points • Registration of customer specific URL • Subscription, set-up and processing of the customer's meter points to the Website within 5 days of receiving meter information. • Website monitoring • Ongoing product training for the customer's staff, • User names and passwords as requested by the customer	Waived	NIL
	One Time Charges Total	**NIL**

***Notes:** The following terms and conditions shall apply to this Agreement in addition to those already specified and to all additional meters added to the service.

1. All prices are in Canadian dollars.
2. Applicable taxes are not included and are payable by the Customer in accordance with the Agreement.
3. Data collection fees do not include the cost of telephone line installation or monthly telephone line fees incurred by the Customer. Data collection does include any applicable long distance charges incurred by the Company in the collection of meter data.
4. Data collection fees include Validation, Editing and Estimating routines according to existing MV-90xi algorithms or future IESO/OEB standards.
5. All payments are net 30 days.
6. The Settlement Service includes twenty-four (24) months of on-line data storage.
7. A single Meter Point for wholesale and retail meters is defined as:
   - up to two (2) channels of a meter data from a physical meter
   - the third and fourth channels of meter data from a physical meter are considered a separate and additional point, etc.
   - the aggregation of two or more meter points into a virtual meter point will only be charged for the virtual meter channels, provided that only the virtual point meter data is provided to and used by Utilismart for processing
   - the calculation and display of any unmetered loads such as streetlight loads, contracted loads, bilateral loads, etc. (if metered data, 1 point = 2 channels of data).
8. The following minimum configuration is required on the Customer's PC workstation:
   - Internet access;
   - Internet Explorer 6.x, Mozilla Firefox 1.5x Browser or higher;
   - Pentium 1 or equivalent processor, though Pentium 4 or dual core processor are currently recommended; and
   - 56 K modem, though ADSL or higher is recommended internet speed

Attachment 2 – utilismart™ Service Description

NPE-01-SM-010109

GENERAL

This Attachment 2, utili**smart**™ Service Description, is an attachment to the utili**smart**™ Customer Agreement, (the "Agreement") between **Niagara Peninsula Energy Inc.** (hereinafter referred to as the "Customer") and utili**smart**™ **Corporation** (hereinafter referred to as the "Company").

The description of the utili**smart**™ Settlement Manager service is as follows:

DATA COLLECTION

- Daily collection of interval meter data directly from the metered site – wholesale and retail, including:
  - Initial set up of metering data files as per the completed meter subscription form submitted by the Customer or their Meter Service Provider (MSP).
  - Subscription Summary indicating the settings that have been loaded for each metered point subscribed – including kWh, demand values, multipliers, kVA, kW, other meter data.
  - Commencement of daily data collection and processing begins after the Customer or their MSP verifies that the Subscription Summary is accurate and complete.
  - In instances where the Company is unable to collect meter data from a site, the Company will indicate the data collection problem via email to the Customer or their MSP. If the data collection problem is due to an error in the Company's system, the Company will attempt to fix it in a timely manner and will indicate when data collection will commence for the affected meter points. In most instances, the Company will have data loaded by Noon of the following day.
  - If the data collection problem is due to a problem at the meter site, the Company will try to identify the nature of the problem in an email notification to the Customer or their MSP. It is the responsibility of the Customer to troubleshoot and repair metering and communications issues at the meter site.
  - Only data that has passed the validation, editing and estimating (VEE) process will be loaded to the web application.
  - Meter data will be loaded on a daily basis and available to the users on a 24 hours/day – 7 days/week basis. During normal operations, where there are no meter or phone problems and the data passes VEE it is loaded to the web application by 8:00 AM every day for the previous day's data up to Midnight.
  - In instances where meter data fails validation routines, it is flagged for manual investigation and in most cases is loaded to the web application by 8:00 AM of the following day.

- Daily Validation, Editing and Estimating of meter data – VEE as per the accepted Independent Electricity Market Operator (IESO) standards as outlined in the IESO Market Rules.
  - Estimation of data as recommended by the IESO.
  - Estimation of data as per the Customer's internal policy.

- Automated daily email notification of meter discrepancies between the IESO meter data and the utili**smart**™ data (Trading Day Exception Report).

- Email notification of any wholesale and retail meter problems (Meter Trouble Report).

CUSTOMER ACCESS via THE WEB

- Provides access via a secure socket connection to prohibit interception of data being transferred. Utilizes the international standard of 128-bit data encryption.

- Is accessible via Netscape or Internet Explorer browsers (version 4.0 and higher).

- Allows individual assignment of user access to web functions and individual metering points, allowing retail meter data reporting for LDC customers as well as full wholesale and retail meter data reporting for LDC.

- Daily and Monthly Demand Profile Graphs and Data Tables.

- Daily and Monthly Consumption Profile Graphs and Data Tables delineating time of use periods.

- Minimum, Maximum and Average Profile Graphs and Data Tables.

- Monthly Calendar with daily and month-to-date values for Energy (kWh), Peak Demand (kW or kVA), Time of Peak and Load Factors.

- Daily presentation of hourly Ontario energy price data with individual meter point energy usage in graphical and data table formats.

- Daily presentation of Cost Prediction Tool for retail accounts, until April 30, 2008.

- Daily calculation of Net System Load Shape (NSLS) – graph and table display for daily and monthly values.

- Daily calculation of Average Weighted Price for each point.

- Daily download of IESO price and consumption data included in a Trading Day Report for wholesale meter points. The report displays Provisional, Preliminary and Final values for each Trading Day.

- The Trading Day Exception Report, which displays discrepancies between IESO wholesale meter point readings and utili**smart**™ wholesale meter point readings.
    - If exceptions are identified in the wholesale meter data between IESO and utili**smart**™ (i.e. Trading Day Report), this information will be flagged in the web application.
    - Based on these exceptions, an automated email notice will be sent to the Customer, on a daily basis.
    - As required, the Company will administer (generate and complete) a Notice of Disagreement form (NOD) and send it to the IESO. The Company will re-verify our meter data within 24 hours before submitting a dispute resolution form. The Company will then be available to work with the IESO, Customer and/or MSP to resolve the issue.

- Statement Report – The Company will download and aggregate preliminary and final statements from the IESO for the current month to date. The Statement Report allows the Customer to view the month to date, daily and hourly charges from the IESO. The Customer is also able to compare any changes and track variances between the IESO preliminary and final statements on a daily basis.

- Cost presentment for individual metered points and aggregated meter points updated daily and presented as actual cost of energy at the close of the calendar month.

- Settlement Report which determines the Average Weighted Price for each point.

- Aggregation of meter points into single meter point for analysis.

- Calculation of virtual meter points to assess – Generation, Streetlight load, Load profiles, Sub-metered loads, Contract loads and alternate rate calculations.

- Customer Information System (CIS) download file - Billing determinant information. The CIS download file will be updated on a daily basis. The standard format is a CSV-comma (,) delimited file with CR-LF record delimiters (Windows Standard).

CUSTOMER SUPPORT

- The Utilismart Corporation call centre provides product support directly to the end use customers during normal business hours through trained energy advisors via the following number - 1-519-652-0689.

- Customer support is provided from 8:00 AM – 5:00 PM, Monday through Friday.

- Limited customer support may be available, but is not guaranteed, during non-business hours from 5:00 PM - 8:00 AM on normal business days and all day on holidays and weekends.

- Observed holidays include New Year's Day, Family Day, Good Friday, Easter Monday, Victoria Day, Canada Day, Civic Holiday, Labour Day, Thanksgiving Day, Remembrance Day, Christmas Day and Boxing Day.

- Service includes the following:
  - Overview of service offering and pricing structure.
  - Request for subscription forms and overview of subscription processes.
  - Internet access troubleshooting and support.
  - Username and password access support.
  - Explanation of web site navigation and report information.
  - Requests for changes to aggregation of meter points.
  - Definition of energy management terms and concepts.
  - Explanation of rate calculations.
  - Definition of data estimation processes.
  - Requests for changes to user access levels.
  - User trouble shooting on issues regarding product/service offerings.
  - Three on-site workshops for product training for the customer's staff.
  - Initial and ongoing staff training is included in the Monthly Fee.

PROGRAM BRANDING

The **utilismart™** SETTLEMENT MANAGER service has been designed to allow Customers the ability to strengthen their relationship with their end customer through reinforcement of their brand and presence on the web site and in the program collateral. Program branding elements include:

- Incorporation of the Customer's logo and colours within the Master Web Page Template.
- Integration of the Customer's web page links in main tool bar.
- Registration of a Customer URL for web site.
- Incorporation of the Customer's contact information in On Site Help.

The following incremental support for print ready reports is available, for an additional cost:

- Print ready program brochures in soft copy with the Customer's Logo and Colours integrated.
- End User Agreements in print ready format with the Customer's Logo and Colours integrated.

SYSTEM AVAILABILITY

- System Availability - The Web application will be available 24 hours per day, 7 days per week, except as outlined below:
  - Planned maintenance will normally be conducted on the weekends. Users will be notified a minimum of 24 hours before a planned maintenance period via email if not scheduled for a weekend period.
  - Backups of the system are conducted every weekend for 1-2 hours, during this time the system may not be available.

- Product Support – Business Hours - Product support is provided through the Utilismart Corporation call centre from 8:00 AM – 5:00 PM, Monday through Friday. The call centre provides full product support for the Web Application, including username and password verification and generation, troubleshooting access to the web site, navigation of the web application, and explanation of data presented in the application. The call centre can be reached by calling 1-519-652-0689.

- Product Support – Non-business Hours – Limited product support may be available, but is not guaranteed, during non-business hours from 5:00 PM - 8:00 AM on normal business days and all day on holidays and weekends.

- System Recovery – Every reasonable effort will be made to restore the system within 2 business days when failure is due to individual component failures. Every reasonable effort will be made to restore the system within 14 business days when failure is due to catastrophic and/or multiple component failures.

SYSTEM AND DATABASE BACK-UP

Production System Back-up

- The Utilismart Production System (UPS) is backed up with a fully mirrored offsite system that includes a completely operational hardware platform, software applications, MV90xi database, and Oracle database.

- The offsite system's databases are updated weekly with fresh installs of the UPS Oracle/MV90xi databases. Copies of the UPS Oracle Transaction Logs are sent to the offsite system using a secure VPN connection. The Transaction Logs are applied to the offsite Oracle database to bring it up to date with the UPS.

- In the event of a critical problem with the UPS, the offsite system will be brought up to date and will be available to Utilismart customers within 24 hours.

- The offsite location is 50kms away from the UPS main location in London and is connected to a separate power distribution network. This provides additional protection as should there be a major power interruption in the London area, the back-up system would still be available from the separate power network location.

- Within the UPS, should any piece of hardware malfunction beyond recovery, appropriate arrangements are in place with personal computer and Sun Microsystems suppliers to provide same day emergency hardware replacements. The personal computer supplier is located 2 blocks from the UPS location and Sun Microsystems has a regional hardware distribution centre located in London.

Database Back-up

- The UPS Oracle database is backed up twice a week to a hard drive at the main location and all Oracle Transaction Logs are also backed up locally.

- In the event of a disk failure, the locally backed up database will be recovered and brought up to date using the Transaction Logs. The system hard drives are mirrored and hot swappable. Should a hard drive fail that drive will be replaced with minor system down time and disruption.

- In addition, the complete Utilismart systems (including databases) are backed up to tapes once a week, which are stored offsite at a secure location. To augment these complete tape back-ups, nightly incremental tape back-ups are done to capture all system changes that have occurred following the prior complete back-up. The incremental tape back-ups are stored offsite. The tape back-up can be used to restore part or all of the Utilismart system at either Utilismart location.

- Windows back-ups and PC Ghosting are done on a regular schedule to maintain a complete local back up of the entire Utilismart PC network.

ATTACHMENT # 7-Shareholder Agreement-IRR#30

SHAREHOLDERS AGREEMENT

Dated as of January 1, 2008

NIAGARA FALLS HYDRO HOLDING CORPORATION

- and -

PENINSULA WEST POWER INC.

- and -

NIAGARA PENINSULA ENERGY INC.

- and -

SUCH OTHER PERSONS AS MAY BECOME SHAREHOLDERS IN NIAGARA PENINSULA ENERGY INC.

Borden Ladner Gervais LLP
Scotia Plaza, 40 King Street West
Toronto, Ontario
M5H 3Y4

SHAREHOLDERS AGREEMENT

THIS AGREEMENT made as of the 1st day of January, 2008.

AMONG:

NIAGARA FALLS HYDRO HOLDING CORPORATION, a corporation duly incorporated under the *Business Corporations Act* (Ontario) (hereinafter referred to as **"NFHC"**)

\- and -

PENINSULA WEST POWER INC., a corporation duly incorporated under the *Business Corporations Act* (Ontario) (hereinafter referred to as **"PWPI"**)

\- and -

NIAGARA PENINSULA ENERGY INC., a corporation duly amalgamated under the *Business Corporations Act* (Ontario) (hereinafter referred to as the "**Corporation**")

\- and -

SUCH OTHER PERSONS AS MAY FROM TIME TO TIME BECOME SHAREHOLDERS IN THE CORPORATION AND PARTIES HERETO

RECITALS:

A. NFHC was the sole shareholder of Niagara Falls Hydro Inc. ("**NFHI**") an electricity distribution company created pursuant to Section 142 of the *Electricity Act, 1998* (Ontario) (the "**Electricity Act**");

B. PWPI was the sole shareholder of Peninsula West Utilities Limited ("**PWUL**") an electricity distribution company created pursuant to Section 142 of the Electricity Act;

C. NFHC is wholly-owned by Niagara Falls;

D. PWPI is owned by Lincoln, Pelham and West Lincoln;

E. NFHC and PWPI agreed to amalgamate NFHI and PWUL to form the Corporation (the "**Amalgamation**") pursuant to the terms of the Merger Agreement dated December 31, 2007 among NFHC, NFHI, PWPI and PWUL (the "**Merger Agreement**") and the Amalgamation Agreement among NFHC, NFHI, PWPI and PWUL dated December 31, 2007 and the Amalgamation was effective January 1, 2008;

F. Upon the Amalgamation, NFHC received seven hundred and forty-five (745) common shares in exchange for one hundred (100) common shares in the capital of

"**Additional Shareholders**" means such Persons, other than NFHC or PWPI, as may from time to time become shareholders of the Corporation and parties to this Agreement.

"**Affiliate Relationships Code**" means the Affiliate Relationships Code for Electricity Distributors and Transmitters issued by the OEB, as amended from time to time and any replacement code or directive.

"**Agreement**" means this Shareholders Agreement, and includes any agreement which is supplementary to or an amendment or confirmation of this Agreement (and which is entered into in accordance with this Agreement) and any schedules hereto or thereto.

"**Amalgamation**" has the meaning set forth in the Recitals to this Agreement.

"**Applicable Law**" means, collectively, all applicable federal, provincial and municipal laws, statutes, ordinances, decrees, rules, regulations, by-laws, legally enforceable policies, codes, or guidelines, judicial, arbitral, administrative, ministerial, departmental or regulatory judgments, orders, decisions, directives, rulings or awards, and conditions of any grant of approval, permission, certification, consent, registration, authority or licence by any statutory body, self-regulatory authority or other Governmental Authority.

"**Articles**" means the articles of amalgamation of the Corporation in effect on the date hereof.

"**Board**" means the board of directors of the Corporation as elected by the Shareholders from time to time in accordance with the provisions of this Agreement.

"**Business**" means, with respect to the Corporation, the distribution of electricity to the customers of the Corporation and the provision of such ancillary services as may be determined from time to time and such other businesses which may be permitted to be undertaken by the Corporation pursuant to Section 2.3 of this Agreement.

"**Business Day**" means any day except Saturday, Sunday or any day which is a statutory holiday in the Province of Ontario.

"**Chair**" means the director who is appointed chair of the Board from time to time as provided in this Agreement.

"**Council**" means the municipal Council at such time of the Municipalities or of any other municipality which may become a direct or indirect shareholder of the Corporation from time to time.

LDC's and related businesses and the amalgamation of the Corporation with other LDC's.

"**Parties**" means the Shareholders and the Corporation and "Party" means any one of them.

"**Pelham**" means the Town of Pelham.

"**Permitted Transferee**" has the meaning set forth in Section 7.3(a).

"**Person**" means any individual, corporation, partnership, firm, joint venture, syndicate, association, trust, Governmental Authority and any other form of entity or organization.

"**Pro Rata**" means in the same proportion that the number of common shares owned by a Shareholder is to all of the then issued and outstanding common shares of all Shareholders of the Corporation.

"**Prospective Purchaser**" has the meaning set forth in Section 8.3.

"**Purchase Notice**" has the meaning set forth in Section 8.2.

"**Purchase Price**" has the meaning set forth in Section 8.1(a).

"**Right of First Refusal Period**" has the meaning set forth in Section 8.2.

"**Remaining Shareholders**" has the meaning set forth term in Section 8.1(b).

"**Sale Notice**" has the meaning set forth in Section 8.1(a).

"**Selling Shareholder**" has the meaning set forth in Section 8.1(a).

"**Shareholder**" means individually any, and "**Shareholders**" means collectively all, of NFHC and PWPI and any Person to whom any Shares are transferred, or issued, in accordance with the terms of this Agreement, at any time subsequent to the date of this Agreement.

"**Shares**" means common shares of the Corporation.

"**Share Purchase Price**" has the meaning set forth in Section 12.3.

"**Special Resolution**" means a resolution that is submitted to a meeting of the Shareholders called for the purpose of considering the resolution and passed, with or without amendment, at the meeting by at least two-thirds (2/3) of the votes cast.

"**Standstill Period**" means the five (5) year period from the date of this Agreement to and including January 1, 2013.

Schedule A Valuation Method

ARTICLE 2 - OBJECTIVES, GUIDING PRINCIPLES AND PERMITTED BUSINESS ACTIVITIES

2.1 **Guiding Principles and Objectives:** The Parties acknowledge and recognize the following guiding principles and objectives of the Corporation and the intention of the Shareholders that the Corporation be managed in a manner consistent with these guiding principles and objectives:

(a) maintain local presence and control over the management of electricity services and rates;

(b) improve electricity distribution services to local customers;

(c) improve the utilization of existing resources;

(d) explore business options that achieve new economics of scale and avoid duplication of services and costs to the customer;

(e) pursue strategic partnerships that contribute to a strengthened corporate presence and voice – locally and provincially;

(f) improve corporate flexibility to better respond to emerging business opportunities and complexities in the electricity market; and

(g) increase corporation value to maximize Shareholder wealth.

2.2 **Financial Policies, Risk Management and Strategic Plan:** The Shareholders expect that the Board will establish policies to:

(a) Capital Structure - develop and maintain a prudent financial and capitalization structure for the Corporation consistent with industry norms and sound financial principles and established on the basis that the Corporation is a self-financing entity;

(b) Distribution Rates – ensure the establishment of just and reasonable electricity distribution rates for the regulated electricity distribution business of the Corporation which are:

(i) consistent with similar utilities in comparable growth areas and as may be permitted under the OEB Act;

(ii) intended to enhance the value of the Corporation; and

(iii) consistent with the encouragement of economic development and activity for each of the Shareholders.

3.2 **Endorsement on Share Certificates:** Share Certificates of the Corporation shall bear the following language either as an endorsement or on the face thereof:

> "The shares represented by this certificate are subject to all the terms and conditions of an agreement made as of January 1, 2008, a copy of which is on file at the registered office of the Corporation."

ARTICLE 4 - DIRECTORS AND OFFICERS

4.1 **Number of Directors**:

(a) The Articles of the Corporation shall provide for the Board to consist of a minimum of four (4) directors and a maximum of twelve (12) directors.

(b) The initial Board shall consist of eight (8) directors.

4.2 **Nomination of the Initial Directors:** Subject to Sections 4.4, 4.6 and 4.8 , NFHC shall be entitled to nominate four (4) directors and PWPI shall be entitled to nominate four (4) directors and thereafter each of NFHC and PWPI shall be entitled to nominate an equal number of directors. Directors shall hold office until such time as their successors are elected by the Shareholders.

4.3 **Election of Directors:** The Shareholders shall at all times act and vote their Shares to elect as directors of the Corporation the individuals nominated as directors by each Shareholder, and, if required by a Shareholder, to remove such director(s). The Shareholders shall at all times act and vote their Shares to maintain the equal representation of both NFHC and PWPI on the Board.

4.4 **Changing the Number of Directors:** In the event that the Shareholders desire to increase or decrease the number of directors serving on the Board, the Shareholders shall elect such directors, as determined by the Shareholders, in order to maintain the equal representation of both NFHC and PWPI on the Board.

4.5 **Qualification of Directors:**

(a) In addition to the requirements of the OBCA, the qualifications of candidates for the Board shall, where possible, include the following:

(i) commercial experience, sensitivity and acumen;

(ii) time availability;

(iii) corporate finance; accounting experience;

(iv) corporate governance experience;

(v) market development experience;

individual elect a successor or successors, as the case may be, by providing a direction in writing to the Corporation and to the other Shareholders who shall elect such replacement director or directors. Upon the resignation or removal of a director from the Board, the Shareholder that nominated such director shall use reasonable efforts to obtain and deliver to the Corporation a resignation and release from such director in a form satisfactory to the Corporation.

4.10 **Voting:**

(a) All matters to be determined by the Board shall be determined by a majority vote of directors at a duly convened meeting of the Board and, in case of an equality of votes, the matter shall not be approved and the chairman of the meeting shall not be entitled to a second or casting vote.

(b) Notwithstanding Section 4.10(a) above, in lieu of a meeting of the directors, the consent of the directors with respect to any matter may be evidenced by a resolution in writing (which may be in counterparts) signed by all of the directors.

4.11 **Meeting of Directors:**

(a) The Board shall meet at least once each financial quarter at a time and place to be determined by the Chair. Additional meetings of the Board may be called by the Chair or any other director by notice in writing to every other director of the time, place and purpose of the meeting of the Board and the matters to be considered.

(b) All meetings of the Board shall, unless held by telephone or video conference, be held within the Province of Ontario.

(c) Any one or more of the directors may participate in a meeting of the Board by any telephonic or video device which permits all participants in the meeting to communicate with each other simultaneously and instantaneously, and such participation shall be deemed to constitute attendance at the meeting of the Board for the purpose of this Section 4.11. The Chair may determine that any meeting of the Board may be held by telephone or video conference.

(d) At least seven (7) Business Days prior to each meeting, each director shall be notified in writing of the time, place and purpose of the meeting of the Board and the matters to be considered.

(e) A director may waive notice of any meeting of the Board by an instrument in writing delivered to the Secretary of the Corporation.

4.12 **Quorum – Meetings of Directors**

(a) A quorum for a meeting of the Board shall consist of a majority of the total number of elected directors, (rounded up to the next whole number) provided that, so long as NFHC and PWPI are the only Shareholders of the

4.17 **Initial Senior Executive Arrangements:**

(a) The Parties acknowledge and agree Brian Wilkie shall be the initial President and Chief Executive Officer of the Corporation.

(b) In addition to the senior executive arrangements provided in Section 4.17(a) the Board shall appoint such other officers of the Corporation as the Board may determine.

ARTICLE 5 - APPROVAL OF CERTAIN CORPORATE ACTIONS

5.1 **Unanimous Approval by Shareholders:** Subject to Section 5.3, unless first approved by an unanimous resolution of Shareholders, either adopted at a meeting of the Shareholders called for that purpose or evidenced by a resolution in writing signed by all of the Shareholders, no action shall be taken by the Corporation with respect to any of the following matters:

(a) Amalgamating, consolidating, reorganizing or merging the Corporation with another entity;

(b) Create new classes of shares;

(c) 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 grant any option or other right to purchase any shares or securities convertible into such shares;

(d) Amend the rights, restrictions or privileges of any Shares of the Corporation;

(e) Disposing of or encumbering all or substantially all of the assets of the Corporation;

(f) Changing the dividend policy for the Corporation;

(g) Any amendment to the provisions of this Agreement regarding proportional representation of the Shareholders on the Board or the rights of Shareholders to nominate members of the Board;

(h) Entering into any partnership, joint venture or other business venture that would involve the expenditure or investments of funds by the Corporation outside of the Ordinary Course of Business or that would change the status of the Corporation for taxation purposes, under the Electricity Act or the *Income Tax Act* (Canada), *Corporations Tax Act* (Ontario) or other Applicable Law;

(i) Changing the capitalization policy or the financing policy for the Corporation;

(p) Change in the location of the head office of the Corporation.

5.3 **Additional Shareholders:** In the event that Persons become Shareholders of the Corporation in addition to NFHC and PWPI other than in accordance with Articles 7, 8, 9, 10, 11 and 12 of this Agreement, the parties acknowledge that provisions of this Agreement shall be reviewed and, if required, revised in a manner to be determined by the parties consistent with the guiding principles of the Corporation as described in Section 2.1 of this Agreement.

ARTICLE 6 - REPRESENTATIONS AND WARRANTIES

6.1 **Representations and Warranties by Shareholders.** Each Shareholder represents and warrants to each of the other Shareholders and acknowledges that each of the other Shareholders is relying on these representations and warranties in connection with entering into this Agreement:

(a) that each Shareholder owns beneficially and of record the number of issued and outstanding Shares which is set out opposite its name in Recital F to this Agreement, that those Shares are not subject to any mortgage, hypothec, lien, charge, priority, pledge, encumbrance, security interest or adverse claim, and that no Person has any rights to become a holder or possessor of any of those Shares or of the certificates representing them;

(b) that it is duly incorporated and validly existing under the laws of its jurisdiction of incorporation and that it has the corporate power and capacity to own its assets and to enter into and perform its obligations under this Agreement;

(c) that this Agreement has been duly authorized, executed and delivered by it, and (assuming due execution and delivery by the other Parties) is a legal, valid and binding obligation of it enforceable against it in accordance with its terms;

(d) that the execution, delivery and performance of this Agreement does not and will not contravene the provisions of its articles, by-laws, constating documents or other organizational documents, or the provisions of any contract, agreement or other instrument to which it is a party or by which it may be bound;

(e) that the Shareholder is not a non-resident for purposes of the *Income Tax Act* (Canada); and

(f) that all of the representations and warranties set out in Section 6.1(a) through (f) will continue to be true and correct during the term of this Agreement.

shall be granted, at any time after the date of this Agreement, except in compliance with this Section 7.4.

(b) If the Corporation proposes to issue any Shares or other securities of the Corporation (in this Section 7.4, the "**Affected Securities**"), the Corporation shall give notice (an "**Issue Notice**") to the Shareholders of the proposed issuance. The Issue Notice shall constitute an offer for subscription by each of the Shareholders of that number of the Affected Securities (in this Section 7.4, its "**Proportionate Entitlement**") which bear the same relationship to the total number of Affected Securities as the number of issued and outstanding Shares held by each such Shareholder bears to the total number of issued and outstanding Shares (as reflected on the securities registers of the Corporation) at the date of the Issue Notices (in this Section 7.4, the "**Notice Date** ") at the subscription price determined by the Board for all those Affected Securities. Each Issue Notice shall:

(i) be made in writing by the Secretary and be made concurrently to all Shareholders in the same manner (whether by delivery, prepaid courier service or facsimile);

(ii) contain a description of the terms and conditions relating to the Affected Securities, the price at which the Affected Securities are offered and the date on which the purchase of the Affected Securities by the Shareholders is to be completed; and

(iii) state that any Shareholder that wishes to subscribe for less than its Proportionate Entitlement shall, in its notice of subscription, specify the number of Affected Securities (up to its Proportionate Entitlement) that it wishes to subscribe for.

The offer constituted by each Issue Notice shall be irrevocable and shall remain open for acceptance by the Shareholders for a period of thirty (30) days after the Notice Date.

(c) Each of the Shareholders shall have the right, exercisable by notice given to the Corporation within the period during which the offer constituted by the Issue Notice is open for acceptance under Section 7.4(b), to accept the offer constituted by the Issue Notice to subscribe for its Proportionate Entitlement of the Affected Securities or, if it wishes to subscribe for less than its Proportionate Entitlement, to indicate how many Affected Securities (up to its Proportionate Entitlement) it wishes to subscribe for. If no notice is given by a Shareholder under this Section 7.4(c), that Shareholder shall be deemed to have rejected the offer made available to it to subscribe for Affected Securities.

(d) If any of the Shareholders does not agree to purchase all of its Proportionate Entitlement of the Affected Securities or is deemed to have rejected the offer made available to it to subscribe for Affected Securities (in this Section 7.4, a

(a) Any Shareholder (hereinafter in this Article 8 referred to as the "**Selling Shareholder**") who desires to transfer or sell all, but not less than all, of its Shares (hereinafter in this Article 8 referred to as the "**Offered Shares**") shall give notice of such proposed sale (hereinafter in this Article 8 referred to as the "**Sale Notice**") to the Corporation and to the other Shareholders and shall set out in the Sale Notice the terms upon which and the price at which it desires to sell the Offered Shares (such price being hereinafter in this Article 8 referred to as the "**Purchase Price**"). A Shareholder selling Shares under this Section 8.1 must sell all, and not less than all, of its Offered Shares, unless the other Shareholders otherwise agree.

(b) Upon the Sale Notice being given, the other Shareholders (hereinafter in this Article 8 referred to as the "**Remaining Shareholders**") shall have the right to purchase all, but not less than all, of the Offered Shares for the Purchase Price on a Pro Rata basis as described in Section 8.2.

8.2 **Exercise of Right of First Refusal:** The Remaining Shareholders shall have the option, exercisable by giving written notice of the exercise of such option (hereinafter in this Article 8 referred to as the "**Purchase Notice**") to the Selling Shareholder and the Corporation within ninety (90) days (hereinafter in this Article 8 referred to as the "**Right of First Refusal Period**") subsequent to the date of deemed receipt, pursuant to Section 15.1 hereof, by the Remaining Shareholders of the Sale Notice, to purchase all but not less than all of the Offered Shares, on a Pro Rata basis, determined on the basis of the ratio of the number of Shares owned by each Remaining Shareholder to the number of Shares owned by all Remaining Shareholders at the Purchase Price and the terms set forth in the Sale Notice. If all the Offered Shares have not been purchased by the Remaining Shareholders then the remaining Offered Shares shall be offered to those Remaining Shareholders which have purchased Offered Shares on a Pro Rata basis until all of the Offered Shares have been purchased. The closing of the sale of the Offered Shares shall occur on the first Business Day following the expiry of the sixty (60) day period following the date of deemed receipt, pursuant to Section 15.1 hereof, by the Remaining Shareholders and the Corporation of the Purchase Notice or, if the completion of such sale requires the prior approval of or notice to a third Person or Governmental Authority under Applicable Law or any instrument or agreement, within thirty (30) Business Days after receipt of such approval or required period of notice or on such later date as may be agreed by the Parties.

8.3 **Sale of Shares:** In the event that the Remaining Shareholders do not exercise their right of first refusal pursuant to Section 8.2, the rights of the Remaining Shareholders, subject as hereinafter provided, to purchase the Offered Shares shall forthwith terminate and the Selling Shareholder, subject to the restrictions on transfer or sale specified in Section 13.5 hereof, may sell the Offered Shares to any Person (the "**Prospective Purchaser**") within ninety (90) days after the termination of the Right of First Refusal Period, for a price not less than the Purchase Price and on other terms no more favourable to the Prospective Purchaser than those set forth in the Sale Notice, provided that the Prospective Purchaser agrees prior to such transaction to be

Selling Shareholder. The Tag-Along Offer will be binding upon the Third Party and shall contain only such terms and conditions as are identical to those upon which the Majority proposes to sell to the Third Party the Offered Majority Shares pursuant to Section 8.3, provided that the offer price per Share, which shall be specified in the Tag-Along Offer, shall be the same consideration as the consideration per Share at which the Majority Selling Shareholder proposes to sell to the Third Party the Offered Majority Shares pursuant to Section 8.3.

(c) The closing date and other closing arrangements for the purchase and sale transaction between the Majority Shareholder and the Third Party shall be specified in the Tag-Along Offer and shall be the same, *mutatis mutandis*, as those specified between the Third Party and the Minority Shareholder.

9.2 **Drag-Along Rights**:

(a) In the event that the Majority Shareholder proposes to sell the Offered Majority Shares to a Third Party pursuant to Section 8.3 and a Minority Shareholder (a "Non-Selling Minority Shareholder)(has not exercised its Tag Along rights under Section 9.1, then the Majority Shareholder may, by written notice to the Non-Selling Minority Shareholders delivered within thirty (30) days following the expiry of the ninety (90) day period referred to in Section 9.1, accompanied by an irrevocable offer (the "**Drag-Along Offer**") from the Third Party to the Non-Selling Minority Shareholders to purchase, for a consideration that is the same as the consideration per Share at which the Majority Shareholder proposes to sell the Offered Majority Shares to the Third Party pursuant to Section 8.3, the Shares owned by the Non-Selling Minority Shareholders (the "**Dragged Shares**"), require the Non-Selling Minority Shareholder to sell to the Third Party all such Dragged Shares at the price specified in the Drag-Along Offer.

(b) The delivery by the Majority Shareholder of an irrevocable Drag-Along Offer shall bind the Non-Selling Minority Shareholder to sell the Dragged Shares. The date on which the sale is to close and the other closing arrangements (which shall be the same, *mutatis mutandis*, as those for the purchase and sale between the Third Party and the Majority Shareholder) shall be as specified in the Drag-Along Offer. Except as specifically provided for above, the Drag-Along Offer shall contain only such terms and conditions, if any, as are identical to those pursuant to which the Majority Shareholder proposes to sell to the Third Party the Offered Shares.

ARTICLE 10- BUY-SELL RIGHTS

10.1 **Buy-Sell:**

(1) Any Shareholder (in this Section 10.1, an "**Offeror**") may give notice (a "**Purchase or Sale Notice**") to the other Shareholders (in this Section 10.1, the "**Other**

(5) Once a Shareholder gives a Purchase or Sale Notice, no Other Shareholder may give a Purchase or Sale Notice with respect to Shares, until such time as either the Affected Shares are sold to the Purchasing Shareholders or the Shares held by the Other Shareholders are sold to the Offeror pursuant to this Section 10.1.

ARTICLE 11 - PUT OPTION

11.1 **Put Option:**

(a) The Shareholders other than the Majority Shareholder (in this Section 11.1, the "**Other Shareholders**") shall have the irrevocable right and option (the "**Put Option**") by notice to Majority Shareholder and the Corporation with a copy to the other Shareholders, to force the purchase by the Majority Shareholder or the Corporation, of all of the Shares held by that Other Shareholder at a total purchase price equal to the Put Option Price described in Section 11.1(b) below. The closing of the Put Option shall occur on the thirtieth (30^{th}) day after the deemed receipt of notice of the exercise of the Put Option pursuant to Section 15.1 by the Majority Shareholder and the Corporation.

(b) The "**Put Option Price**" for the purposes of this Article 11 shall mean the fair market value of each Share in which the Shareholder is deemed to have exercised the Put Option. Such Put Option Price shall be determined in a manner provided in Schedule A with the sixty (60) days immediately following the date of exercise of the Put Option.

ARTICLE 12 - PURCHASE OF SHARES ON DEEMED WITHDRAWAL

12.1 **Deemed Withdrawal from the Corporation:**

(a) Subject to 12.1(b), for the purposes of this Article 12, a Shareholder shall be deemed to withdraw from the Corporation on that date (the "Withdrawal Date") when such Shareholder,

(i) or its Controlling Shareholder: (i) files a petition or otherwise commences, authorizes or acquiesces in the commencement of a proceeding or cause of action under any bankruptcy or similar Applicable Law for the protection of creditors, including, the *Bankruptcy and Insolvency Act* (Canada) and the *Companies Creditors Arrangement Act* (Canada), the *Municipal Affairs Act* (Ontario) or other statute applicable to insolvent municipalities or has such petition filed against it and such petition is not withdrawn or dismissed for sixty (60) days after such filing; (ii) otherwise becomes bankrupt or insolvent (however evidenced); or (iii) is unable to pay its debts as they fall due;

(c) In the event that the remaining Shareholders purchase such Shares, they shall be entitled to purchase them on a Pro Rata basis in proportion to their respective holdings of Shares or in any other proportion as they may choose, and the provisions of Section 12.2 of this Agreement shall apply *mutatis mutandis* provided however, that no Shareholder shall be obliged to purchase any such Shares.

12.4 **Share Purchase Price Determination:** The Share Purchase Price for the purposes of this Article 12 shall mean the fair market value of each Share as determined at the Withdrawal Date. Such Share Purchase Price shall be determined in the manner provided in Schedule A hereto within the sixty (60) days immediately following the Withdrawal Date.

12.5 **Cancellation of Shares:** Upon the acquisition of any Shares by the Corporation pursuant to this Article 12 of this Agreement, such Shares shall be cancelled and shall not be reissued.

ARTICLE 13 - PROVISIONS APPLICABLE TO SALES OF SHARES PURSUANT TO THIS AGREEMENT

13.1 **Application to All Sales:** Except as, or in addition to, what may otherwise be provided in this Agreement, this Article 13 shall apply to any sale of Shares effected pursuant to the provisions of this Agreement.

13.2 **Closing:** The closing of all sales of Shares effected pursuant to this Agreement shall take place at the offices of the Corporation at the address designated in Section 15.1 hereof, at 10:00 in the morning (Toronto time) on the date stipulated, either pursuant to the provisions hereof or pursuant to any agreement executed in connection with any such sale, as the date on which such closing is to occur.

13.3 **Cancellation of Share Certificates:** The President of the Corporation, or such other officer as may be designated by resolution of the directors of the Corporation shall attend all closings of any such sale of Shares and shall deliver to the Corporation for cancellation share certificates evidencing Shares which are to be sold and shall take custody of new share certificates, if any, issued in replacement of such cancelled share certificates so that at all times the Corporation shall have custody of share certificates representing all of the Shares.

13.4 **Resignation of Seller's Nominees:** At the closing of any sale of Shares, the Shareholder selling its Shares shall cause to be delivered to the Corporation signed resignations of its nominees as directors of the Corporation, and shall assign and transfer to the purchaser of such Shares, all of its right, title and interest in such Shares.

(a) is deemed to withdraw from the Corporation, pursuant to Section 14.1 of this Agreement; or

(b) sells all of its Shares in accordance with this Agreement,

such Shareholder shall not, and shall use its commercially reasonable efforts to ensure that its shareholders do not, individually or in partnership or in conjunction with any Person, as principal, agent, shareholder, consultant or otherwise, directly or indirectly, carry on or be engaged in, or advise, acquire an interest in, or permit its name or any part thereof to be used or employed by an association, syndicate or corporation engaged in or concerned with or interested in, the business of distributing electricity as regulated by the OEB unless the consent of the other Shareholders has first been obtained.

14.2 **Necessary Covenants:** Each Shareholder hereby confirms that all restrictions in this Article 14 are reasonable and valid, that they are necessary for the protection of the Corporation's legitimate interests and that they do not unduly affect their earning capacity, and waive all defences to the strict enforcement thereof.

14.3 **Confidential Information:** The Shareholders hereby acknowledge that they have had and will have access to confidential information and trade secrets concerning the Business, the Corporation, and the Corporation's Affiliates (as defined in the OBCA), if any, and their customers and suppliers (hereinafter in this Article 14 referred to as the "**Information**") and they each undertake and agree that they shall not, and their Controlling Shareholder shall not, directly or indirectly, use, disclose or divulge to any Person or other entity any of the Information otherwise than in the Ordinary Course of Business of the Corporation, and its Affiliated Bodies Corporate and as may be required by Applicable Law or order of any Governmental Authority.

14.4 **Survival of Obligations:** The obligations and covenants in this Article 14 shall survive the termination of this Agreement.

ARTICLE 15 - NOTICES

15.1 **Notices:** Any notice or other communication required or permitted to be given under this Agreement shall be in writing and shall be given by facsimile or other means of electronic communication or by hand-delivery as provided below. Any such notice or other communication, if sent by facsimile or other means of electronic communication, shall be deemed to have been received on the Business Day following the sending, or if delivered by hand, shall be deemed to have been received at the time it is delivered to the applicable address noted below either to the individual designated below or to an individual at such address having apparent authority to accept deliveries on behalf of the addressee. Notice of change of address shall also be governed by this Section 11.1. Notices and other communications shall be addressed as follows:

(a) in the case of PWPI:

(a) The arbitration shall take place in the Province of Ontario, and shall be conducted in English;

(b) The arbitration shall be conducted by a single arbitrator having no financial, business or personal interest in the outcome of the arbitration. The arbitrator shall be appointed jointly by agreement of the parties to such dispute. In the event the parties to such dispute are unable to agree on the appointment of the arbitrator within ten (10) days after notice of a demand for arbitration is given by a party and agreed to by the other parties to such dispute, then the arbitrator shall be selected pursuant to the provisions of the *Arbitration Act, 1991* (Ontario).

(c) The arbitrator shall have the authority to award any remedy or relief that a court could order or grant in accordance with this Agreement including, without limitation, specific performance of any obligation, the issuance of an interim, interlocutory or permanent injunction, or the imposition of sanctions for abuse or frustration of the arbitration process.

(d) The arbitrator shall have sole and exclusive jurisdiction to examine into, hear and determine all matters and questions of fact and law in respect of which any powers or authority has been conferred upon the arbitrator, including questions of jurisdiction. The arbitral award shall be in writing, stating the reasons for the award and shall be final and conclusive and is not open to appeal, question or review in any court and any determination by the arbitrator made under this Article is hereby ratified and confirmed and is binding upon all persons. No proceedings by or before the arbitrator shall be restrained by injunction, prohibition or other process or proceeding in any court, or are removable by certiorari or otherwise into any court.

ARTICLE 17 - MISCELLANEOUS

17.1 **Termination:** This Agreement shall terminate upon (a) the written agreement of all the Parties hereto to this effect, (b) the bankruptcy, receivership or dissolution of the Corporation, or (c) the ownership of all the Shares of the Corporation by one Shareholder.

17.2 **Successors and Assigns:** This Agreement shall be binding upon, and enure to the benefit of, the Parties hereto and their respective successors and permitted assigns.

17.3 **Assignment:** Except as specifically provided in this Agreement, none of the Parties hereto may assign its rights or obligations under this Agreement without the prior written consent of all of the other Parties hereto.

17.4 **Time is of the Essence:** Time shall be the essence of this Agreement in all respects.

17.5 **Further Assurances:** Each Party hereto shall promptly do, execute, deliver or cause to be done, executed and delivered all further acts, documents and matters in

IN WITNESS WHEREOF the Parties hereto have executed this Agreement as of the day first above written.

By Suzanne Wilson
Treasurer

NIAGARA FALLS HYDRO HOLDING CORPORATION

By:
Name: BRIAN WILKIE
Title: PRESIDENT, CEO

By: M.A. Forcier
Name: Maria A. Forcier
Title: Board Secretary

PENINSULA WEST POWER INC.

By:
Name: W. BRIAN WALKER
Title: PRESIDENT

By:
Name:
Title:

NIAGARA PENINSULA ENERGY INC.

By:
Name: BRIAN WILKIE
Title: PRESIDENT, CEO

By: Suzanne Wilson
Name: Suzanne Wilson
Title: VP Finance

[EXECUTION PAGE TO SHAREHOLDERS AGREEMENT]

SCHEDULE 2.2

AMALGAMATION AGREEMENT

Please see attached.

AMALGAMATION AGREEMENT

THIS AGREEMENT made the 31st day of December, 2007.

BETWEEN

NIAGARA FALLS HYDRO INC., a corporation existing under the laws of Ontario

(hereinafter called **"NFHI"**)

-and-

PENINSULA WEST UTILITIES LIMITED, a corporation existing under the laws of Ontario

(hereinafter called **"PWUL"**)

BACKGROUND FACTS:

A. NFHI and PWUL (collectively, the "**Amalgamating Corporations**") are each governed by the *Business Corporations Act* (Ontario) (the "**Act**");

B. The Amalgamating Corporations, acting under the authority contained in the Act, have agreed to amalgamate upon the terms and conditions hereinafter set out;

NOW THEREFORE THE PARTIES AGREE AS FOLLOWS:

1. In this Agreement, the expression the "**Corporation**" means the Corporation continuing from the amalgamation of the Amalgamating Corporations.

2. Effective as of 12:00:01 a.m on January 1, 2008 the Amalgamating Corporations shall amalgamate under the provisions of Section 174 of the Act and continue as one corporation on and subject to the terms and conditions set out below.

3. The name of the Corporation shall be Niagara Peninsula Energy Inc.

4. The registered office of the Corporation shall be in the City of Niagara Falls, in the Province of Ontario and shall be located at 7447 Pin Oak Drive, P.O. Box 102, Niagara Falls, ON, L2E 6S9.

Corporation on the basis of 0.745 common shares of the Corporation for one common share of NFHI so held; and

(b) the holder of the 100 issued and outstanding common shares of PWUL shall receive 255 issued and outstanding commonshares of the Corporation on the basis of 2.55 common shares of the Corporation for one common share of PWUL so held.

11. The by-laws of the Corporation shall not be those of either of the Amalgamating Corporations. The proposed by-laws of the Corporation may be inspected at 7447 Pin Oak Drive, Niagara Falls, ON, L2E 6S9.

12. The shareholders of the Amalgamating Corporations having approved this Agreement in accordance with the provisions of the Act, the Amalgamating Corporations shall complete and send articles of amalgamation in the prescribed form to the Director under the Act, providing for the amalgamation of the Amalgamating Corporations on and subject to the terms and conditions of this Agreement.

13. This Agreement may not be modified in any manner except by instrument in writing signed by the Amalgamating Corporations which specifically refers to this Agreement and its amendment provided such amendment is approved by a special resolution of each of the Amalgamating Corporations.

[EXECUTION PAGE FOLLOWS]

SCHEDULE 1

Voting Rights

The holders of the Common Shares shall be entitled to receive notice of and to attend and vote at all meetings of the shareholders of the Corporation, and each such share shall confer the right to one vote in person or by proxy at all meetings of shareholders of the Corporation.

Dividends

The holders of the Common Shares shall be entitled to receive dividends as and when declared by the directors from time to time out of moneys of the Corporation properly applicable to the payment of dividends, and the amount per share of each such dividend shall be determined by the directors of the Corporation at the time of declaration.

Return of Capital

In the event of the liquidation, dissolution or winding up of the Corporation or other distribution of its assets among the shareholders by way of repayment of capital, whether voluntary or involuntary, the holders of the Common Shares shall be entitled to receive the remaining property of the Corporation.

SCHEDULE 2.5(A)

NFHI – EXCLUDED ASSETS

Nil.

SCHEDULE 2.5(B)

PWUL – EXCLUDED ASSETS

Nil.

SCHEDULE 5.2(4)

NFHI - OPTIONS

1. NFHI issued a promissory note to NF Holdco on April 1, 2000, representing an obligation to pay NF Holdco the principle sum of $3,605,090.00.

2. NFHI issued a promissory note to City of Niagara Falls on April 1, 2000, in the principle amount of $22,000,000.00.

SCHEDULE 5.2(7)

NFHI – CONDUCT OF BUSINESS

Nil.

SCHEDULE 5.2(9)

NFHI – REAL PROPERTY

NTD: These findings were as of search completed in 1999. To be updated prior to closing.

Properties quoted to the Commission were transferred to Niagara Falls Hydro as of April 1, 2000.

