EB-2014-0096

IN THE MATTER of the *Ontario Energy Board Act 1998*, Schedule B to the *Energy Competition Act*, 1998, S.O. 1998, c.15;

AND IN THE MATTER OF an Application by Niagara Peninsula Energy Inc. for an Order or Orders approving just and reasonable distribution rates and other service charges for the distribution of electricity, effective May 1, 2015.

INTERROGATORIES

FROM THE

SCHOOL ENERGY COALITION

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.

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.

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. .

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.

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.

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.

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.

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.

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.

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.

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.

12. [Ex. 1/3/1, Attach 2, p. 9] Please provide a list of the "certain topic areas of importance" referred to.

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.

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.

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.

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.

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.

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.

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.

20. [Ex. 1/6/20, Attach 1.9] Please provide a copy of the current, signed agreement including all amendments.

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.

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.

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.

24. [Ex. 2/1/2, p. 26] Please identify the Hydro One contribution in Table 2-9.

25. [Ex. 2/1/2, p. 32] Please provide details of all commercial services costs in 2014 to date.

26. [Ex. 2/1/2, p. 34] With respect to the new arrangements with the Niagara Parks Commission:

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

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

    c. 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.

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.
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.

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.

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.

Submitted by the School Energy Coalition December 2, 2014.

Jay Shepherd
Counsel for School Energy Coalition

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 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