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December 18, 2015

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

RE: 2016 IRM Rate Application (EB-2015-0090) and Application to Dispose of LRAMVA Balance (EB-2015-0328)

Dear Ms. Walli:

In accordance with Procedural Order No.1, issued November 10, 2015, and the Board's Letter of Combined Hearing, issued November 27, 2015, Niagara Peninsula Energy Inc. ("NPEI") hereby submits responses to Interrogatories received from Board Staff, Energy Probe Research Foundation ("Energy Probe") and the Vulnerable Energy Consumers Coalition ("VECC").

An electronic copy of the Interrogatory Responses and the accompanying Excel files have been submitted to the Board through the RESS system. Two hard copies will be delivered to the OEB office by courier.

This document is being filed pursuant to the Board's e-filing service.

Please contact myself should anything further be required, I can be reached at 905-353-6004.

Yours truly,
NIAGARA PENINSULA ENERGY INC.

S Wilson

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Appendices

Niagara Peninsula Energy Inc. ("NPEI")

EB-2015-0090 (IRM Application) and EB-2015-0328 (LRAMVA Application)

Interrogatory Responses

IRM and Lead/Lag Interrogatories

1. OEB Board Staff-IR#1-Manager's Summary

Ref: IRM Application, pages 6 and 7

NPEI states that it requests the OEB allow it to update its revenue requirement and current interim tariff of rates and charges to be effective November 1, 2015 on a final basis. NPEI notes that its revenue requirement, after PILs, will increase by $25,945 due to the adoption of a working capital allowance (WCA) percentage of 13.22%. NPEI also requested that the "current 2016 IRM Application [be] updated with the final 2015 tariff rates once approved."

OEB staff notes that NPEI has not provided a derivation of the base rates that would result from the adoption of a WCA percentage of 13.22%

a) Please provide a derivation of the base rates that result from the adoption of a WCA percentage of 13.22%, as well as, a revenue reconciliation.
b) Please clarify NPEI's request. Is NPEI seeking any lost revenues for the difference between interim rates and any final rates approved by the OEB? Is NPEI proposing that its customers would be charged the updated base rates, calculated in a), as of November 1, 2015?

NPEI Response

a) NPEI included an updated RRWF in Appendix G (page 144) of its IRM rate application. The updated RRWF was updated for the 13.22% WCA as a result of the lead/lag study. The revenue requirement increased by $25,946, for a total base revenue requirement of $28,691,137 and a total service revenue requirement of $30,293,659. The following table illustrates the Revenue-to Cost Ratios updated for the WCA at 13.22%:

The revenue to cost ratios by rate class remains unchanged from the revenue-to-cost ratios in NPEI's settlement agreement – See Appendix A.

Cost Allocation Based Calculations

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	Check Revenue Cost Ratios from 2015 Cost Allocation Model	Revenue to Cost Ratio after Settlement	Service Revenue after Settlement	Miscellaneous Revenue	Base Revenue after Settlement
Residential	20,957,188	15,639,005	1,262,498	16,901,504	80.65%	80.65%	91.65%	19,206,215	1,262,498	17,943,717
GS < 50 kW	3,206,026	3,662,327	188,449	3,850,776	120.11%	120.11%	120.00%	3,847,231	188,449	3,658,783
GS >50	5,610,208	8,928,284	138,127	9,066,411	161.61%	161.61%	120.00%	6,732,525	138,127	6,594,399
Sentinel Lights	89,334	58,167	5,257	63,423	71.00%	71.00%	91.65%	81,870	5,257	76,614
Street Lighting	321,214	274,102	6,039	280,141	87.21%	87.21%	91.65%	294,377	6,039	288,338
USL	109,689	129,252	2,153	131,405	119.80%	119.80%	119.83%	131,441	2,153	129,288
TOTAL	**30,293,659**	**28,691,137**	**1,602,522**	**30,293,659**	100.0%	**100.0%**		**30,293,659**	**1,602,522**	**28,691,137**

In the table below the fixed versus variable split by rate class is illustrated. The Residential rate class is at a 58% to 42% split which agrees to the OEB's decision and order dated May 14, 2015. See Appendix B.