Description/Address	Location	Type of Property
7447 Pin Oak Drive **Instrument Number LT-25018 (registered September 1982)** **Lots 4 and 13, Plan M-40 and Part of Block B, Plan M-40 designated as Part 1, Plan 59R-3785**		**Business Office and Service Centre of Niagara Falls Hydro**
Instrument Number 307918 and 307921 (registered April 1978) **Part Twp. Lot 164 Stamford, now City of Niagara Falls, being Parts 1 and 2, Reference Plan 59R-2392**	**Kalar Road west side between McLeod Road and Lundy's Lane, near Coventry Road**	
Instrument number: 55809 (registered 1953) Part of lots 2 and 3, Plan 35, Block EE, now Plan 999 and 1000, Niagara Falls	**Lands on the north side of Park street, east of Crysler Avenue**	**This property is subject to an easement in favour of Bell Canada registered as instrument 712014 in 1996.**
Instrument number: 39575 (registered September, 1941) Lot 217, Plan 997, City of Niagara Falls	**East side of Hickson Avenue, north of Buttrey**	
Instrument number: 51709 and 51103 (registered May	**South side of Huron Street,**	**This parcel was conveyed to the Commission in two**

Description/Address	Location	Type of Property
1950) minus lands conveyed away by instrument 51711 (October 1950) Part lots 80 and 81, plan 27, now plan 325, City of Niagara Falls	west of Homewood	separate deeds and then the Commission transferred the frontage on Homewood to a private individual leaving a parcel with a frontage of about 50 feet on Huron Street.
Instrument number: 80652A (Registered October 1962) 132087 (Registered October, 1970) Part of lots 28,29,and 30, Plan 276 and part of losts 150 and 201 on the south side of Armoury Street, Plan 1002	Lands at 5034 and 5036 Victoria Avenue	Former commission offices on Victoria at Armoury. *** Note: asset excluded from merger transaction.***
Instrument number: 55785 (registered June, 1953) Lot 13, plan 41 now known as Plan 328	5034 Ontario Avenue	This property is subject to an easement in favour of the Niagara Region for sewer purposes as set out in instrument number 596641. It is also subject to an unregistered Agreement respecting parking for the use of a neighbour Donald Braun.
Instrument Number 52861 (registered June 1951) Lot 29, Plan 1063, now Plan 11 City of Niagara Falls	Southeast side of Lewis Avenue between Magdalen and Centre	
Instrument Number 361029 (registered May 1980) less lands conveyed by instrument 382665 (December 1981) Our lands now Part 2, Plan 59R-3643 – Part of	Northeast side of Swayze Drive, east of Johnson Drive	The Commission transferred part of the land first conveyed to it to a neighbouring land owner leaving a parcel owned by the Commission of about 80 feet frontage on Swayze by

Description/Address	Location	Type of Property
Township Lot 43 for the Township of Stamford		about 40 feet depth.
Instrument number 37492 (registered November 1945) Lot 32, Plan 56, Township of Stamford, now City of Niagara Falls	Lands on the north side of Virginia Street at the corner of Carroll	
Created by instrument 87174 (1956) and assigned to Commission by instrument 469722 (1977)	East side of Portage Road south of Thorold Stone Road	
Instrument number 469809 (registered April 1986)	Rear lands south of Corwin Crescent, north of Dunn Street, east of Dorchester Road	
Instrument number 50401 (registered November 1949)	North side of Margaret Street between Joyce Avenue and Drummond Road	
Instrument Number: 78199A (registered August, 1962) Part of Twp. Lots 5, 16, 25 and road allowance between Lots 16 and 25, all Stamford Township, now City of Niagara Falls	Lands east of St. Paul Street, north of Mountain Road	Three separate parcels running east of St. Paul Street from Mountain Road apparently to connect to water facilities of the former Township of Niagara
Instrument Number 46656 (registered June 1951) Part Twp. Lot 49 Stamford, now City of Niagara Falls (60’ x 60’ parcel)	East side of Thorold Town Line, north of Mountain Road	

Please note the locations of substations as listed in the April 30, 2006 Financial Statements:

- **Ontario Avenue**
- **Park Street**
- **Lewis Avenue**
- **Robinson Street**
- **Drummond Road**
- **Margaret Street**
- **Kalar Road**
- **Virginia Street**
- **Sinnicks**
- **Pew Street**

SCHEDULE 5.2(10)

NFHI – LEASED PROPERTY

Nil.

SCHEDULE 5.2(11)(F)

NFHI – ENCUMBRANCES

Nil.

SCHEDULE 5.2(13)

NFHI – EQUIPMENT LEASES

Nil

SCHEDULE 5.2(16)

NFHI – INSURANCE POLICIES

Policy No.	Name of Insurer	Type of Coverage	Coverage/Limit	Deductible	Period Covered	Annual Premium
L2006N1FA1	The Municipal Electric Association Reciprocal Insurance Exchange	General Liability (including premises and operations and products and completed operations); Bodily Injury; Personal Injury; Property Damage; Tenants Legal Liability; Environmental Impairment; Errors & Omissions/Professional Liability; Non-Owned Automobile; Legal Expense Reimbursement; and Enhanced Directors and Officer's Liability.	$20,000,000.00 per occurrence.	Individual Member Deductible: $0 Environmental Impairment Deductible: $20,000.00 or 1% of annual service revenue, whichever is the lesser.	January 1, 2006 to January 1,2007 (12:01 a.m.)	$58,780.00 (net of premium reduction) $9,494.00 (before taxes) is the deductible to be paid with respect to Enhanced Directors and Officers Liability claims.
AUTO-2006-188	The Municipal Electric Association Reciprocal Insurance Exchange	Bodily Injury; Property Damage; Accident Benefits (Basic Benefits); Uninsured Automobile; Direct Compensation-Property Damage; and	$15,000,000.00 for Bodily Injury and Property Damage. With respect to Uninsured Automobile, the	Loss or Damage (all perils) is $1,000.00.	January 1, 2006 to January 1, 2007 (12:01 a.m.)	2006 Premium; $29,645.00

Policy No.	Name of Insurer	Type of Coverage	Coverage/Limit	Deductible	Period Covered	Annual Premium
		Uninsured Automobile.	limit is stated in Section 5 of the Policy.			
	AON Corporation	Casualty (Comprehensive Crime and Councillors' Accident) and Property (Property/Data Processing and Boiler and Machinery)	Blanket Amount on Property Insured; $21,303,700.00 (basis of loss is replacement cost). Limit on Valuable Papers; $500,000.00. Limit on Accounts Receivable; $500,000.00. Limit on Extra Expense Insured at Any One Location; $500,000.00. Rent or Rental Value Form; $500,000.00.	$1,000.00 for Data Processing Insurance. $5,000.00 for all other claims. Exceptions: • Peril of Flood is $25,000.00 • Peril of Earthquake is 3% or minimum $300,000.00	May 1, 2005 to May 1, 2006.	$52,815.00 (plus 8% PST)

Policy No.	Name of Insurer	Type of Coverage	Coverage/Limit	Deductible	Period Covered	Annual Premium
			Data Processing Insurance; $867,000.00. Data Processing Insurance; $867,000.00			

Pending Claims:

Nil.

SCHEDULE 5.2(18)

NFHI – MATERIAL CONTRACTS

1. Commitment Letter dated August 18, 2006 from Scotiabank to NFHI regarding the following credit facilities:

    (a) Operating Line of Credit in the authorized amount of $3,000,000 (Credit Number 01);

    (b) Standby Letters of Credit in the authorized amount of $6,000,000 (Credit Number 02);

    (c) Non-Revolving Line of Credit in the authorized amount of $5,761,392 (Credit Number 03 as of December 31, 2007); and

    (d) Corporate VISA and/or VISA Purchase Card and/or Scotia Visa for Business, Availment, interest rate and repayment as per Cardholder/purchase Card Agreement in the authorized amount of $300,000.

SCHEDULE 5.2(20)

NFHI – PERMITS

2. Electricity Distribution Licence ED-2002-0551 dated June 6, 2003 issued by the Ontario Energy Board to Niagara Falls Hydro Inc. Valid until March 31, 2023.

3. IeSo Market Participant #102102

4. Certificate of Exemption from Registration as a Non-Gaming Related Supplier under the Gaming Control Act, 1992, File # 00052230 valid until 2008-04-17; annual renewal

SCHEDULE 5.2(26)

NFHI – UNUSUAL TRANSACTIONS

Nil.

SCHEDULE 5.2(28)

NFHI – LITIGATION

Nil.

SCHEDULE 5.2(29)

NFHI – NON-ARM'S LENGTH TRANSACTIONS

Nil.

SCHEDULE 5.2(30)(A)

NFHI – ENVIRONMENTAL COMPLIANCE

Environmental issues related to Victoria Avenue property.

SCHEDULE 5.2(30)(B)

NFHI – ENVIRONMENTAL PERMITS

Nil.

SCHEDULE 5.2(31)

NFHI – EMPLOYEE PLANS

TYPE OF PLAN	DESCRIPTION OF PLAN	AGREEMENT DATE	CONTRACT NO.	SUPPLIER
Deferred Compensation	N/A			
Bonus Compensation	N/A			
Incentive or Other Compensation	Education/Training			
Share Option or Purchase	N/A			
Severance/Termination	N/A			
Group Benefit Program:		01/FEB/2000	15212	Manulife Financial
Hospitalization	Deductible - Nil			
	100% private room Public Hospital			
Medical Benefit	EHC- 100% Eligible Coverage Deductible - single $10, family $20			
Life/Other Insurance	Basic Term – 150% of annual earnings			
	LTD Board & President			

	$5500 max Managers $3500 max Employees $2600 max			
Vision	Deductible – Nil $375/24 mths			
Dental	Deductible – Nil 100% of applicable fee guide Up to $1900 / 2007 Up to $2000 / 2008			
Drug	Deductible – Nil Except as noted .20 / prescription			
Other	Deductible – Nil 100% $300 lifetime max			
Sick Leave	18 days / year	01/APR/06	N/A	Contract Agreement
Long Term Disability	$5500 / mth max Board of Directors & President $3500 / mth max Managers $2600 / mth max Employees	01/FEB/00	15212	Manulife Financial
Vacation Entitlement	Up to 1 yr – up to 10 days 1 yr – 10 days 3 yrs – 15 days			

	10 yrs – 20 days 16 yrs – 25 days 22 yrs – 26 days 23 yrs – 27 days 25 yrs – 30 days			
Supplemental Unemployment Benefits	WSIB – Top-up to full wage (difference paid by company)	01/APR/06	N/A	Contract Agreement
Profit Sharing	N/A			
Mortgage Assistance	N/A			
Pension	See plan provisions		403091	OMERS
Supplemental Pension	N/A			
Retirement Compensation	N/A			
Group Registered Retirement Savings	N/A			
Deferred Profit Sharing	N/A			
Employee Profit Sharing	N/A			

Retirement or Supplemental Retirement	N/A			

DESCRIPTION OF RETIREE BENEFITS

5. ***Eligibility and Benefit Term***:

(a) Non-Union Employees:

(i) *Eligibility*: Board of Directors

(ii) *Benefit Term*: Until age 75

(b) Union Employees:

(i) *Eligibility*: Regular employees

(ii) *Benefit Term*: Until age 65 or retirement whichever is earlier with a minimum of 20 years of service. **see article 21.04 of the collective agreement*

Employees hired before January 1, 2007 are eligible until age 65 with a minimum of 20 years of service.

6. ***Spouse Coverage***:

(a) *Eligibility*: Dependants of employees

(b) *Spouse/Dependent Coverage*:

(i) Included as above, however years of service does not apply if employee dies – *see article 21.0 of the collective agreement*

7. ***Life Insurance***: MEARIE

8. ***Supplementary Health Benefits***: Coordination of benefits provision

(a) *Prescription Drugs*:

(b) *Major Medical*:

(c) *Hospital*:

(d) *Out of Country Coverage*: Travel – deductible-nil 100% of eligible charges

Deluxe Travel – Max 60 days coverage – 1,000,000 / person

(e) *Out of Province Coverage*: Travel – deductible-nil 100% of eligible charges

Deluxe Travel – Max 60 days coverage – 1,000,000 / person

(f) *Dental*:

(g) *Vision care*:

SCHEDULE 5.2(32)

NFHI – EMPLOYEE MATTERS

Nil.

SCHEDULE 5.2(35)

NFHI – JOINT VENTURE INTERESTS

Nil.

SCHEDULE 5.2(37)

NFHI – THIRD PARTY CONSENTS

1. Consent of Scotiabank pursuant to the Commitment Letter dated August 18, 2006 from Scotiabank to NFHI.

SCHEDULE 5.3(7)

PW HOLDCO – LITIGATION

1. Possible West Lincoln Shareholder litigation arising from its non-approval of the Amalgamation

SCHEDULE 5.4(4)

PWUL – OPTIONS

Nil

SCHEDULE 5.4(7)

PWUL – CONDUCT OF BUSINESS

Nil.

SCHEDULE 5.4(9)

PWUL – REAL PROPERTY

Description/Address	Location	Type of Property
Decommissioned DS RSC #3187 Part of Lot 9, Gore A being Parts 1 & 3, Plan 30R-4596 and surface rights only for part 2, Plan 30R-4596		**Vacant Land**
JORDAN D.S. 2860 RED MAPLE AVE CON 3 PT LOT 18 JORDAN ONTARIO RP 30R9768 PART1		**Distribution Station**
CAMPDEN D.S. 4299 FLY RD PLAN 30M14 PT LOT 18 CAMPDEN ONTARIO RP 30R308 PT 1		**Distribution Station**
GREENLANE D.S. 3897 GREENLANE RD CON 1 PT LOT 5 BEAMSVILLE ONTARIO RP 30R9770 PART 1		**Distribution Station**
PELHAM ST D.S. 1420 PELHAM ST PLAN 715 PT LOT 1 FONTHILL ONTARIO RP 59R10058 PART 1		**Distribution Station**
PELHAM D.S. 1582 PELHAM ST PLAN 12 PT LOT 23 FONTHILL ONTARIO		**Distribution Station**

STATION STREET D.S. STATION ST WS FONTHILL ONTARIO RP59R5448 PART 1	**Distribution Station**
SMITHVILLE D.S. CON 9 PT LOT 5 265 ST CATHARINES ST SMITHVILLE ONTARIO	**Distribution Station**

SCHEDULE 5.4(10)

PWUL – LEASED PROPERTY

Description of Lease	Parties	Execution Date	Expiry Date	Option to Renew, if any	Location of Leased Lands and Premises	Lease Payments
OFFICE SPACE	ABRAM DUECK IN TRUST and PWUL	OCT 19/06	OCT 31/07	YES	4548 ONTARIO ST UNIT 2	$3476.92 PER MOS
Service Center	PWP and PWU	See Lease	See Lease	See Lease	Quarry Road Service Centre 3768 Quarry Road Beamsville Ontario	See Lease

SCHEDULE 5.4(11)(F)

PWUL – REAL PROPERTY ENCUMBRANCES

1. TD Bank security, including a General Security Agreement, regarding PWUL;
2. TD Bank security, including a General Security Agreement, regarding PWUL guarantee of NWTC.

SCHEDULE 5.4(12)

PWUL –PERSONAL PROPERTY ENCUMBRANCES

1. TD Bank security, including a General Security Agreement, regarding PWUL;

2. TD Bank security, including a General Security Agreement, regarding PWUL guarantee of NWTC.

SCHEDULE 5.4(13)

PWUL – EQUIPMENT LEASES

Description of Property	Lease No.	Lessor	Date of Lease	Term (Months)	Term (Period)	Instalment Price	Renewal Options	Lease Payments	Buyout
Ricoh AF2060 Copier Printer Scanner SR850 finisher with 3-hole punch	**NA**	De Lage Landen Lease (JBM Office Systems)]	**JULY 26/06**	**48**	Expires 2010	**NA**	If the equipment is not returned upon expiration of the term of the lease, the lease will automatically renew for an additional 12-month term. Cannot cancel lease for any reason including equipment failure, loss or damage. Cannot transfer the lease to a new owner without prior written consent. If the lessor consents, the lessor may charge an assignment fee of up to 2% of the original cost of the equipment	$685 per month plus taxes	**NA**
Hydro metering equipment	**5194-1**	Culease Financial Services	Dec 2002	84 months	**2009**	**NA**	**NONE**	$1,699.84 plus taxes per month	**NA**
software licence and consulting equipment	**NA**	Advanced Utility Systems	April 23, 1999	Initial term is one year and shall continue on an annual basis.	Indefinite unless terminated	**NA**	Initial term is one year and shall continue on an annual basis provided that the Organization pay the annual support fee unless terminated by either party upon giving to the other not less than 90 days notice in writing prior to the end of the first year or any subsequent anniversary of such	Must pay annual fees to an escrow agent for performing its obligations under section 2.5 of the lease agreement. Annual Licence fee $35,000 Consulting	**NA**

Description of Property	Lease No.	Lessor	Date of Lease	Term (Months)	Term (Period)	Instalment Price	Renewal Options	Lease Payments	Buyout
							date.	Services Hourly rate is $100 per hour. Annual support fee of $ 8,750.	

SCHEDULE 5.4(16)

PWUL – INSURANCE POLICIES

Policy No.	Name of Insurer	Type of Coverage	Coverage/Limit	Deductible	Period Covered	Annual Premium
L2007PENW1	The Municipal Electric Association Reciprocal Insurance Exchange	General Liability (including premises and operations and products and completed operations); Bodily Injury; Personal Injury; Property Damage; Tenants Legal Liability; Environmental Impairment; Errors & Omissions/Professional Liability; Non-Owned Automobile; Legal Expense Reimbursement; and Enhanced Directors and Officer's Liability.	$20,000,000.00 per occurrence.	Individual Member Deductible: $0 Environmental Impairment Deductible: $20,000.00 or 1% of annual service revenue, whichever is the lesser.	January 1, 2006 to January 1, 2007 (12:01 a.m.)	$41589.
AUTO2007-148	The Municipal Electric Association Reciprocal Insurance Exchange	Bodily Injury; Property Damage; Accident Benefits (Basic Benefits); Uninsured Automobile; Direct Compensation-Property Damage; and	$15,000,000.00 for Bodily Injury and Property Damage. With respect to Uninsured	0.	January 1, 2006 to January 1, 2007 (12:01 a.m.)	$16570.

		Uninsured Automobile.	Automobile, the limit is stated in Section 5 of the Policy.			
P2007PENW1	The Municipal Electric Association Reciprocal Insurance Exchange	PROPERTY	LIMIT $4,000,000.	0	JAN 1/07 TO JAN 1, 08	$9126.

SCHEDULE 5.4(18)

PWUL – MATERIAL CONTRACTS

1. Toronto-Dominion Term Loan of $ 9,500, 000 as at December 31, 2006 due July2008;

2. Toronto Dominion Bank banking agreement – dated January 30, 2006 1) Operating loan - $ 1,000,000 Prime + 0%; 2) Committed Revolving Facility $12, 500, 000 Prime + 0%; 3) Letter of Credit $ 2, 120, 000;

3. Business and Banking Services Agreement dated July 6, 2006;

4. Corporate VISA Royal Bank for Business availment, interest rate and repayment as per Cardholder/purchase Card Agreement ;

5. PWUL Guarantee of NWTC up to $3,250,000 in favour of TD Bank and all related documentation, including a General Security Agreement;

6. Joint Venture Agreement Dated dated as of September 15, 2003 among Niagara WestTransformation Corporation ("NWTC"), PW Holdco, PWUL, Niagara Power Inc. and Grimsby Power Inc.(the "NWTC Joint Venture Agreement");

7. Pole Line Agreement dated January 1, 2004 between PWUL and Grimsby Power Inc.

8. Connection and Cost Recovery Agreement between PWUL and Hydro One;

SCHEDULE 5.4(20)

PWUL – PERMITS

OEB DISTRIBUTION LICENSE ED 2002-0555

IESO MARKET PARTICIPANT MP # 104289

SCHEDULE 5.4(26)

PWUL – UNUSUAL TRANSACTIONS

1. Ongoing PWUL Guarantee of NWTC up to $3,250,000 in favour of TD Bank and all related documentation, including a General Security Agreement;

2. On May 25, 2007, PWUL transfer of 120 Class "A" shares in the capital of NWTC to PW Holdco.

3. Transfer of the Quarry Road property from PWUL to PW Holdco.

SCHEDULE 5.4(28)

PWUL – LITIGATION

1. Any potential action by Municipality of West Lincoln regarding the Amalgamation.

SCHEDULE 5.4(29)

PWUL – NON-ARM'S LENGTH TRANSACTIONS

Parties	Description of Agreement/ Transaction	Written Agreement (Yes/No)	Date of Agreement	Term	Expiry Date	Annual Fee/ Commitments	Comments
PWPI	SERVICE AGREEMENT	YES	NOV1, 2000	NO EXPIRY DATE		BASED ON ANNUAL HOURS SPENT	
PWSL	SERVICE AGREEMENT	YES	NOV1, 2000	NO EXPIRY DATE		BASED ON ANNUAL HOURS SPENT	
NWTC	NWTC Joint VentureAgreement	YES	Sept 5/03	NO EXPIRY DATE			
NWTC	POLE LINE AGREEMENT RE NWTC	YES	Jan 1/04	NO EXPIRY DATE			

SCHEDULE 5.4(30)(A)

PWUL – ENVIRONMENTAL COMPLIANCE

1. Environmental issues related to Quarry Road property;

SCHEDULE 5.4(30)(B)

PWUL – ENVIRONMENTAL PERMITS

1. CA regarding remediation of Quarry Road property

SCHEDULE 5.4(31)

PWUL – EMPLOYEE PLANS]

TYPE OF PLAN	DESCRIPTION OF PLAN	AGREEMENT DATE	CONTRACT NO.	SUPPLIER
Deferred Compensation	NA			
Bonus Compensation	NA			
Incentive or Other Compensation	NA			
Share Option or Purchase	NA			
Severance/Termination	NA			
Group Benefit Program:				
Hospitalization	SEMI PRIVATE	JAN 1 – DEC 31/07	0130	MEARIE
Medical Benefit	100 % COST OF MEDICAL SRV, DRUG & VISION	JAN 1 – DEC 31/07	0130	MEARIE
Life/Other Insurance	2X ANN. EARN TO MAX $200,000. MEDICAL EVID AFTER $100,000.	JAN 1 – DEC 31/07	0130	MEARIE

Vision				
Dental	100% BASED ON BASIC DENT SRV.	JAN 1 – DEC 31/07	0130	MEARIE
Drug				
Other				
Sick Leave	PER COLLECTIVE AGREEMENT			
Long Term Disability	PAYABLE AFTER 17 WEEKS	JAN 1 – DEC 31/07	0130	MEARIE
Vacation Entitlement	PER COLLECTIVE AGREEMENT			
Supplemental Unemployment Benefits	NA			
Profit Sharing	NA			
Mortgage Assistance	NA			

Pension	OMERS			
Supplemental Pension	NA			
Retirement Compensation	NA			
Group Registered Retirement Savings	NA			
Deferred Profit Sharing	NA			
Employee Profit Sharing	NA			
Retirement or Supplemental Retirement	NA			

DESCRIPTION OF RETIREE BENEFITS

1. ***Eligibility and Benefit Term***:

   (a) Non-Union Employees:

      (i) *Eligibility*:

      (ii) *Benefit Term*:

   (b) Union Employees:

      (i) *Eligibility*:

(ii) *Benefit Term*:

2. ***Spouse Coverage***:

(a) *Eligibility*:

(b) *Spouse/Dependent Coverage*:

(i)

3. ***Life Insurance***:

4. ***Supplementary Health Benefits***:

(a) *Prescription Drugs*:

(b) *Major Medical*:

(c) *Hospital*:

(d) *Out of Country Coverage*:

(e) *Out of Province Coverage*:

(f) *Dental*:

(g) *Visioncare*:

SCHEDULE 5.4(32)

PWUL – EMPLOYEE MATTERS

Temporary Employee written contract for the position of Administrative Assistant, expiry date of July 2008

SCHEDULE 5.4(35)

PWUL – JOINT VENTURE INTERESTS

1. PWUL is a party to the NWTC Joint Venture Agreement.

SCHEDULE 5.4(37)

PWUL – THIRD PARTY CONSENTS

1. Consent of Toronto-Dominion Bank pursuant to the Toronto-Dominion Term Loan of $9,500, 000 as at December 31, 2006 due July 2008;

2. Consent of Toronto-Dominion Bank pursuant to the Toronto Dominion Bank banking agreement – dated January 30, 2006:

   (a) Operating loan - $ 1,000,000 @ Prime + 0%;

   (b) Committed Revolving Facility $12, 500, 000 @ Prime + 0%;

   (c) Consent of Toronto-Dominion Bank pursuant to the Letter of Credit $ 2,120,000;

3. Consent of Toronto-Dominion Bank pursuant to the Business and Banking Services Agreement dated July 6, 2006;

4. TD Bank Consent to the PWUL Guarantee of NWTC being assumed by Mergeco.

ATTACHMENT # 8-Loan financing documentation-IRR#32

niagara peninsula energy

Our energy works for you.

Head Office:
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Box 120
Niagara Falls, Ontario
L2E 6S9

T: 905-356-2681
Toll Free 1-877-270-3938
F: 905-356-0118
E: info@npei.ca
www.npei.ca

March 6, 2012

Mr. Brian Walker
President
Peninsula West Power Inc.

Dear Mr. Walker:

Niagara Peninsula Energy Inc. is currently preparing a request for proposal to undertake a long term borrowing up to ten million dollars. Niagara Peninsula Energy has internally financed $41.6 million in capital expenditures over the past four years. As well, Niagara Peninsula Energy has made principle repayments of $5.6 million on its current long term borrowings over the past four years and has repaid $3.8 million of regulatory liabilities in 2011. As a result of these activities Niagara Peninsula Energy's cash position has decreased by approximately $6.0 million since the end of the fiscal year ending December 31, 2008.

In accordance with the Shareholders Agreement dated January 1, 2008, Article 5 – Approval of Certain Corporate Actions, section 5.2 – Special Resolution by Shareholders, part (k) Borrowing of money in excess of $5 million dollars, Niagara Peninsula Energy requires a Special Resolution approved by its shareholders Niagara Falls Hydro Holding Corporation and Peninsula West Power Inc.

Please see the enclosed Special Resolution requesting approval to obtain long term financing up to ten million dollars in 2012.

Please contact myself should anything further be required, I can be reached at 905-353-6004 or by email at Suzanne.Wilson@npei.ca.

Sincerely,

Suzanne Wilson
VP Finance
Niagara Peninsula Energy Inc.

Encl.

Cc: George Mitges
Brian Wilkie
Sue Forcier
Barb Krol

PENINSULA WEST POWER INC.
Special Resolution

In accordance with the Shareholders Agreement dated January 1, 2008,

WHEREAS Article 5 – Approval of Certain Corporate Actions, section 5.2 – Special Resolution by Shareholders, part (k) Borrowing of money in excess of $5 million dollars.

WHEREAS Niagara Peninsula Energy requires a Special Resolution approved by its shareholders Niagara Falls Hydro Holding Corporation and Peninsula West Power Inc.

THEREFORE BE IT RESOLVED that Peninsula West Power Inc.'s Board of Directors approves the borrowing of money in excess of $5 million dollars up to $10 million dollars in 2012.

Mch 21, 2012	
Dave Augustyn - Chair	**Date**
	March 21 2012
Brian Walker - President	**Date**

niagara peninsula energy

Our energy works for you.

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March 6, 2012

Mr. Wayne Thomson
Chairman
Niagara Falls Hydro Holding Corporation
7447 Pin Oak Drive
Niagara Falls, ON
L2E 6S9

Dear Mr. Thomson:

Niagara Peninsula Energy Inc. is currently preparing a request for proposal to undertake a long term borrowing up to ten million dollars. Niagara Peninsula Energy has internally financed $41.6 million in capital expenditures over the past four years. As well, Niagara Peninsula Energy has made principle repayments of $5.6 million on its current long term borrowings over the past four years and has repaid $3.8 million of regulatory liabilities in 2011. As a result of these activities Niagara Peninsula Energy's cash position has decreased by approximately $6.0 million since the end of the fiscal year ending December 31, 2008.

In accordance with the Shareholders Agreement dated January 1, 2008, Article 5 – Approval of Certain Corporate Actions, section 5.2 – Special Resolution by Shareholders, part (k) Borrowing of money in excess of $5 million dollars, Niagara Peninsula Energy requires a Special Resolution approved by its shareholders Niagara Falls Hydro Holding Corporation and Peninsula West Power Inc.

Please see the enclosed Special Resolution requesting approval to obtain long term financing up to ten million dollars in 2012.

Please contact myself should anything further be required, I can be reached at 905-353-6004 or by email at Suzanne.Wilson@npei.ca.

Sincerely,

S Wilson

Suzanne Wilson
VP Finance
Niagara Peninsula Energy Inc.

Encl.

Cc: George Mitges
Brian Wilkie
Sue Forcier
Barb Krol

Niagara Falls Hydro Holding Corporation

Special Resolution

In accordance with the Shareholders Agreement dated January 1, 2008,

WHEREAS Article 5 – Approval of Certain Corporate Actions, section 5.2 – Special Resolution by Shareholders, part (k) Borrowing of money in excess of $5 million dollars.

WHEREAS Niagara Peninsula Energy requires a Special Resolution approved by its shareholders Niagara Falls Hydro Holding Corporation and Peninsula West Power Inc.

THEREFORE BE IT RESOLVED that Niagara Falls Hydro Holding Corporation Board of Directors approves the borrowing of money in excess of $5 million dollars.

Wayne Thomson, Chair
Niagara Falls Hydro Holding Corporation

Brian Walker, Chair
Peninsula West Power Inc.

Request for Proposal (RFP) regarding the long term financing in the amount of ten million dollars

An RFP was issued regarding the long term financing in the amount of ten million dollars on May 25th, 2012. Proponents were asked to submit their intent to propose by June 4th, 2012 and submit the final proposal no later than noon on June 8th, 2012.

Meridian Credit Union, Toronto Dominion (TD), Royal Bank of Canada (RBC) and Scotiabank submitted both their intent and their proposals by the deadline. CIBC declined to propose and Bank of Montreal did not respond at all.

A comparison of the key components of the RFP (Schedule A) is attached.

The Proponents were asked to propose a fixed interest rate on a ten million dollar loan for the longest time period possible with only interest payments being made (i.e. an unamortized loan) and they were to complete Schedule A.

The Finance Committee met on June 13th at 9:00 am. The four proponents that did propose were each given a ten minute window to present their proposals and answer any questions. The presentations commenced at 9:05 and ended at 10:10 am. Meridian Credit Union presented first, followed by the Royal Bank of Canada, followed by Scotiabank and lastly TD.

Discussion took place after the four presentations regarding the fixed interest rates, the interest rate swap option provided by several banks, the various terms of the loan options, legal fees, repayment terms and other terms.

Staff recommendation was asked for. The Royal Bank did not provide what was asked for in the RFP, no fixed rate was quoted and the repayment of principal commences after two years. Scotiabank quoted a 10 year fixed rate at 4.39%. Meridian quoted 3.87% based on Cost of Funds on June 7th, 2012 for a 10 year term. Hence Meridian's 10 year rate is preferable to Scotiabank.

TD quoted 2.432% for an amortized loan (i.e. principal is repaid) and 2.83% for an unamortized (interest only payments) over 5 years and Meridian quoted 3.06% fixed rate as at June 7th, 2012 over 5 years. The annual interest payments over 5 years would be as follows: TD $283,000 and Meridian $306,000. The interest expense savings would be $23,000 per year or $115,000 over five years. TD has proposed no additional fees and Meridian has proposed a $1,000 Commitment fee along with NPEI would be responsible for the legal fees to amend the Inter-Creditor agreement and the General Security Agreement. The legal fees were approximately $ 5,000 per bank for the original Inter-Creditor Agreement. The legal fees could be estimated to cost an additional $15,000 (now have 3 banks to agree on any amendments). As a result the additional fees saved with the TD proposal are $16,000 for a total of $131,000 over 5 years.

The interest rate swap option was discussed. An advantage to the swap would be if the intention is to pay it off inside the 5 or 10 year window, with the expectation that the interest rate would increase, and hence the result being NPEI would be "in the money" where the Lender would pay the Borrower the net present value of the change in swap rates for the outstanding period of the notional amount of the loan. Since it is not NPEI's current plan to retire the debt early, the swap is not advantageous for NPEI. Also the RFP did not request the proponents to propose a swap option. The RFP only requested the proponents to propose a fixed interest rate or Cost of Funds. Meridian Credit Union did not propose this option while the other three proponents did include it. However, after narrowing the choices between the TD bank and Meridian Credit Union the interest rate swap could not be compared. It was also discussed that in the future this option will be included in future RFP's.

The rate quoted by Meridian over a 10 year term was 3.87%. The interest expense over the first five years would by $1,935,000 (3.87% X $10M = $387,000 per year X 5 years = $1,935,000) versus TD's 5 year rate of 2.83% X $10M = $283,000 X 5 years =$1,415,000, which is a savings of $520,000 now to NPEI. TD's longest term for an unamortized (i.e. no principal repayments) loan is 5 years.

Staff recommended award the RFP to TD with a 5 year fixed interest rate loan with interest only repayments in order to achieve the $520,000 savings now and revisit the long term financing position annually.

A motion was made by Joann Chechalk to accept Staff's recommendation and was seconded by Brian Walker and all were in favour.

The Finance Committee's recommendation to the Board of Directors is to award the RFP to the TD bank in accordance with the terms provided in the RFP for the Term Sheet using Cost of Funds.

2012 Comparison of loan

	Meridian	TD	Royal	Scotia
Interest Rate/Cost of Funds (COF)	5 yrs COF + 120bps, min.3% (3.06% 6/7/12) 10 yrs COF + 145 bps, min. 3% (3.87% 6/7/12)	**Amortized** Loan 5 year Indicative Spot rate as of June 8/12 = 2.432% Indicative Forward Start Rate at July 13/12 = 2.476% **UNAmortized** Loan 5 year Indicative Spot rate as of June 8/12 = 2.83% Indicative Forward Start Rate at July 13/12 = 2.87%	No fixed rate proposed	Fixed Rate + 0.75%. All in Indicative Rate at May 29/12 = 4.14%, June 7/12 =4.39%
Interest Rate/ BA Swap	Not proposed	5 year Indicative Spot rate as of June 8/12 = 2.65% Indicative Forward Start Rate at July 13/12 = 2.67%	2.34% (Indicative spot 1.89% + 0.45% Stamping fee for 10 years)	All in Indicative Rate at May 29/12 = 3.92%, June 7/12 =4.09%
Term of Loan	Choice of 5 or 10 years	5 years; Interest only payments monthly (non-amortizing)	10 years. Maximum amortization of 15 years	**10 years**
Repayment	Interest only, bullet payment July 15, 2022	Interest only, bullet payment July 2017	Monthly repayments of interest only for first 2 years Interest + principal for following 8 years based on 13 year amortization	Interest only, bullet payment of any outstanding principal and Interest July 31, 2022
Prepayment Options	Up to $1,000,000 per year prepayment without penalty	COF: Standard prepayment penalties apply BA Swap: Subject to unwinding costs	**BA Loan** Spread penalty: None. The Bankers Acceptance (BA) loan can be paid down at the end of every month, quarter, or semi-annually (depending on the frequency on interest payments chosen by the borrower) without penalty; however, no BA can be repaid before its maturity. **Interest rate Swap facility** The interest rate swap can be unwound at any time subject toa 2 way interest rate differential calculation. A 2 way calcualtion implies that if prevailing swap rates have moved down(compared to the original swap rate) the Borrower will owe the Lender the Net Present Value (NPV) of the change in swap rates for the outstanding period of the notional amount of the loan. If prevailing swap rates have moved up (compared to the original swap rate), the Lender will pay the Borrower the NPV of the change in swap rates for the outstanding period of the notional amount of the loan.	Prepayment of the loan in whole or in part is permitted at any time on payment of the bank's funding loss. If at the time of the prepayment the prevailing interest rates are higher than the booked rate there will be no prepayment penalty.
Commitment Fees	$1,000	N/A	NA	Nil
Legal Fees for amendments to existing Intercreditor Agreement	Any legal cost for account of borrower—NPEI may use its own legal firm	$Nil	To be determined by legal counse for each bank involved	Nil
Any and all other Fees	No other fees	$Nil	All reasonable legal, Bank fees, costs and expenses associated with the preparation of the Credit facility documentation between the Lender and the Borrower are for the Borrowers account	Nil
General Security Requirements	GSA & Inter-lender agreement only	No new security documentation is required	General Security Agreement to rank in 1st position and pari passu with other lenders	No change to existing arrangement General Security Agreement and Inter Creditor Agreement
Debt Covenants	Debt:Capitalization 0.70:1 maximum Debt Service Ratio 1.50:1	Debt:Capitalization 0.60:1 maximum Debt Service Ratio 1.25:1	Debt:Capitalization 0.60:1 maximum A default in any agreement with any other lender constitutes a default with RBC Such standard covenants that the Lender may incorporate in the final Credit Agreement	No change to existing arrangement Debt:Capitalization 0.70:1 maximum Debt Service Ratio 1.50:1 or better
Latest Date Funds will be Transferred to NPEI's account	No later than July 15, 2012 Can be funded as soon as credit agreement signed by NPEI and security provided	July 31/12 or earlier or later. We will provide maximum flexibility to meet the specific timeline requested by NPEI	13-Jul-12	15-Jul-12
Reporting Requirements	Annual Audited FS within 120 days of year-end and copy of budget annually	Annual Audited FS within 120 days of year-end and copy of budget annually within 120 days and Quarterly statements	Annual Audited FS and Annual Operating and Capital Budgets	No change to existing arrangement. Annual audited FS and Annual approved budget
Other Notations/Comments	NPEI to establish chequing account for purposes of loan payments	None	NA	None

NPEI 5 year vs 10 year analysis
Long term Financing
Comparison Meridian vs TD

Year	Interest Rate %	1	2	3	4	5	Total
5 Year comparison							
Meridian							
5 yr	3.06	306,000	306,000	306,000	306,000	306,000	1,530,000
Legal fees & commitment fees		16,000					16,000
		322,000	306,000	306,000	306,000	306,000	1,546,000
TD							
5 yr	2.83	283,000	283,000	283,000	283,000	283,000	1,415,000
SAVINGS Difference in 5 yr base points	0.23	39,000	23,000	23,000	23,000	23,000	131,000

Year	Interest Rate %	1	2	3	4	5	6	7	8	9	10	Total
10 Year comparison												
Meridian												
10 yr	3.87	387,000	387,000	387,000	387,000	387,000	387,000	387,000	387,000	387,000	387,000	3,870,000
Legal fees		16,000										16,000
		403,000	387,000	387,000	387,000	387,000	387,000	387,000	387,000	387,000	387,000	3,886,000
TD at 5 years + balancing rate for next five years		283,000	283,000	283,000	283,000	283,000	494,200	494,200	494,200	494,200	494,200	3,886,000
Interest rate %		2.83	2.83	2.83	2.83	2.83	4.942	4.942	4.942	4.942	4.942	3.89
					Bases Point Difference	2.112	74.63%	% increase				

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peninsula
energy

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September 10, 2013

Mr. Wayne Thomson
Chairman
Niagara Falls Hydro Holding Corporation
7447 Pin Oak Drive
Niagara Falls, ON
L2E 6S9

Dear Mr. Thomson:

Niagara Peninsula Energy Inc. is currently preparing a request for proposal to undertake a long term borrowing up to ten million dollars. The purpose of this financing is for general purposes and to replenish current cash flows. Niagara Peninsula Energy Inc. has internally financed $54.7 million dollars in capital expenditures over the past six years, since the merger between the former Niagara Falls Hydro Inc. and the former Peninsula West Utilities Ltd. As well Niagara Peninsula Energy Inc. has made principal repayments of $10.6 million dollars on its current long term borrowings over the past six years and has repaid $1.8 million dollars of regulatory liabilities in 2013 alone. Niagara Peninsula Energy has an additional $2.7 million dollars of regulatory liabilities to re-pay between August 2013 and May of 2014 and an additional $3.1 million dollars of the 2012 Deferral and Variance balances between May 1, 2014 and April 30, 2015. As a result of these activities Niagara Peninsula Energy's cash position has decreased by approximately $11.3 million since the end of the fiscal year ending December 31, 2008.

In accordance with the Shareholders Agreement dated January 1, 2008, Article 5 – Approval of Certain Corporate Actions, section 5.2 – Special Resolution by Shareholders, part (k) Borrowing of money in excess of $5 million dollars, Niagara Peninsula Energy requires a Special Resolution approved by its shareholders Niagara Falls Hydro Holding Corporation and Peninsula West Power Inc.

Please see the enclosed Special Resolution requesting approval to obtain long term financing up to ten million dollars in 2013.

Please contact myself should anything further be required, I can be reached at 905-353-6004 or by email at Suzanne.Wilson@npei.ca.

Sincerely,

Suzanne Wilson CPA, CA
VP Finance
Niagara Peninsula Energy Inc.

Encl.

Cc: George Mitges
Brian Wilkie
Sue Forcier
Barb Krol

Niagara Falls Hydro Holding Corporation

Special Resolution

In accordance with the Shareholders Agreement dated January 1, 2008,

WHEREAS Article 5 – Approval of Certain Corporate Actions, section 5.2 – Special Resolution by Shareholders, part (k) Borrowing of money in excess of $5 million dollars.

WHEREAS Niagara Peninsula Energy requires a Special Resolution approved by its shareholders Niagara Falls Hydro Holding Corporation and Peninsula West Power Inc.

THEREFORE BE IT RESOLVED that Niagara Falls Hydro Holding Corporation Board of Directors approves the borrowing of money in excess of $5 million dollars up to $10 million dollars in 2013.

Thomson

Wayne Thomson, Chair
Niagara Falls Hydro Holding Corporation

Oct 8/2013

Date

niagara peninsula energy

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September 10, 2013

Mr. Brian Walker
President
Peninsula West Power Inc.

Dear Mr. Walker:

Niagara Peninsula Energy Inc. is currently preparing a request for proposal to undertake a long term borrowing up to ten million dollars. The purpose of this financing is for general purposes and to replenish current cash flows. Niagara Peninsula Energy Inc. has internally financed $54.7 million dollars in capital expenditures over the past six years, since the merger between the former Niagara Falls Hydro Inc. and the former Peninsula West Utilities Ltd. As well Niagara Peninsula Energy Inc. has made principal repayments of $10.6 million dollars on its current long term borrowings over the past six years and has repaid $1.8 million dollars of regulatory liabilities in 2013 alone. Niagara Peninsula Energy has an additional $2.7 million dollars of regulatory liabilities to re-pay between August 2013 and May of 2014 and an additional $3.1 million dollars of the 2012 Deferral and Variance balances between May 1, 2014 and April 30, 2015. As a result of these activities Niagara Peninsula Energy's cash position has decreased by approximately $11.3 million since the end of the fiscal year ending December 31, 2008.

In accordance with the Shareholders Agreement dated January 1, 2008, Article 5 – Approval of Certain Corporate Actions, section 5.2 – Special Resolution by Shareholders, part (k) Borrowing of money in excess of $5 million dollars, Niagara Peninsula Energy requires a Special Resolution approved by its

Please see the enclosed Special Resolution requesting approval to obtain long term financing up to ten million dollars in 2013.

Please contact myself should anything further be required, I can be reached at 905-353-6004 or by email at Suzanne.Wilson@npei.ca.

Sincerely,

S Wilson

Suzanne Wilson CPA, CA
VP Finance
Niagara Peninsula Energy Inc.

Encl.

Cc: George Mitges
Brian Wilkie
Sue Forcier
Barb Krol

PENINSULA WEST POWER INC.
Special Resolution

In accordance with the Shareholders Agreement dated January 1, 2008,

WHEREAS Article 5 – Approval of Certain Corporate Actions, section 5.2 – Special Resolution by Shareholders, part (k) Borrowing of money in excess of $5 million dollars.

WHEREAS Niagara Peninsula Energy requires a Special Resolution approved by its shareholders Niagara Falls Hydro Holding Corporation and Peninsula West Power Inc.

THEREFORE BE IT RESOLVED that Peninsula West Power Inc.'s Board of Directors approves the borrowing by Niagara Peninsula Energy Inc. of money in excess of $5 million dollars up to $10 million dollars in 2013.

Dave Augustyn 7 October 2013

Dave Augustyn - Chair **Date**

Brian Walker 7 October 2013

Brian Walker - President **Date**

MINUTES
NIAGARA PENINSULA ENERGY INC.
FINANCE COMMITTEE MEETING
October 8, 2013 9:30 a.m.

A Finance Committee Meeting was held on October 8, 2013

Those present from the **Board of Directors** were:
Chair George Mitges, Brian Walker, Wayne Thomson, Wayne Campbell

Those present from **STAFF** were:
Brian Wilkie, President & CEO, Suzanne Wilson, Vice President of Finance, Barb Krol, Executive Assistant

Regrets: Joann Chechalk

Meeting Called to Order

Chair George Mitges called the meeting to order at 9:22 a.m.

Previous Minutes

George Mitges asked for a motion to accept the Minutes dated April 22, 2013.

MOVED BY: Wayne Thomson
SECONDED BY: Wayne Campbell

That the Minutes of April 22, 2013 be accepted.

CARRIED

Financial Institutions Presentations for Request for Proposal for Loan Financing

Suzanne Wilson referred to an RFP comparison sheet listing the 5 financial institutions, that she had contacted for financing for the amount of 10 million dollars for NPEI. These institutions included Meridian Credit Union, Royal Bank, Bank of Montreal, Scotiabank, and Toronto Dominion. Each financial institution was invited to give a ten minute presentation to present their proposals and answer any questions.

Suzanne also noted that she had received two special resolutions from both Niagara Falls Holding Corporation and Peninsula West Power Inc., allowing NPEI to proceed in obtaining 10 million dollars in financing.

A discussion took place after the five presentations took place. It was recommended to go with (TD) Toronto Dominion with a 5 year fixed interest rate loan based on the rate of $2.83% + Spread 0.32% = 3.15% all in rate.

It was decided to move forward and send out a poll vote to the Board for approval to award TD the RFP to finance 10 million dollars for NPEI.

MOVED BY: Wayne Thomson
SECONDED BY: Wayne Campbell

The Finance Committee's recommendation to the Board of Directors is to award the RFP to the TD bank in accordance with the terms provided in the RFP for the Term Sheet using Cost of Funds.

A Poll Vote was sent out and received back in favor of awarding TD the RFP to finance NPEI in the amount of 10 million dollars.

CARRIED

Proposed Finance Committee Mandate Review Memo – George Mitges

Wayne Campbell asked George Mitges why he approached Crawford, Smith and Swallow regarding the Finance Committee mandate review. Wayne said that George should have approached the Finance Committee first. George said he took the incentive to approach Crawford, Smith and Swallow, after doing research on his own. Wayne Thomson said that George should have first reported to the Finance Committee for approval.

Wayne Campbell referred to an article by Anthony Harrington entitled "Reaffirming The Role of the Audit Committee". Different aspects of George's mandate review were discussed. George maintained that he wants to strengthen the mandate for the Finance Committee, and that in doing so, he is looking after NPEI 's best interest. Wayne Campbell said that is up to the Board of Directors to look at this - it is not the role of the Finance Committee.

MOVED BY: Wayne Campbell
SECONDED BY: Wayne Thomson

That the Mandate Review be received on file.

Note: Brian Walker voted not in favor.

RECEIVED ON FILE

A discussion continued regarding the role of the Chair of the Finance Committee.

New Business

None at this time.

Adjournment

MOVED BY: Wayne Thomson
SECONDED BY:

That the meeting be adjourned at 10:45 a.m.

Chair George Mitges

Barbara Krol
Secretary

Next Finance Committee Meeting
Monday, December 2, 2013
NPEI Board Room

Niagara Peninsula Energy Inc
RFP Comparison for $10M loan financing - Schedule A
30-Sep-13

Description	TD	BMO	Scotiabank	Royal Bank	Meridian
Interest Rate/Cost of Funds (COF)					
5 Year Rate	Spot rate at Sept 30/13 = 2.83% + Spread 0.32% = 3.15% All in Rate 5 Year Forward Start rate Dec 10/13 =2.93% + Spread 0.32% = 3.25% All in Rate	Prime at Sept 30/2013 =3.00% + 0.20% = 3.20%	Cost of Funds Sept 30/2013 =3.06% + 0.50% = 3.56% All in Rate	Cost of Funds Sept 24/2013 = 3.57% All in Rate	Cost of Funds Sept 30/2013 = 2.84% + Spread 0.75% = 3.59% All in Rate
10 Year Rate	Spot rate at Sept 30/13 = 3.79% + Spread 0.32% = 4.11% All in Rate 10 Year Forward Start rate Dec 10/13 =3.9% + Spread 0.32% = 4.22% All in Rate	Prime at Sept 30/2013 =3.86% + .28% = 4.14%	NA	NA	Cost of Funds Sept 30/2013 = 4.01% + Spread 0.75% = 4.76% All in Rate

Description	TD	BMO	Scotlabank	Royal Bank	Meridian
Term of Loan	5 years: Interest only payments monthly (non-amortizing) OR 10 years: Interest only payments monthly (non-amortizing)	Demand Loan Non-Revolving -Interest only for 3 years maximum Fixed Rate Term Loan - principle payments commence immediately - no interest only option	5 Years	5 Years Interest only monthly payments	5 years: Interest only payments monthly (non-amortizing) OR 10 years: Interest only payments monthly (non-amortizing)
Prepayment Options	Standard prepayment penalties apply	No prepayment allowed on Fixed Rate Term Loan Demand Loan can be repaid anytime	Prepayment of the loan in whole or in part is permitted at any time on payment of an amount equal to the greater of 2 interest calculations	Fixed Rate Term Loan: Limited	Up to $1,000,000 per year prepayment without penalty
Commitment Fees	$Nil	$Nil	$Nil	$Nil	$1,000
Legal Fees for amendments to existing Inter-Creditor Agreement	$Nil	To be determined by NPEI's legal counsel	$Nil	To be determined by the legal counsels for each financial institution included	Any legal cost for account of Borrower--NPEI may use its own legal firm

Description	TD	BMO	Scotiabank	Royal Bank	Meridian
Any and all Other Fees	$Nil	Nil-security documents, annual review, booking/application, admin, monitoring	$Nil	All reasonable legal, Bank fees, costs, and expenses associated with the preparation of the Credit Facility documentation between the Lender and the Borrower are for the Borrower's account	No other fees
General Security Requirements	No new security documentation is required	General Security Agreement-Pari-Pasu with TD bank and Scotia Bank supported by Intercreditor Agreement	No change to existing arrangement - General Security Agreement and Inter-Creditor Agreement	General Security Agreement to rank in 1st position and pari-passu with other lenders	General Security Agreement and Inter-Lender agreement only
Debt Covenants	MinimumDebt Service Coverage Ratio = 1.25X Maximum Debt to Capitalization 0.60:1	Minimum Current Ratio: 1.10:1 Maximum Total Liabilities/Tangible Net Worth: 1.50:1	Maximum Debt to Capitalization 0.70:1 EBITDA to interest expense plus current portion of Long Term Debt and capital leases to be maintained at 1.50:1 or better	Maximum Debt to Capital Ratio: 60% Other standard covenants	Maximum Debt:Capitalization: 0.70:1 Debt Service Ratio: 1.50:1

Description	TD	BMO	Scotiabank	Royal Bank	Meridian
Latest Date Funds will be Transferred to NPEI's account	December 10, 2013 or earlier	No later than December 10, 2013	No later than December 10, 2013	No later than December 10, 2013	No later than December 10, 2013
Reporting Requirements	1)Audit annual F/S within 120 days of fiscal Y/E 2) Annual Budget within 120 days 3) Q1, Q2 and Q3 internal F/S	Audited Financial Statements Copy of Annual Budget	Audited Financial Statements Copy of Annual Budget	Audited Financial Statements Annual Operating and Capital Budget	1)Audit annual F/S within 120 days of fiscal Y/E 2) Annual Budget within 120 days
Other Notations/Comments	None	Funds subject to BMO review of the inter-creditor agreement	None	None	NPEI to establish chequing account for purposes of loan payments

**NPEI 5 year vs 10 year analysis
Long term Financing
Comparison**

	Interest Rate %	1	2	3	4	5	Total
5 Year comparison							
TD 5 yr	3.15	315,000	315,000	315,000	315,000	315,000	1,575,000
		315.000	315.000	315.000	315.000	315.000	1.575.000

Year	Interest Rate %	1	2	3	4	5	6	7	8	9	10	Total
10 Year comparison												
TD 10 yr	4.11	411,000	411,000	411,000	411,000	411,000	411,000	411,000	411,000	411,000	411,000	4,110,000
		411.000	411.000	411.000	411.000	411.000	411.000	411.000	411.000	411.000	411.000	4.110.000
TD at 5 years + balancing rate for next five years		315.000	315.000	315.000	315.000	315.000	507.000	507.000	507.000	507.000	507.000	4.110.000
Interest rate %		3.15	3.15	3.15	3.15	3.15	5.07	5.07	5.07	5.07	5.07	4.11

Bases Point Difference 1.92 60.95% % increase

Savings rate differential of 5.07 - 5.045691 12,154

2012 5 year rate	2.8
2013 5 year rate	3.15
Base point change	0.35
% Base point change	12.50%
Growth rate of 12.5% over next 5 years	5.045691

niagara peninsula energy

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September 2, 2014

Mr. Wayne Thomson
Chairman
Niagara Falls Hydro Holding Corporation
7447 Pin Oak Drive
Niagara Falls, ON
L2E 6S9

Dear Mr. Thomson:

Niagara Peninsula Energy Inc. ("NPEI") is seeking approval from its shareholders to undertake a long term borrowing of ten million dollars in 2014. The purpose of this financing is for general purposes and to replenish current cash flows and continue to fulfill the 2014 capital projects that were approved in the 2014 budget.

Niagara Peninsula Energy Inc. has internally financed $67.3 million dollars in capital expenditures over the past seven years, since the merger between the former Niagara Falls Hydro Inc. and the former Peninsula West Utilities Ltd. As well Niagara Peninsula Energy Inc. has made principal repayments of $12.5 million dollars on its current long term borrowings over the past seven years which has been offset by two interest only debt instruments in the amount of $10 million each. NPEI repaid $3.1 million dollars of regulatory liabilities in 2013 alone.

In 2014, Niagara Peninsula Energy is required to repay an additional $3.2 million dollars of regulatory liabilities between May 2014 and April of 2015. These regulatory balances relate to the retail settlement variances as at December 31, 2012.

Water billing was returned to the City of Niagara Falls in May 2014. The final true-up balance in the amount of $8.6 million was paid to Niagara Falls Hydro Services Inc. which is the affiliate company that performed the water billing, customer service and collections activities on behalf of Niagara Peninsula Energy Inc. for the water customers in the City of Niagara Falls.

Niagara Peninsula Energy has an approved capital budget in the amount of $12.9 million for 2014. Niagara Peninsula Energy is currently on track for the 2014 capital projects.

The global adjustment charge included in June and July's power bill from the IESO (Independent Electricity System Operator) was $6.4 million and $6.9 million respectively. The total power bill for June was $11.9 million and the total power bill for July was $$11.7 million. The increase in the global adjustment and the total power bill has put a strain on cash flows in the last two months. The total cost of power for the seven months ending July 31, 2014 is $77.5 million which has increased by $7.5 million for the same period ending July 31, 2013.

Currently, Niagara Peninsula Energy has an eight (8) million dollar operating line of credit of which NPEI will be required to draw on in September 2014 due to the cash balances declining. NPEI also has an $11.8 million dollar letter of credit held by the IESO in support of the monthly power bill. NPEI has a good payment history rating with the IESO and as a result received a reduction in the prudential support obligation in 2013. The operating line of credit at $8.0 million is currently insufficient to support a monthly power bill in the amount of $11.9 million.

Without this additional financing, NPEI would be unable to pay its power bill to the IESO in November 2014. NPEI would be unable to fulfill the 2014 capital projects and a strain on operations could result as well.

NPEI is currently preparing its 2015 Cost of Service rate application for rates effective May 1st, 2015. The last rebasing of rates for NPEI was in 2011. The Ontario Energy Board's capital structure policy is 60% debt, 40% equity in the calculation of the return on equity. NPEI's actual long term debt to equity ratio at the end of December 2013 was 44% debt and 56% equity. NPEI is currently under leveraged and as a result the actual return on equity (5.89%) is well below the deemed return on equity (9.58%) for 2013.

As a result of these activities Niagara Peninsula Energy's cash position at the end of July 2014 has decreased by approximately $7.5 million since the end of the fiscal year ending December 31, 2013.

In accordance with the Shareholders Agreement dated January 1, 2008, Article 5 – Approval of Certain Corporate Actions, section 5.2 – Special Resolution by Shareholders, part (k) Borrowing of money in excess of $5 million dollars, Niagara Peninsula Energy requires a Special Resolution approved by its shareholders Niagara Falls Hydro Holding Corporation and Peninsula West Power Inc.

Please see the enclosed Special Resolution requesting approval to obtain long term financing in the amount of ten million dollars in 2014.

Please contact myself should anything further be required, I can be reached at 905-353-6004 or by email at Suzanne.Wilson@npei.ca.

Sincerely,

S Wilson

Suzanne Wilson CPA, CA
VP Finance
Niagara Peninsula Energy Inc.

Encl.

Cc: George Mitges
Brian Wilkie
Sue Forcier
Barb Krol

Niagara Falls Hydro Holding Corporation

Special Resolution

In accordance with the Shareholders Agreement dated January 1, 2008,

WHEREAS Article 5 – Approval of Certain Corporate Actions, section 5.2 – Special Resolution by Shareholders, part (k) Borrowing of money in excess of $5 million dollars.

WHEREAS Niagara Peninsula Energy requires a Special Resolution approved by its shareholders Niagara Falls Hydro Holding Corporation and Peninsula West Power Inc.

THEREFORE BE IT RESOLVED that Niagara Falls Hydro Holding Corporation Board of Directors approves the borrowing by Niagara Peninsula Energy Inc. in the amount of $10 million dollars in 2014.

W Thomson

Wayne Thomson, Chair
Niagara Falls Hydro Holding Corporation

September 8, 2014

Date

niagara peninsula energy

Our energy works for you.

Head Office:
7447 Pin Oak Drive
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Niagara Falls, Ontario
L2E 6S9

T: 905-356-2681
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E: info@npei.ca
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September 2, 2014

Mr. Brian Walker
President
Peninsula West Power Inc.

Dear Mr. Walker:

Niagara Peninsula Energy Inc. ("NPEI") is seeking approval from its shareholders to undertake a long term borrowing of ten million dollars in 2014. The purpose of this financing is for general purposes and to replenish current cash flows and continue to fulfill the 2014 capital projects that were approved in the 2014 budget.

Niagara Peninsula Energy Inc. has internally financed $67.3 million dollars in capital expenditures over the past seven years, since the merger between the former Niagara Falls Hydro Inc. and the former Peninsula West Utilities Ltd. As well Niagara Peninsula Energy Inc. has made principal repayments of $12.5 million dollars on its current long term borrowings over the past seven years which has been offset by two interest only debt instruments in the amount of $10 million each. NPEI repaid $3.1 million dollars of regulatory liabilities in 2013 alone.

In 2014, Niagara Peninsula Energy is required to repay an additional $3.2 million dollars of regulatory liabilities between May 2014 and April of 2015. These regulatory balances relate to the retail settlement variances as at December 31, 2012.

Water billing was returned to the City of Niagara Falls in May 2014. The final true-up balance in the amount of $8.6 million was paid to Niagara Falls Hydro Services Inc. which is the affiliate company that performed the water billing, customer service and collections activities on behalf of Niagara Peninsula Energy Inc. for the water customers in the City of Niagara Falls.

Niagara Peninsula Energy has an approved capital budget in the amount of $12.9 million for 2014. Niagara Peninsula Energy is currently on track for the 2014 capital projects.

The global adjustment charge included in June and July's power bill from the IESO (Independent Electricity System Operator) was $6.4 million and $6.9 million respectively. The total power bill for June was $11.9 million and the total power bill for July was $$11.7 million. The increase in the global adjustment and the total power bill has put a strain on cash flows in the last two months. The total cost of power for the seven months ending July 31, 2014 is $77.5 million which has increased by $7.5 million for the same period ending July 31, 2013.

Currently, Niagara Peninsula Energy has an eight (8) million dollar operating line of credit of which NPEI will be required to draw on in September 2014 due to the cash balances declining. NPEI also has an $11.8 million dollar letter of credit held by the IESO in support of the monthly power bill. NPEI has a good payment history rating with the IESO and as a result received a reduction in the prudential support obligation in 2013. The operating line of credit at $8.0 million is currently insufficient to support a monthly power bill in the amount of $11.9 million.

Without this additional financing, NPEI would be unable to pay its power bill to the IESO in November 2014. NPEI would be unable to fulfill the 2014 capital projects and a strain on operations could result as well.

NPEI is currently preparing its 2015 Cost of Service rate application for rates effective May 1st, 2015. The last rebasing of rates for NPEI was in 2011. The Ontario Energy Board's capital structure policy is 60% debt, 40% equity in the calculation of the return on equity. NPEI's actual long term debt to equity ratio at the end of December 2013 was 44% debt and 56% equity. NPEI is currently under leveraged and as a result the actual return on equity (5.89%) is well below the deemed return on equity (9.58%) for 2013.

As a result of these activities Niagara Peninsula Energy's cash position at the end of July 2014 has decreased by approximately $7.5 million since the end of the fiscal year ending December 31, 2013.

In accordance with the Shareholders Agreement dated January 1, 2008, Article 5 – Approval of Certain Corporate Actions, section 5.2 – Special Resolution by Shareholders, part (k) Borrowing of money in excess of $5 million dollars, Niagara Peninsula Energy requires a Special Resolution approved by its shareholders Niagara Falls Hydro Holding Corporation and Peninsula West Power Inc.

Please see the enclosed Special Resolution requesting approval to obtain long term financing in the amount of ten million dollars in 2014.

Please contact myself should anything further be required, I can be reached at 905-353-6004 or by email at Suzanne.Wilson@npei.ca.

Sincerely,

Suzanne Wilson CPA, CA
VP Finance
Niagara Peninsula Energy Inc.

Encl.

Cc: George Mitges
Brian Wilkie
Sue Forcier
Barb Krol

PENINSULA WEST POWER INC.
Special Resolution

In accordance with the Shareholders Agreement dated January 1, 2008,

WHEREAS Article 5 – Approval of Certain Corporate Actions, section 5.2 – Special Resolution by Shareholders, part (k) Borrowing of money in excess of $5 million dollars.

WHEREAS Niagara Peninsula Energy requires a Special Resolution approved by its shareholders Niagara Falls Hydro Holding Corporation and Peninsula West Power Inc.

THEREFORE BE IT RESOLVED that Peninsula West Power Inc.'s Board of Directors approves the borrowing by Niagara Peninsula Energy Inc. of money in the amount of $10 million dollars in 2014.

Oct 2/14

Dave Augustyn - Chair **Date**

Oct 2 2014

Brian Walker - President **Date**

2014 Request for Proposal ("RFP") regarding the long term financing in the amount of ten million dollars

An RFP was issued regarding the long term financing in the amount of ten million dollars on September 19, 2014. Proponents were asked to submit their intent to propose by September 26, 2014 and submit the final proposal no later than noon on October 24, 2014.

Meridian Credit Union, Toronto Dominion (TD), Royal Bank of Canada (RBC) and Scotiabank submitted both their intent and their proposals by the deadline. CIBC declined to propose by email and the Bank of Montreal did not respond at all.

The Proponents were asked to propose a fixed interest rate on a ten million dollar loan with only interest payments being made (i.e. an unamortized loan) and they were asked to complete Schedule A.

A comparison of the key components of the RFP (Schedule A) is attached.

The five year fixed rate proposed by TD Bank has a 0.30% spread, Scotiabank' s spread was 0.32% and Meridian's spread was 0.5%. Due to the Royal Bank's proposal being an interest rate swap option it is difficult to compare their interest rate to the proponents who submitted a fixed interest rate. The Cost of Funds submitted in the RFP varied between the TD Bank, Scotiabank and Meridian Credit Union due to the different dates the financial institutions requested the spot rate or cost of funds on the market. However, subsequently NPEI received the Cost of Funds from Scotiabank and Meridian for October 24th. The following is an updated comparison of the five year rates.

TD Bank – October 24th – COF = 2.26% + 0.30% spread = 2.56% all in rate
Scotiabank – October 24th – COF = 2.51% + 0.32% spread = 2.83% all in rate
Meridian – October 24th – COF = 2.55% + 0.50% spread = 3.05% all in rate

The interest rate swap option was proposed by Royal Bank. An advantage to the swap would be if the intention is to pay it off inside the 5 or 10 year window, with the expectation that the interest rate would increase, and hence the result being NPEI would be "in the money" where the Lender would pay the Borrower the net present value of the change in swap rates for the outstanding period of the notional amount of the loan. Since it is not NPEI's current plan to retire the debt early, the swap is not advantageous for NPEI. Also the RFP did not request the proponents to propose a swap option. The RFP only requested the proponents to propose a fixed interest rate or Cost of Funds.

NPEI's historical interest rates supporting its financial borrowings are as noted below:

July 2009 – 4.58%
September 2010 – 4.97%
June 2012 – 2.80%
December 2013 – 2.933%
October 2014 – range in current RFP - 2.56% - 3.05%

As noted above the interest rate has decreased by 2.02% from 2009 to 2014 when using the low range of the current RFP proposed rates. Had NPEI opted for a five year interest rate swap in 2009, the Company would be subject to an interest rate swap loss in 2014.

Staff recommends awarding the RFP to TD with a fixed interest rate loan with interest only repayments. Staff also recommends a term of 5 years due to the historical declining trend in rates noted above.

Suzanne Wilson CPA, CA
VP Finance

Niagara Peninsula Energy Inc
RFP Comparison for $10M loan financing - Schedule A
27-Oct-14

Description	TD	Scotiabank	Royal Bank	Meridian
<u>Interest Rate/Cost of Funds (COF)</u> 5 Year Rate	Spot rate at Oct. 24/2014 = 2.26% + Spread 0.30% = 2.56% All in Rate	COF at Oct. 22/2014 =2.45% + 0.32% = 2.76% All in rate	BA Loan, hedged with Interest Rate Swap Floating Rate Loan (all pricing indicative as at 4:00 pm Oct 15, 2014 COF + BA spread = 1.82% + 1.11% = 2.93%	COF Sept 22/2014 = 2.77% + Spread 0.5% = 3.27% All in Rate
7 Year Rate	NA	COF at Oct. 22/2014 =2.73% + 0.50% = 3.23% All in rate	NA	NA
10 Year Rate	Spot rate at Oct. 24/2014 = 3.04% + Spread 0.30% = 3.34% All in Rate	NA	(all pricing indicative as at 4:00 pm Oct 15, 2014 COF + BA spread = 2.45% + 1.59% = 4.04%	COF Sept 22/2014 = 3.67% + Spread 0.50% = 4.17% All in Rate
Term of Loan	5 years: Interest only payments monthly (non-amortizing) OR 10 years: Interest only payments monthly (non-amortizing)	5 years: Interest only payments monthly (non-amortizing) 7 years: Interest only payments monthly (non-amortizing)	5 year interest only OR 10 year interest only. Interest Rate is locked in for term selected.	5 years: Interest only payments monthly (non-amortizing) OR 10 years: Interest only payments monthly (non-amortizing)

Description	TD	Scotiabank	Royal Bank	Meridian
Prepayment Options	Standard prepayment penalties apply	Prepayment of the loan in whole or in part is permitted at any time on payment of the bank's funding loss. If at the time of the prepayment the prevailing interest rates are higher than the booked rate there will be no prepayment penalty.	BA/SWAP loan: Spread penalty - None. The Bankers' Acceptance ("BA) loan can be paid down at the end of each month, quarter, or semi-annually (depending on the frequency of interest payments chosen by the borrower) without penalty. No BA can be repaid prior to its maturity. Interest Rate SWAP Facility: The Interest Rate Swap can be unwound at any time subject to a two-way interest rate differential calculation. A two-way calculation implies that if prevailing swap rates have moved down (compared to the original swap rate) the Borrower will owe the lender the Net Present Value ("NPV") of the change in swap rates for the outstanding period of the notional amount of the loan. If prevailing swap rates have moved up (compared to the original swap rate), the Lender will pay the Borrower the NPV of the change in swap rates for the outstanding period of the notional amount of the loan.	Up to $1,000,000 per year prepayment without penalty
Commitment Fees	$Nil	$Nil	$Nil	$Nil
Legal Fees for amendments to existing Inter-Creditor Agreement	$Nil	$Nil	To be determined by the legal counsels for each bank involved	Any legal cost for account of Borrower-- NPEI may use its own legal firm

Description	TD	Scotiabank	Royal Bank	Meridian
Any and all Other Fees	$Nil	$Nil	All reasonable legal, Bank fees, costs, and expenses associated with the preparation of the Credit Facility documentation between the Lender and the Borrower are for the Borrower's account	No other fees
General Security Requirements	No new security documentation is required	No change to existing arrangement - General Security Agreement and Inter-Creditor Agreement	General Security Agreement to rank in 1st position and pari-passu with other lenders	General Security Agreement and Inter-Lender agreement only
Debt Covenants	Minimum Debt Service Coverage Ratio = 1.20X Maximum Debt to Capitalization 0.60:1	EBITDA to interest expense plus current portion of Long Term Debt and capital leases to be maintained at 1.50:1 or better Maximum Debt to Capitalization 0.70:1	Maximum Debt to Capital Ratio: 60% Such standard covenants that the lender may incorporate in the final Credit Agreement A default in any agreement with any other lender constitutes a default with RBC.	Maximum Debt: Capitalization: 0.70:1 Debt Service Ratio: 1.50:1
Latest Date Funds will be Transferred to NPEI's account	November 12, 2014 or earlier	November 12, 2014 or earlier	November 12, 2014, upon receipt by the Bank of duly executed security documentation.	November 12, 2014 or earlier

Description	TD	Scotiabank	Royal Bank	Meridian
Reporting Requirements	1)Audit annual F/S within 120 days of fiscal Y/E 2) Annual Budget within 120 days 3) Q1, Q2 and Q3 internal F/S within 45 days 4) Annual OEB rate submission and SQI if applicable	Audited Financial Statements Copy of Annual Budget	Audited Financial Statements within 180 days of fiscal year end Copy of Annual Operating and Capital Budget Quarterly in-house financial statements (to include balance sheet and income statement) compared to annual budget.	1)Audit annual F/S within 120 days of fiscal Y/E 2) Copy of Annual Budget
Other Notations/Comments	None	None	None	NPEI to establish chequing account for purposes of loan payments

ATTACHMENT # 9-FMR consultant documentation-IRR#38

niagara peninsula energy Inc.

Supply Chain Process Review
September 09 – September 27, 2013

Prepared by: Focused Management Resources

735 Avenue Road Toronto, Ontario M5P 2J9 V: 416-489-8885 F: 416-544-0204 Web: www.fmrcg.com

Contents

niagara peninsula energy inc.

niagara peninsula energy inc.

Opportunities for Improvement

Opportunities: Automation

- GP modified to generate Usage reports. i.e.. flag transactions at 0 for slow moving or obsolete stock.
- Auto-generation of PO's for routine purchases. Functionality exists in GP.
- Modifications to PO generation in GP: allow for multiple Ship To addresses, allow additional fields to include Description, additional fields to include Standard (ESA requirement), additional fields for US Vendors, add field for Product #.
- Set up electronic repositories to reduce paper filing and for ease of reference.

Opportunities: Automation

niagara peninsula energy Inc.

- Move to Bar Coding for matching on the dock. Also for accuracy of returning stock into inventory.
- GP modified to allow inventory to be put on hold for assigned projects.(medium to large projects). Contingent on firm start date within 2 to 3 weeks of start date.
- Additional functionality in GP to identify back orders.
- Generate Daily Receiving Report in GP.

Opportunities: Process

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- Obsolete and slowing moving inventory tagged and separated from routine stock. Subject Matter Expert opinion: 2 of existing 5 aisles has obsolete stock.
- Aisles and associated stock aligned with optimum material flow . i.e.. high running and complementary stock grouped for ease of handling.
- Stock organized on shelves according to like work activity. i.e... Tx, Insulators.
- BOM adjusted to only include A and B items with highest degree accuracy and the least issues to pick and stage.
- Designated areas for Returns, Quarantine, Scrap and Staging. i.e... Painted floors and signage.

Opportunities: Process

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- Location of each SKU ties to a set shelf and location.
- Uniform measurements on floor i.e... for wire requirement. Move from Metric and Imperial to Metric.
- Standardized matching process (current manual): match Open PO to Packing Slip and then generate Receiving Report by Storekeeper at dock.
- Alternative to Storekeeper matching is AP matching and entering into GP in edit mode at dock.
- Standardized review of the BOM. Standard practice: reviewed by Materials prior to issue for Build.

Opportunities: Process

- Eliminate Stores 2 as Returns area for inventory that can be used on other jobs. Unable to accurately cost a completed job, inventory not accurate.
- Schedule adherence on projected start date estimated at 50% accurate. Impact on inventory levels. Best practice- 80% schedule adherence.
- Move from metallic labels to fixed identifiers or fixed inserts.
- Use of vending machines for non-inventory items i.e... ear plugs, bug spray, sunscreen. Activate with swipe card.

Opportunities: Process

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- Wire segmented by functional areas i.e... UG, OH.
- Standard prep time for Stores from Operation as to start date for a job. Communicated with 2 to 3 weeks of job start date. Allow time to pull, kit and stage. Actual time needed is estimated 1.5 to 2.5 days in advance.
- Only stage A and B items for greater accuracy.
- Use of locked cages for kitted material (for medium to large jobs). Standard industry practice.
- Migrate to JIT and Drop shipments over long term. Contingent on effective Planning and scheduling.
- Move to Strategic Supplier relationships. Contingent on effective Planning and scheduling.

Opportunities: Process

- Standard racking applied-height and width and number.
- Standard process for stock discrepancies identified at the dock.
- Print two copies of PO in Purchasing prior to routing to AP: one kept in binder and one sent to AP matched to Packing slip (in lieu of photocopying in AP and routing original back to Purchasing).
- Introduce Signature Book in Accounting for reference.
- Ordering all stock on one blue Material Movement Sheet versus multiple sheets (contingent on ability to kit and stage with lead provided from Operations to Stores)

Opportunities: Process

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- Pink Material Movement Sheets sent directly to Engineering by Stores versus Stores > Purchasing Manager > Engineering. (non value add).
- Formal documentation of Vendor performance.
- Explore 3 year contracts for enhanced Supplier stability. Identify where 3 year contracts are reasonable i.e.. landscaping.
- Tx returns:
  - Tag as return
  - Tag as assessed and returned to inventory
  - Move to Bar coding versus manual logs
  - Identify what is in repair on J Drive

Opportunities: Process

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- Generate separate PO's for different yards as interim step to GP modification of PO. Note: label with Smithville address can be put over NF address but not consistently applied.
- Consistent closing out of PO's versus identified as cancelled.
- Buying Consortiums with other LDC's (being considered). Objectives:
  - Collective buying for economies of scale
  - Sharing product information
  - Identification of performance issues

Opportunities: Process

- Need to document Material Handling and Inventory Management procedures and move from “Tribal Knowledge” to mitigate disruption due to absenteeism.
- Assess overall inventory philosophy: Lean approach versus “insurance” approach. Contingent on effectiveness of Planning and Scheduling.
- Formalize approach of dealing with wire inventory to reduce partial reels:
  - Group by function
  - Tag and hold for specific jobs
  - Rack off ground
  - Use of electronic sensors to determine remaining stock
  - Ensure completion of Material Movement Sheets

Opportunities: Process

- Determine root cause for extensive gap between Material Movement Sheets (Blue versus Pink):

6 month YTD for 2013

	MMS	MMR
NF	686	52
PW	312	9
	998	**61**

Opportunities: Role Clarity

- Project planning for upcoming year uses the Triangle of Operations, Engineering and Supply Chain.
- Standardized activities between yards i.e... BOM review, generating Receiving Report.
- Ownership of yard standardized and aligned with standard practice: Stores owns the yard. i.e.. doing ongoing count of A items at minimum.
- Stores not to accept Material Movement Sheets (Pink or Blue) without Project # and other mandatory data.
- Introduction of Inspection function at dock with guidance from Engineering. Coupled with designated Quarantine for Engineering review.

Opportunities: Role Clarity

niagara peninsula energy inc.

- Move to supplier managed inventory for expense items i.e... coffee, paper supplies, toiletries.
- Introduction of Standards Review Committee to review inventory utilization and standards. Comprised of Engineering. Operations and Supply Chain. (identify and remove non stock, identify slow moving stock and move to back aisles and avoid mixing with stock items)
- Variance analysis and reconciliation performed by the Tech. Standard practice. i.e.. lessons learned on a job, accuracy of job costing.
- Documented procedures or work instructions: movement of material during day or off hours; returns; other.

Opportunities: Role Clarity

- Standard Pre Construction meeting between Tech and LH at site. Communicate changes to material requirements prior to job issue.
- Discontinue breakdown of stock into small quantities i.e.. baggies with defined quantities. Not material activity.
- Introduce IT Advisory Committee to identify proposed modifications to GP, modifications to existing reports, other.
- Reallocation of responsibilities. Storekeeper made responsible for reordering low cost expense items. i.e.. paper supplies.
- Identify who is back up in Purchasing to backfill.
- Current job description for Storekeeper is appropriate for Laborer position not Material Handler.

Opportunities: Reports, Performance Management and Metrics

- Review and apply functionality that currently exists in GP: Inventory Turns Report, ABC Groupings, Transactions Report. Associated metrics can be output.
- Visual management applied in Stores: aisles clearly marked, shelves and shelf locations identified, current Projects and projected start dates (within 2 to 3 weeks) on white board, other. Move from "Tribal Knowledge."
- Basic work instructions (one page) for Returns, Material Movement Sheets, other.

Opportunities: Performance Management and Metrics

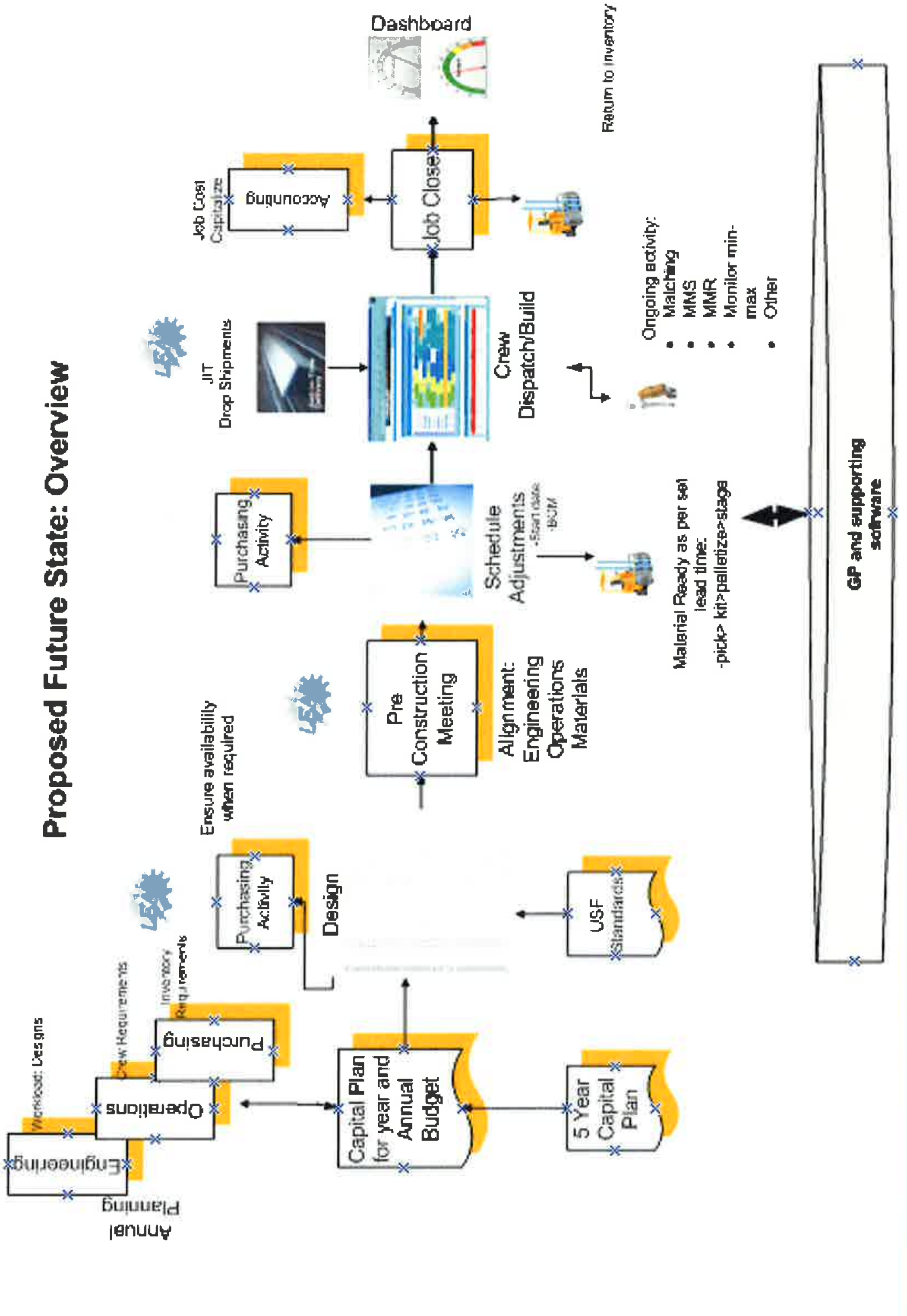
- Schematic of revised layout (i.e... stock locations) in public view. Used by Operations i.e.. Trouble crews and Accounting i.e.. cycle counts.
- Ongoing review of inventory cost and levels as a standard metric- extent to which inventory serves as an insurance policy.
- Introduction of Key Performance Indicators(including targets) in Balanced scorecard approach: i.e..
  - Supply chain: on time delivery, invoice issues, inventory level, turns, slow moving and obsolete, inventory discrepancies
  - Operations: shortages, window time and time leaving yard, number of Blue Sheets off the road
  - Engineering: deviations from spec, items not passed Inspection
  - Accounting: write offs, inventory level, waste, cycle time for Returns (job close to return to inventory)

Opportunities: Other

- Education on the importance of completing the Material Movement Sheets (Blue and Pink) with mandatory data i.e... Project #.
- Use of 5S Checklist to identify and assess the effectiveness and efficiency of new layout and floor design.
- Educate on intended use of the BOM-used as a guideline.
- Use of e-forms for reconciling Truck time with hours worked and tied to Project #.
- Formal Planning and Scheduling approach introduced: Capacity planning, identification of planning factors and dependencies such as seasonality, historical Demand and Reactive work. Goal: improve Schedule Adherence to enable JIT, drop shipments, normalize inventory level over time.

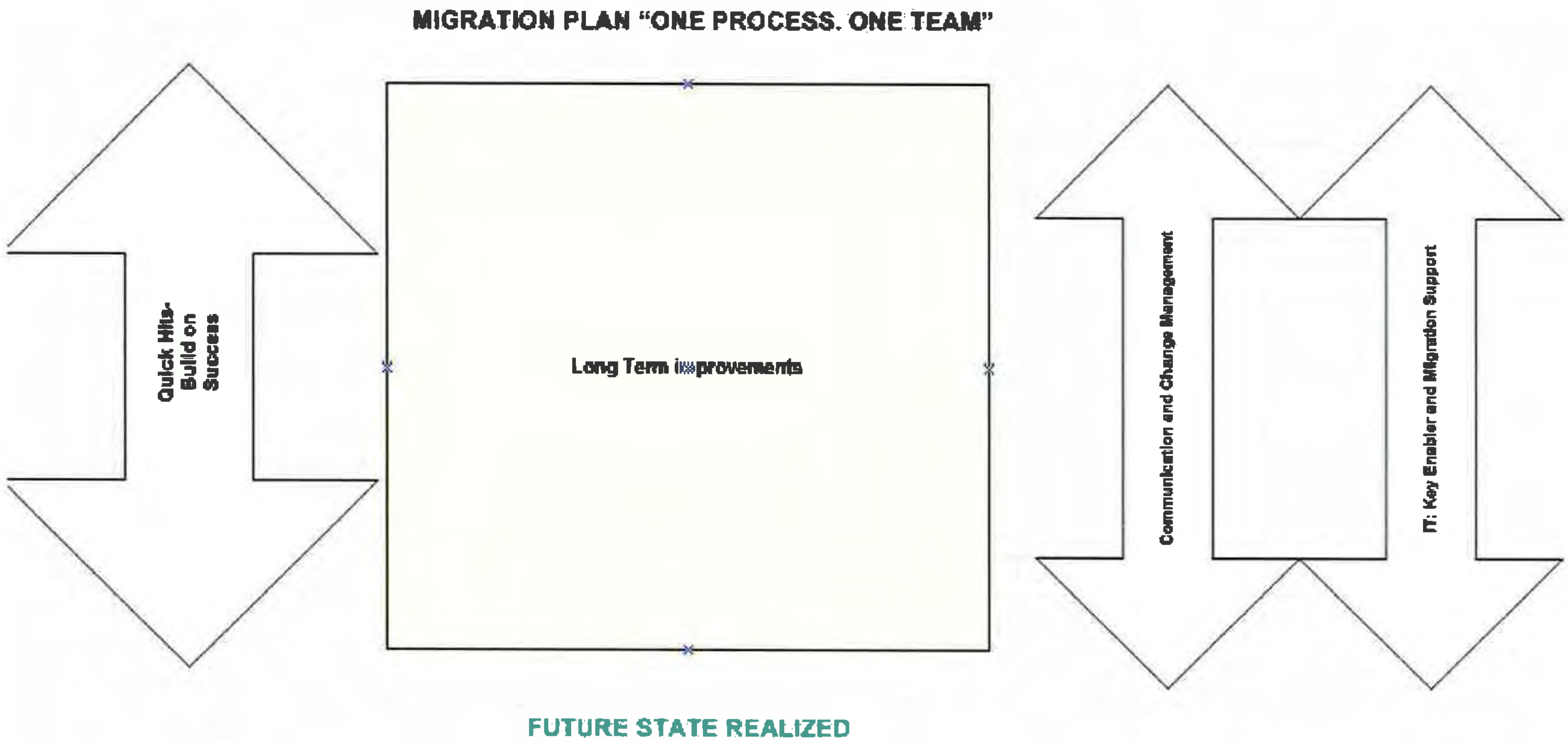
niagara peninsula energy Inc.

Proposed Future State

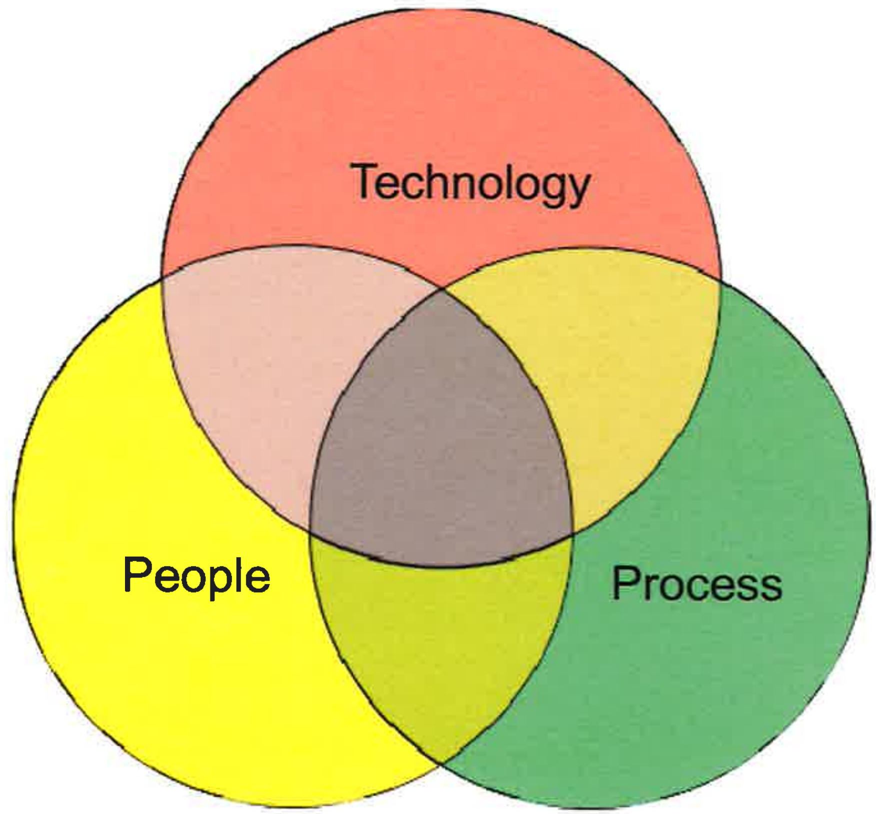

Proposed Future State: Overview
Annual Planning
Engineering
Workload: Designs
Operations
Crew Requirements
Purchasing
Inventory Requirements
Capital Plan for year and Annual Budget
5 Year Capital Plan
Purchasing Activity
Design
Ensure availability when required
USF Standards
Pre Construction Meeting
Alignment:
Engineering
Operations
Materials
Purchasing Activity
Schedule Adjustments
JIT
Drop Shipments
Crew Dispatch/Build
Material Ready as per set lead time:
-pick> kit>palletize>stage
Ongoing activity:
Matching
MMS
MMR
Monitor min-max
Other
Job Cost
Capitalize
Accounting
Job Close
Return to inventory
Dashboard
GP and supporting software

Migration Plan

Migration Plan



Coordinated Approach



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Quick Hits

(Minimal or No Cost)

Quick Hits

- Introduction of basic tagging system i.e.. Red: Obsolete stock.
- Identify obsolete stock, tag and remove.
- Eliminate Stores 2.
- Eliminate non value add activity:
  - AP printing off copies of original hard copy PO
  - Routing of MMR from Stores to Purchasing Manager
  - Other

Quick Hits

- Generate separate PO's for yards.
- Introduce supplier managed inventory for low value expense items.
- Purchasing backup identified.
- Basic Visual Management introduced i.e.. whiteboard with Project # and Start Date.
- Initiate auto generation of PO's for routine and low cost items.

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Long Term Improvements (>3 Months)

Improvements

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- Matching Process: PO to packing slip and generate Receiving Report. Phased implementation:
  - Phase 1: AP matches PO to Packing slip at dock and enters information into GP in edit mode.
  - Phase 2: Stores uses bar coding to match upon receipt at dock.
- Material Movement Sheets(Blue and Pink): compliance to a standard process.
- Space design and build:
  - Design based on Lean approach to inventory control and material handling (see 5S Checklist).
  - Design based on desired role definition for Supervision and Stores staff.
  - Design tied to optimizing productivity for Supervision and staff (reduction in “Red” as per Day In the Life studies).

Improvements

- Formalize Pre-Construction process with a triangle approach of Engineering, Operations and Materials. Agreement on start date, BOM, materials required and available. Can occur 2 to 3 weeks in advance of start date.
- Pre-Construction meetings includes set checklists and agendas.
- For medium to large sized projects: standard practice implemented to kit materials, palletize, shrink wrap and stage. Stage in designated areas with locked cages. Initially pick and stage A and B class inventory.
- For simplicity, only include A and B items on BOM. Other items covered through Material Movement Sheets.

Improvements

niagara peninsula energy inc.

- Variance analysis and reconciliation performed by Techs. Can be a phased approach: Materials reconciliation then Hours reconciliation.
- Increase schedule adherence via following:

  - Formal Pre-Construction meetings which includes Materials
  - Set lead times for Stores to prepare, pick and stage
  - Consideration of key planning and scheduling factors including crew availability, historical Reactive and Demand work, seasonality and capacity of crews

  Schedule adherence facilitates drop shipments, JIT delivery, supplier managed inventory and enhanced supplier relationships.

Improvements

- Introduction of IT Advisory Committee to suggest modifications to O/S and Standards Review Committee to review and assess material requirements.
- Movement to professional Purchasing:

  -delegating or eliminating non value activity

  -introduction of KPI's

  -routinely monitor usage patterns and correct inventory

  -move to a supply chain approach in which Purchasing and Stores are an integral part of a project lifecycle from Design to Build to Close.

Communication and Change Management

Communication and Change Management

niagara peninsula energy Inc.

- Job review for key positions. Standard industry practice used as a benchmark. Determine modification to existing job descriptions or creation of new positions. i.e.. combining of existing activities. Confirm required job specs and accountability for each position. i.e. ownership of Yard
- Identify optimum structure and reporting relationships.
- Stakeholder analysis conducted to assess readiness and willingness for change. Issues identified.
- Skills matrix conducted to assess skills gaps between current and desired competencies.
- Training plan developed and implemented tied to improvements and desired skill sets.
- Re-organization identified and initiated –roles and reporting relationships.
- Mentoring and coaching as required.

Communication and Change Management

niagara peninsula energy inc.

- Pace and magnitude of change estimated. Factored into overall Project Plan.
- Periodic audit of change - revised work practices and activities. General rule: 10 weeks of sustained change constitutes behavioral change.
- Key Messages for Project Champions identified and routinely communicated.
- Successful implementation of change communicated i.e.. Quick Hits routinely communicated and celebrated.
  - *GOAL: Sustained change*.

IT: Key Enabler and Migration Support

IT: Key Enabler and Migration Support

- Confirm existing GP functionality.
- Confirm existing reports that can be generated in GP.
- Identify changes to GP- initial emphasis on PO and Inventory.
- Assess feasibility and cost of suggested GP modifications.
- Modifications done or overseen.
- Support the generation of key electronic reports.
- Introduction of new technology (hardware or software) including doing or overseeing the creation of functional and technical specs, testing, UAT, implementation, other.
- Support creation of a holistic dashboard-Key Performance Indicators useful to Accounting, Purchasing, Operations and Engineering. (maximum of 5 to 10 KPI's that be produced electronically).

Proposed Future State Benefits

Benefits

- Reduced rework
- Increased availability
- Greater Quality Assurance
- Enhanced productivity
- Strategic arrangements with Suppliers
- Lower supplier costs and greater stability
- Less waste
- Effective Management Reports

Benefits

niagara peninsula energy inc.

- Schedule adherence
- Improved morale
- Supports Strategic decision making
- Clear expectations
- Improved Performance Management
- Proactive management and supervision
- Reduced dependency on “Tribal Knowledge”
- Optimizing resources

niagara peninsula energy Inc.

Business Case For Change

Opportunities

niagara peninsula energy inc.

- **Opportunity One:** Eliminate obsolete inventory.
  - **How:** Review usage patterns and aging. Physical inspection. Red tag obsolete stock and move to quarantine. Set up annual write off allowance and tie to budget. Scrap and cost recovery.
  - **Value:** Estimated $50K in obsolete stock.
  - **Considerations:** Coordinated effort between Engineering, Operations and Materials.

Opportunities cont'd

- **Opportunity Two:** Buying based on usage Patterns
  - **How:** Identify Quarterly needs. Set buying to usage requirements.
  - **Value:** Reduce the number of unplanned issues. Reduce inventory on hand. TBD.
  - **Considerations:** Training on how to apply usage patterns as a parameter. GP modification.

Opportunities cont'd

- **Opportunity Three:** Rationalize inventory levels "Provide what's needed at a minimum cost"
  - **How:** Reduce inventory as schedule adherence improves and understanding of usage patterns. Goal: 70 to 80% schedule adherence.
  - **Value:** Estimated reduction in annual spend of $.5M. (compared to inventory practices in other LDC's).
  - **Considerations:** Move from inventory as an "insurance policy."

Opportunities cont'd

- **Opportunity Four:** Alignment of BOM with Material pick.
  - **How:** Pre-Construction agreement on BOM between Operations, Engineering and Materials and then sign off.

    BOM Focus: A and B stock.
  - **Value:** See Opportunity Nine for Value
  - **Considerations:** Need alignment between Engineering, Operations and Materials. Feedback to Engineering is needed if there is a change in specifications.

Opportunities cont'd

- **Opportunity Five:** Kit material and stage for internal crews
  - **How:** Standardize material handling between yards. Kit>Palletize>Shrink Wrap>Place WO >Stage>Pick up
  - Standardize handling regardless of changes to Planning and Scheduling
  - **Value:** Reduce traffic at Stores window. Move crews quickly out of yard. $ TBD.
  - **Considerations:** Does not eliminate parts substitution and not working to the BOM. Will still have periodic traffic at window.

Opportunities cont'd

- **Opportunity Six:** Develop Supplier relationships. i.e. drop shipments, JIT delivery, supplier managed inventory.
  - **How:** Identify high performance Suppliers with strong buying power who desire long term strategic alliances
  - **Value:** TBD
  - **Considerations:** Need to develop solid Planning and Scheduling with schedule adherence.

Opportunities cont'd

niagara peninsula energy inc.

- **Opportunity Seven:** Drop shipments to the Site
  - **How:** Identify selected specific items for drop shipment i.e. Tx, Reels, Poles. Drop ship for large capital jobs. Set up reasonable Re-Order points and Re-Order Quantities for material. Set up secure storage (i.e. containers) on site. Coordinate with Vendor.
  - **Value:** Reduce movement in and out of Stores for material and waiting time (i.e. $500 per hour per crew).
  - **Considerations:** Limited drop shipments without effective Planning and Scheduling.

Opportunities cont'd

- **Opportunity Eight:** Reduction in waste.
  - **How:** Development and adherence to standard procedures for material returns, tagging and holding reels of Wire for set projects, reduction in partial reels for Wire, elimination of Stores 2.
  - **Value:** Estimated $50K+
  - **Considerations:** Compliance with defined procedures. Ownership of the yard defined and followed.

Opportunities cont'd

- **Opportunity Nine:** Reduction in non value add time
  - **How:** Increase in value time through changes to following processes:
    - PO generation and matching
    - Review of Material Management Sheets
    - Review of Material Management Returns
    - Bill of Materials and Material pick
    - Inventory Discrepancies
    - Supplier managed inventory
    - Use of existing GP functionality i.e. Auto generation of PO's
    - Introduction of Bar code technology
  - **Value:** 1 to 2 FTE's of non value add time eliminated across various positions (excluding Stores)
  - **Considerations:** Understanding and adherence to defined work practices and roles.