Rate Design Fixed% versus Variable %

Customer Class Name	Existing Fixed/Variable Split (c)			Rate Application			Base Revenue Requirement $		
	Rate	Fixed %	Variable %	Fixed Rate	Fixed %	Variable %	Total (d)	Fixed (e)	Variable (f)
Residential	$18.44	58.05%	41.95%	$18.44	58.05%	41.95%	17,943,716	10,416,828	7,526,889
General Service < 50 kW	$37.79	54.35%	45.65%	$37.79	54.35%	45.65%	3,658,783	1,988,576	1,670,206
General Service > 50	$132.76	20.82%	79.18%	$102.38	16.06%	83.94%	6,594,398	1,058,980	5,535,418
Unmetered Scattered Load	$19.55	76.50%	23.50%	$19.55	76.50%	23.50%	129,288	98,906	30,382
Sentinel Lighting	$16.97	80.52%	19.48%	$16.97	80.52%	19.48%	76,614	61,691	14,923
Street Lighting	$1.21	65.46%	34.54%	$1.21	65.46%	34.54%	288,338	188,732	99,605
							28,691,137	13,813,713	14,877,423

The bill impacts updated for the Lead/Lag study change in WCA compared to the current interim rate tariff was included in Appendix J of the 2016 IRM rate application.

b) NPEI's request for base rates to be updated November 1, 2015 was overly optimistic and that NPEI wanted to ensure any changes were coordinated with one of the 2 rate changes (November/May) used by the Board and to avoid customer confusion. It is anticipated NPEI will not receive a decision from the OEB until March or April 2016. In the interest of NPEI's customers NPEI is proposing one rate change that will incorporate the 2016 IRM rate application combined with the LRAMVA application for rates effective May 1, 2016.

2. OEB Board Staff – IR #2-Collection Days

Ref: IRM Application, page 31

Table 3 from the Lead/Lag study, which shows the derivation of the collection lag of 30 days, is reproduced below.

Aging Categories	Mid Point	Average A/R $	Weight	Collection Lag
Current 0-30	16	$ 9,712,733	91.07%	14.57
Overdue 31-60	45	$ 220,467	2.07%	0.93
Overdue 61-90	75	$ 93,250	0.87%	0.66
Overdue > 91	135	$ 184,090	1.73%	2.33
Overdue > 180	270	$ 454,631	4.26%	11.51
		10,665,170.68	100.00%	30.00

a) Why were intervals of 30 days chosen for this analysis?
b) If possible, please provide an updated version of this table separated in to smaller bin sizes (e.g. 10 or 14-day increments). If not possible, please explain why NPEI is unable to update the table.
c) Was the collections lag determined using a sample of bills? If so, please show how the sample was statistically representative.
d) At what point (in number of days) does NPEI transition a bill from being overdue to becoming bad debt?
e) The mid-point for the “Overdue > 180” group is 270. This would imply that NPEI receives payments from some bills up to 540 days (1.5 years) after they are issued. Please explain the selection of the mid-point of 270 days.

NPEI Response

a) The interval of 30 days was used due to NPEI bills its customers on a monthly basis. NPEI incorporates a due date of nineteen days plus a seven day grace period before a reminder notice is sent out. The interest charge commences on the 26th day after the billing date. The due date is calculated as the minimum payment period of sixteen days plus the allowance of three days for mailing. The seven day grace period is the allowance for the customers who mail their payments back to NPEI. The 30 day interval mirrors NPEI’s billing cycle as well as its accounting month end cycle. 30 day intervals are commonly used in aging accounts receivable and accounts payable.

b) Please see the Table below:

Alternate Methodology				
Agreed to method in Veridian's Settlement agreement				
Aging Categories	Mid Point	Average A/R $	Weight	Collection Lag
Current 0-19	9.5	$ 9,457,387	88.68%	8.42
Current 20-30	5.5	$ 255,346	2.39%	0.13
Overdue 31-60	45.5	$ 220,467	2.07%	0.94
Overdue 61-90	75.5	$ 93,250	0.87%	0.66
Overdue 91-180	135.5	$ 184,090	1.73%	2.34
Overdue > 181	273	$ 454,631	4.26%	11.64
		10,665,170.68	100.00%	24.13

c) The collections lag was determined by running the month-end A/R Aging report from NPEI's billing system which details the account number, account name, and balances owing by aged category i.e. 0-30, 31-60, 61-90 etc. See the Table below which details the totals by month for each aged category.

Month	1-30 Days	31-60 Days	61-90 Days	91-180 days	> 181 days	Total (Outstanding)
May	6,052,545.01	244,868.59	108,429.73	254,831.01	476,036.00	7,136,710.35
June	8,561,465.88	252,692.70	124,493.61	207,210.89	558,392.11	9,704,255.19
July	9,481,342.98	180,487.51	115,456.54	223,519.81	580,209.12	10,581,015.96
August	11,549,573.50	160,574.59	79,181.71	211,999.45	597,107.69	12,598,436.95
September	9,215,239.51	187,091.87	63,307.47	188,523.35	611,962.59	10,266,124.79
October	9,873,109.55	169,768.87	106,764.71	157,288.76	293,429.25	10,600,361.15
November	10,130,498.43	344,256.65	67,057.82	162,291.39	318,530.16	11,022,634.44
December	9,893,622.68	258,462.10	98,673.21	192,363.79	350,721.80	10,793,843.59
January	10,010,446.59	198,785.63	120,477.50	195,541.57	380,523.18	10,905,774.48
February	11,802,516.72	188,469.32	72,608.01	164,948.71	405,557.38	12,634,100.14
March	11,317,436.43	235,915.85	75,021.08	128,949.00	420,488.90	12,177,811.25
April	8,664,997.36	224,229.67	87,528.10	121,607.45	462,617.32	9,560,979.91
TOTAL	**116,552,794.66**	**2,645,603.34**	**1,118,999.49**	**2,209,075.17**	**5,455,575.50**	**127,982,048.17**
# months	**12**	**12**	**12**	**12**	**12**	**12**
Average	**9,712,733**	**220,467**	**93,250**	**184,090**	**454,631**	**10,665,171**

d) NPEI issues a customer a Reminder Notice twenty six days after the bill date. Ten days after the reminder notice is issued and if there is still no payment received or payment arrangements made by the customer, NPEI issues a 48 hour disconnect notice. After thirty eight days, NPEI waits another five day grace period before disconnection is completed if there is no payment received or payment arrangement made. At forty three days after the bill date NPEI disconnects the service, finalizing the account and sends the receivable to a third party.

   Write-offs are completed in the first quarter of every year for balances owing on December 31st of the preceding year. Accounts which are finalized are included on the write-off listing. Balances are reviewed for payments received in the first quarter from the third party and adjusted prior to the finalization of the write-off listing. Write-offs are approved by NPEI's Finance committee and then NPEI's Board of Directors. After approval, NPEI prepares the write-off journal and reviews again for any payments received from the third party and adjusts the write-off journal. The journal is usually posted in August or September each year.

e) The mid-point for the "Overdue > 180" group is actually 272.5 days. The mid-point for all aging categories was corrected; please see IR # 8 below. The balances in this category include bankruptcies for which NPEI is listed as a creditor, accounts in estate settlements, customers on the arrears management program, customers who are active and have made payment arrangements and customers who may have had a billing error where the time frame for repayment is twenty four months.

3. OEB Board Staff-IR#3-Cost of Power

Ref: IRM Application, page 34

In its Lead/Lag study, NPEI states:

> NPEI obtained its daily exposure data from the IESO for the period of May 2014 to April 2015 and re-ran the study period data against the current updated trading limit to determine if there would have been an exposure to additional margin call warnings, which occur when the daily market exposure reaches 70% of the trading limit. This new trading limit is more reflective of the 2015 Test year and results in a weighted average expense lead time for the IESO of 28.99 days.

a) Please explain how the trading limit and margin call warnings would have an impact on the lead time for IESO cost of power expenses.
b) What would be the resulting working capital allowance if the actual IESO lead of 30.39 days was used to derive the weighted lead time for the cost of power?

NPEI Response

a) Upon receipt of a margin call warning, NPEI makes a prepayment to the IESO in order to prevent NPEI's market exposure from exceeding its trading limit. The result is that a portion of that month's IESO invoice has been paid prior to the usual payment date. This decreases the lead time for IESO cost of power expenses.

b) Using an IESO lead time of 30.39 days, and after the following corrections:
   - HST receivables and payables correction to the model (see NPEI's responses to IR#17 Energy Probe-12 and IR#19 Energy Probe-14)
   - adjusting the mid-points on the collection lag for the correct number of days (see NPEI's response to IR#8 Energy Probe-3)
   - correction to the regulatory prepaid expenses (see NPEI's responses to IR#5 OEB Staff-5 and IR# 16 Energy Probe-11) the WCA would be reduced from 12.61% to 12.28%.

The table below shows the calculation of the weighted average cost of power expense lead using 30.39 days for the IESO.

Cost of Power Expense Lead				
Month	Amount ($) Per Rate App	Weight Factor	Expense Lead (Days)	Weighted Lead Time
IESO	140,521,891.33	97.48%	30.39	29.63
Hydro One	3,305,311.98	2.29%	51.23	1.17
NWTC	322,465.69	0.22%	66.82	0.15
	144,149,669.00	**100%**	**148.44**	**30.95**

The table below shows the WCA calculation of 12.28% based on using an expense lead of 30.39 days for the IESO.