Opportunities cont'd

niagara peninsula energy inc.

- **Opportunity Ten:** Improved Stores productivity
  - **How:** Productivity will be improved from following:
    - Various procedural changes (see Opportunity Nine)
    - Floor design based on Lean approach
    - Floor design based on expectations of Supervisors and staff
    - Review and change to job specs, reporting relationship
    - Setting and adherence to expectations
  - **Value:** .5 FTE of improved productivity.
  - **Considerations:** Understanding and adherence to defined work practices and roles.

Conclusions

FMR Implementation

- Involvement on all levels
- Constructive confrontation of issues
- A sense of urgency
- Focus on results
- Joint commitment to delivery
- Accountability for performance
- Ownership of solutions
- A requirement for honesty and an appropriate response

"Doing what we say we will do"

ATTACHMENT # 10-Service Reliability Raw Data-IRR #39

Fig.5-4

Month	2009	2010	2011	2012	2013
1	0.0428	0.0457	0.0143	0.1098	0.2827
2	0.2285	0.0116	0.0355	0.2766	0.0583
3	0.0610	0.1672	0.0630	0.3576	0.0766
4	0.0950	0.3709	0.4333	0.0590	0.1407
5	0.4274	0.4208	0.0503	0.0416	0.0763
6	0.2919	0.2515	0.0847	0.1013	0.1417
7	0.0353	0.2298	0.9400	0.1473	2.3378
8	1.2731	0.0799	0.2889	0.7614	0.4443
9	0.1069	0.3882	0.2635	0.4397	0.2232
10	0.0370	0.0332	0.3075	0.1566	0.2338
11	0.0378	0.0844	0.0138	0.1087	0.2986
12	0.0439	0.0286	0.0857	0.1937	1.2442
Totals	**2.6806**	**2.1117**	**2.5806**	**2.7533**	**5.5583**

Fig 5-5

Month	2009	2010	2011	2012	2013
1	0.0428	0.0457	0.0143	0.1049	0.2814
2	0.2285	0.0116	0.0355	0.2701	0.0583
3	0.0610	0.1672	0.0630	0.3573	0.0766
4	0.0950	0.0320	0.4329	0.0590	0.1264
5	0.4274	0.4208	0.0503	0.0377	0.0761
6	0.2919	0.2515	0.0847	0.0883	0.1124
7	0.0353	0.2298	0.9400	0.1472	2.1753
8	1.2731	0.0799	0.2889	0.4019	0.4443
9	0.1069	0.3882	0.2635	0.4397	0.2231
10	0.0370	0.0332	0.3075	0.1566	0.1999
11	0.0378	0.0844	0.0138	0.1087	0.2921
12	0.0439	0.0286	0.0857	0.1369	1.2426
Totals	**2.6806**	**1.7729**	**2.5801**	**2.3082**	**5.3085**

Fig 5-7

Month	2009	2010	2011	2012	2013
1	0.0428	0.0457	0.0143	0.1049	0.2814
2	0.2285	0.0116	0.0355	0.2701	0.0583
3	0.0610	0.1672	0.0630	0.3573	0.0766
4	0.0950	0.0320	0.4329	0.0590	0.1264
5	0.4274	0.4208	0.0503	0.0377	0.0761
6	0.2919	0.2515	0.0847	0.0883	0.1124
7	0.0353	0.2298	0.9400	0.1472	0.6184
8	1.2731	0.0799	0.2889	0.4019	0.4443
9	0.1069	0.3882	0.2635	0.4397	0.2231
10	0.0370	0.0332	0.3075	0.1566	0.1999
11	0.0378	0.0844	0.0138	0.1087	0.2921
12	0.0439	0.0286	0.0857	0.1369	0.0384
Totals	**2.6806**	**1.7729**	**2.5801**	**2.3082**	**2.5474**

Fig 5-10

Month	2009	2010	2011	2012	2013
1	0.0147	0.0092	0.0033	0.0888	0.2444
2	0.1500	0.0046	0.0309	0.1427	0.0384
3	0.0817	0.1166	0.0220	0.2397	0.0308
4	0.0475	0.1976	0.4855	0.0876	0.0656
5	0.1251	0.2661	0.0662	0.0248	0.0334
6	0.2124	0.1075	0.0881	0.1512	0.0625
7	0.0123	0.2493	0.4653	0.0975	0.5354
8	0.2825	0.0456	0.0865	0.2097	0.1968
9	0.0771	0.1527	0.0852	0.1174	0.1273
10	0.0199	0.0249	0.1697	0.0850	0.2406
11	0.0622	0.0511	0.0099	0.1225	0.2410
12	0.0343	0.0096	0.0289	0.3347	0.3915
Totals	**1.1197**	**1.2348**	**1.5415**	**1.7015**	**2.2078**

Fig 5-11

Month	2009	2010	2011	2012	2013
1	0.0147	0.0092	0.0033	0.0624	0.2420
2	0.1500	0.0046	0.0309	0.1146	0.0384
3	0.0817	0.1166	0.0220	0.2393	0.0308
4	0.0475	0.0238	0.4758	0.0876	0.0251
5	0.1251	0.2661	0.0662	0.0245	0.0215
6	0.2124	0.1075	0.0881	0.0477	0.0336
7	0.0123	0.2493	0.4653	0.0975	0.4638
8	0.2825	0.0456	0.0865	0.1848	0.1967
9	0.0771	0.1527	0.0852	0.1174	0.1269
10	0.0199	0.0249	0.1697	0.0847	0.1643
11	0.0622	0.0511	0.0099	0.1225	0.1990
12	0.0343	0.0096	0.0289	0.0465	0.3913
Totals	**1.1197**	**1.0610**	**1.5318**	**1.2294**	**1.9334**

Fig 5-12

Month	2009	2010	2011	2012	2013
1	0.0147	0.0092	0.0033	0.0624	0.2420
2	0.1500	0.0046	0.0309	0.1146	0.0384
3	0.0817	0.1166	0.0220	0.2393	0.0308
4	0.0475	0.0238	0.4758	0.0876	0.0251
5	0.1251	0.2661	0.0662	0.0245	0.0215
6	0.2124	0.1075	0.0881	0.0477	0.0336
7	0.0123	0.2493	0.4653	0.0975	0.0643
8	0.2825	0.0456	0.0865	0.1848	0.1967
9	0.0771	0.1527	0.0852	0.1174	0.1269
10	0.0199	0.0249	0.1697	0.0847	0.1643
11	0.0622	0.0511	0.0099	0.1225	0.1990
12	0.0343	0.0096	0.0289	0.0465	0.0131
Totals	**1.1197**	**1.0610**	**1.5318**	**1.2294**	**1.1558**

Fig 5-15

Month	2009	2010	2011	2012	2013
1	2.9073	4.9800	4.3374	1.2360	1.1567
2	1.5236	2.5263	1.1511	1.9385	1.5198
3	0.7468	1.4332	2.8654	1.4923	2.4855
4	2.0007	1.8768	0.8927	0.6737	2.1433
5	3.4155	1.5813	0.7598	1.6753	2.2824
6	1.3744	2.3401	0.9613	0.6700	2.2682
7	2.8794	0.9217	2.0204	1.5107	4.3663
8	4.5061	1.7542	3.3387	3.6311	2.2583
9	1.3853	2.5418	3.0909	3.7438	1.7533
10	1.8645	1.3327	1.8119	1.8424	0.9716
11	0.6070	1.6502	1.3877	0.8878	1.2388
12	1.2786	2.9876	2.9693	0.5788	3.1779
Totals	**2.3940**	**1.7102**	**1.6741**	**1.6182**	**2.5176**

Fig 5-16

Month	2009	2010	2011	2012	2013
1	2.9073	4.9800	4.3374	1.6806	1.1627
2	1.5236	2.5263	1.1511	2.3577	1.5198
3	0.7468	1.4332	2.8654	1.4933	2.4855
4	2.0007	1.3430	0.9099	0.6737	5.0355
5	3.4155	1.5813	0.7598	1.5340	3.5453
6	1.3744	2.3401	0.9613	1.8501	3.3454
7	2.8794	0.9217	2.0204	1.5103	4.6898
8	4.5061	1.7542	3.3387	2.1746	2.2583
9	1.3853	2.5418	3.0909	3.7438	1.7580
10	1.8645	1.3327	1.8119	1.8491	1.2166
11	0.6070	1.6502	1.3877	0.8878	1.4673
12	1.2786	2.9876	2.9693	2.9447	3.1758
Totals	**2.3940**	**1.6709**	**1.6844**	**1.8775**	**2.7456**

Fig 5-17

Month	2009	2010	2011	2012	2013
1	2.9073	4.9800	4.3374	1.6806	1.1627
2	1.5236	2.5263	1.1511	2.3577	1.5198
3	0.7468	1.4332	2.8654	1.4933	2.4855
4	2.0007	1.3430	0.9099	0.6737	5.0355
5	3.4155	1.5813	0.7598	1.5340	3.5453
6	1.3744	2.3401	0.9613	1.8501	3.3454
7	2.8794	0.9217	2.0204	1.5103	9.6147
8	4.5061	1.7542	3.3387	2.1746	2.2583
9	1.3853	2.5418	3.0909	3.7438	1.7580
10	1.8645	1.3327	1.8119	1.8491	1.2166
11	0.6070	1.6502	1.3877	0.8878	1.4673
12	1.2786	2.9876	2.9693	2.9447	2.9281
Totals	**2.3940**	**1.6709**	**1.6844**	**1.8775**	**2.2040**

ATTACHMENT # 11 Feeder Performance Summary by SAIFI-IRR #42

2012 Feeder Performance Summary
Sorted by SAIFI

Substation Name	Feeder ID	Total Cust Hours of Interruption (1)	Total Customer Interruptions (2)	Total # of Customers (3)	SAIDI Averae Hours of Interruptions / Cust. (4) = (1) / (3)	SAIFI Average # of Interruptions / Cust. (5) = (2) / (3)	CAIDI Speed of Power Restoration (6) = (4) / (5)
Kalar TS	KM3	5,714	9465	1591	3.591	5.949	0.604
Murray TS	3M30	5,438	3283	852	6.382	3.853	1.656
Niagara West TS	2508M5	8,303	4324	1297	6.402	3.334	1.920
Murray TS	3M27	6,054	3301	1083	5.590	3.048	1.834
Murray TS	3M17	17,412	6374	2563	6.793	2.487	2.732
Stanley TS	12M43	6,817	5191	2514	2.712	2.065	1.313
Murray TS	3M54	4,933	3390	1774	2.781	1.911	1.455
Niagara West TS	2508M4	416	265	151	2.753	1.755	1.569
Stanley TS	12M6	6,599	3837	2274	2.902	1.687	1.720
Kalar TS	KM8	936	1754	1089	0.859	1.611	0.533
Murray TS	3M56	2,954	3168	1971	1.499	1.607	0.932
Murray TS	3M52	1,823	566	376	4.849	1.505	3.221
Stanley TS	12M42	1,716	1841	1299	1.321	1.417	0.932
Beamsville TS	18M4	125	83	61	2.051	1.361	1.508
Murray TS	3M51	3,453	1903	1606	2.150	1.185	1.814
Vineland DS	4501F1	3,999	1981	1756	2.277	1.128	2.019
Kalar TS	KM4	8,116	1476	1649	4.922	0.895	5.499
Beamsville TS	18M1	5,572	3951	4739	1.176	0.834	1.410
Stanley TS	12M31	1,346	749	1087	1.239	0.689	1.798
Kalar TS	KM7	3,908	1222	2781	1.405	0.439	3.198
Murray TS	3M29	38	19	47	0.805	0.404	1.991
Murray TS	3M14	144	98	253	0.570	0.387	1.471
Beamsville TS	18M2	1,415	910	2447	0.578	0.372	1.555
Murray TS	3M26	700	176	529	1.324	0.333	3.979
Stanley TS	12M32	1,409	410	1539	0.915	0.266	3.436
Vineland DS	4501F2	1,661	484	1886	0.880	0.257	3.431
Allanburg TS	45M7	3,742	292	1321	2.833	0.221	12.815
Stanley TS	12M41	1,346	450	2155	0.625	0.209	2.992
Murray TS	3M16	140	32	201	0.695	0.159	4.363
Murray TS	3M15	6	5	36	0.171	0.139	1.233
Stanley TS	12M5	2,294	186	1358	1.689	0.137	12.334
Niagara West TS	2508M2	789	314	2359	0.335	0.133	2.514

2012 Feeder Performance Summary
Sorted by SAIFI

Substation Name	Feeder ID	Total Cust Hours of Interruption (1)	Total Customer Interruptions (2)	Total # of Customers (3)	SAIDI Averae Hours of Interruptions / Cust. (4) = (1) / (3)	SAIFI Average # of Interruptions / Cust. (5) = (2) / (3)	CAIDI Speed of Power Restoration (6) = (4) / (5)
Stanley TS	12M33	929	240	1877	0.495	0.128	3.869
Kalar TS	KM1	108	69	608	0.177	0.113	1.563
Beamsville TS	18M3	116	19	217	0.532	0.088	6.081
Stanley TS	12M4	75	48	696	0.108	0.069	1.561
Murray TS	3M53	7	1	23	0.304	0.043	6.983
Kalar TS	KM2	33	3	854	0.039	0.004	11.011

	Lowest Level of Feeder Performance
	Highest Level of Feeder Performance

2013 Feeder Performance Summary
Sorted by SAIFI

Substation Name	Feeder ID	Total Cust Hours of Interruption (1)	Total Customer Interruptions (2)	Total # of Customers (3)	SAIDI Averae Hours of Interruptions / Cust. (4) = (1) / (3)	SAIFI Average # of Interruptions / Cust. (5) = (2) / (3)	CAIDI Speed of Power Restoration (6) = (4) / (5)
Beamsville TS	18M1	43,163	24213	4933	8.750	4.908	1.783
Vineland DS	4501F1	28,624	8763	1803	15.876	4.860	3.266
Niagara West TS	2508M5	21,728	6263	1318	16.485	4.752	3.469
Murray TS	3M16	3,205	962	203	15.787	4.739	3.331
Beamsville TS	18M4	483	218	64	7.543	3.406	2.215
Murray TS	3M17	14,168	8073	2610	5.428	3.093	1.755
Niagara West TS	2508M4	889	470	153	5.812	3.072	1.892
Murray TS	3M56	15,142	3940	1340	11.300	2.940	3.843
Murray TS	3M30	22,864	2240	872	26.220	2.569	10.207
Niagara West TS	2508M2	22,077	5263	2448	9.018	2.150	4.195
Stanley TS	12M42	6,479	2607	1314	4.931	1.984	2.485
Kalar TS	KM8	8,166	2049	1096	7.450	1.870	3.985
Stanley TS	12M32	4,125	2901	1561	2.643	1.858	1.422
Vineland DS	4501F2	7,688	3427	1931	3.982	1.775	2.243
Kalar TS	KM3	3,005	2365	1605	1.872	1.474	1.271
Murray TS	3M54	14,983	3210	2194	6.829	1.463	4.668
Stanley TS	12M41	6,718	2782	2160	3.110	1.288	2.415
Stanley TS	12M33	6,198	2382	1887	3.284	1.262	2.602
Beamsville TS	18M3	419	265	221	1.898	1.199	1.583
Murray TS	3M26	272	715	601	0.453	1.190	0.380
Kalar TS	KM7	2,767	3476	2959	0.935	1.175	0.796
Murray TS	3M28	26	15	13	1.968	1.154	1.706
Murray TS	3M14	423	289	252	1.677	1.147	1.462
Stanley TS	12M43	2,469	957	861	2.868	1.111	2.580
Stanley TS	12M1	2,474	2266	2143	1.155	1.057	1.092
Kalar TS	KM1	808	671	667	1.211	1.006	1.204
Murray TS	3M27	4,081	1672	1789	2.281	0.935	2.441
Murray TS	3M51	8,755	1558	1747	5.011	0.892	5.619
Stanley TS	12M6	6,751	1520	2288	2.951	0.664	4.441
Murray TS	3M15	41	22	37	1.104	0.595	1.857
Allanburg TS	45M7	744	731	1337	0.557	0.547	1.018

2013 Feeder Performance Summary
Sorted by SAIFI

Substation Name	Feeder ID	Total Cust Hours of Interruption (1)	Total Customer Interruptions (2)	Total # of Customers (3)	SAIDI Averae Hours of Interruptions / Cust. (4) = (1) / (3)	SAIFI Average # of Interruptions / Cust. (5) = (2) / (3)	CAIDI Speed of Power Restoration (6) = (4) / (5)
Stanley TS	12M31	1,036	573	1124	0.922	0.510	1.809
Murray TS	3M52	1,250	381	769	1.625	0.495	3.280
Murray TS	3M29	36	24	51	0.706	0.471	1.500
Stanley TS	12M4	174	102	221	0.786	0.462	1.702
Beamsville TS	18M2	6,055	1130	2497	2.425	0.453	5.359
Kalar TS	KM4	2,513	555	1520	1.653	0.365	4.528
Murray TS	3M53	24	7	22	1.108	0.318	3.483
Stanley TS	12M5	786	273	1377	0.571	0.198	2.880
Kalar TS	KM6	193	22	601	0.322	0.037	8.786
Kalar TS	KM5	79	11	464	0.170	0.024	7.161
Kalar TS	KM2	31	7	995	0.031	0.007	4.381

	Lowest Level of Feeder Performance
	Highest Level of Feeder Performance

ATTACHMENT # 12 Contract with “Enbridge Contractor”-IRR #50

Proposal

March 13, 2013

To: Niagara Peninsula Energy
Attn: Kevin Carver
Phone: 905-356-2681
Fax: 905-356-2831
From: Brad Brewster
Phone: 905-227-2719

Quotation: **Supply all labour and equipment to install NPE material for all joint trench hydro services for new subdivision work in NPE territory.**

Service (Lump Sum)........$450.00/ea
Separate Trench (LS)........$450.00/ea
Tee Tap Services(LS)........$1,050.00/ea

Additional Pricing
Extra length after 15m........$25.00/m
Sand Padding (if required)........$10.00/m
24 Hour Rush Premium........+100%
Winter Premium (Jan. 01-Mar. 31)........+25%

The following items are not included in this price.

- HST not included
- Restoration not included

Price valid for 30 days.

Brad Brewster
General Manager

Acceptance of Proposal: The above prices, specifications and conditions are satisfactory and are hereby accepted. You are authorized to do the work specified. Payment will be made as outlined above.

Signature:__________ Signature:__________

NPEI Manager DeRose Bros. Manager

DAN SEIBERT V.P OPERATIONS

ATTACHMENT # 13-Operating Agreement with NPC-IRR #64

OPERATING AGREEMENT

-between-

Niagara Peninsula Energy Inc.

and

NIAGARA PARKS COMMISSION

Agreement Authorization

It is mutually agreed by all parties that all conditions and policies as outlined herein will be binding and take effect on April 24, 2013.

Brian Wilke, C.G.A.
President & CEO
NiagaraPeninsula Energy Inc.

Len Warner

NIAGARA PARKS COMMISSION

Issue Date: April 24, 2013
Expiry Date: April 24, 2018
Number: O.A.33-2013

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1.0 INTRODUCTION

1.1 This Operating Directive defines an agreement between NIAGARA PARKS COMMISSION, and Niagara Peninsula Energy Inc. The agreement establishes operating procedures and associated responsibilities for supplied components to ensure safe, secure and efficient operation of the electrical power supply to NIAGARA PARKS COMMISSION Facilities.

1.2 NIAGARA PARKS COMMISSION **13.8 kV** supplied Facilities (as detailed by the single line diagrams in appendix B) are normally supplied from the 3M27, 3M28 and the 3M29, 13.8kV feeders supplied from Niagara Murray TS, and 12M4, 13.8kV feeder from Stanley TS.

1.3 NIAGARA PARKS COMMISSION is a customer of the Niagara Peninsula Energy Inc.

1.4 This document will normally be valid for a period of five years from date of issue unless another period is specified. Proposals to revise this document may be put forward by either party at any time. If no changes are deemed necessary by the expiry date, the document will remain in effect until it is superseded by an approved revision.

1.6 In this document 13.8kV and 4.16kVsupply to the NIAGARA PARKS COMMISSION refers to the single line drawings detailed in **appendix B.**

2.0 DEFINITIONS

2.1 Customer : NIAGARA PARKS COMMISSION

2.2 Utility: Niagara Peninsula Energy Inc.

2.3 Supervisory Control : The control which is exercised by a station having authority to issue instructions in broad outline to another station, which in turn, may exercise its judgment as to proper method of carrying out such instructions.

2.4 Operating Control : Having the exclusive authority to perform, direct, or authorize the operation of devices in a definitively specified manner. (Operating Control is not synonymous with ownership, nor does it necessarily convey total independence of action).

2.5 Supporting Guarantee : A guarantee issued in support of a Work Protection ensuring isolation/de-energizing at switches, or other devices, under the operating control of the issuer. (Such guarantees may be communicated orally, but must be logged or otherwise documented by the issuer).

2.6 Agent : A person who has been trained and delegated to perform specified operations.

2.7 Working Day :This refers to Monday to Friday not including holidays. For example five working days notice for work on Friday would require outage being submitted to Niagara Peninsula Energy the Friday of the preceding week.

2.8 Hold-Off Procedure : A procedure used to limit operation of apparatus to facilitate work or reduce work hazards. Under no circumstances shall a hold-off be used in place of a Work Protection.

When a hold-off is in effect on a line, or other electrical apparatus, it shall not be re-energized following an automatic trip, until communication is established with the holder and consent is obtained. It is a basic requirement of hold-off procedures that suitable communications be established and maintained between the control authority and the person issued the hold-off.

3.0 OWNERSHIP

3.1 Generally, the Customer owns all equipment on the property at the location defined by the single line operating diagrams in appendix "B". For specific equipment ownership at site locations, refer to appendix "B" for details.

3.2 Niagara Peninsula Energy Inc. owns all equipment supplying NIAGARA PARKS COMMISSION facilities detailed in appendix "B".

4.0 OPERATING CONTROL and OPERATING AUTHORITIES

4.1 The Customer operating authority is exercised by NIAGARA PARKS COMMISSION through an agent of Niagara Peninsula Energy Inc.

NIAGARA PARKS COMMISSION has operating control of all customer owned equipment on the customers property as detailed in appendix "B" only when high voltage switching is performed by an agent of Niagara Peninsula Energy Inc..

4.2 Niagara Peninsula Energy Inc. operating authority is the Niagara Peninsula Energy dispatcher/operator.

Niagara Peninsula Energy Inc. has operating control of the feeder up to the customers' equipment as defined in appendix "B".

5.0 NORMAL OPERATIONS

(see 4.1 & 4.2)

5.1 OPERATING RESTRICTIONS

5.1.1 Under normal conditions the operation of any switch on feeders within NIAGARA PARKS COMMISSION operating authority can only be executed under a hold-off condition on the affected feeders. This hold-off condition will be obtained by NIAGARA PARKS COMMISSION through phone communications to the Niagara Peninsula Energy Inc. dispatcher/operator, who in turn will communicate with Hydro One for the procurement of the hold-off. Normal operation of any switches on the electrical supply within NIAGARA PARKS COMMISSION operating authority without notification to the Niagara Peninsula Energy Inc. dispatcher\ operator and hold-off protection (where applicable) is **not** permitted. Any switching required by NIAGARA PARKS COMMISSION for purposes of isolation, repairs, maintenance, outage restoration or system reconfiguration shall be done only through an agent of the Niagara Peninsula

Energy Inc. with as much advanced notice as is reasonably possible, during the normal working hours of the Niagara Peninsula Energy Inc.

5.2 MAINTENANCE RESPONSIBILITIES

Each authority is responsible for the maintenance of equipment under their respective ownerships.

5.3 OUTAGE CO-ORDINATION

The Customer shall communicate directly with the Niagara Peninsula Energy dispatcher\operator on operating matters regarding scheduled outages. Formal application for outage to electrical equipment requiring the operation of the feeder disconnect switches owned and operated by Niagara Peninsula Energy Inc. shall be made sufficiently far in advance to allow for proper planning and co-ordination. Normally five working days notice shall be given.

5.4 WORK PROTECTION

5.4.1 When work is done by the Customer on apparatus that can be isolated by devices under the operating control of the Customer and performed by an agent of the Niagara Peninsula Energy Inc., the work procedures and the protection provided shall be in accordance with Customer practices.

5.4.2 When work is done by the Customer on apparatus requiring the operation of a disconnect switch owned and operated by Niagara Peninsula Energy, the Customer will apply to the Niagara Peninsula Energy Inc. dispatcher/operator, then Niagara Peninsula Energy will issue a Supporting Guarantee. This application should be made at least five working days in advance.

5.4.3 Hold-offs required by the Customer on feeders shall be obtained from the Barrie TOC station operator by the Niagara Peninsula Energy Inc. dispatcher \ operator.

5.5 SWITCHING

5.5.1 Normally, the Customer will carry out switching on Customer owned equipment following the operating procedures and restrictions as set fourth in this agreement.

When isolation is required by NIAGARA PARKS COMMISSION with isolation points in the Niagara Peninsula Energy Inc. operating area, Niagara Peninsula Energy Inc. will switch, lock and tag these devices and issue NIAGARA PARKS COMMISSION a Supporting Guarantee on isolation at these points.

5.6 ACCESS TO STATIONS

Niagara Peninsula Energy Inc. will require access to the Customers property for the purpose of switching procedures and equipment verification. NIAGARA PARKS COMMISSION will make every effort to comply with Niagara Peninsula Energy's requirement for access and will provide a minimum of procedural delays to expedite Niagara Peninsula Energy Inc. personnel access.

The Customer will be responsible for advising Niagara Peninsula Energy staff of hazards in the area which the Niagara Peninsula Energy staff should be made aware of.

Niagara Peninsula Energy Inc. employees normally use the protective equipment required in their normal work setting. Where specialized safety equipment is required by the Customer, the Customer will provide it.

5.7 INFORMATION AND DATA COLLECTION

Niagara Peninsula Energy Inc. and the Customer operating authority shall endeavour to keep each other informed of conditions and events in their respective jurisdictions that may affect the other's operations.

Operating data and other information shall be conveyed between authorities as necessary to ensure safe and efficient operation. These will include items such as:

(1) Additions to Customer's peak load.

(2) Proposed changes to Customers equipment which could effect Niagara Peninsula Energy Inc. equipment.

(3) Niagara Peninsula Energy Inc. network conditions which could affect Customer security of supply.

(4) Customer and Niagara Peninsula Energy Inc. operating diagrams.

6.0 UNSCHEDULED \ EMERGENCY OPERATIONS

6.1 The feeders normally supplying the Customer are equipped with reclosing breaker protection. After an automatic trip from a fault the feeder breaker will automatically reclose within 0.8 second. If the fault persists the breaker will trip again.A second re-closure will occur after a time delay of approximately 15 seconds, and if the fault persists the breaker will trip again, and lock out. The Barrie TOC station operator will then make one manual attempt to close the feeder breaker. Further attempts to re-energize the feeder will be directed by the Niagara Peninsula Energy Inc. dispatcher / operator.

6.2 In an emergency situation where power must be interrupted as soon as possible within the jurisdiction of NIAGARA PARKS COMMISSION operating area, operation of the load break switches as defined on the operating diagram, without notification of the supply authority and/or hold-off protection will be allowed subject to the following conditions.

1. NIAGARA PARKS COMMISSION will assume all responsibility for personnel and property affected within their operating jurisdiction by the switching operation.

2. The Niagara Peninsula Energy Inc. dispatcher / operator or their designate as defined in this agreement be notified of the switching operation and subsequent reason for the operation as soon as possible.

6.3 The Niagara Peninsula Energy Inc. dispatcher / operator will notify the customer of automatic operations or permanent faults on the Customer's supply as soon as practical after the fact to allow the

Customer more informed in-plant operating decisions.

6.4 The customer will notify the Niagara Peninsula Energy Inc. dispatcher / operator as soon as is practical of faults in customer's equipment which have caused automatic trips in Niagara Peninsula Energy Inc. circuits.

6.5 Assistance to the Customer from Niagara Peninsula Energy Inc. in times of unscheduled outages or emergencies shall be coordinated through the Niagara Peninsula Energy Inc. dispatcher / operator. If the emergency is after normal working hours, the answering service for Niagara Peninsula Energy Inc. will direct assistance calls to the duty man. Charges may be applied.

6.6 It is agreed that no switching of circuits owned by NIAGARA PARKS COMMISSION will take place by Niagara Peninsula Energy Inc. without prior knowledge of NIAGARA PARKS COMMISSION, except in emergency situations. In the later case, notification shall be provided as soon as possible, by contacting the appropriate number provided in Appendix "A". In all cases the demand meters shall be read prior to the switching or adjustments made in the demand charges levied.

7.0 COMMUNICATIONS

Communications between the Customer and Niagara Peninsula Energy Inc. on operating matters will normally be through phone communications. Each authority will immediately notify the other when changes are made to this listing.

All contact information is listed in **Appendix A**.

APPENDIX A

NIAGARA PENINSULA ENERGY INC.

NIAGARA PENINSULA ENERGY INC.DISPATCHER / OPERATOR
PHONE: 905-353-6024
FAX: 905-356-2831
Email: control@npei.ca

NOTE: AFTER HOURS CALLS WILL BE RECEIVED BY THE ANSWERING SERVICE @ 1-877-270-3938 WHO WILL IN TURN CONTACT THE DUTY MAN ON CALL.

NIAGARA PARKS COMMISSION
(Normal hours of Operation are:)

Customer Operating Authority (Normal hours)	
	Tibor Papp
Phone Number	905-295-2262 ex.230
Cell Number	905-321-3163
Fax Number	905-295-4328
Email	tpapp@niagaraparks.com
	Ron Carpenter
Phone Number	905-295-2262 ex.249
Cell Number	905-658-5308
Fax Number	905-295-4328
Email	rcarpenter@niagaraparks.com
Customer Operating Authority (After hours)	
Tibor Papp - Home Number	289-820-7575
Ron Carpenter - Home Number	905-937-1310
	Len Warner
Home Number	905-688-1806
Cell Number	905-658-5276
Email	lwarner@niagaraparks.com
	Dean Ostryhon
Home Number	905-899-2345
Cell Number	905-658-5214
Email	dostryhon@niagaraparks.com
	Marcelo Gruosso
Home Number	905-704-1315
Cell Number	905-329-2619
Email	mgruosso@niagaraparks.com

APPENDIX B

SINGLE LINE OPERATING DIAGRAMS
EQUIPMENT OWNED BY NIAGARA PARKS COMMISSION

OPERATE DRAWING NUMBER	DRAWING TITLE AND LOCATION DESCRIPTION	OPERATING VOLTAGE	NORMAL FEEDER NAME	OVERVIEW DRAWING NUMBER
A180-1	REFRECTORY	13.8kV	3-M-28	H 6
A180-15	ILLUMINATION	13.8kV	3-M-28	H 6
A180-2	TABLE ROCK	13.8kV	3-M-28	H 6
A180-3	HORSESHOE INCLINE	13.8kV	3-M-28	H 6
A180-4	GREENHOUSE (7145 NIAGARA RIVER PKWY)	13.8kV	3-M-28	I 6
A180-5	DUFFERIN ISLAND LIGHTING	13.8kV	3-M-28	I 6
A180-6	DUFFERIN ISLAND	13.8kV	3-M-27	I 6
A180-7	N.P.C. - CUB. #1	13.8kV	3-M-28	G 6
A180-8	N.P.C. - CUB #2	13.8kV	3-M-28	G 6
A180-9	N.P.C. - CUB #3	13.8kV	3-M-28	G 6
A180-10	N.P.C. - CUB #4	13.8kV	3-M-28	G 6
A180-11	N.P.C. - CUB #5	13.8kV	3-M-28	H 6
A-284	OAKHALL	4.16kV	3-M-27	I 6
	SPANISH AERO CAR	4.16kV	12-M-4	D 6
A386	MAID OF THE MIST PLAZA	13.8kV	3-M-29	G 6
WHIRLPOOL GOLF COURSE – INCLUDES ALL PRIMARY LATERALS AS WELL AS THE BELOW C.O. STATIONS		13.8kV	12-M-4	B 7 C 6 C 7 D 6
A180-12	N.P.C. - CUB. #6	13.8kV	12-M-4	
A180-13	N.P.C. - CUB. #7	13.8kV	12-M-4	
A180-14	N.P.C. - CUB. #8	13.8kV	12-M-4	
A440	BUTTERFLY CONSERVATORY	13.8kV	12-M-4	

ATTACHMENT # 14-OPA Final Verified Annual 2013 CDM Report- #99

saveONenergy

Message from the Vice President:

The OPA is pleased to provide you with the enclosed Final 2013 Verified Results Report.

2013 Report highlights:

- We have achieved 86% of our cumulative energy savings target and 48% of our annual peak demand savings target to date (Scenario 2).

  By the end of 2013, 42 LDCs have exceeded 80% of their energy target and 19 LDCs have met or exceeded their 2011-14 energy target.
- In 2013, LDCs have achieved over 600 GWh in savings, representing an increase of 20% over the 2012 net incremental energy savings results.
- The BUSINESS PROGRAM continues to generate strong interest and participation amongst business customers with significant savings results. 71% of total energy savings in 2013 came from the BUSINESS PROGRAM and its momentum continues. Also, as the program matures, we are seeing more and more studies in the PROCESS AND SYSTEMS pipeline converting to completed projects.
- Within 4 cents per kWh, Conservation programs continue to be a valuable and cost effective resource for customers across the province.

2013 has been a year of significant operational advancements centered around creating a better customer and LDC experience:

- A number of operational changes were made in 2013 to enhance processes, such as payment of LDC invoices streamlined to an average of 20 days, enhanced reporting and iCon updates to improve users' experience.
- Proactive updates to measures incentivized through saveONenergy have allowed programs to stay ahead of changing market conditions. Specifically in 2013, LEDs became popular measures in both the Consumer and Business programs.
- Technical tools also played a significant role in 2013, which included an updated Measure and Assumptions List as well as new and improved engineering worksheets for RETROFIT which allow customers to more easily access programs by building strong business cases based on latest estimates of savings potential.
- The Conservation Fund introduced the LDC Fast Track stream to support LDCs with innovative program ideas. 2013 LDC pilots included Oshawa PUC Networks Inc.'s retro-commissioning program, Toronto Hydro-Electric System Limited multi-unit demand response, and Niagara-on-the-Lake Hydro Inc.'s electric vehicles load shifting program.
- Key market sectors were also engaged in 2013 through Capability Building programs targeted at Home Builders and HVAC Installers to build conservation knowledge with these partners. Energy Efficiency Services Programs (EESPs) also provided valuable support to a variety of sectors.

The format of this report was developed in collaboration with the Reporting Working Group and is designed to help LDCs populate their 2013 Annual Reports that will be submitted to the OEB by September 30th. Any additional 2013 program activity not captured here will be reported in your Final 2014 Verified Results Report.

Please continue to monitor saveONenergy E-blasts for any further updates and should you have any other questions or comments please contact LDC.Support@powerauthority.on.ca.

We appreciate your ongoing collaboration and cooperation throughout the reporting and evaluation process. We look forward to another successful year in 2014.

Sincerely,

Andrew Pride

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OPA-Contracted Province-Wide CDM Programs Final Verified 2013 Results

LDC: Niagara Peninsula Energy Inc.

FINAL 2013 Progress to Targets	2013 Incremental	Program-to-Date Progress to Target (Scenario 1)	Scenario 1: % of Target Achieved	Scenario 2: % of Target Achieved
Net Annual Peak Demand Savings (MW)	2.0	3.6	**23.2%**	**28.0%**
Net Energy Savings (GWh)	7.1	55.0	**94.7%**	**94.7%**

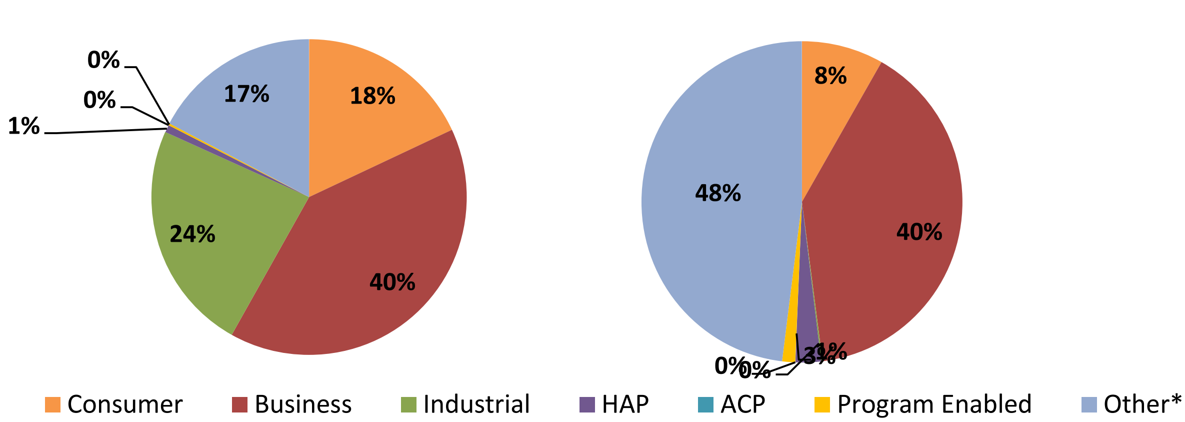
Scenario 1 = Assumes that demand response resources have a persistence of 1 year

Scenario 2 = Assumes that demand response resources remain in the LDC service territory until 2014

Achievement by Sector

2013 Incremental Peak Demand Savings (MW)

2013 Incremental Energy Savings (GWh)

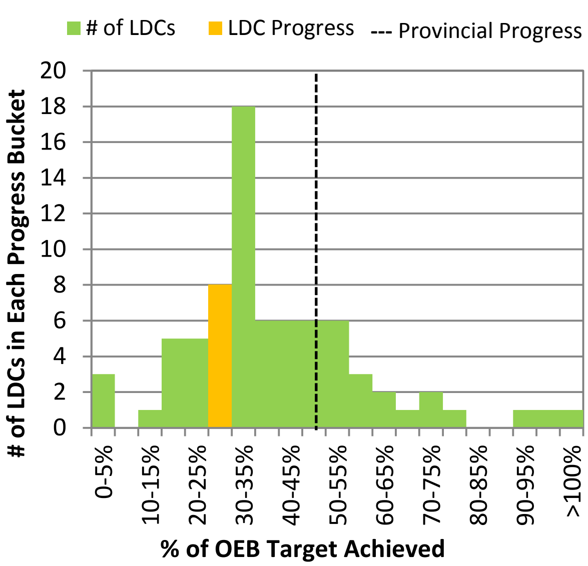


**Other includes adjustments to previous years' results and savings from pre-2011 initiatives*

Comparison: LDC Achievement vs. LDC Community Achievement (Progress to Target)

The following graphs assume that demand response resources remain in the LDC service territory until 2014 (aligns with Scenario 2)

% of OEB Peak Demand Savings Target Achieved



% of OEB Energy Savings Target Achieved

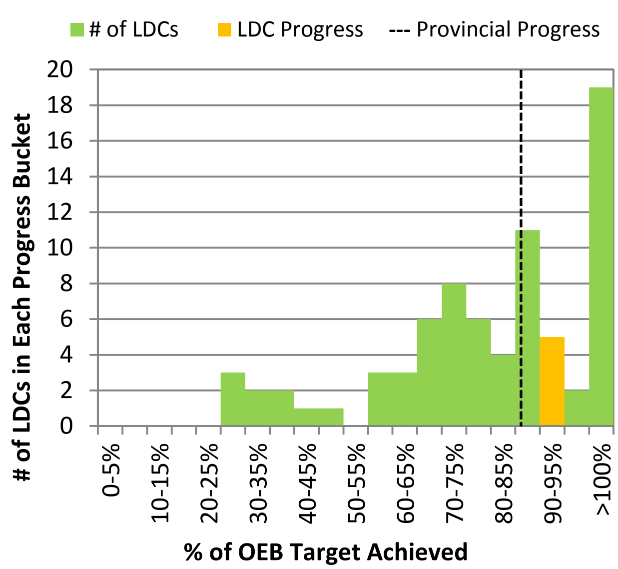


Table 1: Niagara Peninsula Energy Inc. Initiative and Program Level Net Savings by Year (Scenario 1)

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR)	
														2014 Net Annual Peak Demand Savings (kW)	2011-2014 Net Cumulative Energy Savings (kWh)
		2011*	2012*	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	512	339	158		30	20	11		214,685	135,814	67,743		60	1,400,960
Appliance Exchange	Appliances	44	56	40		4	8	8		4,714	14,737	14,778		18	89,796
HVAC Incentives	Equipment	882	733	731		282	151	150		504,642	253,365	253,570		583	3,285,802
Conservation Instant Coupon Booklet	Items	7,729	307	3,450		15	2	5		272,325	13,904	76,648		23	1,284,309
Bi-Annual Retailer Event	Items	9,469	10,550	9,395		17	15	12		292,245	266,332	170,846		43	2,309,666
Retailer Co-op	Items	0	0	0		0	0	0		0	0	0		0	0
Residential Demand Response	Devices	47	0	392		26	0	175		0	0	208		0	208
Residential Demand Response (IHD)	Devices	0	0	357		0	0	0		0	0	0		0	0
Residential New Construction	Homes	0	0	0		0	0	0		0	0	0		0	0
Consumer Program Total						**376**	**196**	**360**		**1,288,610**	**684,152**	**583,793**		**727**	**8,370,741**
Business Program															
Retrofit	Projects	36	85	115		168	767	520		927,120	3,486,336	2,142,104		1,430	18,321,584
Direct Install Lighting	Projects	347	217	150		333	177	176		903,623	712,848	620,149		547	6,514,626
Building Commissioning	Buildings	0	0	0		0	0	0		0	0	0		0	0
New Construction	Buildings	0	0	0		0	0	0		0	0	0		0	0
Energy Audit	Audits	3	9	1		0	41	9		0	201,410	48,451		50	701,132
Small Commercial Demand Response	Devices	4	0	5		3	0	3		0	0	5		0	5
Small Commercial Demand Response (IHD)	Devices	0	0	1		0	0	0		0	0	0		0	0
Demand Response 3	Facilities	3	3	2		106	106	95		4,146	1,548	1,500		0	7,194
Business Program Total						**610**	**1,092**	**803**		**1,834,889**	**4,402,143**	**2,812,209**		**2,027**	**25,544,540**
Industrial Program															
Process & System Upgrades	Projects	0	0	0		0	0	0		0	0	0		0	0
Monitoring & Targeting	Projects	0	0	0		0	0	0		0	0	0		0	0
Energy Manager	Projects	0	0	0		0	0	0		0	0	0		0	0
Retrofit	Projects	1	0	0		2	0	0		13,815	0	0		2	55,261
Demand Response 3	Facilities	1	1	5		63	65	472		3,710	1,578	10,747		0	16,035
Industrial Program Total						**65**	**65**	**472**		**17,526**	**1,578**	**10,747**		**2**	**71,297**
Home Assistance Program															
Home Assistance Program	Homes	10	44	320		0	5	15		9,137	54,743	181,895		21	563,795
Home Assistance Program Total						**0**	**5**	**15**		**9,137**	**54,743**	**181,895**		**21**	**563,795**
Aboriginal Program															
Home Assistance Program	Homes	0	0	0		0	0	0		0	0	0		0	0
Direct Install Lighting	Projects	0	0	0		0	0	0		0	0	0		0	0
Aboriginal Program Total						**0**	**0**	**0**		**0**	**0**	**0**		**0**	**0**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	23	0	0		264	0	0		1,480,972	0	0		264	5,923,887
High Performance New Construction	Projects	3	2	0		77	136	0		395,844	643,518	0		213	3,513,933
Toronto Comprehensive	Projects	0	0	0		0	0	0		0	0	0		0	0
Multifamily Energy Efficiency Rebates	Projects	0	0	0		0	0	0		0	0	0		0	0
LDC Custom Programs	Projects	0	0	0		0	0	0		0	0	0		0	0
Pre-2011 Programs completed in 2011 Total						**341**	**136**	**0**		**1,876,816**	**643,518**	**0**		**477**	**9,437,820**
Other															
Program Enabled Savings	Projects	10	18	3		0	0	4		0	0	93,443		4	186,886
Time-of-Use Savings	Homes	0	0	0		0	0	0		0	0	0		0	0
Other Total						**0**	**0**	**4**		**0**	**0**	**93,443**		**4**	**186,886**
Adjustments to 2011 Verified Results							**-7**	**192**			**-170,184**	**1,313,384**		**176**	**4,537,276**
Adjustments to 2012 Verified Results								**153**				**2,086,995**		**153**	**6,260,986**
Energy Efficiency Total						**1,193**	**1,323**	**910**		**5,019,121**	**5,783,008**	**3,669,626**		**3,258**	**44,151,637**
Demand Response Total (Scenario 1)						**198**	**172**	**744**		**7,856**	**3,126**	**12,461**		**0**	**23,443**
Adjustments to Previous Years' Verified Results Total						**0**	**-7**	**346**		**0**	**-170,184**	**3,400,379**		**329**	**10,798,262**
OPA-Contracted LDC Portfolio Total (inc. Adjustments)						**1,392**	**1,488**	**2,000**		**5,026,977**	**5,615,950**	**7,082,466**		**3,587**	**54,973,341**
													Full OEB Target:	**15,490**	**58,040,000**
													% of Full OEB Target Achieved to Date (Scenario 1):	**23.2%**	**94.7%**

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

The IHD line item on the 2013 annual report has been left blank pending a results update from evaluations; results will be updated once sufficient information is made available.

*Includes adjustments after Final Reports were issued

Energy Manager, Aboriginal Program and Program Enabled Savings were not independently evaluated

Table 2: Adjustments to Niagara Peninsula Energy Inc. Net Verified Results due to Variances

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)			
		2011*	2012*	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program													
Appliance Retirement	Appliances	0	0			0	0			0	0		
Appliance Exchange	Appliances	0	0			0	0			0	0		
HVAC Incentives	Equipment	-180	21			-47	4			-85,312	8,601		
Conservation Instant Coupon Booklet	Items	82	0			0	0			2,741	0		
Bi-Annual Retailer Event	Items	814	0			1	0			21,713	0		
Retailer Co-op	Items	0	0			0	0			0	0		
Residential Demand Response	Devices	0	0			0	0			0	0		
Residential Demand Response (IHD)	Devices	0	0			0	0			0	0		
Residential New Construction	Homes	0	0			0	0			0	0		
Consumer Program Total						**-46**	**4**			**-60,858**	**8,601**		
Business Program													
Retrofit	Projects	2	5			4	38			30,127	284,462		
Direct Install Lighting	Projects	27	0			32	0			91,276	0		
Building Commissioning	Buildings	0	0			0	0			0	0		
New Construction	Buildings	0	0			0	0			0	0		
Energy Audit	Audits	1	1			5	5			25,176	25,176		
Small Commercial Demand Response	Devices	0	0			0	0			0	0		
Small Commercial Demand Response (IHD)	Devices	0	0			0	0			0	0		
Demand Response 3	Facilities	0	0			0	0			0	0		
Business Program Total						**41**	**43**			**146,579**	**309,638**		
Industrial Program													
Process & System Upgrades	Projects	0	0			0	0			0	0		
Monitoring & Targeting	Projects	0	0			0	0			0	0		
Energy Manager	Projects	0	0			0	0			0	0		
Retrofit	Projects	0	0			0	0			0	0		
Demand Response 3	Facilities	0	0			0	0			0	0		
Industrial Program Total						**0**	**0**			**0**	**0**		
Home Assistance Program													
Home Assistance Program	Homes	0	0			0	0			0	0		
Home Assistance Program Total						**0**	**0**			**0**	**0**		
Aboriginal Program													
Home Assistance Program	Homes	0	0			0	0			0	0		
Direct Install Lighting	Projects	0	0			0	0			0	0		
Aboriginal Program Total						**0**	**0**			**0**	**0**		
Pre-2011 Programs completed in 2011													
Electricity Retrofit Incentive Program	Projects	0	0			0	0			0	0		
High Performance New Construction	Projects	0	0			-1	0			-255,067	0		
Toronto Comprehensive	Projects	0	0			0	0			0	0		
Multifamily Energy Efficiency Rebates	Projects	0	0			0	0			0	0		
LDC Custom Programs	Projects	0	0			0	0			0	0		
Pre-2011 Programs completed in 2011 Total						**-1**	**0**			**-255,067**	**0**		
Other													
Program Enabled Savings	Projects	10	18			192	106			1,312,546	1,768,756		
Time-of-Use Savings	Homes	0	0			0	0			0	0		
Other Total						**192**	**106**			**1,312,546**	**1,768,756**		
Adjustments to 2011 Verified Results						**186**				**1,143,200**			
Adjustments to 2012 Verified Results							**153**				**2,086,995**		
Total Adjustments to Previous Years' Verified Results						**186**	**153**			**1,143,200**	**2,086,995**		

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

The IHD line item on the 2013 annual report has been left blank pending a results update from evaluations; results will be updated once sufficient information is made available.

Adjustments to previous years' results shown in this table will not align to adjustments shown in Table 1 as the information presented above does not consider persistence of savings

Table 3: Niagara Peninsula Energy Inc. Realization Rate & NTG

Initiative	Peak Demand Savings								Energy Savings							
	Realization Rate				Net-to-Gross Ratio				Realization Rate				Net-to-Gross Ratio			
	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program																
Appliance Retirement	1.00	1.00	n/a		0.51	0.46	0.42		1.00	1.00	n/a		0.52	0.47	0.44	
Appliance Exchange	1.00	1.00	1.00		0.52	0.52	0.53		1.00	1.00	1.00		0.52	0.52	0.53	
HVAC Incentives	1.00	1.00	n/a		0.61	0.50	0.48		1.00	1.00	n/a		0.60	0.49	0.48	
Conservation Instant Coupon Booklet	1.00	1.00	1.00		1.13	1.00	1.11		1.00	1.00	1.00		1.10	1.05	1.13	
Bi-Annual Retailer Event	1.00	1.00	1.00		1.13	0.91	1.04		1.00	1.00	1.00		1.10	0.92	1.04	
Retailer Co-op	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Residential Demand Response	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Residential Demand Response (IHD)	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Residential New Construction	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Business Program																
Retrofit	0.92	0.98	0.95		0.73	0.79	0.71		1.18	1.16	1.00		0.75	0.79	0.72	
Direct Install Lighting	1.08	0.68	0.81		0.93	0.94	0.94		0.90	0.85	0.84		0.93	0.94	0.94	
Building Commissioning	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
New Construction	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Energy Audit	n/a	n/a	1.02		n/a	n/a	0.66		n/a	n/a	0.97		n/a	n/a	0.66	
Small Commercial Demand Response	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Small Commercial Demand Response (IHD)	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Demand Response 3	0.76	n/a	n/a		n/a	n/a	n/a		1.00	n/a	n/a		n/a	n/a	n/a	
Industrial Program																
Process & System Upgrades	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Monitoring & Targeting	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Energy Manager	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Retrofit																
Demand Response 3	0.84	n/a	n/a		n/a	n/a	n/a		1.00	n/a	n/a		n/a	n/a	n/a	
Home Assistance Program																
Home Assistance Program	1.00	1.06	0.59		0.70	1.00	1.00		1.00	1.01	0.89		0.70	1.00	1.00	
Aboriginal Program																
Home Assistance Program	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Direct Install Lighting	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Pre-2011 Programs completed in 2011																
Electricity Retrofit Incentive Program	0.80	n/a	n/a		0.53	n/a	n/a		0.79	n/a	n/a		0.53	n/a	n/a	
High Performance New Construction	1.00	1.00	1.00		0.50	0.50	0.50		1.00	1.00	1.00		0.50	0.50	0.50	
Toronto Comprehensive	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Multifamily Energy Efficiency Rebates	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
LDC Custom Programs	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Other																
Program Enabled Savings	n/a	n/a	1.00		n/a	n/a	1.00		n/a	n/a	1.00		n/a	n/a	1.00	
Time-of-Use Savings	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	

Energy Manager, Aboriginal Program and Program Enabled Savings were not independently evaluated

Summary Progress Towards CDM Targets

Results are attributed to target using current OPA reporting policies. Energy efficiency resources persist for the duration of the effective useful life. Any upcoming code changes are taken into account. Demand response resources persist for 1 year (Scenario 1). Please see methodology tab for more detailed information.

Table 4: Net Peak Demand Savings at the End User Level (MW) (Scenario 1)

Implementation Period	Annual			
	2011	2012	2013	2014
2011 - Verified	1.4	1.2	1.2	1.1
2012 - Verified†	0.0	1.5	1.3	1.3
2013 - Verified†	0.2	0.3	2.0	1.3
2014				
Verified Net Annual Peak Demand Savings Persisting in 2014:				**3.6**
Niagara Peninsula Energy Inc. 2014 Annual CDM Capacity Target:				**15.5**
Verified Portion of Peak Demand Savings Target Achieved in 2014 (%):				**23.2%**

Table 5: Net Energy Savings at the End User Level (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011 - Verified	5.0	5.0	4.9	4.6	19.6
2012 - Verified†	-0.2	5.6	5.6	5.5	16.5
2013 - Verified†	1.3	3.4	7.1	7.1	18.9
2014					
Verified Net Cumulative Energy Savings 2011-2014:					**55.0**
Niagara Peninsula Energy Inc. 2011-2014 Annual CDM Energy Target:					**58.0**
Verified Portion of Cumulative Energy Target Achieved in 2014 (%):					**94.7%**

†Includes adjustments to previous Years' verified results

Table 6: Province-Wide Initiatives and Program Level Net Savings by Year (Scenario 1)

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR)	
														2014 Net Annual Peak Demand Savings (kW)	2011-2014 Net Cumulative Energy Savings (kWh)
		2011*	2012*	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	56,110	34,146	20,952		3,299	2,011	1,433		23,005,812	13,424,518	8,713,107		6,605	149,603,072
Appliance Exchange	Appliances	3,688	3,836	5,337		371	556	1,106		450,187	974,621	1,971,701		1,795	8,455,927
HVAC Incentives	Equipment	92,743	87,427	91,581		32,037	19,060	19,552		59,437,670	32,841,283	33,923,592		70,650	404,121,713
Conservation Instant Coupon Booklet	Items	567,678	30,891	346,896		1,344	230	517		21,211,537	1,398,202	7,707,573		2,091	104,455,900
Bi-Annual Retailer Event	Items	952,149	1,060,901	944,772		1,681	1,480	1,184		29,387,468	26,781,674	17,179,841		4,345	232,254,579
Retailer Co-op	Items	152	0	0		0	0	0		2,652	0	0		0	10,607
Residential Demand Response	Devices	19,550	98,388	171,733		10,947	49,038	93,076		24,870	359,408	390,303		0	774,582
Residential Demand Response (IHD)	Devices	0	49,689	133,657		0	0	0		0	0	0		0	0
Residential New Construction	Homes	26	19	86		0	2	18		743	17,152	163,690		20	381,811
Consumer Program Total						**49,681**	**72,377**	**116,886**		**133,520,941**	**75,796,859**	**70,049,807**		**85,506**	**900,058,189**
Business Program															
Retrofit	Projects	2,819	6,134	8,785		24,467	61,147	59,678		136,002,258	314,922,468	345,346,008		142,831	2,168,497,702
Direct Install Lighting	Projects	20,741	18,691	17,782		23,724	15,284	18,708		61,076,701	57,345,798	64,315,558		49,886	519,693,356
Building Commissioning	Buildings	0	0	0		0	0	0		0	0	0		0	0
New Construction	Buildings	22	69	86		123	764	1,584		411,717	1,814,721	4,959,266		2,472	17,009,564
Energy Audit	Audits	198	345	319		0	1,450	2,811		0	7,049,351	15,455,795		4,261	52,059,644
Small Commercial Demand Response	Devices	132	294	1,211		84	187	773		157	1,068	373		0	1,597
Small Commercial Demand Response (IHD)	Devices	0	0	378		0	0	0		0	0	0		0	0
Demand Response 3	Facilities	145	151	175		16,218	19,389	23,706		633,421	281,823	346,659		0	1,261,903
Business Program Total						**64,617**	**98,221**	**107,261**		**198,124,253**	**381,415,230**	**430,423,659**		**199,449**	**2,758,523,766**
Industrial Program															
Process & System Upgrades	Projects	0	0	3		0	0	294		0	0	2,603,764		294	5,207,528
Monitoring & Targeting	Projects	0	0	0		0	0	0		0	0	0		0	0
Energy Manager	Projects	0	42	205		0	1,086	3,558		0	7,372,108	21,994,263		3,194	54,888,570
Retrofit	Projects	433	0	0		4,615	0	0		28,866,840	0	0		4,613	115,462,282
Demand Response 3	Facilities	124	185	281		52,484	74,056	162,543		3,080,737	1,784,712	4,309,160		0	9,174,609
Industrial Program Total						**57,098**	**75,141**	**166,395**		**31,947,577**	**9,156,820**	**28,907,187**		**8,101**	**184,732,989**
Home Assistance Program															
Home Assistance Program	Homes	46	5,033	26,756		2	566	2,361		39,283	5,442,232	20,987,275		2,904	57,949,913
Home Assistance Program Total						**2**	**566**	**2,361**		**39,283**	**5,442,232**	**20,987,275**		**2,904**	**57,949,913**
Aboriginal Program															
Home Assistance Program	Homes	0	0	584		0	0	267		0	0	1,609,393		267	3,218,786
Direct Install Lighting	Projects	0	0	0		0	0	0		0	0	0		0	0
Aboriginal Program Total						**0**	**0**	**267**		**0**	**0**	**1,609,393**		**267**	**3,218,786**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	2,028	0	0		21,662	0	0		121,138,219	0	0		21,662	484,552,876
High Performance New Construction	Projects	179	69	4		5,098	3,251	772		26,185,591	11,901,944	3,522,240		9,121	147,492,677
Toronto Comprehensive	Projects	577	0	0		15,805	0	0		86,964,886	0	0		15,805	347,859,545
Multifamily Energy Efficiency Rebates	Projects	110	0	0		1,981	0	0		7,595,683	0	0		1,981	30,382,733
LDC Custom Programs	Projects	8	0	0		399	0	0		1,367,170	0	0		399	5,468,679
Pre-2011 Programs completed in 2011 Total						**44,945**	**3,251**	**772**		**243,251,550**	**11,901,944**	**3,522,240**		**48,967**	**1,015,756,510**
Other															
Program Enabled Savings	Projects	14	56	13		0	2,304	3,692		0	1,188,362	4,075,382		5,996	11,715,850
Time-of-Use Savings	Homes	0	0	0		0	0	0		0	0	0		0	0
Other Total						**0**	**2,304**	**3,692**		**0**	**1,188,362**	**4,075,382**		**5,996**	**11,715,850**
Adjustments to 2011 Verified Results							**1,406**	**641**			**18,689,081**	**1,736,381**		**1,797**	**80,864,121**
Adjustments to 2012 Verified Results								**6,260**				**41,947,840**		**6,180**	**126,287,857**
Energy Efficiency Total						**136,610**	**109,191**	**117,536**		**603,144,419**	**482,474,435**	**554,528,447**		**351,190**	**4,920,743,312**
Demand Response Total (Scenario 1)						**79,733**	**142,670**	**280,099**		**3,739,185**	**2,427,011**	**5,046,495**		**0**	**11,212,691**
Adjustments to Previous Years' Verified Results Total						**0**	**1,406**	**6,901**		**0**	**18,689,081**	**43,684,221**		**7,976**	**207,151,978**
OPA-Contracted LDC Portfolio Total (inc. Adjustments)						**216,343**	**253,267**	**404,536**		**606,883,604**	**503,590,526**	**603,259,163**		**359,166**	**5,139,107,980**
													Full OEB Target:	**1,330,000**	**6,000,000,000**
													% of Full OEB Target Achieved to Date (Scenario 1):	**27.0%**	**85.7%**

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

The IHD line item on the 2013 annual report has been left blank pending a results update from evaluations; results will be updated once sufficient information is made available.

*Includes adjustments after Final Reports were issued

Energy Manager, Aboriginal Program and Program Enabled Savings were not independently evaluated

Table 7: Adjustments to Province-Wide Net Verified Results due to Variances

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)			
		2011*	2012*	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program													
Appliance Retirement	Appliances	0	0			0	0			0	0		
Appliance Exchange	Appliances	0	0			0	0			0	0		
HVAC Incentives	Equipment	-18,844	2,206			-5,271	452			-9,709,500	907,735		
Conservation Instant Coupon Booklet	Items	8,216	0			16	0			275,655	0		
Bi-Annual Retailer Event	Items	81,817	0			108	0			2,183,391	0		
Retailer Co-op	Items	0	0			0	0			0	0		
Residential Demand Response	Devices	0	0			0	0			0	0		
Residential Demand Response (IHD)	Devices	0	0			0	0			0	0		
Residential New Construction	Homes	19	0			1	0			13,767	0		
Consumer Program Total						**-5,146**	**452**			**-7,236,687**	**907,735**		
Business Program													
Retrofit	Projects	303	529			3,204	4,443			16,216,165	28,739,635		
Direct Install Lighting	Projects	444	197			501	204			1,250,388	736,541		
Building Commissioning	Buildings	0	0			0	0			0	0		
New Construction	Buildings	12	0			828	0			3,520,620	0		
Energy Audit	Audits	95	65			492	337			2,391,744	1,636,457		
Small Commercial Demand Response	Devices	0	0			0	0			0	0		
Small Commercial Demand Response (IHD)	Devices	0	0			0	0			0	0		
Demand Response 3	Facilities	0	0			0	0			0	0		
Business Program Total						**5,025**	**4,984**			**23,378,917**	**31,112,632**		
Industrial Program													
Process & System Upgrades	Projects	0	0			0	0			0	0		
Monitoring & Targeting	Projects	0	0			0	0			0	0		
Energy Manager	Projects	0	3			0	68			0	719,235		
Retrofit	Projects	0	0			0	0			0	0		
Demand Response 3	Facilities	0	0			0	0			0	0		
Industrial Program Total						**0**	**68**			**0**	**719,235**		
Home Assistance Program													
Home Assistance Program	Homes	0	0			0	0			0	0		
Home Assistance Program Total						**0**	**0**			**0**	**0**		
Aboriginal Program													
Home Assistance Program	Homes	0	0			0	0			0	0		
Direct Install Lighting	Projects	0	0			0	0			0	0		
Aboriginal Program Total						**0**	**0**			**0**	**0**		
Pre-2011 Programs completed in 2011													
Electricity Retrofit Incentive Program	Projects	12	0			138	0			545,536	0		
High Performance New Construction	Projects	34	0			1,407	0			2,065,200	0		
Toronto Comprehensive	Projects	0	0			0	0			0	0		
Multifamily Energy Efficiency Rebates	Projects	0	0			0	0			0	0		
LDC Custom Programs	Projects	0	0			0	0			0	0		
Pre-2011 Programs completed in 2011 Total						**1,545**	**0**			**2,610,736**	**0**		
Other													
Program Enabled Savings	Projects	14	40			624	824			1,673,712	9,927,473		
Time-of-Use Savings	Homes	0	0			0	0			0	0		
Other Total						**624**	**824**			**1,673,712**	**9,927,473**		
Adjustments to 2011 Verified Results						**2,047**				**20,426,678**			
Adjustments to 2012 Verified Results							**6,328**				**42,667,076**		
Adjustments to Previous Years' Verified Results Total						**2,047**	**6,328**			**20,426,678**	**42,667,076**		

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

The IHD line item on the 2013 annual report has been left blank pending a results update from evaluations; results will be updated once sufficient information is made available.

Adjustments to previous years' results shown in this table will not align to adjustments shown in Table 1 as the information presented above does not consider persistence of savings

Table 8: Province-Wide Realization Rate & NTG

Initiative	Peak Demand Savings								Energy Savings							
	Realization Rate				Net-to-Gross Ratio				Realization Rate				Net-to-Gross Ratio			
	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program																
Appliance Retirement	1.00	1.00	1.00		0.51	0.46	0.42		1.00	1.00	1.00		0.46	0.47	0.44	
Appliance Exchange	1.00	1.00	1.00		0.51	0.52	0.53		1.00	1.00	1.00		0.52	0.52	0.53	
HVAC Incentives	1.00	1.00	1.00		0.60	0.50	0.48		1.00	1.00	1.00		0.50	0.49	0.48	
Conservation Instant Coupon Booklet	1.00	1.00	1.00		1.14	1.00	1.11		1.00	1.00	1.00		1.00	1.05	1.13	
Bi-Annual Retailer Event	1.00	1.00	1.00		1.12	0.91	1.04		1.00	1.00	1.00		0.91	0.92	1.04	
Retailer Co-op	1.00	n/a	n/a		0.68	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Residential Demand Response	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Residential Demand Response (IHD)	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Residential New Construction	1.00	3.65	0.78		0.41	0.49	0.63		3.65	7.17	3.09		0.49	0.49	0.63	
Business Program																
Retrofit	1.06	0.93	0.92		0.72	0.75	0.73		0.93	1.05	1.01		0.75	0.76	0.73	
Direct Install Lighting	1.08	0.69	0.82		1.08	0.94	0.94		0.69	0.85	0.84		0.94	0.94	0.94	
Building Commissioning	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
New Construction	0.50	0.98	0.68		0.50	0.49	0.54		0.98	0.99	0.76		0.49	0.49	0.54	
Energy Audit	n/a	n/a	1.02		n/a	n/a	0.66		n/a	n/a	0.97		n/a	n/a	0.66	
Small Commercial Demand Response	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Small Commercial Demand Response (IHD)	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Demand Response 3	0.76	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Industrial Program																
Process & System Upgrades	n/a	n/a	0.85		n/a	n/a	0.94		n/a	n/a	0.87		n/a	n/a	0.93	
Monitoring & Targeting	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Energy Manager	n/a	1.16	0.90		n/a	0.90	0.90		1.16	1.16	0.90		0.90	0.90	0.90	
Retrofit	1.11	n/a	n/a		0.72	n/a	n/a		0.91	n/a	n/a		0.75	n/a	n/a	
Demand Response 3	0.84	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Home Assistance Program																
Home Assistance Program	1.00	0.32	0.26		0.70	1.00	1.00		0.32	0.99	0.88		1.00	1.00	1.00	
Aboriginal Program																
Home Assistance Program	n/a	n/a	0.05		n/a	n/a	1.00		n/a	n/a	0.95		n/a	n/a	1.00	
Direct Install Lighting	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Pre-2011 Programs completed in 2011																
Electricity Retrofit Incentive Program	0.80	n/a	n/a		0.54	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
High Performance New Construction	1.00	1.00	1.00		0.49	0.50	0.50		1.00	1.00	1.00		0.50	0.50	0.50	
Toronto Comprehensive	1.13	n/a	n/a		0.50	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Multifamily Energy Efficiency Rebates	0.93	n/a	n/a		0.78	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
LDC Custom Programs	1.00	n/a	n/a		1.00	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Other																
Program Enabled Savings	n/a	1.06	1.00		n/a	1.00	1.00		1.06	2.26	1.00		1.00	1.00	1.00	
Time-of-Use Savings	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	

Energy Manager, Aboriginal Program and Program Enabled Savings were not independently evaluated

Summary Provincial Progress Towards CDM Targets

Table 9: Province-Wide Net Peak Demand Savings at the End User Level (MW)

Implementation Period	Annual			
	2011	**2012**	**2013**	**2014**
2011	216.3	136.6	135.8	129.0
2012†	1.4	253.3	109.8	108.2
2013†	0.6	7.0	404.5	122.0
2014				
Verified Net Annual Peak Demand Savings in 2014:				**359.2**
2014 Annual CDM Capacity Target:				**1,330**
Verified Portion of Peak Demand Savings Target Achieved in 2014 (%):				**27.0%**

Table 10: Province-Wide Net Energy Savings at the End-User Level (GWh)

Implementation Period	Annual				Cumulative
	2011	**2012**	**2013**	**2014**	**2011-2014**
2011	606.9	603.0	601.0	582.3	2,393.1
2012†	18.7	503.6	498.4	492.6	1,513.3
2013†	1.7	44.4	603.3	583.4	1,232.8
2014					
Verified Net Cumulative Energy Savings 2011-2014:					**5,139.1**
2011-2014 Cumulative CDM Energy Target:					**6,000**
Verified Portion of Cumulative Energy Target Achieved in 2014 (%):					**85.7%**

†Includes adjustments to previous Years' verified results

METHODOLOGY

All results are at the end-user level (not including transmission and distribution losses)

EQUATIONS	
Prescriptive Measures and Projects	**Gross Savings = Activity * Per Unit Assumption** **Net Savings = Gross Savings * Net-to-Gross Ratio** **All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)**
Engineered and Custom Projects	**Gross Savings = Reported Savings * Realization Rate** **Net Savings = Gross Savings * Net-to-Gross Ratio** **All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)**
Demand Response	**Peak Demand: Gross Savings = Net Savings = contracted MW at contributor level * Provincial contracted to ex ante ratio** **Energy: Gross Savings = Net Savings = provincial ex post energy savings * LDC proportion of total provincial contracted MW** **All savings are annualized (i.e. the savings are the same regardless of the time of year a participant began offering DR)**
Adjustments to Previous Years' Verified Results	All variances from the Final Annual Results Reports from prior years will be adjusted within this report. Any variances with regards to projects counts, data lag, and calculations etc., will be made within this report. Considers the cumulative effect of energy savings.

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Consumer Program			
Appliance Retirement	Includes both retail and home pickup stream; Retail stream allocated based on average of 2008 & 2009 residential throughput; Home pickup stream directly attributed by postal code or customer selection.	Savings are considered to begin in the year the appliance is picked up.	Peak demand and energy savings are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Appliance Exchange	When postal code information is provided by customer, results are directly attributed to the LDC. When postal code is not available, results allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year that the exchange event occurred.	
HVAC Incentives	Results directly attributed to LDC based on customer postal code.	Savings are considered to begin in the year that the installation occurred.	

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Conservation Instant Coupon Booklet	LDC-coded coupons directly attributed to LDC; Otherwise results are allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year in which the coupon was redeemed.	Peak demand and energy savings are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Bi-Annual Retailer Event	Results are allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year in which the event occurs.	
Retailer Co-op	When postal code information is provided by the customer, results are directly attributed. If postal code information is not available, results are allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year of the home visit and installation date.	Peak demand and energy savings are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Residential Demand Response	Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists.	Savings are considered to begin in the year the device was installed and/or when a customer signed a peaksaver PLUS™ participant agreement.	Peak demand savings are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. Energy savings are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year and accounts for any “snapback” in energy consumption experienced after the event. Savings are assumed to persist for only 1 year, reflecting that savings will only occur if the resource is activated.

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Residential New Construction	Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system; Initiative was not evaluated in 2011, reported results are presented with forecast assumptions as per the business case.	Savings are considered to begin in the year of the project completion date.	Peak demand and energy savings are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Business Program			
Efficiency: Equipment Replacement	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see page for Building type to Sector mapping.	Savings are considered to begin in the year of the actual project completion date on the iCON CRM system.	Peak demand and energy savings are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
	Additional Note: project counts were derived by filtering out invalid statuses (e.g. Post-Project Submission - Payment denied by LDC) and only including projects with an "Actual Project Completion Date" in 2013)		

<table>
<tr><th>Initiative</th><th>Attributing Savings to LDCs</th><th>Savings 'start' Date</th><th>Calculating Resource Savings</th></tr>
<tr><td>Direct Installed Lighting</td><td>Results are directly attributed to LDC based on the LDC specified on the work order.</td><td>Savings are considered to begin in the year of the actual project completion date.</td><td>Peak demand and energy savings are determined using the verified measure level per unit assumptions multiplied by the uptake of each measure accounting for the realization rate for both peak demand and energy to reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings take into account net-to-gross factors such as free-ridership and spillover for both peak demand and energy savings at the program level (net).</td></tr>
<tr><td>Existing Building Commissioning Incentive</td><td>Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011 or 2012.</td><td>Savings are considered to begin in the year of the actual project completion date.</td><td rowspan="2">Peak demand and energy savings are determined by the total savings for a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).</td></tr>
<tr><td>New Construction and Major Renovation Incentive</td><td>Results are directly attributed to LDC based on LDC identified in the application.</td><td>Savings are considered to begin in the year of the actual project completion date.</td></tr>
<tr><td>Energy Audit</td><td>Projects are directly attributed to LDC based on LDC identified in the application.</td><td>Savings are considered to begin in the year of the audit date.</td><td>Peak demand and energy savings are determined by the total savings resulting from an audit as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).</td></tr>
</table>

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Commercial Demand Response (part of the Residential program schedule)	Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists	Savings are considered to begin in the year the device was installed and/or when a customer signed a peaksaver PLUS™ participant agreement.	Peak demand savings are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. Energy savings are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year. Savings are assumed to persist for only 1 year, reflecting that savings will only occur if the resource is activated.
Demand Response 3 (part of the Industrial program schedule)	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year in which the contributor signed up to participate in demand response.	Peak demand savings are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. Energy savings are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.
Industrial Program			
Process & System Upgrades	Results are directly attributed to LDC based on LDC identified in application.	Savings are considered to begin in the year in which the incentive project was completed.	Peak demand and energy savings are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Monitoring & Targeting	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011, 2012 or 2013.	Savings are considered to begin in the year in which the incentive project was completed.	Peak demand and energy savings are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
Energy Manager	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the project was completed by the energy manager. If no date is specified the savings will begin the year of the Quarterly Report submitted by the energy manager.	Peak demand and energy savings are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping.	Savings are considered to begin in the year of the actual project completion date on the iCON CRM system.	Peak demand and energy savings are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
Demand Response 3	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year in which the contributor signed up to participate in demand response.	Peak demand savings are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. Energy savings are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Home Assistance Program			
Home Assistance Program	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the measures were installed.	Peak demand and energy savings are determined using the measure level per unit assumption multiplied by the uptake of each measure (gross), taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Aboriginal Program			
Aboriginal Program	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the measures were installed.	Peak demand and energy savings are determined using the measure level per unit assumption multiplied by the uptake of each measure (gross), taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Pre-2011 Programs completed in 2011			
Electricity Retrofit Incentive Program	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011, 2012 or 2013 assumptions as per 2010 evaluation.	Savings are considered to begin in the year in which a project was completed.	Peak demand and energy savings are determined by the total savings from a given project as reported. A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). If energy savings are not available, an estimate is made based on the kWh to kW ratio in the provincial results from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
High Performance New Construction	Results are directly attributed to LDC based on customer data provided to the OPA from Enbridge; Initiative was not evaluated in 2011, 2012 or 2013, assumptions as per 2010 evaluation.	Savings are considered to begin in the year in which a project was completed.	
Toronto Comprehensive	Program run exclusively in Toronto Hydro-Electric System Limited service territory; Initiative was not evaluated in 2011, 2012 or 2013, assumptions as per 2010 evaluation.		

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Multifamily Energy Efficiency Rebates	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011, 2012 or 2013, assumptions as per 2010 evaluation.	Savings are considered to begin in the year in which a project was completed.	Peak demand and energy savings are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). If energy savings are not available, an estimate is made based on the kWh to kW ratio in the provincial results from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
Data Centre Incentive Program	Program run exclusively in PowerStream Inc. service territory; Initiative was not evaluated in 2011, assumptions as per 2009 evaluation.		
EnWin Green Suites	Program run exclusively in ENWIN Utilities Ltd. service territory; Initiative was not evaluated in 2011 or 2012, assumptions as per 2010 evaluation.		

Retrofit Sector (C&I vs. Industrial Mapping)

Building Type	Sector
Agribusiness - Cattle Farm	C&I
Agribusiness - Dairy Farm	C&I
Agribusiness - Greenhouse	C&I
Agribusiness - Other	C&I
Agribusiness - Other,Mixed-Use - Office/Retail	C&I
Agribusiness - Other,Office,Retail,Warehouse	C&I
Agribusiness - Other,Office,Warehouse	C&I
Agribusiness - Poultry	C&I
Agribusiness - Poultry,Hospitality - Motel	C&I
Agribusiness - Swine	C&I
Convenience Store	C&I
Education - College / Trade School	C&I
Education - College / Trade School,Multi-Residential - Condominium	C&I
Education - College / Trade School,Multi-Residential - Rental Apartment	C&I
Education - College / Trade School,Retail	C&I
Education - Primary School	C&I
Education - Primary School,Education - Secondary School	C&I
Education - Primary School,Multi-Residential - Rental Apartment	C&I
Education - Primary School,Not-for-Profit	C&I
Education - Secondary School	C&I
Education - University	C&I
Education - University,Office	C&I
Hospital/Healthcare - Clinic	C&I
Hospital/Healthcare - Clinic,Hospital/Healthcare - Long-term Care,Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Clinic,Industrial	C&I
Hospital/Healthcare - Clinic,Retail	C&I
Hospital/Healthcare - Long-term Care	C&I
Hospital/Healthcare - Long-term Care,Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Medical Building,Mixed-Use - Office/Retail	C&I
Hospital/Healthcare - Medical Building,Mixed-Use - Office/Retail,Office	C&I
Hospitality - Hotel	C&I
Hospitality - Hotel,Restaurant - Dining	C&I
Hospitality - Motel	C&I
Industrial	Industrial
Mixed-Use - Office/Retail	C&I
Mixed-Use - Office/Retail,Industrial	Industrial
Mixed-Use - Office/Retail,Mixed-Use - Other	C&I
Mixed-Use - Office/Retail,Mixed-Use - Other,Not-for-Profit,Warehouse	C&I
Mixed-Use - Office/Retail,Mixed-Use - Residential/Retail	C&I
Mixed-Use - Office/Retail,Office,Restaurant - Dining,Restaurant - Quick Serve,Retail,Warehouse	C&I

Mixed-Use - Office/Retail,Office,Warehouse	C&I
Mixed-Use - Office/Retail,Retail	C&I
Mixed-Use - Office/Retail,Warehouse	C&I
Mixed-Use - Office/Retail,Warehouse,Industrial	Industrial
Mixed-Use - Other	C&I
Mixed-Use - Other,Industrial	Industrial
Mixed-Use - Other,Not-for-Profit,Office	C&I
Mixed-Use - Other,Office	C&I
Mixed-Use - Other,Other: Please specify	C&I
Mixed-Use - Other,Retail,Warehouse	C&I
Mixed-Use - Other,Warehouse	C&I
Mixed-Use - Residential/Retail	C&I
Mixed-Use - Residential/Retail,Multi-Residential - Condominium	C&I
Mixed-Use - Residential/Retail,Multi-Residential - Rental Apartment	C&I
Mixed-Use - Residential/Retail,Retail	C&I
Multi-Residential - Condominium	C&I
Multi-Residential - Condominium,Multi-Residential - Rental Apartment	C&I
Multi-Residential - Condominium,Other: Please specify	C&I
Multi-Residential - Rental Apartment	C&I
Multi-Residential - Rental Apartment,Multi-Residential - Social Housing Provider,Not-for-Profit	C&I
Multi-Residential - Rental Apartment,Not-for-Profit	C&I
Multi-Residential - Rental Apartment,Warehouse	C&I
Multi-Residential - Social Housing Provider	C&I
Multi-Residential - Social Housing Provider,Industrial	C&I
Multi-Residential - Social Housing Provider,Not-for-Profit	C&I
Not-for-Profit	C&I
Not-for-Profit,Office	C&I
Not-for-Profit,Other: Please specify	C&I
Not-for-Profit,Warehouse	C&I
Office	C&I
Office,Industrial	Industrial
Office,Other: Please specify	C&I
Office,Other: Please specify,Warehouse	C&I
Office,Restaurant - Dining	C&I
Office,Restaurant - Dining,Industrial	Industrial
Office,Retail	C&I
Office,Retail,Industrial	C&I
Office,Retail,Warehouse	C&I
Office,Warehouse	C&I
Office,Warehouse,Industrial	Industrial
Other: Please specify	C&I
Other: Please specify,Industrial	Industrial
Other: Please specify,Retail	C&I
Other: Please specify,Warehouse	C&I
Restaurant - Dining	C&I
Restaurant - Dining,Retail	C&I

Restaurant - Quick Serve	C&I
Restaurant - Quick Serve,Retail	C&I
Retail	C&I
Retail,Industrial	Industrial
Retail,Warehouse	C&I
Warehouse	C&I
Warehouse,Industrial	Industrial

Consumer Program Allocation Methodology

Results can be allocated based on average of 2008 & 2009 residential throughput for each LDC (below) when additional information is not available. Source: OEB Yearbook Data 2008 & 2009

Local Distribution Company	Allocation
Algoma Power Inc.	0.2%
Atikokan Hydro Inc.	0.0%
Attawapiskat Power Corporation	0.0%
Bluewater Power Distribution Corporation	0.6%
Brant County Power Inc.	0.2%
Brantford Power Inc.	0.7%
Burlington Hydro Inc.	1.4%
Cambridge and North Dumfries Hydro Inc.	1.0%
Canadian Niagara Power Inc.	0.5%
Centre Wellington Hydro Ltd.	0.1%
Chapleau Public Utilities Corporation	0.0%
COLLUS Power Corporation	0.3%
Cooperative Hydro Embrun Inc.	0.0%
E.L.K. Energy Inc.	0.2%
Enersource Hydro Mississauga Inc.	3.9%
ENTEGRUS	0.6%
ENWIN Utilities Ltd.	1.6%
Erie Thames Powerlines Corporation	0.4%
Espanola Regional Hydro Distribution Corporation	0.1%
Essex Powerlines Corporation	0.7%
Festival Hydro Inc.	0.3%
Fort Albany Power Corporation	0.0%
Fort Frances Power Corporation	0.1%
Greater Sudbury Hydro Inc.	1.0%
Grimsby Power Inc.	0.2%
Guelph Hydro Electric Systems Inc.	0.9%
Haldimand County Hydro Inc.	0.4%
Halton Hills Hydro Inc.	0.5%
Hearst Power Distribution Company Limited	0.1%
Horizon Utilities Corporation	4.0%
Hydro 2000 Inc.	0.0%
Hydro Hawkesbury Inc.	0.1%
Hydro One Brampton Networks Inc.	2.8%
Hydro One Networks Inc.	30.0%

Hydro Ottawa Limited	5.6%
Innisfil Hydro Distribution Systems Limited	0.4%
Kashechewan Power Corporation	0.0%
Kenora Hydro Electric Corporation Ltd.	0.1%
Kingston Hydro Corporation	0.5%
Kitchener-Wilmot Hydro Inc.	1.6%
Lakefront Utilities Inc.	0.2%
Lakeland Power Distribution Ltd.	0.2%
London Hydro Inc.	2.7%
Middlesex Power Distribution Corporation	0.1%
Midland Power Utility Corporation	0.1%
Milton Hydro Distribution Inc.	0.6%
Newmarket - Tay Power Distribution Ltd.	0.7%
Niagara Peninsula Energy Inc.	1.0%
Niagara-on-the-Lake Hydro Inc.	0.2%
Norfolk Power Distribution Inc.	0.3%
North Bay Hydro Distribution Limited	0.5%
Northern Ontario Wires Inc.	0.1%
Oakville Hydro Electricity Distribution Inc.	1.5%
Orangeville Hydro Limited	0.2%
Orillia Power Distribution Corporation	0.3%
Oshawa PUC Networks Inc.	1.2%
Ottawa River Power Corporation	0.2%
Parry Sound Power Corporation	0.1%
Peterborough Distribution Incorporated	0.7%
PowerStream Inc.	6.6%
PUC Distribution Inc.	0.9%
Renfrew Hydro Inc.	0.1%
Rideau St. Lawrence Distribution Inc.	0.1%
Sioux Lookout Hydro Inc.	0.1%
St. Thomas Energy Inc.	0.3%
Thunder Bay Hydro Electricity Distribution Inc.	0.9%
Tillsonburg Hydro Inc.	0.1%
Toronto Hydro-Electric System Limited	12.8%
Veridian Connections Inc.	2.4%
Wasaga Distribution Inc.	0.2%
Waterloo North Hydro Inc.	1.0%
Welland Hydro-Electric System Corp.	0.4%
Wellington North Power Inc.	0.1%
West Coast Huron Energy Inc.	0.1%
Westario Power Inc.	0.5%
Whitby Hydro Electric Corporation	0.9%
Woodstock Hydro Services Inc.	0.3%

Reporting Glossary

Annual: the peak demand or energy savings that occur in a given year (includes resource savings from new program activity in a given year and resource savings persisting from previous years).

Cumulative Energy Savings: represents the sum of the annual energy savings that accrue over a defined period (in the context of this report the defined period is 2011 - 2014). This concept does not apply to peak demand savings.

End-User Level: resource savings in this report are measured at the customer level as opposed to the generator level (the difference being line losses).

Free-ridership: the percentage of participants who would have implemented the program measure or practice in the absence of the program.

Incremental: the new resource savings attributable to activity procured in a particular reporting period based on when the savings are considered to 'start'.

Initiative: a Conservation & Demand Management offering focusing on a particular opportunity or customer end-use (i.e. Retrofit, Fridge & Freezer Pickup).

Net-to-Gross Ratio: The ratio of net savings to gross savings, which takes into account factors such as free-ridership and spillover

Net Energy Savings (MWh): energy savings attributable to conservation and demand management activities net of free-riders, etc.

Net Peak Demand Savings (MW): peak demand savings attributable to conservation and demand management activities net of free-riders, etc.

Program: a group of initiatives that target a particular market sector (e.g. Consumer, Industrial).

Realization Rate: A comparison of observed or measured (evaluated) information to original reported savings which is used to adjust the gross savings estimates.

Settlement Account: the grouping of demand response facilities (contributors) into one contractual agreement

Spillover: Reductions in energy consumption and/or demand caused by the presence of the energy efficiency program, beyond the program-related gross savings of the participants. There can be participant and/or non-participant spillover.

Unit: for a specific initiative the relevant type of activity acquired in the market place (i.e. appliances picked up, projects completed, coupons redeemed).

Table 11: Niagara Peninsula Energy Inc. Initiative and Program Level Gross Savings by Year

Initiative	Unit	Gross Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Gross Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)			
		2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program									
Appliance Retirement**	Appliances	61	20	23		420,544	135,814	144,354	
Appliance Exchange**	Appliances	8	8	16		9,146	14,737	28,076	
HVAC Incentives	Equipment	467	302	308		842,023	514,767	530,338	
Conservation Instant Coupon Booklet	Items	14	2	5		248,680	13,185	68,043	
Bi-Annual Retailer Event	Items	15	16	11		267,501	290,600	163,502	
Retailer Co-op	Items	0	0	0		0	0	0	
Residential Demand Response	Devices	26	0	175		0	0	208	
Residential Demand Response (IHD)	Devices	0	0	0		0	0	0	
Residential New Construction	Homes	0	0	0		0	0	0	
Consumer Program Total		**591**	**349**	**537**		**1,787,893**	**969,104**	**934,521**	
Business Program									
Retrofit	Projects	230	859	729		1,233,531	3,710,884	2,965,787	
Direct Install Lighting	Projects	311	238	186		973,166	856,732	657,027	
Building Commissioning	Buildings	0	0	0		0	0	0	
New Construction	Buildings	0	0	0		0	0	0	
Energy Audit	Audits	0	41	13		0	201,410	73,311	
Small Commercial Demand Response	Devices	3	0	3		0	0	5	
Small Commercial Demand Response (IHD)	Devices	0	0	0		0	0	0	
Demand Response 3	Facilities	106	106	95		4,146	1,548	1,500	
Business Program Total		**650**	**1,246**	**1,026**		**2,210,844**	**4,770,573**	**3,697,630**	
Industrial Program									
Process & System Upgrades	Projects	0	0	0		0	0	0	
Monitoring & Targeting	Projects	0	0	0		0	0	0	
Energy Manager	Projects	0	0	0		0	0	0	
Retrofit	Projects	3	0	0		18,333	0	0	
Demand Response 3	Facilities	63	65	472		3,710	1,578	10,747	
Industrial Program Total		**66**	**65**	**472**		**22,044**	**1,578**	**10,747**	
Home Assistance Program									
Home Assistance Program	Homes	1	5	15		13,053	54,313	181,895	
Home Assistance Program Total		**1**	**5**	**15**		**13,053**	**54,313**	**181,895**	
Aboriginal Program									
Home Assistance Program	Homes	0	0	0		0	0	0	
Direct Install Lighting	Projects	0	0	0		0	0	0	
Aboriginal Program Total		**0**	**0**	**0**		**0**	**0**	**0**	
Pre-2011 Programs completed in 2011									
Electricity Retrofit Incentive Program	Projects	496	0	0		2,802,732	0	0	
High Performance New Construction	Projects	154	272	0		791,689	1,287,037	0	
Toronto Comprehensive	Projects	0	0	0		0	0	0	
Multifamily Energy Efficiency Rebates	Projects	0	0	0		0	0	0	
LDC Custom Programs	Projects	0	0	0		0	0	0	
Pre-2011 Programs completed in 2011 Total		**650**	**272**	**0**		**3,594,421**	**1,287,037**	**0**	
Other									
Program Enabled Savings	Projects	0	0	4		0	0	93,443	
Time-of-Use Savings	Homes	0	0	0		0	0	0	
Other Total		**0**	**0**	**4**		**0**	**0**	**93,443**	
Adjustments to 2011 Verified Results		**0**	**119**	**193**		**0**	**-56,960**	**1,313,972**	
Adjustments to 2012 Verified Results		**0**	**0**	**169**		**0**	**0**	**2,177,838**	
Energy Efficiency Total		**1,760**	**1,765**	**1,310**		**7,620,398**	**7,079,479**	**4,905,775**	
Demand Response Total		**198**	**172**	**744**		**7,856**	**3,126**	**12,461**	
Adjustments to Previous Years' Verified Results Total		**0**	**119**	**361**		**0**	**-56,960**	**3,491,809**	
OPA-Contracted LDC Portfolio Total (inc. Adjustments)		**1,958**	**2,056**	**2,416**		**7,628,254**	**7,025,645**	**8,410,046**	

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

The IHD line item on the 2013 annual report has been left blank pending a results update from evaluations; results will be updated once sufficient information is made available.

Adjustments to previous years' results shown in this table will not align to adjustments shown in Table 1 as the information presented above does not consider persistence of savings

Gross results are presented for informational purposes only and are not considered official 2013 Final Verified Results

**Net results substituted for gross results due to unavailability of data

Table 12: Adjustments to Niagara Peninsula Energy Inc. Gross Verified Results due to Variances

Initiative	Unit	Gross Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Gross Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)			
		2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program									
Appliance Retirement	Appliances	0	0			0	0		
Appliance Exchange	Appliances	0	0			0	0		
HVAC Incentives	Equipment	-79	10			-142,763	17,515		
Conservation Instant Coupon Booklet	Items	0	0			2,546	0		
Bi-Annual Retailer Event	Items	1	0			23,605	0		
Retailer Co-op	Items	0	0			0	0		
Residential Demand Response	Devices	0	0			0	0		
Residential Demand Response (IHD)	Devices	0	0			0	0		
Residential New Construction	Homes	0	0			0	0		
Consumer Program Total		**-77**	**10**			**-116,613**	**17,515**		
Business Program									
Retrofit	Projects	5	48			42,173	366,390		
Direct Install Lighting	Projects	34	0			98,300	0		
Building Commissioning	Buildings	0	0			0	0		
New Construction	Buildings	0	0			0	0		
Energy Audit	Audits	5	5			25,176	25,176		
Small Commercial Demand Response	Devices	0	0			0	0		
Small Commercial Demand Response (IHD)	Devices	0	0			0	0		
Demand Response 3	Facilities	0	0			0	0		
Business Program Total		**45**	**53**			**165,650**	**391,566**		
Industrial Program									
Process & System Upgrades	Projects	0	0			0	0		
Monitoring & Targeting	Projects	0	0			0	0		
Energy Manager	Projects	0	0			0	0		
Retrofit	Projects	0	0			0	0		
Demand Response 3	Facilities	0	0			0	0		
Industrial Program Total		**0**	**0**			**0**	**0**		
Home Assistance Program									
Home Assistance Program	Homes	0	0			0	0		
Home Assistance Program Total		**0**	**0**			**0**	**0**		
Aboriginal Program									
Home Assistance Program	Homes	0	0			0	0		
Direct Install Lighting	Projects	0	0			0	0		
Aboriginal Program Total									
Pre-2011 Programs completed in 2011									
Electricity Retrofit Incentive Program	Projects	0	0			0	0		
High Performance New Construction	Projects	153	0			-104,571	0		
Toronto Comprehensive	Projects	0	0			0	0		
Multifamily Energy Efficiency Rebates	Projects	0	0			0	0		
LDC Custom Programs	Projects	0	0			0	0		
Pre-2011 Programs completed in 2011 Total		**153**	**0**			**-104,571**	**0**		
Other									
Program Enabled Savings	Projects	192	106			1,312,546	1,768,756		
Time-of-Use Savings	Homes	0	0			0	0		
Other Total		**192**	**106**			**1,312,546**	**1,768,756**		
Adjustments to 2011 Verified Results		**312**				**1,257,012**			
Adjustments to 2012 Verified Results			**169**				**2,177,838**		
Total Adjustments to Previous Years' Verified Results		**312**	**169**			**1,257,012**	**2,177,838**		

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

The IHD line item on the 2013 annual report has been left blank pending a results update from evaluations; results will be updated once sufficient information is made available.