Working Capital Allowance - HST Adjusted							
Budget Item Description	Revenue Lag Days	Expense Lead Days	Net Lag (Lead) Days	WCA Factor	Test Year Expenses ($)	WCA ($)	WCA (%)
Cost of Power	64.75	30.95	33.80	9%	144,149,669	13,347,220	
Retailer Expenses	64.75	37.94	26.81	7%	2,417,005	177,520	
OM&A Expenses	64.75	-1.73	66.48	18%	16,424,995	2,991,420	
Interest on Long Term Debt	64.75	4.38	60.37	17%	2,345,596	387,927	
PILs	64.75	-562.75	627.50	172%	163,430	280,964	
Debt Retirement Charges	64.75	28.26	36.48	10%	8,456,444	845,245	
Sub-Total					173,957,139	18,030,297	11.23%
HST (Receivables)			-10.45	-2.86%	(22,603,800)	(646,921)	
HST (Expenses)			43.63	11.95%	19,499,180	2,330,815	
Total (inc. HST)					**170,852,518**	**19,714,190**	12.28%

4. OEB Board Staff-IR#4-PILS

Ref: IRM Application, page 36

In its Lead/Lag study, NPEI states:

> As of June 30, 2013, NPEI has a credit balance with the Ministry of Finance related to its PILs. The credit arose from NPEI making tax installments in 2013 based on its 2012 tax return…
>
> The credit is being used to offset any PILs payments that NPEI would need to make to the Ministry of Finance during the study period. This is expected to continue for a few more years. As a result of this credit the PILs expense lead for the study period is -562.75 days.

a) For how many years does NPEI expect to continue to be in a credit position with the Ministry of Finance? Will there continue to be a credit in the 2015 test year?
b) What is the expense lead for PILs expenses if the credit balance is not considered?

NPEI Response

a) NPEI currently has a credit balance of approximately $700,000 with the Ministry of Finance. Due to CCA exceeding depreciation and NPEI having a taxable loss in 2014 available for use in 2015, NPEI estimates it would have a credit balance for 2015 and possibly for the next five years. NPEI has not made any PILS installments during the period of the lead/lag study and has not made any PILS payments in the 2015 test year.

However, the change in reserves related to the regulatory assets and liabilities could change NPEI's taxes to an amount owing in any year. Since it is very difficult to predict and estimate the changes in the RSVA particularly power and global adjustment, NPEI cannot predict that the credit would be available for five years. Using the updated PILS amount of $129,617 calculated in NPEI's 2015 Cost of Service rate application, the credit would be available for 5.4 years ($700,000 / $129,617). The PILS model included in NPEI's 2015 COS rate application included a minimal impact for the change in RSVA reserves for the purpose of calculating and setting rates. Therefore, any change in reserves for should be excluded from PILS considerations.

b) The expense lead would be 36.22 days (15.22 service lead plus 21 payment days).

5. OEB Board Staff-IR#5-Annual Prepaid expenses

Ref: IRM Application, page 37

NPEI's Lead/Lag study has calculated an expense lead of -292.67 days for annual prepaid OM&A expenses. These expenses include "software maintenance, insurance and memberships" and "regulatory expenses relating to NPEI's 2015 COS Rate Application." NPEI states that the service period for these costs is the 2015 Test Year and the subsequent 4 year IRM period.

a) Which of the annual prepaid expenses are paid by NPEI each year and which are one-time expenses? Please provide a break-down in dollars that separates one-time costs from repeated annual expenses.
b) Using the dollar breakdown from a), please derive the weighted expense lead for annual prepaid expenses by applying a one year service period to annual costs and a 5 year service periods to one-time costs.
c) If an expense is paid annually, why would the service period for that expense last longer than one year?
d) What is the impact on the overall OM&A expense lead if annual prepaid expenses are assumed to have a one year service period?

NPEI Response

a) Under the heading 'Annual Prepaid Expenses', NPEI included both annual prepaid expenses that are paid by NPEI each year as well as the regulatory expenses for NPEI's 2015 COS Application, which relate to the period June 1, 2015 to April 30, 2020.

NPEI's original analysis for the actual prepaids during was study period was $1,208,091 for both annual and the 2015 COS prepaid expenses, which were paid between May 2014 and April 2015. The table below provides a summary of the dollar amounts included in the analysis.

Prepaid Expenses - Annual and 2015 COS		
(Actual payments between May 2014 and April 2015)		
Regulatory Expenses for 2015 COS Rate Application		139,576
LEAP	37,100	
Insurance	283,556	
Other annual Prepaid Expenses	747,859	
Total Annual Prepaids		1,068,514
Total Annual and 2015 COS Prepaids		1,208,091

The full details are provided at Appendix C.