Gross results are presented for informational purposes only and are not considered official 2013 Final Verified Results

Table 13: Province-Wide Initiatives and Program Level Gross Savings by Year

Initiative	Unit	Gross Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Gross Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)			
		2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program									
Appliance Retirement**	Appliances	6,750	2,011	3,151		45,971,627	13,424,518	18,616,239	
Appliance Exchange**	Appliances	719	556	2,101		873,531	974,621	3,746,106	
HVAC Incentives	Equipment	53,209	38,346	40,418		99,413,430	66,929,213	71,225,037	
Conservation Instant Coupon Booklet	Items	1,184	231	464		19,192,453	1,325,898	6,842,244	
Bi-Annual Retailer Event	Items	1,504	1,622	1,142		26,899,265	29,222,072	16,441,329	
Retailer Co-op	Items	0	0	0		3,917	0	0	
Residential Demand Response	Devices	10,390	49,038	93,076		23,597	359,408	390,303	
Residential Demand Response (IHD)	Devices	0	0	0		0	0	0	
Residential New Construction	Homes	0	1	29		1,813	4,884	259,826	
Consumer Program Total		**73,757**	**91,805**	**140,380**		**192,379,633**	**112,240,615**	**117,521,084**	
Business Program									
Retrofit	Projects	34,201	78,965	82,896		184,070,265	387,817,248	478,410,896	
Direct Install Lighting	Projects	22,155	20,469	19,807		65,777,197	68,896,046	68,140,249	
Building Commissioning	Buildings	0	0	0		0	0	0	
New Construction	Buildings	247	1,596	2,934		823,434	3,755,869	9,183,826	
Energy Audit	Audits	0	1,450	4,283		0	7,049,351	23,386,108	
Small Commercial Demand Response	Devices	55	187	773		131	1,068	373	
Small Commercial Demand Response (IHD)	Devices	0	0	0		0	0	0	
Demand Response 3	Facilities	21,390	19,389	23,706		633,421	281,823	346,659	
Business Program Total		**78,048**	**122,056**	**134,399**		**251,304,448**	**467,801,406**	**579,468,111**	
Industrial Program									
Process & System Upgrades	Projects	0	0	313		0	0	2,799,746	
Monitoring & Targeting	Projects	0	0	0		0	0	0	
Energy Manager	Projects	0	1,034	3,953		0	7,067,535	24,438,070	
Retrofit	Projects	6,372	0	0		38,412,408	0	0	
Demand Response 3	Facilities	176,180	74,056	162,543		4,243,958	1,784,712	4,309,160	
Industrial Program Total		**182,552**	**75,090**	**166,809**		**42,656,366**	**8,852,247**	**31,546,976**	
Home Assistance Program									
Home Assistance Program	Homes	4	1,777	2,361		56,119	5,524,230	20,987,275	
Home Assistance Program Total		**4**	**1,777**	**2,361**		**56,119**	**5,524,230**	**20,987,275**	
Aboriginal Program									
Home Assistance Program	Homes	0	0	267		0	0	1,609,393	
Direct Install Lighting	Projects	0	0	0		0	0	0	
Aboriginal Program Total		**0**	**0**	**267**		**0**	**0**	**1,609,393**	
Pre-2011 Programs completed in 2011									
Electricity Retrofit Incentive Program	Projects	40,418	0	0		223,956,390	0	0	
High Performance New Construction	Projects	10,197	6,501	772		52,371,183	23,803,888	3,522,240	
Toronto Comprehensive	Projects	33,467	0	0		174,070,574	0	0	
Multifamily Energy Efficiency Rebates	Projects	2,553	0	0		9,774,792	0	0	
LDC Custom Programs	Projects	534	0	0		649,140	0	0	
Pre-2011 Programs completed in 2011 Total		**87,169**	**6,501**	**772**		**460,822,079**	**23,803,888**	**3,522,240**	
Other									
Program Enabled Savings	Projects	0	2,177	3,692		0	525,011	4,075,382	
Time-of-Use Savings	Homes	0	0	0		0	0	0	
Other Total		**0**	**2,177**	**3,692**		**0**	**525,011**	**4,075,382**	
Adjustments to 2011 Verified Results			**13,266**	**645**			**48,705,294**	**1,744,645**	
Adjustments to 2012 Verified Results				**8,707**				**55,101,043**	
Energy Efficiency Total		**213,515**	**156,735**	**168,583**		**942,317,539**	**616,320,385**	**753,683,966**	
Demand Response Total		**208,015**	**142,670**	**280,099**		**4,901,107**	**2,427,011**	**5,046,495**	
Adjustments to Previous Years' Verified Results Total		**0**	**13,266**	**9,352**		**0**	**48,705,294**	**56,845,688**	
OPA-Contracted LDC Portfolio Total (inc. Adjustments)		**421,530**	**312,671**	**458,033**		**947,218,646**	**667,452,690**	**815,576,149**	

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

The IHD line item on the 2013 annual report has been left blank pending a results update from evaluations; results will be updated once sufficient information is

Adjustments to previous years' results shown in this table will not align to adjustments shown in Table 1 as the information presented above does not consider persistence of savings

Gross results are presented for informational purposes only and are not considered official 2013 Final Verified Results

**Net results substituted for gross results due to unavailability of data

Table 14: Adjustments to Province-Wide Gross Verified Results due to Variances

Initiative	Unit	Gross Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Gross Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)			
		2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program									
Appliance Retirement	Appliances	0	0			0	0		
Appliance Exchange	Appliances	0	0			0	0		
HVAC Incentives	Equipment	-8,762	1,036			-16,245,279	1,854,833		
Conservation Instant Coupon Booklet	Items	15	0			255,975	0		
Bi-Annual Retailer Event	Items	117	0			2,373,616	0		
Retailer Co-op	Items	0	0			0	0		
Residential Demand Response	Devices	0	0			0	0		
Residential Demand Response (IHD)	Devices	0	0			0	0		
Residential New Construction	Homes	0	0			328,256	0		
Consumer Program Total		**-8,630**	**1,036**			**-13,287,430**	**1,854,833**		
Business Program									
Retrofit	Projects	4,504	6,218			22,046,931	40,101,273		
Direct Install Lighting	Projects	541	217			1,346,618	781,858		
Building Commissioning	Buildings	0	0			0	0		
New Construction	Buildings	3,243	0			11,323,593	0		
Energy Audit	Audits	492	337			2,391,744	1,636,457		
Small Commercial Demand Response	Devices	0	0			0	0		
Small Commercial Demand Response (IHD)	Devices	0	0			0	0		
Demand Response 3	Facilities	0	0			0	0		
Business Program Total		**8,780**	**6,771**			**37,108,886**	**42,519,588**		
Industrial Program									
Process & System Upgrades	Projects	0	0			0	0		
Monitoring & Targeting	Projects	0	0			0	0		
Energy Manager	Projects	0	75			0	799,151		
Retrofit	Projects	0	0			0	0		
Demand Response 3	Facilities	0	0			0	0		
Industrial Program Total		**0**	**75**			**0**	**799,151**		
Home Assistance Program									
Home Assistance Program	Homes	0	0			0	0		
Home Assistance Program Total		**0**	**0**			**0**	**0**		
Aboriginal Program									
Home Assistance Program	Homes	0	0			0	0		
Direct Install Lighting	Projects	0	0			0	0		
Aboriginal Program Total		**0**	**0**			**0**	**0**		
Pre-2011 Programs completed in 2011									
Electricity Retrofit Incentive Program	Projects	266	0			1,049,108	0		
High Performance New Construction	Projects	12,872	0			23,905,663	0		
Toronto Comprehensive	Projects	0	0			0	0		
Multifamily Energy Efficiency Rebates	Projects	0	0			0	0		
LDC Custom Programs	Projects	0	0			0	0		
Pre-2011 Programs completed in 2011 Total		**13,137**	**0**			**24,954,771**	**0**		
Other									
Program Enabled Savings	Projects	624	824			1,673,712	9,927,473		
Time-of-Use Savings	Homes	0	0			0	0		
Other Total		**624**	**824**			**1,673,712**	**9,927,473**		
Adjustments to 2011 Verified Results		**13,911**				**50,449,939**			
Adjustments to 2012 Verified Results			**8,707**				**55,101,043**		
Adjustments to Previous Years' Verified Results Total		**13,911**	**8,707**			**50,449,939**	**55,101,043**		

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

The IHD line item on the 2013 annual report has been left blank pending a results update from evaluations; results will be updated once sufficient information is made available.

Gross results are presented for informational purposes only and are not considered official 2013 Final Verified Results

ATTACHMENT # 15-Job Descriptions- IRR# 139

Position Title: Conservation & Demand Management (CDM) Program Advisor	Date of Last Revision: February 23, 2011
Reports To: Manager of Communications, Marketing & Public Affairs	Grade:
Division: Executive	

Position Summary:

Reporting to the Manager of Communications, Marketing & Public Affairs, the CDM Program Advisor will be responsible for assisting in the delivery of the CDM programs related to energy conservation, energy efficiency and load management for residential, commercial, industrial and low income customers in accordance with the Ontario Energy's mandated codes.

Dimensions:
Direct Reports: 0

Primary Duties & Responsibilities:

1. Coordinates with Marketing & Communications Coordinator regarding CDM Programs, ensuring that regulated targets are achieved.
2. Assist in the marketing efforts for conservation programs
3. Assist in the development of CDM program budgets
4. Assist in the regulatory reporting required by the OPA and OEB as required.
5. Assist in preparing reports on program initiatives
6. Liaise with commercial, residential customers and community groups in relation to energy conservation programs
7. Conducts site visits to customer facilities to promote conservation programs and assist with power-quality and cost management initiatives.

Skills, Knowledge & Education:

Skills:
This position requires a demonstrated level of initiative and judgment in order to organize and prioritize tasks, workload and projects. Courtesy, tact and diplomacy are required in dealing with colleagues in every day working relationships.

- Experience in the Ontario Electricity Market assisting with commercial/industrial customers and facility Managers is an asset.
- Demonstrated project management experience and the ability to manage multiple projects.
- Demonstrated experience with budget preparation, financial reporting, monitoring and accounting practices.
- Proficient use of Microsoft Office software, including advanced spreadsheet applications.
- Advanced written and verbal communications and public speaking skills
- Requires an understanding of inter-related work processes to be able to adapt to differing assignments.

- Ability to pay close attention to details. Makes sure work is done correctly and thoroughly - keeps accurate records.
- Draws on a number of known creative and analytical options to solve problems and to develop improvements.
- Highly self-motivated and directed
- Ability to prioritize and execute tasks in high-pressure environments
- Adaptable to set and prioritize work with varying exceptions.
- Ability to work independently and in teams
- Able to work with diverse personalities and styles.
- Delivers informative, well-organized presentations and training materials
- Understands how to communicate difficult/sensitive information tactfully
- Communicates effectively with departments to identify needs and evaluate alternative business solutions with project management
- Communicates well in writing by composing clear documents; facility with editing and/or proof-reading is required.
- Excellent time management skills
- Good project management skills

Education & Job Knowledge:

- Registered with the Ontario Association of Certified Engineering Technicians and Technologist (OACETT) or be a graduate of a college program leading to certification with OACETT as an Electrical Technician or Technologist.
- Certified Energy Manager (CEM) designation or willingness to obtain

Experience:

- Work experience in an electric utility

Certificates, Licenses or Registration:

- Must hold and maintain a valid Class “G” driver’s license with a good driving record.

Safety:

- Supports the corporate Occupational Health & Safety initiatives by incorporating safe work practices into daily work routine.
- Reports any unsafe conditions or observed unsafe work practices to manager.

Working Conditions:

** Incumbents are required to exert the following physical effort; however, reasonable accommodations may be made to enable individuals with disabilities to perform the essential functions.*

Physical Effort:
Most of the time is spent sitting in a comfortable position with the occasional opportunity to stand or move about. The incumbent may be required to occasionally kneel, reach, bend, or stretch and carry light objects consistent with usual office materials such as, paper, files and other office supplies.

Physical Environment:
Regular exposure to factors causing moderate discomfort. Slight possibility of accident or illness. Level of noise at any given time is mild to moderate and may experience frequent interruptions.

Sensory Concentration:
There is a regular need to give close attention, much of the time requiring the use of two or more senses simultaneously.

Mental Stress:
The incumbent may be exposed to situations which may cause mild to moderate mental stress. There is pronounced pressure from deadlines, production quotas, accuracy or similar demands. Unpleasant situations are probable but infrequent. The stress levels felt would not be noticeably disruptive to the work nor would the unpleasant reaction be strong or persistent

Note: This job profile indicates the general nature and level of work expected of the incumbent. It is not designed to cover or contain a comprehensive listing of activities, duties or responsibilities required of the incumbent. The incumbent may be asked to perform other duties, which may be assigned from time to time.

____________________________ _____________________
Incumbent’s Signature Date

____________________________ _____________________
Manager’s Signature Date

Position Title: Smart Meter Co-ordinator	Date of Last Revision: June, 2009
Reports To: Vice President, Customer Services & IT	Grade:
Division: Customer Service, Billing & IT	

Position Summary:

Reporting directly to the Vice President, Customer Services and IT, the incumbent performs a variety of co-ordination and testing duties to assist in the success of smart meter implementation.

Dimensions:
Direct Reports: 0

Primary Responsibilities:

1. The incumbent will complete co-ordination duties of Customer Service, Billing, Meter and IT resources to ensure that smart meter implementation duties are completed per the smart meter project plan. These duties will include but are not limited to oversee implementation process, to monitor progress, and to coordinate activities between Customer Service, Billing, Meter and IT staff as per the smart meter project plan.
2. Work with Billing Supervisors, IT resource, and Metering staff to determine schedule of implementation per reading schedule. To maintain timelines according to the schedule.
3. Documentation of workflow procedures as developed by Billing and Customer Service Supervisors and staff.
4. The incumbent will participate as a performance tester of smart meter workflow. Documentation of user test scripts and expected results, performance testing, documentation of actual results and update of impacted workflow procedures in customer service and billing.
5. Assist in the training of Billing and Customer Service staff. This may include documentation of training materials, preparation of training materials for training session.
6. Assist in the update of customer correspondence as it relates to smart meter initiatives.

Skills, Knowledge & Education:

Skills:
This position requires a demonstrated level of initiative and judgment in order to organize and prioritize tasks, workload and projects. Courtesy, tact and diplomacy are required in dealing with colleagues in every day working relationships.

- Requires an understanding of inter-related work processes to be able to adapt to differing assignments.
- Provides routine information to coordinate the assignments and work procedures of others.
- Ability to pay close attention to details. Makes sure work is done correctly and thoroughly - keeps accurate records.
- Computer skills to produce effective reports, documents and presentations. Working Knowledge of relevant MS Office software applications including Word, Visio, and MS Project.

- Accurate and efficient data entry skills. Knowledge of acceptable office practices – word processing, effective written communications, filing, general knowledge of processes impacting account processing including cash, customer service, billing, and collections.
- Professional manner, tact, diplomacy and discretion in dealing with customers and colleagues.
- Draws on a number of known creative and analytical options to solve problems and to develop improvements.
- Adaptable to set and prioritize work with varying exceptions. Able to work with diverse personalities and styles.
- Communicates with clarity, verbally and in one on one or group situations, or over the telephone.
- Communicates well in writing by composing clear documents; facility with editing and/or proof-reading is required.
- Excellent time management skills
- Good project management skills

Education & Job Knowledge:

Minimum HSGD education, with additional courses in billing, customer service, or equivalent an asset.
Working knowledge of billing processes, previous customer service or billing experience.
Easily adaptable to change and learned processes.

Experience:
Greater than three years billing/customer service experience.

Certificates, Licenses or Registration:
No specific certificates, licences or registrations are required for this position.

Working Conditions:
** Incumbents are required to exert the following physical effort; however, reasonable accommodations may be made to enable individuals with disabilities to perform the essential functions.*

Physical Effort:
Most of the time is spent sitting in a comfortable position with the occasional opportunity to stand or move about. The incumbent may be required to occasionally kneel, reach, bend, or stretch and carry light objects consistent with usual office materials such as, paper, files and other office supplies.

Physical Environment:
Work is mainly performed in a comfortable office environment. Discomfort could occur by regular exposure to mild discomfort from factors such as dust, heat, noise, drafts, and bright lights. Level of noise at any given time is mild to moderate and may experience frequent interruptions.

Sensory Concentration:
There is a regular need to give close attention, much of the time requiring the use of two or more senses simultaneously.

Mental Stress:
The incumbent may be exposed to situations which may cause mild to moderate mental stress. There is pronounced pressure from deadlines, production quotas, accuracy or similar demands.
Unpleasant situations are probable but infrequent. The stress levels felt would not be noticeably disruptive to the work nor would the unpleasant reaction be strong or persistent

Note: This job profile indicates the general nature and level of work expected of the incumbent. It is not designed to cover or contain a comprehensive listing of activities, duties or responsibilities required of the incumbent. The incumbent may be asked to perform other duties, which may be assigned from time to time.

Incumbent's Signature　　　　Date

Manager's Signature　　　　Date

Position Title: Communications and Marketing Coordinator	**Date of Last Revision:** January 2012
Reports To: Manager, Marketing, Communications and Public Affairs	**Grade:**
Department: Executive	**Previous Revision: April 2011**

Position Summary: This position coordinates marketing initiatives along with Conservation and Demand Management (CDM) Programs related to energy conservation, energy efficiency for residential, commercial, institutional, industrial and low-income customers.

Direct Reports:
None

Primary Responsibilities:
1) Reviews, processes and approves customer applications for CDM programs to ensure compliance with program rules and requirements (as outlined in the program schedules issued by the Ontario Power Authority). Ensures completeness and accuracy of application data using technical requirements, demand and energy saving calculations and financial incentives to be issued.
2) Oversees third party contractors and service providers for all registered CDM programs to ensure correct completion of work, customer satisfaction and compliance with all CDA program rules and requirements. Acts as point of contact for problems that may arise in the field with contractors.
3) Procures third party contractors and service providers to fulfill CDM obligations, including conducting interviews, selecting successful provider and negotiating rates while outlining the terms of the agreements.
4) Assists in compiling and filing the CDM reports to the OEB and the OPA to ensure regulatory compliance.
5) Tracks expenses pertaining to CDM programs to ensure proper accounting allocation to proper accounts using Great Plains. Assists in year-end reconciliation of CDM accounts to ensure programs are allotted within budget and provides updated budget reports.
6) Responds to customer inquiries regarding commercial and industrial CDM programs to encourage uptake in programs and clarity of offerings.
7) Prepares and presents information and training sessions regarding CDM programs, internally for customer service and to local contractors or suppliers to create awareness and understanding of programs and increase participation.
8) Assists in the creation, customization and proofing of NPEI corporate marketing campaigns to communicate messages to customers, including print advertising, radio scripts, corporate newsletters, bill inserts, flyers and web advertising.
9) Provides back up for Executive Assistant to the President as needed.

Safety& Wellness:

1) Supports the corporate Occupational Health & Safety initiatives by incorporating safe work practices into daily work routine.
2) Reports any unsafe conditions or observed unsafe work practices to manager.

Skills/Knowledge/Experience Required:

Skills:

- Demonstrated ability to plan, organize, problem solve and achieve deadlines.
- Uses effective written and verbal communication skills with co-workers and members of the public to achieve positive outcomes for the company.
- Ability to collect and analyze multiple sources of information to prepare a variety of reports.
- Advanced skills in the use of computer software programs for word processing, spreadsheet and presentation applications.

Knowledge/Education:

- Post-Secondary diploma or certificate in Business Administration, Marketing, Communications or equivalent.

Experience:

- Requires a minimum of 2 years administrative related experience in an office environment.

Working Conditions:

Physical Effort: Minimal fatigue or physical stress. Required to stand or sit in one location much of the time in a comfortable indoor location. There is some stooping and lifting or handling of light material.

Physical Environment: Minimal discomfort or risk of ill health. Environment is generally comfortable with exposure to some dust or dirt or other conditions which might produce mild discomfort. Travel to various locations in the Region to attend meetings.

Sensory Attention: Moderate sensory attention. There is a moderate need for sensory attention. There are some events or factors in the environment require concentrated use of two or more senses periodically, demand is not excessive.

Mental Stress: Minor mental stress. Minor mental stress would be experienced by most people.The stress felt would not be noticeably disruptive to the work nor would the unpleasant reaction be strong or persistent. Noticeable pressures from deadlines, quotas, accuracy.

Note: This job description indicates the general nature and level of work expected of the incumbent. It is not designed to cover or contain a comprehensive listing of activities, duties, or responsibilities required of the incumbent. The incumbent may be asked to perform other duties, which may be assigned from time to time.

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Incumbent’s Signature	Date
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Manager’s Signature	Date

Position Title: HR Coordinator	**Date of Last Revision:**December 2011
Reports To: HR Manager	**Grade:**
Department: Human Resources	

<u>Position Summary</u>: This position reports to the Human Resources Manager and is responsible for the supporting the human resourcesand administrative functions that include recruitment, employee and labour relations and performance management. The incumbent is responsible for the administration of the benefits and pension programs for all employees.

<u>Major Responsibilities</u>:

Human Resources Technical:

1) Provides advice and direction regarding HR regulatory and legislative requirements and ensures applicable changes are implemented. Support the implementation for Human Resources initiatives that are implemented throughout the organization.
2) Recruitment/Staffing: Collaborates with the management team to identify human resource requirements and establish criteria. Coordinates the recruitment process by preparing job posting notices for internal and external advertising of job opportunities. Screens and interviews job candidates for non-executive or senior management roles, performs background checks on prospective employees and recommends hire of successful candidate(s). Initiates offers of employment and completes all necessary documentation when hired. Ensures new employees receive appropriate orientation and introduction to the corporation.
3) Policies and Procedures: Assists in the development and updatesof corporate HR policies and procedures and ensures compliance with regulatory and legislative standards.
4) Administrative Services: Reviews monthly benefit reports; prepares reports regarding employee activity and labour/management issues
5) Performance Management: Assists with the administration of the performance appraisal system. Coordinates and follows up on annual performance reviews and initiates any follow up action that may be required to enhance employee performance.
6) Wage/Salary Administration: Liaises with Finance to have the established wage rates administered as determined within the collective agreement. Administers the management salary schedule and requests payroll changes as required.
7) Benefits:Responds to inquiries regarding the OMERS pension plan and employee benefit plans. Informs employees and retirees regarding changes to benefit plans. Updates all benefit information on wage sensitive items. Completes necessary forms when required.
8) Absenteeism: Tracks and prepares absenteeism reports for use by appropriate management staff and to ensure absenteeism levels are minimized.

Provision of Expert Advice:

1) Collaborates with the HR Manager on confidential matters to produce and provide correspondence, performance evaluations, and reports.
2) Assists management in matters relating to discipline and grievances. Liaises with lawyers when required.
3) Assists employees and retirees regarding benefit programs and pension plan information or changes.
4) Provides confidential assistance to employees.

Safety:

1) Supports the corporate Occupational Health & Safety initiatives by incorporating safe work practices into daily work routine. Reports any unsafe conditions or observed unsafe work practices to supervisor.

Labour Relations:

1) Provides interpretation of the collective agreement to ensure the collective agreement is administered in a fair and reasonable manner, as required.

Skills/Knowledge/Experience Required:

Skills:

- Demonstrated ability to analyze problems and utilize organizational and project management skills.
- Basic skills in understanding, selecting, developing, and motivating employees.
- Advanced skills in the use of computer software programs for word processing, spreadsheet and presentation applications.

Knowledge/Education:

- Requires a minimumof a college diploma in Human Resources Management or equivalent.
- Required to obtain CHRP designation.
- Knowledge of Occupational Health and Safety requirements as it relates to individual, organizational and operational requirements.
- General knowledge of management philosophies, techniques and problem-solving methods.
- Basic knowledge of the E&USA rules and OEB codes and regulations is an asset.

Experience:

- Requires a minimum of 1 to 3 years of related experience.

Position(s) supervised:
Direct: **None**

Working Conditions:

Physical Effort:

Minimal fatigue or physical stress.Required to sit in one location much of the time, with opportunity to move about. There is some stooping and lifting or handling of light material.

Physical Environment:

Minimal discomfort or risk of ill-health. Environment is generally comfortable withexposure to some dust or dirt or other conditions which might produce milddiscomfort.

Sensory Attention:

Moderate sensory attention. There is a moderate need for sensory attention. Thereare some events or factors in the environment which require concentrated useof two or more senses periodically, but the demand is not excessive.

Mental Stress:

Moderate mental stress.Moderate mental stress would be experienced by most people because of conditions which are present in the job. The stress felt would notbenoticeably disruptive to the work nor would the unpleasant reaction be strong or persistent. Noticeable pressures from deadlines, quotas, accuracy. Unpleasantsocial contacts or concern about unpleasant situations are probable.

Note: This job description indicates the general nature and level of work expected of the incumbent. It is not designed to cover or contain a comprehensive listing of activities, duties, or responsibilities required of the incumbent. The incumbent may be asked to perform other duties which may be assigned from time to time.

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Incumbent's Signature Date

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Manager's Signature Date

Position Title: Manager, Business Application Support	Date of Last Revision: January 1, 2012
Reports To: Vice President, Customer Services and IT	Grade:
Department: Business Application Support	Previous Revision:

Position Summary: This position reports to the Vice President, Customer Services and IT and is responsible for application user support, analysis and business support of new processes, testing, problem resolution, and documentation of new processes, workflows, and procedures, specifically related to the CIS and its interfaces and sub-systems.

Major Responsibilities:

Budget:

1) Assist in preparation the capital budget for the department, including all software acquisitions and operating budgets for Information Services.

2) Recommends purchase of products and services.

Technical:

1) Business & Software Applications: Plans, organizes, directs and controls the operations of business and software applications for the organization to ensure the corporate goals and objectives are achieved. Solves complex problems related to system analysis, design and implementation of business solutions to support corporate objectives. Manages changes to the advanced metering infrastructure, specifically changes to Customer Information System, and its interfaces with the provincial MDM/R and other subsystems as impacted (i.e., Outage management, Operational Integraph front end tool). Investigates and makes recommendations to the Vice-Presidents to provide business solutions to support the corporate goals and objectives.

2) System Development: Liaises with vendors to determine corporate system development needs and recommends technological changes for implementation. Business support of all interfaces to core systems such as CIS, Great Plains, Integraph, m-care, etc.

3) Policies and Procedures: Develops and implements policies and procedures for software applications, system interface and development. Responsible for documentation, testing, training of core CIS system, and business workflows from/to the CIS.

4) Administration: Organizes and manages Business Application Support staff and liaises with vendors to design, develop, implement and administer computer and telecommunications software. Assists in the Corporation's Disaster Recovery Program, ensuring it is current and that all relevant changes are tested, implemented and communicated.

Safety:

1) Manages the Business Application Support Department's Occupational Health & Safety initiatives by supporting and communicating OHS policies and procedures.

2) Ensures that employees are aware of their individual responsibilities under the OH&SA, responds to safety issues/concerns and ensures reporting of all accidents, injuries and incidents in a timely manner.

3) Provides training as required and investigates, reports and records all accidents, injuries and incidents.

Provision of Expert Advice:

1) Assists users with their system requirements, specifications, costs and timeframes for software.
2) Confers with the Vice-President, Customer Services and IT regarding the day-to-day activities of the department; and advises the VP about unusual circumstances that may have a significant effect on the operation of the organization.

Management:

1) Supervises staff within the department in order to plan, organize and follow up on all assigned work to ensure work is performed in a timely, efficient and safe manner.
2) Conducts annual performance reviews on staff within the department; identifies areas of improvement and initiates corrective action steps when necessary.
3) Participates in interviews of prospective employees and makes recommendations to hire.
4) Performs employee evaluations and follow up interviews.

Labour Relations:

1) Administers all appropriate sections of the collective agreement and represents management in grievance resolution.

<u>Skills/Knowledge/Experience Required:</u>

Skills:

- Demonstrated ability to analyze problems and utilize organizational and project management skills.
- Demonstrated ability to effectively manage, direct, coordinate and mentor a team.
- Uses effective written and verbal communication skills with co-workers and members of the public to achieve positive outcomes for the company.
- Basic skills in understanding, selecting, developing and motivating a team of employees within the department.
- Advanced skills in the use of computer software programs for word processing, spreadsheet and presentation applications, as well as advanced troubleshooting for computer systems and applications.

Knowledge/Education:

- Requires a minimum of a three-year degree/ diploma from a recognized university or college within the discipline of Business/ Information Systems or equivalent.
- Advanced understanding of Occupational Health and Safety requirements as it relates to individual, organizational and operational requirements.
- Advanced knowledge of management philosophies, techniques and problem-solving methods.
- Basic knowledge of the E&USA rules and OEB codes and regulations.

Experience:

Requires more than 5 years progressive management experience in an electrical utility or related field.

<u>Position(s) supervised</u>:
Smart Meter Co-ordinator
AMI Analyst
Business Analyst

Working Conditions:

Physical Effort:	Minimal fatigue or physical stress. Required to stand or sit in one location much of the time in a comfortable indoor location. There is some stooping and lifting or handling of light material.
Physical Environment:	Minimal discomfort or risk of ill-health. Environment is generally comfortable with exposure to some dust or dirt or other conditions that might produce mild discomfort.
Sensory Attention:	Moderate sensory attention. There is a moderate need for sensory attention. There are some events or factors in the environment which require concentrated use of two or more senses periodically, but the demand is not excessive.
Mental Stress:	Moderate mental stress. Moderate mental stress would be experienced by most people because of conditions which are present in the job. The stress felt would not be noticeably disruptive to the work nor would the unpleasant reaction be strong or persistent. Noticeable pressures from deadlines, quotas, accuracy. Unpleasant social contacts or concern about unpleasant situations are probable.

Note: This job description indicates the general nature and level of work expected of the incumbent. It is not designed to cover or contain a comprehensive listing of activities, duties, or responsibilities required of the incumbent. The incumbent may be asked to perform other duties which may be assigned from time to time.

Incumbent's Signature　　　　　　　　Date

Vice-President's Signature　　　　　　　　Date

Position Title: Systems Analyst	Date of Last Revision: January 22, 2008
Reports To: IT Manager	Grade:
Department: Customer Service and Billing	Previous Revision: May 25, 2007

Position Summary: This position reports to the IT Manager and is responsible for providing research, development and implementation of information systems development plans, policies and procedures. The incumbent is responsible for providing advice on a variety of information systems issues and acts as the database administrator for the customer information system.

Major Responsibilities:

Technical:

1) Information Systems: Consults with internal clients and identifies and documents user requirements. Conducts business and technical studies and designs, develops and implements information systems business solutions. Advises staff regarding information systems strategies, policies, management and service delivery

2) System Security: Assesses the physical and technical security risks to data, software and hardware and develops policies, procedures and contingency plans to minimize the effects of security breaches.

3) Policies and Procedures: Collaborates with the IT Manager and IT Specialist/Network Administrator to develop and implement policies and procedures throughout the software development life cycle to maximize efficiencies, effectiveness and overall quality of software products and information systems.

4) System Audit: Collaborates with the IT Manager, the IT Specialist/Network Administator and potential third party system auditors to conduct independent third-party reviews in order to assess quality assurance practices, software products and information systems.

Safety:

1) Supports the corporate Occupational Health & Safety initiatives by incorporating safe work practices into daily work routine.
2) Reports any unsafe conditions or observed unsafe work practices to supervisor.

Provision of Expert Advice:

1) Provides technical assistance by responding to inquiries from others regarding errors, problems, or questions about programs.

2) Consults with IT Manager when designing business system solutions. May provide technical support and guidance for projects.

3) Recommends solutions regarding technological changes when required and provides all required documentation.

Skills/Knowledge/Experience Required:

Skills:

- Advanced troubleshooting, problem solving and analytical skills.
- Demonstrated ability to support corporate vision and to integrate corporate philosophies into the daily routine.
- Advanced skills in the use of computer software programs for word processing, spreadsheet and presentation applications, as well as advanced troubleshooting for computer systems and applications.

Knowledge/Education:

- Requires a minimum of a college diploma in computer science or equivalent.
- Basic knowledge of Occupational Health and Safety requirements as it relates to individual, organizational and operational requirements.
- Advanced knowledge in the design, development and implementation of information systems business solutions.
- Advanced knowledge of Windows, database software, word processing software and networking software, specifically in windows, as well as, linux environment.

Experience:

Requires more than 5 years of related experience.

Working Conditions:

Physical Effort: Minimal fatigue or physical stress. Required to stand or sit in one location much of the time in a comfortable indoor location. There is some stooping and lifting or handling of light material.

Physically able to move computer equipment.

Physical Environment: Minimal discomfort or risk of ill health. Environment generally is comfortable with exposure to some dust or dirt or other conditions which might produce mild discomfort.

Sensory Attention: Moderate sensory attention. There is a moderate need for sensory attention. There are some events or factors in the environment which require concentrated use of two or more senses periodically, but the demand is not excessive.

Mental Stress: Moderate mental stress. Moderate mental stress would be experienced by most people because of one or more conditions which are present in the job. The stress felt would not be noticeably disruptive to the work nor would the unpleasant reaction be strong or persistent. Noticeable pressures from deadlines, quotas, accuracy. Unpleasant social contacts or concern about unpleasant situations are probable.

Note: This job description indicates the general nature and level of work expected of the incumbent. It is not designed to cover or contain a comprehensive listing of activities, duties, or responsibilities required of the incumbent. The incumbent may be asked to perform other duties which may be assigned from time to time.

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Incumbent's Signature Date

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Manager's Signature Date

Position Title: Regulatory Affairs and Accounting Manager	Date of Last Revision: New April 24, 2013
Reports To: Vice-President, Finance	Grade:
Department: Finance	Previous Revision:

Position Summary: This position reports to the Vice-President, Finance and is responsible for the supervision of the Regulatory and Financial Analyst and the preparation of regulatory accounts reconciliations, all required rate filings and regulatory reporting and ensures compliance with all industry regulations. The incumbent will lead, plan and manage the regulatory function to ensure maximum value is delivered to customers and the shareholder.

Major Responsibilities:

Budget:

1) Assists the Vice-President, Finance in the preparation of the corporation's annual budget.

Technical:

1) Financial: Determine the distribution revenue requirements and rates to cover costs of operations, capital, taxes and shareholder return. Prepare and/or assist in the preparation of general ledger reconciliations on a monthly, quarterly and/or year end basis. Provide ongoing strategic analysis on the most efficient/effective way to manage company assets under the regulatory rules.
2) Regulatory: Prepares all required rate filings. Prepares corporate and regulatory financial reports in compliance with corporate policies and procedures and regulatory guidelines. Represent NPEI at all hearings and respond to all interventions. Communicates all regulatory changes and updates throughout the organization. Maintain current knowledge of all relevant statutes and regulations including the Electricity Distribution Rate Handbook, the Retail Settlement Code, the Distribution System Code, the Standard Supply Service Code, the Affiliate Relationships Code, Market Rules, etc. Provide recommendations for the development of codes and regulations of the Ontario Energy Board (OEB), the Ministry of Energy, the Independent Electricity System Operator (IESO) and all other codes and regulations enacted, through active participation and representation on all essential working groups and through establishing and maintaining industry contacts.
3) Audit: Manages the audit process related to all regulatory audits. Prepares the auditor's working papers related to regulatory accounts and performs all recommended follow-up from audit reports.
4) Project Management: Assists the Vice-President and/or Controller in the development and implementation of special short and long-term financial projects for the improvement of the organization.
5) Policies and Procedures: Co-ordinates, implements and maintains sound accounting practices and procedures related to all regulatory issues, processes and changes. Reviews existing policies, initiates and implements new policies and procedures that include detailed work procedures and processes.

Safety:

1) Manages the Regulatory Department's Occupational Health & Safety initiatives by supporting and communicating OHS policies and procedures.
2) Ensures that employees are aware of their individual responsibilities under the OH&SA, responds to safety issues/concerns and ensures reporting of all accidents, injuries and incidents in a timely manner.
3) Provides training as required and investigates reports and records all accidents, injuries and incidents.

Provision of Expert Advice:

1) Counsels and confers with the Vice-President, Finance on the day-to-day business of the department as it relates to matters that may have some impact on the organization.

Management:

1) Supervises staff within the department in order to plan, organize and follow-up on assigned work.
2) Ensures that staff within the department receives the required training to complete all assignment tasks in a competent, efficient and timely manner.
3) Conducts annual performance reviews on staff within the department.
4) Participates in interviews of prospective employees and makes recommendation to hire.
5) Performs employee evaluations and follow-up interviews.
6) In the absence of the Controller and/or Accounting Supervisors, reviews the activities of staff within the department in order to plan organize and follow up on assigned work.
7) In the absence of the Controller and/or Accounting Supervisors, ensures that staff within the department receives the required training to complete all assigned tasks in a competent, efficient and timely manner.
8) In the absence of the Controller and/or Accounting Supervisors, ensures that appropriate training and development is available to staff to enhance their job performance.
9) In the absence of the Controller and/or Accounting Supervisors, delegates and monitors work for efficiencies.
10) In the absence of the Controller and/or Accounting Supervisors, ensures month-end deadlines and year-end deadlines are achieved.
11) In the absence of the Controller and/or Accounting Supervisors, ensures storage of files complies with records retention policy.

Labour Relations:

1) Administers appropriate sections of the collective agreement and represents management in department related grievance meetings.

<u>Skills/Knowledge/Experience Required:</u>

Skills:

- Demonstrated ability to define problems, collects data, establish facts, and draw valid conclusions. Ability to interpret and extensive variety of technical instructions in mathematical or diagram form and deal with several abstract and concrete variables.
- Demonstrated ability to analyze problems and utilize organizational and project management skills.
- Demonstrated ability to effectively manage, direct, coordinates and mentors a team.
- Uses effective written and verbal communication skills with co-workers and members of the public to achieve positive outcomes for the company.
- Intermediate skills in understanding, selecting, developing and motivating a team of employees within the department.
- Advances skills in the use of computer software programs for work processing, spreadsheet and presentation application, as well as financial accounting database, software and query tools.

Knowledge/Education:

- Requires a minimum of a university degree in Business or Finance or equivalent.

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- Requires a professional accounting designation (CA, CMA, CGA)
- Basic knowledge of Occupational Health and Safety requirements as it relates to individual, organization and operational requirements.
- Intermediate understanding of management philosophies, techniques and problem-solving methods.
- Basic knowledge of the E&USA rules and OEB codes and regulations.

Experience:

Requires more than 5 years regulatory related experience.

Position(s) supervised:

Financial and Regulatory Analyst

Working Conditions:

Physical Effort: Minimal fatigue or physical stress. Required to stand or sit in once location much of the time in a comfortable indoor location. There is some stooping and lifting or handling of light material.

Physical Environment: Minimal discomfort or risk of ill health. Environment is generally comfortable with exposure to some dust or dirt or other conditions which might produce mild discomfort.

Sensory Attention: Moderate sensory attention. There is a moderate need for sensory attention. There are some events or factors in the environment which require concentrated use of two or more senses periodically, but the demand is not excessive.

Mental Stress: Considerable mental stress. Considerable mental stress can be experienced from simultaneous priorities or potentially disturbing situations. Some disruption of family/social life regularly. Concern about dangerous situations occurring is common. Positive results and a sense of accomplishment may be irregular.

Note: This job description indicates the general nature and level of work expected of the incumbent. It is not designed to cover or contain a comprehensive listing of activities, duties, or responsibilities required of the incumbent. The incumbent may be asked to perform other duties, which may be assigned from time to time.

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Incumbent’s Signature Date

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Vice-President’s Signature Date

Position Title: Engineering Services Manager	Date of Last Revision: April 20, 2011
Reports To: Director of Engineering Services	Grade:
Department: Engineering	Previous Revision:

Position Summary: This position reports to the Director of Engineering Services and is responsible for creating, maintaining and modifying the utility's asset management plan according to regulatory requirements. This position is also responsible for the maintenance and implementation of the utility's smart grid plan and green energy initiatives. This position assists the Director of Engineering with the maintenance and implementation of the GIS, OMS and SCADA platforms and supporting systems utilized for distribution plant design, asset management, distribution system modeling, outage management, and work management. This position assists the VP, Engineering with annual and long term planning and budgeting.

Major Responsibilities:

Budget:

1) Prepares budgets regarding engineering information system and SCADA requirements. Assists the Vice President, Engineering in the preparation of the Capital Improvement Program and maintenance projects.

Technical:

1) Manages inspection and maintenance of the utility's assets in accordance with the asset management plan and in compliance with applicable regulations to ensure public and worker safety, system reliability and integrity of the distribution system.
2) Manages the G.I.S. and supporting design, analysis, work management and outage management systems to ensure proper functionality and accuracy of the systems and associated data.
3) Manages the implementation and maintenance of the utility's smart grid infrastructure including its integration with related utility systems and processes.
4) Liaises with municipal authorities, other utilities, organizations, contractors, consultants and associations as required.

Safety:

1) Manages the corporate Occupational Health & Safety initiatives by supporting and communicating OHS policies and procedures.
2) Ensures that employees are aware of their individual responsibilities under the OH&SA and responds to safety issues/concerns and ensures reporting of all accidents, injuries and incidents in a timely manner.
3) Attends H&S meetings on a regular basis and incorporates the health and safety philosophies into work environment.

Provision of Expert Advice:

1) Counsels and confers with the Director of Engineering and Vice President, Engineering on the day-to-day business of the department as it relates to matters that may affect the organization.
2) Assists in the preparation of the Utilities Capital Improvement Program. Provides technical expertise to engineering and operations staff as it relates to information system utilization.

Management:

1) Manages the activities of staff to ensure the work is performed in a safe, timely, and efficient manner.
2) Coordinates staffing resources to ensure work is completed within budget and in accordance with established engineering practices and procedures and in compliance with regulatory and/or legislative requirements.
3) Conducts annual performance reviews on staff within the department. Participates in interviews of prospective employees and makes recommendations to hire.

Labour Relations:

1) Administers all appropriate sections of the collective agreement and represents management in grievance resolution.

Skills/Knowledge/Experience Required:

Skills:

- Demonstrated ability to analyze complex problems and utilize organizational and project management skills and the willingness to accept responsibility and make decisions.
- Demonstrated ability to deal with peers and members of the public in a courteous and tactful manner.
- Demonstrated ability to use effective written and verbal communication skills to influence others.
- Expert skills in the use of computer software programs for asset management, data management, system simulation, word processing, spreadsheet and presentation applications.

Knowledge/Education:

- University Degree in Electrical Engineering.
- Must demonstrate eligibility for a Professional Engineering designation.
- Advanced knowledge of the design requirements for the distribution system.
- Advanced knowledge of computer systems for distribution system design, modeling and management.

Experience:

Requires a minimum of 2 years work experience in a related field.

Working Conditions:

Physical Effort: Minimal fatigue or physical stress. Required to stand or sit in one location much of the time in a comfortable indoor location. There is some stooping and lifting or handling of light material.

Physical Environment: Minimal discomfort or risk of ill health. Environment is generally comfortable with exposure to some dust or dirt or other conditions which might produce mild discomfort.

Sensory Attention: Moderate sensory attention. There is a moderate need for sensory attention. There are some events or factors in the environment require concentrated use of two or more senses periodically, demand is not excessive.

Mental Stress:	Moderate mental stress. Moderate mental stress can be experienced from simultaneous priorities or potentially disturbing situations. Some disruption of family/social life is to be expected. Concern about dangerous situations occurring is common. Positive results and a sense of accomplishment may be irregular.

Note: This job description indicates the general nature and level of work expected of the incumbent. It is not designed to cover or contain a comprehensive listing of activities, duties, or responsibilities required of the incumbent. The incumbent may be asked to perform other duties which may be assigned from time to time.

Incumbent's Signature — Date

Vice President's Signature — Date

ATTACHMENT # 16-Signed loan agreement- IRR# 145

TD Commercial Banking

40 King St
St Catharines, ON
L2R 3H4

Telephone No.: (905) 685 7631
Fax No.: (905) 685 7053

November 5, 2014

NIAGARA PENINSULA ENERGY INC.
7447 Pin Oak Drive
Niagara Falls, Ontario
L2E 6S9

Attention: Brian Wilkie, President

Dear Mr. Brian Wilkie,

The following amending agreement (the "Amending Agreement") amends the terms and conditions of the credit facilities (the "Facilities") provided to the Borrower pursuant to the Agreement dated July 14, 2009 and the subsequent Amending Agreements dated December 20, 2010 and June 21, 2012 and November 22, 2013.

BORROWER' LEGAL NAME

NIAGARA PENINSULA ENERGY INC. (herein called the "Borrower")

LENDER

The Toronto-Dominion Bank (the "Bank"), through its 40 King Street branch in St. Catharines, Ontario.

CREDIT LIMIT

4) CAD$10,000,000.

TYPE OF CREDIT AND BORROWING OPTIONS

4) Committed Term Facility (Single Draw) available at the Borrower's option by way of:
- Fixed Rate Term Loan in CAD$

PURPOSE

4) General purposes including repatriation of funds to replenish cash previously utilized for past years capital expenditures.

TENOR

4) Committed

CONTRACTUAL TERM

4) Up to 120 months from the date of drawdown

RATE TERM (FIXED RATE TERM LOAN)

4) Fixed rate: Up to 120 months but never to exceed the Contractual Term Maturity Date

INTEREST RATES AND FEES

Advances shall bear interest and fees as follows:

4) Committed Term Facility:
- Fixed Rate Term Loans: Cost of Funds (COF) + 0.30% per annum

For all Facilities, interest payments will be made in accordance with Schedule "A" unless otherwise stated in this Letter or in the Rate and Payment Terms Notice applicable for a particular drawdown. Information on interest rate and fee definitions, interest rate calculations and payment is set out in the Schedule "A".

DRAWDOWN

4) Single draw, subject to disbursement conditions.

Notice periods, minimum amounts of draws, interest periods and other similar details are set out in the Schedule "A" attached hereto.

REPAYMENT AND REDUCTION OF AMOUNT OF CREDIT FACILITY

4) Interest only monthly for up to 10 years with full principal repayment at the end of contractual term.

PREPAYMENT

4) Fixed Rate: Permitted in whole or in part at any time, subject to standard prepayment penalty.

DISBURSEMENT CONDITIONS

The obligation of the Bank to permit any drawdown hereunder is subject to the Standard Disbursement Conditions contained in Schedule "A" and the following additional drawdown conditions:

- Acknowledgement from Bank of Nova Scotia as per Intercreditor Agreement dated July 31, 2009 - Section 16.
- Executed Loan Amending Agreement.
- To be in compliance with financial covenants pre and post advance, under the Bank of Nova Scotia deal, based on the most recent financial reporting.

POSITIVE COVENANTS

So long as any amounts remain outstanding and unpaid under this Agreement or so long as any commitment under this Agreement remains in effect, the Borrower will and will ensure that its subsidiaries and each of the Guarantors will observe the Standard Positive Covenants set out in Schedule "A" and in addition will:

1,2,3,4) All existing indebtedness (beyond that permitted under Financial Covenants below), is held direct or indirect, secured or unsecured, with no acceleration rights by municipal shareholders and is bound by distribution restrictions outlined by Negative Covenants below.

1,2,3,4) Comply with Affiliate Relationship Code (legislated by OEB).

1,2,3,4) Comply with all applicable environmental regulations at all times.

1,2,3,4) Comply with all contractual obligations and laws, including payment of taxes, at all times.

1,2,3,4) Comply with all terms of all licenses and immediately advise the Bank if the OEB shall notify the Borrower of a default under a license or if the license is amended, cancelled, suspended or revoked. (Any of such occurrences will be an event of default.)

1,2,3,4) File all OEB rate submissions as outlined in three year business plan.

1,2,3,4) LDC to remain in the regulated business of electricity distribution and maintain all requisite licenses to do so.

1,2,3,4) Maintain adequate liability insurance.

1,2,3,4) Provide Audited annual financial statements within 120 days of fiscal year end for Niagara Peninsula Energy Inc.

1,2,3,4) Provide annual OEB rate submission and Service Quality Index (SQI), if applicable.

1,2,3,4) Provide annually within 120 days of fiscal year end a 1 year budget report for Niagara Peninsula Energy Inc. The budget report will include an income statement and schedule of capital expenditures.

1,2,3,4) Provide unaudited quarterly financial statements within 45 days of Q1, Q2 and Q3 (Q4 not required) for Niagara Peninsula Energy Inc.

1,2,3,4) Transfer pricing between affiliates to be in accordance with Affiliate Relationship Code and approved by the OEB, and no compliance orders from the OEB to exist under any OEB Code of Conduct.

NEGATIVE COVENANTS

So long as any amounts remain outstanding and unpaid under this Agreement or so long as any commitment under this Agreement remains in effect, the Borrower will and will ensure that its subsidiaries and each of the Guarantors will observe the Standard Negative Covenants set out in Schedule "A". In addition the Borrower will not and will ensure that its subsidiaries and each of the Guarantors will not:

1,2,3,4) Change its ownership/control without the Bank's prior written consent.

1,2,3,4) Change its status as a Limited Distribution Company.

1,2,3,4) Make distributions beyond (EBITDA - Cash Taxes - Unfinanced Capex (net of contributed capital) - Interest Costs - Principal, if any), providing Debt Service Coverage test exceeds 1.20x and no other default has occurred.

1,2,3,4) Repay shareholder debt, beyond the permitted distributions outlined below, without the Bank's prior written consent.

1,2,3,4) Undertake additional debt or guarantees without the Bank's prior written consent.

1,2,3,4) Undertake further material outside investments, mergers, amalgamations or consolidations without the Bank's prior written consent.

FINANCIAL COVENANTS

The Borrower agrees at all times to:

1,2,3,4) Maintain a Minimum Debt Service Coverage Ratio of 1.20x defined as:

$$\frac{\text{EBITDA* - Cash Taxes (PILS) - 40\% of Capital Expenditures (net of contributed capital)}}{\text{Mandatory Principal + Interest}}$$

*EBITDA is defined as Earnings before Interest, Income Taxes, Depreciation and Amortization.

To be tested on a rolling four quarter basis.

1,2,3,4) Maintain a Notional Minimum Debt Service Coverage Ratio of 1.20x defined as:

$$\frac{\text{EBITDA}^* - \text{Cash Taxes (PILS)} - 40\% \text{ of Capital Expenditures (net of contributed capital)}}{\text{Principal}^{**} + \text{Interest}}$$

*EBITDA is defined as Earnings before Interest, Income Taxes, Depreciation and Amortization.

**Principal defined as non-amortizing term debt repaid notionally over 30 years (i.e. drawn non-amortizing term debt divided by 30) and mandatory principal payments on amortizing term debt.

To be tested annually.

1,2,3,4) Maintain a maximum Debt* to Capitalization** of 0.60:1.

*Debt is defined as all third party interest bearing debt and non-interest bearing debt, including guarantees and contingent liabilities, not subordinated to TD Bank.

** Capitalization is defined as the sum of total Debt, Guarantees, Shareholders' equity, Contributed capital, and Preference share capital net of any Goodwill and other intangible assets such as deferred transition costs.

To be tested quarterly.

EVENTS OF DEFAULT

The Bank may accelerate the payment of principal and interest under any committed credit facility hereunder and cancel any undrawn portion of any committed credit facility hereunder, at any time after the occurrence of any one of the Standard Events of Default contained in Schedule "A" attached hereto and after any one of the following additional Events of Default:

1,2,3,4) Any material adverse change in legislation or regulation of the electrical distribution business in Ontario.

1,2,3,4) Cross Default to Bank of Nova Scotia.

1,2,3,4) Loss of OEB License.

1,2,3,4) Material judgments.

SCHEDULE "A" - STANDARD TERMS AND CONDITIONS

Schedule "A" sets out the Standard Terms and Conditions ("Standard Terms and Conditions") which apply to these credit facilities. The Standard Terms and Conditions, including the defined terms set out therein, form part of this Agreement, unless this letter states specifically that one or more of the Standard Terms and Conditions do not apply or are modified.

We ask that the Borrower acknowledges agreement to these amendments by signing and returning the attached duplicate copy of this Amending Agreement to the undersigned on or before **November 30, 2014.**

ACCURACY OF INFORMATION

The Borrower hereby represents and warrants that all information that it has provided to the Bank is accurate and complete respecting, where applicable:

(i) the names of the Borrower's directors and the names and addresses of the Borrower's beneficial owners;

(ii) the names and addresses of the Borrower's trustees, known beneficiaries and/or settlors; and

(iii) the Borrower's ownership, control and structure.

The Borrower will provide, or cause to be provided, such updated information and/or additional supporting information as the Bank may require from time to time with respect to any or all the matters in the Borrower's foregoing representation and warranty.

Yours truly,

THE TORONTO-DOMINION BANK

David Drosky
Manager

Greg Hoekman
Manager Commercial Credit

TO THE TORONTO-DOMINION BANK:

NIAGARA PENINSULA ENERGY INC. hereby accepts the foregoing offer this 10th day of November, 2014. The Borrower confirms that, except as may be set out above, the credit facility detailed herein shall not be used by or on behalf of any third party.

Brian Wilkie - President

Suzanne Wilson – VP Finance

Suzanne Wilson

From:	Drosky, David [david.drosky@td.com]
Sent:	Thursday, November 13, 2014 11:57 AM
To:	Suzanne Wilson
Cc:	Berridge, Peter
Subject:	NPEI Financing - Interest Rate Booking
Importance:	High

Suzanne,

Thanks for meeting the team today and providing a great NPEI overview and informative tour.

As discussed, we have booked the following loan and interest rate for you and will arrange to deposit funds to your BNS account #10702 0000 116 this PM:

Amount:	$10,000,000.
Term:	5 years
Payments	Interest Only monthly - Non- Amortizing
COF Rate:`	2.363
Spread:	0.300
All-In Rate:	2.663

We kindly request your confirmation of the above.

Thanks,
Dave

David Drosky | Manager | **TD Commercial Banking**
40 King Street, St. Catharines, Ontario L2R 3H4
T: 905-685-7631 | F: 905-685-7053

ATTACHMENT # 17-Bill Impacts- IRR# 164

Appendix 2-W
Bill Impacts

Customer Class: **Residential**

TOU / non-TOU: TOU

Consumption **800** **kWh** May 1 - October 31

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 16.0600	1	$ 16.06	$ 19.9300	1	$ 19.93	$ 3.87	24.10%
Smart Meter Rate Adder	Monthly	$ 0.9000	1	$ 0.90	$ -	1	$ -	-$ 0.90	-100.00%
Distribution Volumetric Rate	kWh	$ 0.0161	800	$ 12.88	$ 0.0149	800	$ 11.92	-$ 0.96	-7.45%
Rate Rider for Disposition of Resi	Monthly	-$ 0.0400	1	-$ 0.04	$ -	1	$ -	$ 0.04	-100.00%
Disposition of Accounts 1575/157	kWh	$ -	800	$ -	-$ 0.0030	800	-$ 2.40	-$ 2.40	
Disposition of Accounts 1575/157	kWh	$ -	800	$ -	$ -	800	$ -	$ -	
Stranded meter recovery	Monthly	$ -	1	$ -	$ 0.8929	1	$ 0.89	$ 0.89	
Sub-Total A (excluding pass through)				$ 29.80			$ 30.34	**$ 0.54**	**1.82%**
Rate Rider for Deferral/Variance Account Disposition	kWh	-$ 0.0057	800	-$ 4.56	-$ 0.0005	800	-$ 0.40	$ 4.16	-91.23%
Rate Rider for Deferral/Variance Account Disposition	kWh	$ -	800	$ -	$ -	800	$ -	$ -	
Rate Rider for Application of Tax Change	kWh	-$ 0.0001	800	-$ 0.08	$ -	800	$ -	$ 0.08	-100.00%
Rate Rider for Application of Tax Change	kWh	$ -	800	$ -	$ -	800	$ -	$ -	
Low Voltage Service Charge	kWh	$ 0.0005	800	$ 0.40	$ 0.0005	800	$ 0.40	$ -	
Line Losses on Cost of Power	kWh	$ 0.0950	44.8	$ 4.26	$ 0.0950	38.3393	$ 3.64	-$ 0.61	-14.42%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 30.61**			**$ 34.78**	**$ 4.17**	**13.62%**
RTSR - Network	kWh	$ 0.0073	845	$ 6.17	$ 0.0076	838	$ 6.37	$ 0.20	3.31%
RTSR - Line and Transformation Connection	kWh	$ 0.0050	845	$ 4.22	$ 0.0053	838	$ 4.44	$ 0.22	5.19%
Sub-Total C - Delivery (including Sub-Total B)				**$ 41.00**			**$ 45.59**	**$ 4.59**	**11.20%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0044	845	$ 3.72	$ 0.0044	838	$ 3.69	-$ 0.03	-0.76%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	845	$ 1.10	$ 0.0013	838	$ 1.09	-$ 0.01	-0.76%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	800	$ 5.60	$ 0.0070	800	$ 5.60	$ -	
TOU - Off Peak	kWh	$ 0.0770	512	$ 39.42	$ 0.0770	512	$ 39.42	$ -	
TOU - Mid Peak	kWh	$ 0.1140	144	$ 16.42	$ 0.1140	144	$ 16.42	$ -	
TOU - On Peak	kWh	$ 0.1400	144	$ 20.16	$ 0.1400	144	$ 20.16	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0880	600	$ 52.80	$ 0.0880	600	$ 52.80	$ -	
Energy - RPP - Tier 2	kWh	$ 0.1030	200	$ 20.60	$ 0.1030	200	$ 20.60	$ -	
Total Bill on TOU (before Taxes)				**$ 127.66**			**$ 132.22**	**$ 4.56**	**3.57%**
HST		13%		$ 16.60	13%		$ 17.19	$ 0.59	3.57%
Total Bill (including HST)				$ 144.26			$ 149.41	$ 5.15	3.57%
Ontario Clean Energy Benefit 1				-$ 14.43			-$ 14.94	-$ 0.51	3.53%
Total Bill on TOU (including OCEB)				**$ 129.83**			**$ 134.47**	**$ 4.64**	**3.57%**
Total Bill on RPP (before Taxes)				**$ 125.06**			**$ 129.62**	**$ 4.56**	**3.64%**
HST		13%		$ 16.26	13%		$ 16.85	$ 0.59	3.64%
Total Bill (including HST)				$ 141.32			$ 146.47	$ 5.15	3.64%
Ontario Clean Energy Benefit 1				-$ 14.13			-$ 14.65	-$ 0.52	3.68%
Total Bill on RPP (including OCEB)				**$ 127.19**			**$ 131.82**	**$ 4.63**	**3.64%**

Loss Factor (%) 5.60% 4.79%

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing must cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Appendix 2-W
Bill Impacts

Customer Class: **Residential**

TOU / non-TOU: TOU

Consumption 800 **kWh** November 1 - April 30

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 16.0600	1	$ 16.06	$ 19.9300	1	$ 19.93	$ 3.87	24.10%
Smart Meter Rate Adder	Monthly	$ 0.9000	1	$ 0.90	$ -	1	$ -	-$ 0.90	-100.00%
Distribution Volumetric Rate	kWh	$ 0.0161	800	$ 12.88	$ 0.0149	800	$ 11.92	-$ 0.96	-7.45%
Rate Rider for Disposition of Resi	Monthly	-$ 0.0400	1	-$ 0.04	$ -	1	$ -	$ 0.04	-100.00%
Disposition of Accounts 1575/157	kWh	$ -	800	$ -	-$ 0.0030	800	-$ 2.40	-$ 2.40	
Disposition of Accounts 1575/157	kWh	$ -	800	$ -	$ -	800	$ -	$ -	
Stranded meter recovery	Monthly	$ -	1	$ -	$ 0.8929	1	$ 0.89	$ 0.89	
Sub-Total A (excluding pass through)				$ 29.80			$ 30.34	**$ 0.54**	**1.82%**
Rate Rider for Deferral/Variance Account Disposition	kWh	-$ 0.0057	800	-$ 4.56	-$ 0.0005	800	-$ 0.40	$ 4.16	-91.23%
Rate Rider for Deferral/Variance Account Disposition	kWh	$ -	800	$ -	$ -	800	$ -	$ -	
Rate Rider for Application of Tax Change	kWh	-$ 0.0001	800	-$ 0.08	$ -	800	$ -	$ 0.08	-100.00%
Rate Rider for Application of Tax Change	kWh	$ -	800	$ -	$ -	800	$ -	$ -	
Low Voltage Service Charge	kWh	$ 0.0005	800	$ 0.40	$ 0.0005	800	$ 0.40	$ -	
Line Losses on Cost of Power	kWh	$ 0.0950	44.8	$ 4.26	$ 0.0950	38.3393	$ 3.64	-$ 0.61	-14.42%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 30.61**			**$ 34.78**	**$ 4.17**	**13.62%**
RTSR - Network	kWh	$ 0.0073	845	$ 6.17	$ 0.0076	838	$ 6.37	$ 0.20	3.31%
RTSR - Line and Transformation Connection	kWh	$ 0.0050	845	$ 4.22	$ 0.0053	838	$ 4.44	$ 0.22	5.19%
Sub-Total C - Delivery (including Sub-Total B)				**$ 41.00**			**$ 45.59**	**$ 4.59**	**11.20%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0044	845	$ 3.72	$ 0.0044	838	$ 3.69	-$ 0.03	-0.76%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	845	$ 1.10	$ 0.0013	838	$ 1.09	-$ 0.01	-0.76%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	800	$ 5.60	$ 0.0070	800	$ 5.60	$ -	
TOU - Off Peak	kWh	$ 0.0770	512	$ 39.42	$ 0.0770	512	$ 39.42	$ -	
TOU - Mid Peak	kWh	$ 0.1140	144	$ 16.42	$ 0.1140	144	$ 16.42	$ -	
TOU - On Peak	kWh	$ 0.1400	144	$ 20.16	$ 0.1400	144	$ 20.16	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0880	800	$ 70.40	$ 0.0880	800	$ 70.40	$ -	
Energy - RPP - Tier 2	kWh	$ 0.1030		$ -	$ 0.1030		$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 127.66**			**$ 132.22**	**$ 4.56**	**3.57%**
HST		13%		$ 16.60	13%		$ 17.19	$ 0.59	3.57%
Total Bill (including HST)				$ 144.26			$ 149.41	$ 5.15	3.57%
Ontario Clean Energy Benefit 1				-$ 14.43			-$ 14.94	-$ 0.51	3.53%
Total Bill on TOU (including OCEB)				**$ 129.83**			**$ 134.47**	**$ 4.64**	**3.57%**
Total Bill on RPP (before Taxes)				**$ 122.06**			**$ 126.62**	**$ 4.56**	**3.73%**
HST		13%		$ 15.87	13%		$ 16.46	$ 0.59	3.73%
Total Bill (including HST)				$ 137.93			$ 143.08	$ 5.15	3.73%
Ontario Clean Energy Benefit 1				-$ 13.79			-$ 14.31	-$ 0.52	3.77%
Total Bill on RPP (including OCEB)				**$ 124.14**			**$ 128.77**	**$ 4.63**	**3.73%**

Loss Factor (%) 5.60% 4.79%

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing must cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Appendix 2-W
Bill Impacts

Customer Class: **General Service < 50 kW**

TOU / non-TOU: TOU

Consumption 2,000 kWh   Non-Residential

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Monthly Service Charge	Monthly	$ 37.7900	1	$ 37.79	$ 46.2200	1	$ 46.22	$ 8.43	22.31%
Smart Meter Rate Adder	Monthly	$ 1.5300	1	$ 1.53	$ -	1	$ -	-$ 1.53	-100.00%
Distribution Volumetric Rate	kWh	$ 0.0138	2000	$ 27.60	$ 0.0108	2000	$ 21.60	-$ 6.00	-21.74%
Rate Rider for Disposition of Resi	Monthly	$ 2.4900	1	$ 2.49	$ -	1	$ -	-$ 2.49	-100.00%
Disposition of Accounts 1575/157	kWh	$ -	2000	$ -	-$ 0.0030	2000	-$ 6.00	-$ 6.00	
Disposition of Accounts 1575/157	kWh	$ -	2000	$ -	$ -	2000	$ -	$ -	
Stranded meter recovery	Monthly	$ -	1	$ -	$ 2.6138	1	$ 2.61	$ 2.61	
Sub-Total A (excluding pass through)				$ 69.41			$ 64.43	**-$ 4.98**	**-7.17%**
Rate Rider for Deferral/Variance Account Disposition	kWh	-$ 0.0057	2000	-$ 11.40	-$ 0.0010	2000	-$ 2.00	$ 9.40	-82.46%
Rate Rider for Deferral/Variance Account Disposition	kWh	$ -	2000	$ -	$ -	2000	$ -	$ -	
Rate Rider for Application of Tax Change	kWh	-$ 0.0001	2000	-$ 0.20	$ -	2000	$ -	$ 0.20	-100.00%
Rate Rider for Application of Tax Change	kWh	$ -	2000	$ -	$ -	2000	$ -	$ -	
Low Voltage Service Charge	kWh	$ 0.0004	2000	$ 0.80	$ 0.0004	2000	$ 0.80	$ -	
Line Losses on Cost of Power	kWh	$ 0.0950	112	$ 10.64	$ 0.0950	95.8481	$ 9.11	-$ 1.53	-14.42%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 70.04**			**$ 73.13**	**$ 3.09**	**4.41%**
RTSR - Network	kWh	$ 0.0066	2112	$ 13.94	$ 0.0069	2096	$ 14.46	$ 0.52	3.75%
RTSR - Line and Transformation Connection	kWh	$ 0.0044	2112	$ 9.29	$ 0.0047	2096	$ 9.85	$ 0.56	6.00%
Sub-Total C - Delivery (including Sub-Total B)				**$ 93.27**			**$ 97.44**	**$ 4.17**	**4.47%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0044	2112	$ 9.29	$ 0.0044	2096	$ 9.22	-$ 0.07	-0.76%
Rural and Remote Rate	kWh	$ 0.0013	2112	$ 2.75	$ 0.0013	2096	$ 2.72	-$ 0.02	-0.76%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	2000	$ 14.00	$ 0.0070	2000	$ 14.00	$ -	
TOU - Off Peak	kWh	$ 0.0770	1280	$ 98.56	$ 0.0770	1280	$ 98.56	$ -	
TOU - Mid Peak	kWh	$ 0.1140	360	$ 41.04	$ 0.1140	360	$ 41.04	$ -	
TOU - On Peak	kWh	$ 0.1400	360	$ 50.40	$ 0.1400	360	$ 50.40	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0880	750	$ 66.00	$ 0.0880	750	$ 66.00	$ -	
Energy - RPP - Tier 2	kWh	$ 0.1030	1250	$ 128.75	$ 0.1030	1250	$ 128.75	$ -	
Total Bill on TOU (before Taxes)				**$ 309.56**			**$ 313.64**	**$ 4.08**	**1.32%**
HST		13%		$ 40.24	13%		$ 40.77	$ 0.53	1.32%
Total Bill (including HST)				$ 349.80			$ 354.41	$ 4.61	1.32%
Ontario Clean Energy Benefit 1				-$ 34.98			-$ 35.44	-$ 0.46	1.32%
Total Bill on TOU (including OCEB)				**$ 314.82**			**$ 318.97**	**$ 4.15**	**1.32%**
Total Bill on RPP (before Taxes)				**$ 314.31**			**$ 318.39**	**$ 4.08**	**1.30%**
HST		13%		$ 40.86	13%		$ 41.39	$ 0.53	1.30%
Total Bill (including HST)				$ 355.17			$ 359.78	$ 4.61	1.30%
Ontario Clean Energy Benefit 1				-$ 35.52			-$ 35.98	-$ 0.46	1.30%
Total Bill on RPP (including OCEB)				**$ 319.65**			**$ 323.80**	**$ 4.15**	**1.30%**

Loss Factor (%) 5.60% 4.79%

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing must cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Appendix 2-W
Bill Impacts

Customer Class: **General Service > 50**

TOU / non-TOU: non-TOU

Consumption 65,000 **kWh** Non-Residential

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 179.5800	1	$ 179.58	$ 156.6100	1	$ 156.61	-$ 22.97	-12.79%
Smart Meter Rate Adder	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Distribution Volumetric Rate	kW	$ 4.2400	180	$ 763.20	$ 3.7301	180	$ 671.42	-$ 91.78	-12.03%
Rate Rider for Disposition of Resi	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Disposition of Accounts 1575/157	kWh	$ -	65000	$ -	$ -	65000	$ -	$ -	
Disposition of Accounts 1575/157	kW	$ -	180	$ -	-$ 1.1363	180	-$ 204.53	-$ 204.53	
Stranded meter recovery	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total A (excluding pass through)				$ 942.78			$ 623.49	**-$ 319.29**	**-33.87%**
Rate Rider for Deferral/Variance Account Disposition	kWh	$ -	65000	$ -	$ -	65000	$ -	$ -	
Rate Rider for Deferral/Variance Account Disposition	kW	-$ 1.9526	180	-$ 351.47	-$ 0.4382	180	-$ 78.88	$ 272.59	-77.56%
Rate Rider for Application of Tax Change	kWh	$ -	65000	$ -	$ -	65000	$ -	$ -	
Rate Rider for Application of Tax Change	kW	-$ 0.0178	180	-$ 3.20	$ -	180	$ -	$ 3.20	-100.00%
Low Voltage Service Charge	kW	$ 0.1592	180	$ 28.66	$ 0.1612	180	$ 29.02	$ 0.36	1.26%
Line Losses on Cost of Power	kWh	$ 0.1030	3640	$ 374.92	$ 0.0950	3115.06	$ 295.93	-$ 78.99	-21.07%
Smart Meter Entity Charge	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 991.68**			**$ 869.57**	**-$ 122.12**	**-12.31%**
RTSR - Network	kW	$ 2.7218	190	$ 517.36	$ 2.8297	189	$ 533.76	$ 16.40	3.17%
RTSR - Line and Transformation Connection	kW	$ 1.7467	190	$ 332.01	$ 1.8460	189	$ 348.20	$ 16.19	4.88%
Sub-Total C - Delivery (including Sub-Total B)				**$ 1,841.06**			**$ 1,751.53**	**-$ 89.53**	**-4.86%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0044	68640	$ 302.02	$ 0.0044	68115	$ 299.71	-$ 2.31	-0.76%
Rural and Remote Rate	kWh	$ 0.0013	68640	$ 89.23	$ 0.0013	68115	$ 88.55	-$ 0.68	-0.76%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	65000	$ 455.00	$ 0.0070	65000	$ 455.00	$ -	
TOU - Off Peak	kWh	$ 0.0770	41600	$ 3,203.20	$ 0.0770	41600	$ 3,203.20	$ -	
TOU - Mid Peak	kWh	$ 0.1140	11700	$ 1,333.80	$ 0.1140	11700	$ 1,333.80	$ -	
TOU - On Peak	kWh	$ 0.1400	11700	$ 1,638.00	$ 0.1400	11700	$ 1,638.00	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0880	750	$ 66.00	$ 0.0880	750	$ 66.00	$ -	
Energy - RPP - Tier 2	kWh	$ 0.1030	64250	$ 6,617.75	$ 0.1030	64250	$ 6,617.75	$ -	
Total Bill on TOU (before Taxes)				**$ 8,862.55**			**$ 8,770.03**	**-$ 92.52**	**-1.04%**
HST		13%		$ 1,152.13	13%		$ 1,140.10	-$ 12.03	-1.04%
Total Bill (including HST)				$ 10,014.69			$ 9,910.14	-$ 104.55	-1.04%
Ontario Clean Energy Benefit 1				-$ 1,001.47			-$ 991.01	$ 10.46	-1.04%
Total Bill on TOU (including OCEB)				**$ 9,013.22**			**$ 8,919.13**	**-$ 94.09**	**-1.04%**
Total Bill on RPP (before Taxes)				**$ 9,371.30**			**$ 9,278.78**	**-$ 92.52**	**-0.99%**
HST		13%		$ 1,218.27	13%		$ 1,206.24	-$ 12.03	-0.99%
Total Bill (including HST)				$ 10,589.57			$ 10,485.02	-$ 104.55	-0.99%
Ontario Clean Energy Benefit 1				-$ 1,058.96			-$ 1,048.50	$ 10.46	-0.99%
Total Bill on RPP (including OCEB)				**$ 9,530.61**			**$ 9,436.52**	**-$ 94.09**	**-0.99%**

Loss Factor (%) 5.60% 4.79%

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing must cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Appendix 2-W
Bill Impacts

Customer Class: **Unmetered Scattered Load**

TOU / non-TOU: non-TOU

Consumption 250 **kWh** Non-Residential

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 19.5300	1	$ 19.53	$ 19.7000	1	$ 19.70	$ 0.17	0.87%
Smart Meter Rate Adder	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Distribution Volumetric Rate	kWh	$ 0.0137	250	$ 3.43	$ 0.0138	250	$ 3.45	$ 0.02	0.73%
Rate Rider for Disposition of Resi	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Disposition of Accounts 1575/157	kWh	$ -	250	$ -	-$ 0.0030	250	-$ 0.75	-$ 0.75	
Disposition of Accounts 1575/157	kWh	$ -	250	$ -	$ -	250	$ -	$ -	
Stranded meter recovery	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total A (excluding pass through)				$ 22.96			$ 22.40	**-$ 0.56**	**-2.42%**
Rate Rider for Deferral/Variance Account Disposition	kWh	-$ 0.0057	250	-$ 1.43	-$ 0.0011	250	-$ 0.28	$ 1.15	-80.70%
Rate Rider for Deferral/Variance Account Disposition	kWh	$ -	250	$ -	$ -	250	$ -	$ -	
Rate Rider for Application of Tax Change	kWh	-$ 0.0002	250	-$ 0.05	$ -	250	$ -	$ 0.05	-100.00%
Rate Rider for Application of Tax Change	kWh	$ -	250	$ -	$ -	250	$ -	$ -	
Low Voltage Service Charge	kWh	$ 0.0004	250	$ 0.10	$ 0.0004	250	$ 0.10	$ -	
Line Losses on Cost of Power	kWh	$ 0.0880	14	$ 1.23	$ 0.0950	11.981	$ 1.14	-$ 0.09	-7.61%
Smart Meter Entity Charge	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 22.81**			**$ 23.36**	**$ 0.55**	**2.42%**
RTSR - Network	kWh	$ 0.0066	264	$ 1.74	$ 0.0069	262	$ 1.81	$ 0.07	3.75%
RTSR - Line and	kWh	$ 0.0044	264	$ 1.16	$ 0.0047	262	$ 1.23	$ 0.07	6.00%
Sub-Total C - Delivery				**$ 25.72**			**$ 26.40**	**$ 0.69**	**2.67%**
Wholesale Market Service	kWh	$ 0.0044	264	$ 1.16	$ 0.0044	262	$ 1.15	-$ 0.01	-0.76%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	264	$ 0.34	$ 0.0013	262	$ 0.34	-$ 0.00	-0.76%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	250	$ 1.75	$ 0.0070	250	$ 1.75	$ -	
TOU - Off Peak	kWh	$ 0.0770	160	$ 12.32	$ 0.0770	160	$ 12.32	$ -	
TOU - Mid Peak	kWh	$ 0.1140	45	$ 5.13	$ 0.1140	45	$ 5.13	$ -	
TOU - On Peak	kWh	$ 0.1400	45	$ 6.30	$ 0.1400	45	$ 6.30	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0880	250	$ 22.00	$ 0.0880	250	$ 22.00	$ -	
Energy - RPP - Tier 2	kWh	$ 0.1030		$ -	$ 0.1030		$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 52.97**			**$ 53.65**	**$ 0.67**	**1.27%**
HST		13%		$ 6.89	13%		$ 6.97	$ 0.09	1.27%
Total Bill (including HST)				$ 59.86			$ 60.62	$ 0.76	1.27%
Ontario Clean Energy Benefit 1				-$ 5.99			-$ 6.06	-$ 0.07	1.17%
Total Bill on TOU (including OCEB)				**$ 53.87**			**$ 54.56**	**$ 0.69**	**1.29%**
Total Bill on RPP (before Taxes)				**$ 51.22**			**$ 51.90**	**$ 0.67**	**1.32%**
HST		13%		$ 6.66	13%		$ 6.75	$ 0.09	1.32%
Total Bill (including HST)				$ 57.88			$ 58.64	$ 0.76	1.32%
Ontario Clean Energy Benefit 1				-$ 5.79			-$ 5.86	-$ 0.07	1.21%
Total Bill on RPP (including OCEB)				**$ 52.09**			**$ 52.78**	**$ 0.69**	**1.33%**

Loss Factor (%) 5.60% 4.79%

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing must cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

File Number:	EB-2014-0096
Exhibit:	
Tab:	
Schedule:	
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Appendix 2-W
Bill Impacts

Customer Class: **Sentinel Lighting**

TOU / non-TOU: non-TOU

Consumption **44** **kWh** Non-Residential

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 12.8700	1	$ 12.87	$ 14.9500	1	$ 14.95	$ 2.08	16.16%
Smart Meter Rate Adder	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Distribution Volumetric Rate	kW	$ 16.0553	0.12	$ 1.93	$ 18.6534	0.12	$ 2.24	$ 0.31	16.18%
Rate Rider for Disposition of Resi	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Disposition of Accounts 1575/157	kWh	$ -	44	$ -	$ -	44	$ -	$ -	
Disposition of Accounts 1575/157	kW	$ -	0.12	$ -	-$ 1.1060	0.12	-$ 0.13	-$ 0.13	
Stranded meter recovery	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total A (excluding pass through)				$ 14.80			$ 17.06	**$ 2.26**	**15.27%**
Rate Rider for	kWh	$ -	44	$ -	$ -	44	$ -	$ -	
Rate Rider for	kW	-$ 2.0980	0.12	-$ 0.25	$ 2.4077	0.12	$ 0.29	$ 0.54	-214.76%
Rate Rider for Application of Tax Change	kWh	$ -	44	$ -	$ -	44	$ -	$ -	
Rate Rider for Application of Tax Change	kW	-$ 0.4168	0.12	-$ 0.05	$ -	0.12	$ -	$ 0.05	-100.00%
Low Voltage Service Charge	kW	$ 0.1330	0.12	$ 0.02	$ 0.1347	0.12	$ 0.02	$ 0.00	1.28%
Line Losses on Cost of Power	kWh	$ 0.0880	2.464	$ 0.22	$ 0.0950	2.10866	$ 0.20	-$ 0.02	-7.61%
Smart Meter Entity Charge	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total B - Distribution				**$ 14.73**			**$ 17.56**	**$ 2.83**	**19.24%**
RTSR - Network	kW	$ 2.0152	0	$ 0.26	$ 2.0951	0	$ 0.26	$ 0.01	3.17%
RTSR - Line and Transformation Connection	kW	$ 1.4595	0	$ 0.18	$ 1.5425	0	$ 0.19	$ 0.01	4.88%
Sub-Total C - Delivery (including Sub-Total B)				**$ 15.17**			**$ 18.02**	**$ 2.85**	**18.79%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0044	46	$ 0.20	$ 0.0044	46	$ 0.20	-$ 0.00	-0.76%
Rural and Remote Rate	kWh	$ 0.0013	46	$ 0.06	$ 0.0013	46	$ 0.06	-$ 0.00	-0.76%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	44	$ 0.31	$ 0.0070	44	$ 0.31	$ -	
TOU - Off Peak	kWh	$ 0.0770	28	$ 2.17	$ 0.0770	28	$ 2.17	$ -	
TOU - Mid Peak	kWh	$ 0.1140	8	$ 0.90	$ 0.1140	8	$ 0.90	$ -	
TOU - On Peak	kWh	$ 0.1400	8	$ 1.11	$ 0.1400	8	$ 1.11	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0880	44	$ 3.87	$ 0.0880	44	$ 3.87	$ -	
Energy - RPP - Tier 2	kWh	$ 0.1030		$ -	$ 0.1030		$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 20.17**			**$ 23.02**	**$ 2.85**	**14.12%**
HST		13%		$ 2.62	13%		$ 2.99	$ 0.37	14.12%
Total Bill (including HST)				$ 22.79			$ 26.01	$ 3.22	14.12%
Ontario Clean Energy Benefit 1				-$ 2.28			-$ 2.60	-$ 0.32	14.04%
Total Bill on TOU (including OCEB)				**$ 20.51**			**$ 23.41**	**$ 2.90**	**14.13%**
Total Bill on RPP (before Taxes)				**$ 19.86**			**$ 22.71**	**$ 2.85**	**14.34%**
HST		13%		$ 2.58	13%		$ 2.95	$ 0.37	14.34%
Total Bill (including HST)				$ 22.44			$ 25.66	$ 3.22	14.34%
Ontario Clean Energy Benefit 1				-$ 2.24			-$ 2.57	-$ 0.33	14.73%
Total Bill on RPP (including OCEB)				**$ 20.20**			**$ 23.09**	**$ 2.89**	**14.30%**
Loss Factor (%)		5.60%			4.79%				

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing must cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Appendix 2-W
Bill Impacts

Customer Class: **Street Lighting**

TOU / non-TOU: non-TOU

Consumption 50 **kWh** Non-Residential

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Monthly Service Charge	Monthly	$ 1.1500	1	$ 1.15	$ 1.1800	1	$ 1.18	$ 0.03	2.61%
Smart Meter Rate Adder	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Distribution Volumetric Rate	kW	$ 4.4657	0.13	$ 0.58	$ 4.5667	0.13	$ 0.59	$ 0.01	2.26%
Rate Rider for Disposition of Resi	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Disposition of Accounts 1575/157	kWh	$ -	50	$ -	$ -	50	$ -	$ -	
Disposition of Accounts 1575/157	kW	$ -	0.13	$ -	-$ 1.0526	0.13	-$ 0.14	-$ 0.14	
Stranded meter recovery	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total A (excluding pass through)				$ 1.73			$ 1.64	**-$ 0.09**	**-5.41%**
Rate Rider for Deferral/Variance Account Disposition	kWh	$ -	50	$ -	$ -	50	$ -	$ -	
Rate Rider for Deferral/Variance Account Disposition	kW	-$ 2.1152	0.13	-$ 0.27	-$ 0.4099	0.13	-$ 0.05	$ 0.22	-80.62%
Rate Rider for Application of	kWh	$ -	50	$ -	$ -	50	$ -	$ -	
Rate Rider for Application of	kW	-$ 0.0439	0.13	-$ 0.01	$ -	0.13	$ -	$ 0.01	-100.00%
Low Voltage Service Charge	kW	$ 0.1223	0.13	$ 0.02	$ 0.1239	0.13	$ 0.02	$ 0.00	1.31%
Line Losses on Cost of Power	kWh	$ 0.0880	2.8	$ 0.25	$ 0.0950	2.3962	$ 0.23	-$ 0.02	-7.61%
Smart Meter Entity Charge	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 1.71**			**$ 1.83**	**$ 0.12**	**6.72%**
RTSR - Network	kW	$ 2.0576	0	$ 0.28	$ 2.1391	0	$ 0.29	$ 0.01	3.17%
RTSR - Line and	kW	$ 1.3420	0	$ 0.18	$ 1.4183	0	$ 0.19	$ 0.01	4.88%
Sub-Total C - Delivery				**$ 2.18**			**$ 2.31**	**$ 0.13**	**6.11%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0044	53	$ 0.23	$ 0.0044	52	$ 0.23	-$ 0.00	-0.76%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	53	$ 0.07	$ 0.0013	52	$ 0.07	-$ 0.00	-0.76%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	50	$ 0.35	$ 0.0070	50	$ 0.35	$ -	
TOU - Off Peak	kWh	$ 0.0770	32	$ 2.46	$ 0.0770	32	$ 2.46	$ -	
TOU - Mid Peak	kWh	$ 0.1140	9	$ 1.03	$ 0.1140	9	$ 1.03	$ -	
TOU - On Peak	kWh	$ 0.1400	9	$ 1.26	$ 0.1400	9	$ 1.26	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0880	50	$ 4.40	$ 0.0880	50	$ 4.40	$ -	
Energy - RPP - Tier 2	kWh	$ 0.1030		$ -	$ 0.1030		$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 7.83**			**$ 7.96**	**$ 0.13**	**1.67%**
HST		13%		$ 1.02	13%		$ 1.03	$ 0.02	1.67%
Total Bill (including HST)				$ 8.85			$ 9.00	$ 0.15	1.67%
Ontario Clean Energy Benefit 1				-$ 0.88			-$ 0.90	-$ 0.02	2.27%
Total Bill on TOU (including OCEB)				**$ 7.97**			**$ 8.10**	**$ 0.13**	**1.60%**
Total Bill on RPP (before Taxes)				**$ 7.48**			**$ 7.61**	**$ 0.13**	**1.75%**
HST		13%		$ 0.97	13%		$ 0.99	$ 0.02	1.75%
Total Bill (including HST)				$ 8.45			$ 8.60	$ 0.15	1.75%
Ontario Clean Energy Benefit 1				-$ 0.85			-$ 0.86	-$ 0.01	1.18%
Total Bill on RPP (including OCEB)				**$ 7.60**			**$ 7.74**	**$ 0.14**	**1.81%**

Loss Factor (%) Current: 5.60% Proposed: 4.79%

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing must cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

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Appendix 2-W
Bill Impacts

Customer Class: **Residential**

TOU / non-TOU: TOU

Consumption 100 **kWh** May 1 - October 31

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 16.0600	1	$ 16.06	$ 19.9300	1	$ 19.93	$ 3.87	24.10%
Smart Meter Rate Adder	Monthly	$ 0.9000	1	$ 0.90	$ -	1	$ -	-$ 0.90	-100.00%
Distribution Volumetric Rate	kWh	$ 0.0161	100	$ 1.61	$ 0.0149	100	$ 1.49	-$ 0.12	-7.45%
Rate Rider for Disposition of Resi	Monthly	-$ 0.0400	1	-$ 0.04	$ -	1	$ -	$ 0.04	-100.00%
Disposition of Accounts 1575/157	kWh	$ -	100	$ -	-$ 0.0030	100	-$ 0.30	-$ 0.30	
Disposition of Accounts 1575/157	kWh	$ -	100	$ -	$ -	100	$ -	$ -	
Stranded meter recovery	Monthly	$ -	1	$ -	$ 0.8929	1	$ 0.89	$ 0.89	
Sub-Total A (excluding pass through)				$ 18.53			$ 22.01	**$ 3.48**	**18.80%**
Rate Rider for Deferral/Variance Account Disposition	kWh	-$ 0.0057	100	-$ 0.57	-$ 0.0005	100	-$ 0.05	$ 0.52	-91.23%
Rate Rider for Deferral/Variance Account Disposition	kWh	$ -	100	$ -	$ -	100	$ -	$ -	
Rate Rider for Application of Tax Change	kWh	-$ 0.0001	100	-$ 0.01	$ -	100	$ -	$ 0.01	-100.00%
Rate Rider for Application of Tax Change	kWh	$ -	100	$ -	$ -	100	$ -	$ -	
Low Voltage Service Charge	kWh	$ 0.0005	100	$ 0.05	$ 0.0005	100	$ 0.05	$ -	
Line Losses on Cost of Power	kWh	$ 0.0950	5.60	$ 0.53	$ 0.0950	4.79	$ 0.46	-$ 0.08	-14.46%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 19.32**			**$ 23.26**	**$ 3.94**	**20.37%**
RTSR - Network	kWh	$ 0.0073	106	$ 0.77	$ 0.0076	105	$ 0.80	$ 0.03	3.31%
RTSR - Line and Transformation Connection	kWh	$ 0.0050	106	$ 0.53	$ 0.0053	105	$ 0.56	$ 0.03	5.19%
Sub-Total C - Delivery (including Sub-Total B)				**$ 20.62**			**$ 24.61**	**$ 3.99**	**19.34%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0044	106	$ 0.46	$ 0.0044	105	$ 0.46	-$ 0.00	-0.77%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	106	$ 0.14	$ 0.0013	105	$ 0.14	-$ 0.00	-0.77%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	100	$ 0.70	$ 0.0070	100	$ 0.70	$ -	
TOU - Off Peak	kWh	$ 0.0770	65	$ 5.01	$ 0.0770	65	$ 5.01	$ -	
TOU - Mid Peak	kWh	$ 0.1140	18	$ 2.00	$ 0.1140	18	$ 2.00	$ -	
TOU - On Peak	kWh	$ 0.1400	18	$ 2.45	$ 0.1400	18	$ 2.45	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0880	100	$ 8.80	$ 0.0880	100	$ 8.80	$ -	
Energy - RPP - Tier 2	kWh	$ 0.1030		$ -	$ 0.1030		$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 31.62**			**$ 35.61**	**$ 3.98**	**12.60%**
HST		13%		$ 4.11	13%		$ 4.63	$ 0.52	12.60%
Total Bill (including HST)				$ 35.73			$ 40.24	$ 4.50	12.60%
Ontario Clean Energy Benefit 1				-$ 3.57			-$ 4.02	-$ 0.45	12.61%
Total Bill on TOU (including OCEB)				**$ 32.16**			**$ 36.22**	**$ 4.05**	**12.60%**
Total Bill on RPP (before Taxes)				**$ 30.97**			**$ 34.96**	**$ 3.98**	**12.86%**
HST		13%		$ 4.03	13%		$ 4.54	$ 0.52	12.86%
Total Bill (including HST)				$ 35.00			$ 39.50	$ 4.50	12.86%
Ontario Clean Energy Benefit 1				-$ 3.50			-$ 3.95	-$ 0.45	12.86%
Total Bill on RPP (including OCEB)				**$ 31.50**			**$ 35.55**	**$ 4.05**	**12.86%**
Loss Factor (%)		5.60%			4.79%				

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing must cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

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Appendix 2-W
Bill Impacts

Customer Class: **Residential**

TOU / non-TOU: TOU

Consumption 100 **kWh** November 1 - April 30

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 16.0600	1	$ 16.06	$ 19.9300	1	$ 19.93	$ 3.87	24.10%
Smart Meter Rate Adder	Monthly	$ 0.9000	1	$ 0.90	$ -	1	$ -	-$ 0.90	-100.00%
Distribution Volumetric Rate	kWh	$ 0.0161	100	$ 1.61	$ 0.0149	100	$ 1.49	-$ 0.12	-7.45%
Rate Rider for Disposition of Resi	Monthly	-$ 0.0400	1	-$ 0.04	$ -	1	$ -	$ 0.04	-100.00%
Disposition of Accounts 1575/157	kWh	$ -	100	$ -	-$ 0.0030	100	-$ 0.30	-$ 0.30	
Disposition of Accounts 1575/157	kWh	$ -	100	$ -	$ -	100	$ -	$ -	
Stranded meter recovery	Monthly	$ -	1	$ -	$ 0.8929	1	$ 0.89	$ 0.89	
Sub-Total A (excluding pass through)				$ 18.53			$ 22.01	**$ 3.48**	**18.80%**
Rate Rider for Deferral/Variance Account Disposition	kWh	-$ 0.0057	100	-$ 0.57	-$ 0.0005	100	-$ 0.05	$ 0.52	-91.23%
Rate Rider for Deferral/Variance Account Disposition	kWh	$ -	100	$ -	$ -	100	$ -	$ -	
Rate Rider for Application of Tax Change	kWh	-$ 0.0001	100	-$ 0.01	$ -	100	$ -	$ 0.01	-100.00%
Rate Rider for Application of Tax Change	kWh	$ -	100	$ -	$ -	100	$ -	$ -	
Low Voltage Service Charge	kWh	$ 0.0005	100	$ 0.05	$ 0.0005	100	$ 0.05	$ -	
Line Losses on Cost of Power	kWh	$ 0.0950	5.60	$ 0.53	$ 0.0950	4.79	$ 0.46	-$ 0.08	-14.46%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 19.32**			**$ 23.26**	**$ 3.94**	**20.37%**
RTSR - Network	kWh	$ 0.0073	106	$ 0.77	$ 0.0076	105	$ 0.80	$ 0.03	3.31%
RTSR - Line and Transformation Connection	kWh	$ 0.0050	106	$ 0.53	$ 0.0053	105	$ 0.56	$ 0.03	5.19%
Sub-Total C - Delivery (including Sub-Total B)				**$ 20.62**			**$ 24.61**	**$ 3.99**	**19.34%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0044	106	$ 0.46	$ 0.0044	105	$ 0.46	-$ 0.00	-0.77%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	106	$ 0.14	$ 0.0013	105	$ 0.14	-$ 0.00	-0.77%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	100	$ 0.70	$ 0.0070	100	$ 0.70	$ -	
TOU - Off Peak	kWh	$ 0.0770	64	$ 4.93	$ 0.0770	64	$ 4.93	$ -	
TOU - Mid Peak	kWh	$ 0.1140	18	$ 2.05	$ 0.1140	18	$ 2.05	$ -	
TOU - On Peak	kWh	$ 0.1400	18	$ 2.52	$ 0.1400	18	$ 2.52	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0880	100	$ 8.80	$ 0.0880	100	$ 8.80	$ -	
Energy - RPP - Tier 2	kWh	$ 0.1030		$ -	$ 0.1030		$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 31.67**			**$ 35.66**	**$ 3.98**	**12.58%**
HST		13%		$ 4.12	13%		$ 4.64	$ 0.52	12.58%
Total Bill (including HST)				$ 35.79			$ 40.29	$ 4.50	12.58%
Ontario Clean Energy Benefit 1				-$ 3.58			-$ 4.03	-$ 0.45	12.57%
Total Bill on TOU (including OCEB)				**$ 32.21**			**$ 36.26**	**$ 4.05**	**12.58%**
Total Bill on RPP (before Taxes)				**$ 30.97**			**$ 34.96**	**$ 3.98**	**12.86%**
HST		13%		$ 4.03	13%		$ 4.54	$ 0.52	12.86%
Total Bill (including HST)				$ 35.00			$ 39.50	$ 4.50	12.86%
Ontario Clean Energy Benefit 1				-$ 3.50			-$ 3.95	-$ 0.45	12.86%
Total Bill on RPP (including OCEB)				**$ 31.50**			**$ 35.55**	**$ 4.05**	**12.86%**

Loss Factor (%) 5.60% 4.79%

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing must cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

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Appendix 2-W
Bill Impacts

Customer Class: Residential

TOU / non-TOU: TOU

Consumption 250 **kWh** May 1 - October 31

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 16.0600	1	$ 16.06	$ 19.9300	1	$ 19.93	$ 3.87	24.10%
Smart Meter Rate Adder	Monthly	$ 0.9000	1	$ 0.90	$ -	1	$ -	-$ 0.90	-100.00%
Distribution Volumetric Rate	kWh	$ 0.0161	250	$ 4.03	$ 0.0149	250	$ 3.73	-$ 0.30	-7.45%
Rate Rider for Disposition of Resi	Monthly	-$ 0.0400	1	-$ 0.04	$ -	1	$ -	$ 0.04	-100.00%
Disposition of Accounts 1575/157	kWh	$ -	250	$ -	-$ 0.0030	250	-$ 0.75	-$ 0.75	
Disposition of Accounts 1575/157	kWh	$ -	250	$ -	$ -	250	$ -	$ -	
Stranded meter recovery	Monthly	$ -	1	$ -	$ 0.8929	1	$ 0.89	$ 0.89	
Sub-Total A (excluding pass through)				$ 20.95			$ 23.80	**$ 2.85**	**13.62%**
Rate Rider for Deferral/Variance Account Disposition	kWh	-$ 0.0057	250	-$ 1.43	-$ 0.0005	250	-$ 0.13	$ 1.30	-91.23%
Rate Rider for Deferral/Variance Account Disposition	kWh	$ -	250	$ -	$ -	250	$ -	$ -	
Rate Rider for Application of Tax Change	kWh	-$ 0.0001	250	-$ 0.03	$ -	250	$ -	$ 0.03	-100.00%
Rate Rider for Application of Tax Change	kWh	$ -	250	$ -	$ -	250	$ -	$ -	
Low Voltage Service Charge	kWh	$ 0.0005	250	$ 0.13	$ 0.0005	250	$ 0.13	$ -	
Line Losses on Cost of Power	kWh	$ 0.0950	14.00	$ 1.33	$ 0.0950	11.98	$ 1.14	-$ 0.19	-14.46%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 21.74**			**$ 25.73**	**$ 3.99**	**18.33%**
RTSR - Network	kWh	$ 0.0073	264	$ 1.93	$ 0.0076	262	$ 1.99	$ 0.06	3.31%
RTSR - Line and Transformation Connection	kWh	$ 0.0050	264	$ 1.32	$ 0.0053	262	$ 1.39	$ 0.07	5.19%
Sub-Total C - Delivery (including Sub-Total B)				**$ 24.99**			**$ 29.11**	**$ 4.12**	**16.48%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0044	264	$ 1.16	$ 0.0044	262	$ 1.15	-$ 0.01	-0.77%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	264	$ 0.34	$ 0.0013	262	$ 0.34	-$ 0.00	-0.77%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	250	$ 1.75	$ 0.0070	250	$ 1.75	$ -	
TOU - Off Peak	kWh	$ 0.0770	163	$ 12.51	$ 0.0770	163	$ 12.51	$ -	
TOU - Mid Peak	kWh	$ 0.1140	44	$ 4.99	$ 0.1140	44	$ 4.99	$ -	
TOU - On Peak	kWh	$ 0.1400	44	$ 6.13	$ 0.1400	44	$ 6.13	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0880	250	$ 22.00	$ 0.0880	250	$ 22.00	$ -	
Energy - RPP - Tier 2	kWh	$ 0.1030		$ -	$ 0.1030		$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 52.12**			**$ 56.22**	**$ 4.11**	**7.88%**
HST		13%		$ 6.78	13%		$ 7.31	$ 0.53	7.88%
Total Bill (including HST)				$ 58.89			$ 63.53	$ 4.64	7.88%
Ontario Clean Energy Benefit 1				-$ 5.89			-$ 6.35	-$ 0.46	7.81%
Total Bill on TOU (including OCEB)				**$ 53.00**			**$ 57.18**	**$ 4.18**	**7.89%**
Total Bill on RPP (before Taxes)				**$ 50.49**			**$ 54.60**	**$ 4.11**	**8.13%**
HST		13%		$ 6.56	13%		$ 7.10	$ 0.53	8.13%
Total Bill (including HST)				$ 57.06			$ 61.70	$ 4.64	8.13%
Ontario Clean Energy Benefit 1				-$ 5.71			-$ 6.17	-$ 0.46	8.06%
Total Bill on RPP (including OCEB)				**$ 51.35**			**$ 55.53**	**$ 4.18**	**8.14%**

Loss Factor (%) Current: 5.60% Proposed: 4.79%

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing must cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

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Appendix 2-W
Bill Impacts

Customer Class: Residential

TOU / non-TOU: TOU

Consumption 250 **kWh** November 1 - April 30

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 16.0600	1	$ 16.06	$ 19.9300	1	$ 19.93	$ 3.87	24.10%
Smart Meter Rate Adder	Monthly	$ 0.9000	1	$ 0.90	$ -	1	$ -	-$ 0.90	-100.00%
Distribution Volumetric Rate	kWh	$ 0.0161	250	$ 4.03	$ 0.0149	250	$ 3.73	-$ 0.30	-7.45%
Rate Rider for Disposition of Resi	Monthly	-$ 0.0400	1	-$ 0.04	$ -	1	$ -	$ 0.04	-100.00%
Disposition of Accounts 1575/157	kWh	$ -	250	$ -	-$ 0.0030	250	-$ 0.75	-$ 0.75	
Disposition of Accounts 1575/157	kWh	$ -	250	$ -	$ -	250	$ -	$ -	
Stranded meter recovery	Monthly	$ -	1	$ -	$ 0.8929	1	$ 0.89	$ 0.89	
Sub-Total A (excluding pass through)				$ 20.95			$ 23.80	**$ 2.85**	**13.62%**
Rate Rider for Deferral/Variance Account Disposition	kWh	-$ 0.0057	250	-$ 1.43	-$ 0.0005	250	-$ 0.13	$ 1.30	-91.23%
Rate Rider for Deferral/Variance Account Disposition	kWh	$ -	250	$ -	$ -	250	$ -	$ -	
Rate Rider for Application of Tax Change	kWh	-$ 0.0001	250	-$ 0.03	$ -	250	$ -	$ 0.03	-100.00%
Rate Rider for Application of Tax Change	kWh	$ -	250	$ -	$ -	250	$ -	$ -	
Low Voltage Service Charge	kWh	$ 0.0005	250	$ 0.13	$ 0.0005	250	$ 0.13	$ -	
Line Losses on Cost of Power	kWh	$ 0.0950	14.00	$ 1.33	$ 0.0950	11.98	$ 1.14	-$ 0.19	-14.46%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 21.74**			**$ 25.73**	**$ 3.99**	**18.33%**
RTSR - Network	kWh	$ 0.0073	264	$ 1.93	$ 0.0076	262	$ 1.99	$ 0.06	3.31%
RTSR - Line and Transformation Connection	kWh	$ 0.0050	264	$ 1.32	$ 0.0053	262	$ 1.39	$ 0.07	5.19%
Sub-Total C - Delivery (including Sub-Total B)				**$ 24.99**			**$ 29.11**	**$ 4.12**	**16.48%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0044	264	$ 1.16	$ 0.0044	262	$ 1.15	-$ 0.01	-0.77%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	264	$ 0.34	$ 0.0013	262	$ 0.34	-$ 0.00	-0.77%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	250	$ 1.75	$ 0.0070	250	$ 1.75	$ -	
TOU - Off Peak	kWh	$ 0.0770	163	$ 12.51	$ 0.0770	163	$ 12.51	$ -	
TOU - Mid Peak	kWh	$ 0.1140	44	$ 4.99	$ 0.1140	44	$ 4.99	$ -	
TOU - On Peak	kWh	$ 0.1400	44	$ 6.13	$ 0.1400	44	$ 6.13	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0880	250	$ 22.00	$ 0.0880	250	$ 22.00	$ -	
Energy - RPP - Tier 2	kWh	$ 0.1030		$ -	$ 0.1030		$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 52.12**			**$ 56.22**	**$ 4.11**	**7.88%**
HST		13%		$ 6.78	13%		$ 7.31	$ 0.53	7.88%
Total Bill (including HST)				$ 58.89			$ 63.53	$ 4.64	7.88%
Ontario Clean Energy Benefit 1				-$ 5.89			-$ 6.35	-$ 0.46	7.81%
Total Bill on TOU (including OCEB)				**$ 53.00**			**$ 57.18**	**$ 4.18**	**7.89%**
Total Bill on RPP (before Taxes)				**$ 50.49**			**$ 54.60**	**$ 4.11**	**8.13%**
HST		13%		$ 6.56	13%		$ 7.10	$ 0.53	8.13%
Total Bill (including HST)				$ 57.06			$ 61.70	$ 4.64	8.13%
Ontario Clean Energy Benefit 1				-$ 5.71			-$ 6.17	-$ 0.46	8.06%
Total Bill on RPP (including OCEB)				**$ 51.35**			**$ 55.53**	**$ 4.18**	**8.14%**
Loss Factor (%)		5.60%			4.79%				

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing must cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

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Appendix 2-W
Bill Impacts

Customer Class: **Residential**

TOU / non-TOU: TOU

Consumption 500 **kWh** May 1 - October 31

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Monthly Service Charge	Monthly	$ 16.0600	1	$ 16.06	$ 19.9300	1	$ 19.93	$ 3.87	24.10%
Smart Meter Rate Adder	Monthly	$ 0.9000	1	$ 0.90	$ -	1	$ -	-$ 0.90	-100.00%
Distribution Volumetric Rate	kWh	$ 0.0161	500	$ 8.05	$ 0.0149	500	$ 7.45	-$ 0.60	-7.45%
Rate Rider for Disposition of Resi	Monthly	-$ 0.0400	1	-$ 0.04	$ -	1	$ -	$ 0.04	-100.00%
Disposition of Accounts 1575/157	kWh	$ -	500	$ -	-$ 0.0030	500	-$ 1.50	-$ 1.50	
Disposition of Accounts 1575/157	kWh	$ -	500	$ -	$ -	500	$ -	$ -	
Stranded meter recovery	Monthly	$ -	1	$ -	$ 0.8929	1	$ 0.89	$ 0.89	
Sub-Total A (excluding pass through)				$ 24.97			$ 26.77	**$ 1.80**	**7.22%**
Rate Rider for Deferral/Variance Account Disposition	kWh	-$ 0.0057	500	-$ 2.85	-$ 0.0005	500	-$ 0.25	$ 2.60	-91.23%
Rate Rider for Deferral/Variance Account Disposition	kWh	$ -	500	$ -	$ -	500	$ -	$ -	
Rate Rider for Application of Tax Change	kWh	-$ 0.0001	500	-$ 0.05	$ -	500	$ -	$ 0.05	-100.00%
Rate Rider for Application of Tax Change	kWh	$ -	500	$ -	$ -	500	$ -	$ -	
Low Voltage Service Charge	kWh	$ 0.0005	500	$ 0.25	$ 0.0005	500	$ 0.25	$ -	
Line Losses on Cost of Power	kWh	$ 0.0950	28.00	$ 2.66	$ 0.0950	23.95	$ 2.28	-$ 0.38	-14.46%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 25.77**			**$ 29.84**	**$ 4.07**	**15.79%**
RTSR - Network	kWh	$ 0.0073	528	$ 3.85	$ 0.0076	524	$ 3.98	$ 0.13	3.31%
RTSR - Line and Transformation Connection	kWh	$ 0.0050	528	$ 2.64	$ 0.0053	524	$ 2.78	$ 0.14	5.19%
Sub-Total C - Delivery (including Sub-Total B)				**$ 32.26**			**$ 36.60**	**$ 4.33**	**13.43%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0044	528	$ 2.32	$ 0.0044	524	$ 2.31	-$ 0.02	-0.77%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	528	$ 0.69	$ 0.0013	524	$ 0.68	-$ 0.01	-0.77%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	500	$ 3.50	$ 0.0070	500	$ 3.50	$ -	
TOU - Off Peak	kWh	$ 0.0770	320	$ 24.64	$ 0.0770	320	$ 24.64	$ -	
TOU - Mid Peak	kWh	$ 0.1140	90	$ 10.26	$ 0.1140	90	$ 10.26	$ -	
TOU - On Peak	kWh	$ 0.1400	90	$ 12.60	$ 0.1400	90	$ 12.60	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0880	500	$ 44.00	$ 0.0880	500	$ 44.00	$ -	
Energy - RPP - Tier 2	kWh	$ 0.1030		$ -	$ 0.1030		$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 86.52**			**$ 90.83**	**$ 4.31**	**4.98%**
HST		13%		$ 11.25	13%		$ 11.81	$ 0.56	4.98%
Total Bill (including HST)				$ 97.77			$ 102.64	$ 4.87	4.98%
Ontario Clean Energy Benefit 1				-$ 9.78			-$ 10.26	-$ 0.48	4.91%
Total Bill on TOU (including OCEB)				**$ 87.99**			**$ 92.38**	**$ 4.39**	**4.99%**
Total Bill on RPP (before Taxes)				**$ 83.02**			**$ 87.33**	**$ 4.31**	**5.19%**
HST		13%		$ 10.79	13%		$ 11.35	$ 0.56	5.19%
Total Bill (including HST)				$ 93.82			$ 98.69	$ 4.87	5.19%
Ontario Clean Energy Benefit 1				-$ 9.38			-$ 9.87	-$ 0.49	5.22%
Total Bill on RPP (including OCEB)				**$ 84.44**			**$ 88.82**	**$ 4.38**	**5.19%**

Loss Factor (%) Current: 5.60% Proposed: 4.79%

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing must cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

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Appendix 2-W
Bill Impacts

Customer Class: **Residential**

TOU / non-TOU: TOU

Consumption 500 **kWh**   November 1 - April 30

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 16.0600	1	$ 16.06	$ 19.9300	1	$ 19.93	$ 3.87	24.10%
Smart Meter Rate Adder	Monthly	$ 0.9000	1	$ 0.90	$ -	1	$ -	-$ 0.90	-100.00%
Distribution Volumetric Rate	kWh	$ 0.0161	500	$ 8.05	$ 0.0149	500	$ 7.45	-$ 0.60	-7.45%
Rate Rider for Disposition of Resi	Monthly	-$ 0.0400	1	-$ 0.04	$ -	1	$ -	$ 0.04	-100.00%
Disposition of Accounts 1575/157	kWh	$ -	500	$ -	-$ 0.0030	500	-$ 1.50	-$ 1.50	
Disposition of Accounts 1575/157	kWh	$ -	500	$ -	$ -	500	$ -	$ -	
Stranded meter recovery	Monthly	$ -	1	$ -	$ 0.8929	1	$ 0.89	$ 0.89	
Sub-Total A (excluding pass through)				$ 24.97			$ 26.77	**$ 1.80**	**7.22%**
Rate Rider for Deferral/Variance Account Disposition	kWh	-$ 0.0057	500	-$ 2.85	-$ 0.0005	500	-$ 0.25	$ 2.60	-91.23%
Rate Rider for Deferral/Variance Account Disposition	kWh	$ -	500	$ -	$ -	500	$ -	$ -	
Rate Rider for Application of Tax Change	kWh	-$ 0.0001	500	-$ 0.05	$ -	500	$ -	$ 0.05	-100.00%
Rate Rider for Application of Tax Change	kWh	$ -	500	$ -	$ -	500	$ -	$ -	
Low Voltage Service Charge	kWh	$ 0.0005	500	$ 0.25	$ 0.0005	500	$ 0.25	$ -	
Line Losses on Cost of Power	kWh	$ 0.0950	28.00	$ 2.66	$ 0.0950	23.95	$ 2.28	-$ 0.38	-14.46%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 25.77**			**$ 29.84**	**$ 4.07**	**15.79%**
RTSR - Network	kWh	$ 0.0073	528	$ 3.85	$ 0.0076	524	$ 3.98	$ 0.13	3.31%
RTSR - Line and Transformation Connection	kWh	$ 0.0050	528	$ 2.64	$ 0.0053	524	$ 2.78	$ 0.14	5.19%
Sub-Total C - Delivery (including Sub-Total B)				**$ 32.26**			**$ 36.60**	**$ 4.33**	**13.43%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0044	528	$ 2.32	$ 0.0044	524	$ 2.31	-$ 0.02	-0.77%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	528	$ 0.69	$ 0.0013	524	$ 0.68	-$ 0.01	-0.77%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	500	$ 3.50	$ 0.0070	500	$ 3.50	$ -	
TOU - Off Peak	kWh	$ 0.0770	320	$ 24.64	$ 0.0770	320	$ 24.64	$ -	
TOU - Mid Peak	kWh	$ 0.1140	90	$ 10.26	$ 0.1140	90	$ 10.26	$ -	
TOU - On Peak	kWh	$ 0.1400	90	$ 12.60	$ 0.1400	90	$ 12.60	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0880	500	$ 44.00	$ 0.0880	500	$ 44.00	$ -	
Energy - RPP - Tier 2	kWh	$ 0.1030		$ -	$ 0.1030		$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 86.52**			**$ 90.83**	**$ 4.31**	**4.98%**
HST		13%		$ 11.25	13%		$ 11.81	$ 0.56	4.98%
Total Bill (including HST)				$ 97.77			$ 102.64	$ 4.87	4.98%
Ontario Clean Energy Benefit 1				-$ 9.78			-$ 10.26	-$ 0.48	4.91%
Total Bill on TOU (including OCEB)				**$ 87.99**			**$ 92.38**	**$ 4.39**	**4.99%**
Total Bill on RPP (before Taxes)				**$ 83.02**			**$ 87.33**	**$ 4.31**	**5.19%**
HST		13%		$ 10.79	13%		$ 11.35	$ 0.56	5.19%
Total Bill (including HST)				$ 93.82			$ 98.69	$ 4.87	5.19%
Ontario Clean Energy Benefit 1				-$ 9.38			-$ 9.87	-$ 0.49	5.22%
Total Bill on RPP (including OCEB)				**$ 84.44**			**$ 88.82**	**$ 4.38**	**5.19%**

Loss Factor (%)   Current: 5.60%   Proposed: 4.79%

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing must cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Appendix 2-W
Bill Impacts

Customer Class: **Residential**

TOU / non-TOU: TOU

Consumption **800** **kWh** May 1 - October 31

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Monthly Service Charge	Monthly	$ 16.0600	1	$ 16.06	$ 19.9300	1	$ 19.93	$ 3.87	24.10%
Smart Meter Rate Adder	Monthly	$ 0.9000	1	$ 0.90	$ -	1	$ -	-$ 0.90	-100.00%
Distribution Volumetric Rate	kWh	$ 0.0161	800	$ 12.88	$ 0.0149	800	$ 11.92	-$ 0.96	-7.45%
Rate Rider for Disposition of Resi	Monthly	-$ 0.0400	1	-$ 0.04	$ -	1	$ -	$ 0.04	-100.00%
Disposition of Accounts 1575/157	kWh	$ -	800	$ -	-$ 0.0030	800	-$ 2.40	-$ 2.40	
Disposition of Accounts 1575/157	kWh	$ -	800	$ -	$ -	800	$ -	$ -	
Stranded meter recovery	Monthly	$ -	1	$ -	$ 0.8929	1	$ 0.89	$ 0.89	
Sub-Total A (excluding pass through)				$ 29.80			$ 30.34	**$ 0.54**	**1.82%**
Rate Rider for Deferral/Variance Account Disposition	kWh	-$ 0.0057	800	-$ 4.56	-$ 0.0005	800	-$ 0.40	$ 4.16	-91.23%
Rate Rider for Deferral/Variance Account Disposition	kWh	$ -	800	$ -	$ -	800	$ -	$ -	
Rate Rider for Application of Tax Change	kWh	-$ 0.0001	800	-$ 0.08	$ -	800	$ -	$ 0.08	-100.00%
Rate Rider for Application of Tax Change	kWh	$ -	800	$ -	$ -	800	$ -	$ -	
Low Voltage Service Charge	kWh	$ 0.0005	800	$ 0.40	$ 0.0005	800	$ 0.40	$ -	
Line Losses on Cost of Power	kWh	$ 0.0950	44.8	$ 4.26	$ 0.0950	38.3393	$ 3.64	-$ 0.61	-14.42%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 30.61**			**$ 34.78**	**$ 4.17**	**13.62%**
RTSR - Network	kWh	$ 0.0073	845	$ 6.17	$ 0.0076	838	$ 6.37	$ 0.20	3.31%
RTSR - Line and Transformation Connection	kWh	$ 0.0050	845	$ 4.22	$ 0.0053	838	$ 4.44	$ 0.22	5.19%
Sub-Total C - Delivery (including Sub-Total B)				**$ 41.00**			**$ 45.59**	**$ 4.59**	**11.20%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0044	845	$ 3.72	$ 0.0044	838	$ 3.69	-$ 0.03	-0.76%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	845	$ 1.10	$ 0.0013	838	$ 1.09	-$ 0.01	-0.76%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	800	$ 5.60	$ 0.0070	800	$ 5.60	$ -	
TOU - Off Peak	kWh	$ 0.0770	512	$ 39.42	$ 0.0770	512	$ 39.42	$ -	
TOU - Mid Peak	kWh	$ 0.1140	144	$ 16.42	$ 0.1140	144	$ 16.42	$ -	
TOU - On Peak	kWh	$ 0.1400	144	$ 20.16	$ 0.1400	144	$ 20.16	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0880	600	$ 52.80	$ 0.0880	600	$ 52.80	$ -	
Energy - RPP - Tier 2	kWh	$ 0.1030	200	$ 20.60	$ 0.1030	200	$ 20.60	$ -	
Total Bill on TOU (before Taxes)				**$ 127.66**			**$ 132.22**	**$ 4.56**	**3.57%**
HST		13%		$ 16.60	13%		$ 17.19	$ 0.59	3.57%
Total Bill (including HST)				$ 144.26			$ 149.41	$ 5.15	3.57%
Ontario Clean Energy Benefit 1				-$ 14.43			-$ 14.94	-$ 0.51	3.53%
Total Bill on TOU (including OCEB)				**$ 129.83**			**$ 134.47**	**$ 4.64**	**3.57%**
Total Bill on RPP (before Taxes)				**$ 125.06**			**$ 129.62**	**$ 4.56**	**3.64%**
HST		13%		$ 16.26	13%		$ 16.85	$ 0.59	3.64%
Total Bill (including HST)				$ 141.32			$ 146.47	$ 5.15	3.64%
Ontario Clean Energy Benefit 1				-$ 14.13			-$ 14.65	-$ 0.52	3.68%
Total Bill on RPP (including OCEB)				**$ 127.19**			**$ 131.82**	**$ 4.63**	**3.64%**
Loss Factor (%)		5.60%			4.79%				

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing must cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

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Appendix 2-W
Bill Impacts

Customer Class: **Residential**

TOU / non-TOU: TOU

Consumption 800 **kWh** November 1 - April 30

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 16.0600	1	$ 16.06	$ 19.9300	1	$ 19.93	$ 3.87	24.10%
Smart Meter Rate Adder	Monthly	$ 0.9000	1	$ 0.90	$ -	1	$ -	-$ 0.90	-100.00%
Distribution Volumetric Rate	kWh	$ 0.0161	800	$ 12.88	$ 0.0149	800	$ 11.92	-$ 0.96	-7.45%
Rate Rider for Disposition of Resi	Monthly	-$ 0.0400	1	-$ 0.04	$ -	1	$ -	$ 0.04	-100.00%
Disposition of Accounts 1575/157	kWh	$ -	800	$ -	-$ 0.0030	800	-$ 2.40	-$ 2.40	
Disposition of Accounts 1575/157	kWh	$ -	800	$ -	$ -	800	$ -	$ -	
Stranded meter recovery	Monthly	$ -	1	$ -	$ 0.8929	1	$ 0.89	$ 0.89	
Sub-Total A (excluding pass through)				$ 29.80			$ 30.34	**$ 0.54**	**1.82%**
Rate Rider for Deferral/Variance Account Disposition	kWh	-$ 0.0057	800	-$ 4.56	-$ 0.0005	800	-$ 0.40	$ 4.16	-91.23%
Rate Rider for Deferral/Variance Account Disposition	kWh	$ -	800	$ -	$ -	800	$ -	$ -	
Rate Rider for Application of Tax Change	kWh	-$ 0.0001	800	-$ 0.08	$ -	800	$ -	$ 0.08	-100.00%
Rate Rider for Application of Tax Change	kWh	$ -	800	$ -	$ -	800	$ -	$ -	
Low Voltage Service Charge	kWh	$ 0.0005	800	$ 0.40	$ 0.0005	800	$ 0.40	$ -	
Line Losses on Cost of Power	kWh	$ 0.0950	44.8	$ 4.26	$ 0.0950	38.3393	$ 3.64	-$ 0.61	-14.42%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 30.61**			**$ 34.78**	**$ 4.17**	**13.62%**
RTSR - Network	kWh	$ 0.0073	845	$ 6.17	$ 0.0076	838	$ 6.37	$ 0.20	3.31%
RTSR - Line and Transformation Connection	kWh	$ 0.0050	845	$ 4.22	$ 0.0053	838	$ 4.44	$ 0.22	5.19%
Sub-Total C - Delivery (including Sub-Total B)				**$ 41.00**			**$ 45.59**	**$ 4.59**	**11.20%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0044	845	$ 3.72	$ 0.0044	838	$ 3.69	-$ 0.03	-0.76%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	845	$ 1.10	$ 0.0013	838	$ 1.09	-$ 0.01	-0.76%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	800	$ 5.60	$ 0.0070	800	$ 5.60	$ -	
TOU - Off Peak	kWh	$ 0.0770	512	$ 39.42	$ 0.0770	512	$ 39.42	$ -	
TOU - Mid Peak	kWh	$ 0.1140	144	$ 16.42	$ 0.1140	144	$ 16.42	$ -	
TOU - On Peak	kWh	$ 0.1400	144	$ 20.16	$ 0.1400	144	$ 20.16	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0880	800	$ 70.40	$ 0.0880	800	$ 70.40	$ -	
Energy - RPP - Tier 2	kWh	$ 0.1030		$ -	$ 0.1030		$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 127.66**			**$ 132.22**	**$ 4.56**	**3.57%**
HST		13%		$ 16.60	13%		$ 17.19	$ 0.59	3.57%
Total Bill (including HST)				$ 144.26			$ 149.41	$ 5.15	3.57%
Ontario Clean Energy Benefit 1				-$ 14.43			-$ 14.94	-$ 0.51	3.53%
Total Bill on TOU (including OCEB)				**$ 129.83**			**$ 134.47**	**$ 4.64**	**3.57%**
Total Bill on RPP (before Taxes)				**$ 122.06**			**$ 126.62**	**$ 4.56**	**3.73%**
HST		13%		$ 15.87	13%		$ 16.46	$ 0.59	3.73%
Total Bill (including HST)				$ 137.93			$ 143.08	$ 5.15	3.73%
Ontario Clean Energy Benefit 1				-$ 13.79			-$ 14.31	-$ 0.52	3.77%
Total Bill on RPP (including OCEB)				**$ 124.14**			**$ 128.77**	**$ 4.63**	**3.73%**

Loss Factor (%) 5.60% 4.79%

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing must cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

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GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

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Appendix 2-W
Bill Impacts

Customer Class: **Residential**

TOU / non-TOU: TOU

Consumption **1,000** **kWh** May 1 - October 31

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 16.0600	1	$ 16.06	$ 19.9300	1	$ 19.93	$ 3.87	24.10%
Smart Meter Rate Adder	Monthly	$ 0.9000	1	$ 0.90	$ -	1	$ -	-$ 0.90	-100.00%
Distribution Volumetric Rate	kWh	$ 0.0161	1,000	$ 16.10	$ 0.0149	1,000	$ 14.90	-$ 1.20	-7.45%
Rate Rider for Disposition of Resi	Monthly	-$ 0.0400	1	-$ 0.04	$ -	1	$ -	$ 0.04	-100.00%
Disposition of Accounts 1575/157	kWh	$ -	1,000	$ -	-$ 0.0030	1,000	-$ 3.00	-$ 3.00	
Disposition of Accounts 1575/157	kWh	$ -	1,000	$ -	$ -	1,000	$ -	$ -	
Stranded meter recovery	Monthly	$ -	1	$ -	$ 0.8929	1	$ 0.89	$ 0.89	
Sub-Total A (excluding pass through)				$ 33.02			$ 32.72	**-$ 0.30**	**-0.90%**
Rate Rider for Deferral/Variance Account Disposition	kWh	-$ 0.0057	1,000	-$ 5.70	-$ 0.0005	1,000	-$ 0.50	$ 5.20	-91.23%
Rate Rider for Deferral/Variance Account Disposition	kWh	$ -	1,000	$ -	$ -	1,000	$ -	$ -	
Rate Rider for Application of Tax Change	kWh	-$ 0.0001	1,000	-$ 0.10	$ -	1,000	$ -	$ 0.10	-100.00%
Rate Rider for Application of Tax Change	kWh	$ -	1,000	$ -	$ -	1,000	$ -	$ -	
Low Voltage Service Charge	kWh	$ 0.0005	1,000	$ 0.50	$ 0.0005	1,000	$ 0.50	$ -	
Line Losses on Cost of Power	kWh	$ 0.0950	56.00	$ 5.32	$ 0.0950	47.90	$ 4.55	-$ 0.77	-14.46%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 33.83**			**$ 38.06**	**$ 4.23**	**12.51%**
RTSR - Network	kWh	$ 0.0073	1056	$ 7.71	$ 0.0076	1048	$ 7.96	$ 0.26	3.31%
RTSR - Line and Transformation Connection	kWh	$ 0.0050	1056	$ 5.28	$ 0.0053	1048	$ 5.55	$ 0.27	5.19%
Sub-Total C - Delivery (including Sub-Total B)				**$ 46.82**			**$ 51.58**	**$ 4.76**	**10.17%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0044	1056	$ 4.65	$ 0.0044	1048	$ 4.61	-$ 0.04	-0.77%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	1056	$ 1.37	$ 0.0013	1048	$ 1.36	-$ 0.01	-0.77%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	1000	$ 7.00	$ 0.0070	1000	$ 7.00	$ -	
TOU - Off Peak	kWh	$ 0.0770	640	$ 49.28	$ 0.0770	640	$ 49.28	$ -	
TOU - Mid Peak	kWh	$ 0.1140	180	$ 20.52	$ 0.1140	180	$ 20.52	$ -	
TOU - On Peak	kWh	$ 0.1400	180	$ 25.20	$ 0.1400	180	$ 25.20	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0880	600	$ 52.80	$ 0.0880	600	$ 52.80	$ -	
Energy - RPP - Tier 2	kWh	$ 0.1030	400	$ 41.20	$ 0.1030	400	$ 41.20	$ -	
Total Bill on TOU (before Taxes)				**$ 155.09**			**$ 159.80**	**$ 4.72**	**3.04%**
HST		13%		$ 20.16	13%		$ 20.77	$ 0.61	3.04%
Total Bill (including HST)				$ 175.25			$ 180.58	$ 5.33	3.04%
Ontario Clean Energy Benefit 1				-$ 17.52			-$ 18.06	-$ 0.54	3.08%
Total Bill on TOU (including OCEB)				**$ 157.73**			**$ 162.52**	**$ 4.79**	**3.04%**
Total Bill on RPP (before Taxes)				**$ 154.09**			**$ 158.80**	**$ 4.72**	**3.06%**
HST		13%		$ 20.03	13%		$ 20.64	$ 0.61	3.06%
Total Bill (including HST)				$ 174.12			$ 179.45	$ 5.33	3.06%
Ontario Clean Energy Benefit 1				-$ 17.41			-$ 17.94	-$ 0.53	3.04%
Total Bill on RPP (including OCEB)				**$ 156.71**			**$ 161.51**	**$ 4.80**	**3.06%**
Loss Factor (%)		5.60%			4.79%				

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing must cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

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Appendix 2-W
Bill Impacts

Customer Class: Residential

TOU / non-TOU: TOU

Consumption 1,000 kWh   November 1 - April 30

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 16.0600	1	$ 16.06	$ 19.9300	1	$ 19.93	$ 3.87	24.10%
Smart Meter Rate Adder	Monthly	$ 0.9000	1	$ 0.90	$ -	1	$ -	-$ 0.90	-100.00%
Distribution Volumetric Rate	kWh	$ 0.0161	1,000	$ 16.10	$ 0.0149	1,000	$ 14.90	-$ 1.20	-7.45%
Rate Rider for Disposition of Resi	Monthly	-$ 0.0400	1	-$ 0.04	$ -	1	$ -	$ 0.04	-100.00%
Disposition of Accounts 1575/157	kWh	$ -	1,000	$ -	-$ 0.0030	1,000	-$ 3.00	-$ 3.00	
Disposition of Accounts 1575/157	kWh	$ -	1,000	$ -	$ -	1,000	$ -	$ -	
Stranded meter recovery	Monthly	$ -	1	$ -	$ 0.8929	1	$ 0.89	$ 0.89	
Sub-Total A (excluding pass through)				$ 33.02			$ 32.72	**-$ 0.30**	**-0.90%**
Rate Rider for Deferral/Variance Account Disposition	kWh	-$ 0.0057	1,000	-$ 5.70	-$ 0.0005	1,000	-$ 0.50	$ 5.20	-91.23%
Rate Rider for Deferral/Variance Account Disposition	kWh	$ -	1,000	$ -	$ -	1,000	$ -	$ -	
Rate Rider for Application of Tax Change	kWh	-$ 0.0001	1,000	-$ 0.10	$ -	1,000	$ -	$ 0.10	-100.00%
Rate Rider for Application of Tax Change	kWh	$ -	1,000	$ -	$ -	1,000	$ -	$ -	
Low Voltage Service Charge	kWh	$ 0.0005	1,000	$ 0.50	$ 0.0005	1,000	$ 0.50	$ -	
Line Losses on Cost of Power	kWh	$ 0.0950	56.00	$ 5.32	$ 0.0950	47.90	$ 4.55	-$ 0.77	-14.46%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 33.83**			**$ 38.06**	**$ 4.23**	**12.51%**
RTSR - Network	kWh	$ 0.0073	1056	$ 7.71	$ 0.0076	1048	$ 7.96	$ 0.26	3.31%
RTSR - Line and Transformation Connection	kWh	$ 0.0050	1056	$ 5.28	$ 0.0053	1048	$ 5.55	$ 0.27	5.19%
Sub-Total C - Delivery (including Sub-Total B)				**$ 46.82**			**$ 51.58**	**$ 4.76**	**10.17%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0044	1056	$ 4.65	$ 0.0044	1048	$ 4.61	-$ 0.04	-0.77%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	1056	$ 1.37	$ 0.0013	1048	$ 1.36	-$ 0.01	-0.77%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	1000	$ 7.00	$ 0.0070	1000	$ 7.00	$ -	
TOU - Off Peak	kWh	$ 0.0770	640	$ 49.28	$ 0.0770	640	$ 49.28	$ -	
TOU - Mid Peak	kWh	$ 0.1140	180	$ 20.52	$ 0.1140	180	$ 20.52	$ -	
TOU - On Peak	kWh	$ 0.1400	180	$ 25.20	$ 0.1400	180	$ 25.20	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0880	1000	$ 88.00	$ 0.0880	1000	$ 88.00	$ -	
Energy - RPP - Tier 2	kWh	$ 0.1030		$ -	$ 0.1030		$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 155.09**			**$ 159.80**	**$ 4.72**	**3.04%**
HST		13%		$ 20.16	13%		$ 20.77	$ 0.61	3.04%
Total Bill (including HST)				$ 175.25			$ 180.58	$ 5.33	3.04%
Ontario Clean Energy Benefit 1				-$ 17.52			-$ 18.06	-$ 0.54	3.08%
Total Bill on TOU (including OCEB)				**$ 157.73**			**$ 162.52**	**$ 4.79**	**3.04%**
Total Bill on RPP (before Taxes)				**$ 148.09**			**$ 152.80**	**$ 4.72**	**3.18%**
HST		13%		$ 19.25	13%		$ 19.86	$ 0.61	3.18%
Total Bill (including HST)				$ 167.34			$ 172.67	$ 5.33	3.18%
Ontario Clean Energy Benefit 1				-$ 16.73			-$ 17.27	-$ 0.54	3.23%
Total Bill on RPP (including OCEB)				**$ 150.61**			**$ 155.40**	**$ 4.79**	**3.18%**

Loss Factor (%) 5.60% (current) 4.79% (proposed)

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing must cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

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Appendix 2-W
Bill Impacts

Customer Class: **Residential**

TOU / non-TOU: TOU

Consumption **1,500** **kWh** May 1 - October 31

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 16.0600	1	$ 16.06	$ 19.9300	1	$ 19.93	$ 3.87	24.10%
Smart Meter Rate Adder	Monthly	$ 0.9000	1	$ 0.90	$ -	1	$ -	-$ 0.90	-100.00%
Distribution Volumetric Rate	kWh	$ 0.0161	1,500	$ 24.15	$ 0.0149	1,500	$ 22.35	-$ 1.80	-7.45%
Rate Rider for Disposition of Resi	Monthly	-$ 0.0400	1	-$ 0.04	$ -	1	$ -	$ 0.04	-100.00%
Disposition of Accounts 1575/157	kWh	$ -	1,500	$ -	-$ 0.0030	1,500	-$ 4.50	-$ 4.50	
Disposition of Accounts 1575/157	kWh	$ -	1,500	$ -	$ -	1,500	$ -	$ -	
Stranded meter recovery	Monthly	$ -	1	$ -	$ 0.8929	1	$ 0.89	$ 0.89	
Sub-Total A (excluding pass through)				$ 41.07			$ 38.67	**-$ 2.40**	**-5.84%**
Rate Rider for Deferral/Variance Account Disposition	kWh	-$ 0.0057	1,500	-$ 8.55	-$ 0.0005	1,500	-$ 0.75	$ 7.80	-91.23%
Rate Rider for Deferral/Variance Account Disposition	kWh	$ -	1,500	$ -	$ -	1,500	$ -	$ -	
Rate Rider for Application of Tax Change	kWh	-$ 0.0001	1,500	-$ 0.15	$ -	1,500	$ -	$ 0.15	-100.00%
Rate Rider for Application of Tax Change	kWh	$ -	1,500	$ -	$ -	1,500	$ -	$ -	
Low Voltage Service Charge	kWh	$ 0.0005	1,500	$ 0.75	$ 0.0005	1,500	$ 0.75	$ -	
Line Losses on Cost of Power	kWh	$ 0.0950	84.00	$ 7.98	$ 0.0950	71.85	$ 6.83	-$ 1.15	-14.46%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 41.89**			**$ 46.29**	**$ 4.40**	**10.50%**
RTSR - Network	kWh	$ 0.0073	1584	$ 11.56	$ 0.0076	1572	$ 11.95	$ 0.38	3.31%
RTSR - Line and Transformation Connection	kWh	$ 0.0050	1584	$ 7.92	$ 0.0053	1572	$ 8.33	$ 0.41	5.19%
Sub-Total C - Delivery (including Sub-Total B)				**$ 61.37**			**$ 66.57**	**$ 5.19**	**8.46%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0044	1584	$ 6.97	$ 0.0044	1572	$ 6.92	-$ 0.05	-0.77%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	1584	$ 2.06	$ 0.0013	1572	$ 2.04	-$ 0.02	-0.77%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	1500	$ 10.50	$ 0.0070	1500	$ 10.50	$ -	
TOU - Off Peak	kWh	$ 0.0770	960	$ 73.92	$ 0.0770	960	$ 73.92	$ -	
TOU - Mid Peak	kWh	$ 0.1140	270	$ 30.78	$ 0.1140	270	$ 30.78	$ -	
TOU - On Peak	kWh	$ 0.1400	270	$ 37.80	$ 0.1400	270	$ 37.80	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0880	600	$ 52.80	$ 0.0880	600	$ 52.80	$ -	
Energy - RPP - Tier 2	kWh	$ 0.1030	900	$ 92.70	$ 0.1030	900	$ 92.70	$ -	
Total Bill on TOU (before Taxes)				**$ 223.65**			**$ 228.78**	**$ 5.12**	**2.29%**
HST		13%		$ 29.07	13%		$ 29.74	$ 0.67	2.29%
Total Bill (including HST)				$ 252.73			$ 258.52	$ 5.79	2.29%
Ontario Clean Energy Benefit 1				-$ 25.27			-$ 25.85	-$ 0.58	2.30%
Total Bill on TOU (including OCEB)				**$ 227.46**			**$ 232.67**	**$ 5.21**	**2.29%**
Total Bill on RPP (before Taxes)				**$ 226.65**			**$ 231.78**	**$ 5.12**	**2.26%**
HST		13%		$ 29.46	13%		$ 30.13	$ 0.67	2.26%
Total Bill (including HST)				$ 256.12			$ 261.91	$ 5.79	2.26%
Ontario Clean Energy Benefit 1				-$ 25.61			-$ 26.19	-$ 0.58	2.26%
Total Bill on RPP (including OCEB)				**$ 230.51**			**$ 235.72**	**$ 5.21**	**2.26%**

Loss Factor (%) Current: 5.60% Proposed: 4.79%

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing must cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

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Appendix 2-W
Bill Impacts

Customer Class: **Residential**

TOU / non-TOU: TOU

Consumption **1,500** **kWh** November 1 - April 30

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 16.0600	1	$ 16.06	$ 19.9300	1	$ 19.93	$ 3.87	24.10%
Smart Meter Rate Adder	Monthly	$ 0.9000	1	$ 0.90	$ -	1	$ -	-$ 0.90	-100.00%
Distribution Volumetric Rate	kWh	$ 0.0161	1,500	$ 24.15	$ 0.0149	1,500	$ 22.35	-$ 1.80	-7.45%
Rate Rider for Disposition of Resi	Monthly	-$ 0.0400	1	-$ 0.04	$ -	1	$ -	$ 0.04	-100.00%
Disposition of Accounts 1575/157	kWh	$ -	1,500	$ -	-$ 0.0030	1,500	-$ 4.50	-$ 4.50	
Disposition of Accounts 1575/157	kWh	$ -	1,500	$ -	$ -	1,500	$ -	$ -	
Stranded meter recovery	Monthly	$ -	1	$ -	$ 0.8929	1	$ 0.89	$ 0.89	
Sub-Total A (excluding pass through)				$ 41.07			$ 38.67	**-$ 2.40**	**-5.84%**
Rate Rider for Deferral/Variance Account Disposition	kWh	-$ 0.0057	1,500	-$ 8.55	-$ 0.0005	1,500	-$ 0.75	$ 7.80	-91.23%
Rate Rider for Deferral/Variance Account Disposition	kWh	$ -	1,500	$ -	$ -	1,500	$ -	$ -	
Rate Rider for Application of Tax Change	kWh	-$ 0.0001	1,500	-$ 0.15	$ -	1,500	$ -	$ 0.15	-100.00%
Rate Rider for Application of Tax Change	kWh	$ -	1,500	$ -	$ -	1,500	$ -	$ -	
Low Voltage Service Charge	kWh	$ 0.0005	1,500	$ 0.75	$ 0.0005	1,500	$ 0.75	$ -	
Line Losses on Cost of Power	kWh	$ 0.0950	84.00	$ 7.98	$ 0.0950	71.85	$ 6.83	-$ 1.15	-14.46%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 41.89**			**$ 46.29**	**$ 4.40**	**10.50%**
RTSR - Network	kWh	$ 0.0073	1584	$ 11.56	$ 0.0076	1572	$ 11.95	$ 0.38	3.31%
RTSR - Line and Transformation Connection	kWh	$ 0.0050	1584	$ 7.92	$ 0.0053	1572	$ 8.33	$ 0.41	5.19%
Sub-Total C - Delivery (including Sub-Total B)				**$ 61.37**			**$ 66.57**	**$ 5.19**	**8.46%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0044	1584	$ 6.97	$ 0.0044	1572	$ 6.92	-$ 0.05	-0.77%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	1584	$ 2.06	$ 0.0013	1572	$ 2.04	-$ 0.02	-0.77%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	1500	$ 10.50	$ 0.0070	1500	$ 10.50	$ -	
TOU - Off Peak	kWh	$ 0.0770	960	$ 73.92	$ 0.0770	960	$ 73.92	$ -	
TOU - Mid Peak	kWh	$ 0.1140	270	$ 30.78	$ 0.1140	270	$ 30.78	$ -	
TOU - On Peak	kWh	$ 0.1400	270	$ 37.80	$ 0.1400	270	$ 37.80	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0880	1000	$ 88.00	$ 0.0880	1000	$ 88.00	$ -	
Energy - RPP - Tier 2	kWh	$ 0.1030	500	$ 51.50	$ 0.1030	500	$ 51.50	$ -	
Total Bill on TOU (before Taxes)				**$ 223.65**			**$ 228.78**	**$ 5.12**	**2.29%**
HST		13%		$ 29.07	13%		$ 29.74	$ 0.67	2.29%
Total Bill (including HST)				$ 252.73			$ 258.52	$ 5.79	2.29%
Ontario Clean Energy Benefit 1				-$ 25.27			-$ 25.85	-$ 0.58	2.30%
Total Bill on TOU (including OCEB)				**$ 227.46**			**$ 232.67**	**$ 5.21**	**2.29%**
Total Bill on RPP (before Taxes)				**$ 220.65**			**$ 225.78**	**$ 5.12**	**2.32%**
HST		13%		$ 28.68	13%		$ 29.35	$ 0.67	2.32%
Total Bill (including HST)				$ 249.34			$ 255.13	$ 5.79	2.32%
Ontario Clean Energy Benefit 1				-$ 24.93			-$ 25.51	-$ 0.58	2.33%
Total Bill on RPP (including OCEB)				**$ 224.41**			**$ 229.62**	**$ 5.21**	**2.32%**

Loss Factor (%) Current: 5.60% Proposed: 4.79%

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing must cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

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Appendix 2-W
Bill Impacts

Customer Class: **Residential**

TOU / non-TOU: TOU

Consumption **2,000** **kWh** May 1 - October 31

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Monthly Service Charge	Monthly	$ 16.0600	1	$ 16.06	$ 19.9300	1	$ 19.93	$ 3.87	24.10%
Smart Meter Rate Adder	Monthly	$ 0.9000	1	$ 0.90	$ -	1	$ -	-$ 0.90	-100.00%
Distribution Volumetric Rate	kWh	$ 0.0161	2,000	$ 32.20	$ 0.0149	2,000	$ 29.80	-$ 2.40	-7.45%
Rate Rider for Disposition of Resi	Monthly	-$ 0.0400	1	-$ 0.04	$ -	1	$ -	$ 0.04	-100.00%
Disposition of Accounts 1575/157	kWh	$ -	2,000	$ -	-$ 0.0030	2,000	-$ 6.00	-$ 6.00	
Disposition of Accounts 1575/157	kWh	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
Stranded meter recovery	Monthly	$ -	1	$ -	$ 0.8929	1	$ 0.89	$ 0.89	
Sub-Total A (excluding pass through)				$ 49.12			$ 44.62	**-$ 4.50**	**-9.16%**
Rate Rider for Deferral/Variance Account Disposition	kWh	-$ 0.0057	2,000	-$ 11.40	-$ 0.0005	2,000	-$ 1.00	$ 10.40	-91.23%
Rate Rider for Deferral/Variance Account Disposition	kWh	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
Rate Rider for Application of Tax Change	kWh	-$ 0.0001	2,000	-$ 0.20	$ -	2,000	$ -	$ 0.20	-100.00%
Rate Rider for Application of Tax Change	kWh	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
Low Voltage Service Charge	kWh	$ 0.0005	2,000	$ 1.00	$ 0.0005	2,000	$ 1.00	$ -	
Line Losses on Cost of Power	kWh	$ 0.0950	112.00	$ 10.64	$ 0.0950	95.80	$ 9.10	-$ 1.54	-14.46%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 49.95**			**$ 54.51**	**$ 4.56**	**9.14%**
RTSR - Network	kWh	$ 0.0073	2112	$ 15.42	$ 0.0076	2096	$ 15.93	$ 0.51	3.31%
RTSR - Line and Transformation Connection	kWh	$ 0.0050	2112	$ 10.56	$ 0.0053	2096	$ 11.11	$ 0.55	5.19%
Sub-Total C - Delivery (including Sub-Total B)				**$ 75.93**			**$ 81.55**	**$ 5.62**	**7.40%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0044	2112	$ 9.29	$ 0.0044	2096	$ 9.22	-$ 0.07	-0.77%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	2112	$ 2.75	$ 0.0013	2096	$ 2.72	-$ 0.02	-0.77%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	2000	$ 14.00	$ 0.0070	2000	$ 14.00	$ -	
TOU - Off Peak	kWh	$ 0.0770	1280	$ 98.56	$ 0.0770	1280	$ 98.56	$ -	
TOU - Mid Peak	kWh	$ 0.1140	360	$ 41.04	$ 0.1140	360	$ 41.04	$ -	
TOU - On Peak	kWh	$ 0.1400	360	$ 50.40	$ 0.1400	360	$ 50.40	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0880	600	$ 52.80	$ 0.0880	600	$ 52.80	$ -	
Energy - RPP - Tier 2	kWh	$ 0.1030	1400	$ 144.20	$ 0.1030	1400	$ 144.20	$ -	
Total Bill on TOU (before Taxes)				**$ 292.22**			**$ 297.75**	**$ 5.53**	**1.89%**
HST		13%		$ 37.99	13%		$ 38.71	$ 0.72	1.89%
Total Bill (including HST)				$ 330.20			$ 336.45	$ 6.25	1.89%
Ontario Clean Energy Benefit 1				-$ 33.02			-$ 33.65	-$ 0.63	1.91%
Total Bill on TOU (including OCEB)				**$ 297.18**			**$ 302.80**	**$ 5.62**	**1.89%**
Total Bill on RPP (before Taxes)				**$ 299.22**			**$ 304.75**	**$ 5.53**	**1.85%**
HST		13%		$ 38.90	13%		$ 39.62	$ 0.72	1.85%
Total Bill (including HST)				$ 338.11			$ 344.36	$ 6.25	1.85%
Ontario Clean Energy Benefit 1				-$ 33.81			-$ 34.44	-$ 0.63	1.86%
Total Bill on RPP (including OCEB)				**$ 304.30**			**$ 309.92**	**$ 5.62**	**1.85%**
Loss Factor (%)		5.60%			4.79%				

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing must cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

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Tab:
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Appendix 2-W
Bill Impacts

Customer Class: **Residential**

TOU / non-TOU: TOU

Consumption **2,000** **kWh** November 1 - April 30

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 16.0600	1	$ 16.06	$ 19.9300	1	$ 19.93	$ 3.87	24.10%
Smart Meter Rate Adder	Monthly	$ 0.9000	1	$ 0.90	$ -	1	$ -	-$ 0.90	-100.00%
Distribution Volumetric Rate	kWh	$ 0.0161	2,000	$ 32.20	$ 0.0149	2,000	$ 29.80	-$ 2.40	-7.45%
Rate Rider for Disposition of Resi	Monthly	-$ 0.0400	1	-$ 0.04	$ -	1	$ -	$ 0.04	-100.00%
Disposition of Accounts 1575/157	kWh	$ -	2,000	$ -	-$ 0.0030	2,000	-$ 6.00	-$ 6.00	
Disposition of Accounts 1575/157	kWh	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
Stranded meter recovery	Monthly	$ -	1	$ -	$ 0.8929	1	$ 0.89	$ 0.89	
Sub-Total A (excluding pass through)				$ 49.12			$ 44.62	**-$ 4.50**	**-9.16%**
Rate Rider for Deferral/Variance Account Disposition	kWh	-$ 0.0057	2,000	-$ 11.40	-$ 0.0005	2,000	-$ 1.00	$ 10.40	-91.23%
Rate Rider for Deferral/Variance Account Disposition	kWh	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
Rate Rider for Application of Tax Change	kWh	-$ 0.0001	2,000	-$ 0.20	$ -	2,000	$ -	$ 0.20	-100.00%
Rate Rider for Application of Tax Change	kWh	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
Low Voltage Service Charge	kWh	$ 0.0005	2,000	$ 1.00	$ 0.0005	2,000	$ 1.00	$ -	
Line Losses on Cost of Power	kWh	$ 0.0950	112.00	$ 10.64	$ 0.0950	95.80	$ 9.10	-$ 1.54	-14.46%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 49.95**			**$ 54.51**	**$ 4.56**	**9.14%**
RTSR - Network	kWh	$ 0.0073	2112	$ 15.42	$ 0.0076	2096	$ 15.93	$ 0.51	3.31%
RTSR - Line and Transformation Connection	kWh	$ 0.0050	2112	$ 10.56	$ 0.0053	2096	$ 11.11	$ 0.55	5.19%
Sub-Total C - Delivery (including Sub-Total B)				**$ 75.93**			**$ 81.55**	**$ 5.62**	**7.40%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0044	2112	$ 9.29	$ 0.0044	2096	$ 9.22	-$ 0.07	-0.77%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	2112	$ 2.75	$ 0.0013	2096	$ 2.72	-$ 0.02	-0.77%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	2000	$ 14.00	$ 0.0070	2000	$ 14.00	$ -	
TOU - Off Peak	kWh	$ 0.0770	1280	$ 98.56	$ 0.0770	1280	$ 98.56	$ -	
TOU - Mid Peak	kWh	$ 0.1140	360	$ 41.04	$ 0.1140	360	$ 41.04	$ -	
TOU - On Peak	kWh	$ 0.1400	360	$ 50.40	$ 0.1400	360	$ 50.40	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0880	1000	$ 88.00	$ 0.0880	1000	$ 88.00	$ -	
Energy - RPP - Tier 2	kWh	$ 0.1030	1000	$ 103.00	$ 0.1030	1000	$ 103.00	$ -	
Total Bill on TOU (before Taxes)				**$ 292.22**			**$ 297.75**	**$ 5.53**	**1.89%**
HST		13%		$ 37.99	13%		$ 38.71	$ 0.72	1.89%
Total Bill (including HST)				$ 330.20			$ 336.45	$ 6.25	1.89%
Ontario Clean Energy Benefit 1				-$ 33.02			-$ 33.65	-$ 0.63	1.91%
Total Bill on TOU (including OCEB)				**$ 297.18**			**$ 302.80**	**$ 5.62**	**1.89%**
Total Bill on RPP (before Taxes)				**$ 293.22**			**$ 298.75**	**$ 5.53**	**1.89%**
HST		13%		$ 38.12	13%		$ 38.84	$ 0.72	1.89%
Total Bill (including HST)				$ 331.33			$ 337.58	$ 6.25	1.89%
Ontario Clean Energy Benefit 1				-$ 33.13			-$ 33.76	-$ 0.63	1.90%
Total Bill on RPP (including OCEB)				**$ 298.20**			**$ 303.82**	**$ 5.62**	**1.88%**

Loss Factor (%) 5.60% 4.79%

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

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GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.