The total prepaids for the test year amounted to $1,147,164 for both the annual and the 2015 COS prepaid expenses in the original Lead/lag report (See Table 11), which includes annual costs of $78,650 related to NPEI's 2015 COS Application (EB-2015-0096).

The $78,650 is the annual amount (1/5 of the total) approved in the EB-2014-0096 decision. However, as per the table above, the portion of these costs that were actually paid during the test period of May 2014 to April 2015 is $139,576. NPEI has corrected the 2015 COS costs in the Lead/Lag Study to be $139,576 / 5 = $27,915 instead of $78,650. The revised amount of both the annual and the 2015 COS prepaid expenses are $1,096,430. The impact of this change is an increase in the weighted-average OM&A expense lead from -2.75 days to -1.73 days. See Table 11 in the updated Lead/Lag report in Appendix D.

b) The expense lead of -292.67 days was calculated based on using a one year service period for annual costs and a 5 year service period for the 2015 COS costs. Please see Appendix C for details.

c) For expenses that are paid annually, NPEI used a service period of one year.

d) There is no impact, as NPEI did use a service period of one year for annual prepaid expenses.

6. Energy Probe-1-Bill Date, Due Date

Ref: Pages 30-31

The evidence states that the difference between the Bill Date and the Bill to Date was calculated to obtain the number of bill days and that these bill days were then weighted over all billing journals queried to obtain a weighted number of bill days. The evidence also indicates that this information was obtained by rate class.

a) What weighting was used to obtain the number of bill days for each rate class shown in Table 2?
b) Please provide the weighted number of days between the Bill Date and the Due Date using the total dollars billed as the weights using the same format as shown in Table 2.
c) Does the billing system also record the date that payment is received? If yes, please provide the weighted number of days between the Bill Date and the date payment is received, again using total dollars billed as the weights and in the same format as shown in Table 2.
d) If the pricing information is received from the IESO on the 10th business day after the read date, and taking into consideration weekends, this would imply that the pricing information is received between 12 to 14 days after the read date. Please explain why the number of days between the billing date and the meter read is 4 to 6 days greater than this figure.

NPEI Response

a) Please see the table below:

Sample of Billing Journals Queried		
	excludes Adjustment journals	Weighting Factor used
Residential	68,254,337.01	37.21%
GS<50	20,324,983.86	11.08%
GS>50	93,215,401.42	50.82%
Unmetered Scattered Load	303,373.55	0.17%
Streetlighting	1,293,191.94	0.71%
Sentinel Lights	33,762.28	0.02%
	183,425,050.06	100.00%

b) Please see the table below:

Sample of Billing Journals Queried				
	excludes Adjustment journals	Weighting Factor used	Number of Days between Billing Date and End of Service Period	Weighted lag excluding Adjustment Journals
Residential	68,254,337.01	37.21%	17.34	6.45
GS<50	20,324,983.86	11.08%	18.80	2.08
GS>50	93,215,401.42	50.82%	18.32	9.31
Unmetered Scattered Load	303,373.55	0.17%	18.22	0.03
Streetlighting	1,293,191.94	0.71%	16.65	0.12
Sentinel Lights	33,762.28	0.02%	17.64	0.00
	183,425,050.06	100.00%		18.00

c) Payments are recorded in the billing system on a customer account basis in Cash Receipts Journals. The payments are not matched to specific Billing Journals. Therefore, it is not possible to query the billing system to determine the number of days between the Bill Date and the date payment is received.

d) NPEI notes that the interval between the read date and the date that pricing information is received from the IESO may actually be longer than 14 days due to weekends and statutory holidays. Once the pricing is received, the bills are generated, reviewed by a Billing Supervisor, and then processed through the mail machine.

NPEI's commercial accounts are read monthly. For example, for the period October 1 to October 31, 2015, the 10th business day after the read date was November 16, due to November 11 being a settlement holiday for the IESO. The bills were processed, reviewed, put through the mail machine and then mailed out on November 17.

7. Energy Probe-2-Table 2, Table 3, Table 4 link

Ref: Pages 31-32

Please explain the link between the total dollar figures shown in Table 2 ($164,532,857), Table 3 ($10,665,171) and Table 4 ($190,117,768).

NPEI Response

There is not really a link between tables 2, 3 and 4. Table 2 and Table 4 differ primarily due to DRC and HST and capital contributions would be a relatively small component. Table 2 is the actual total sales from May 2014 to April 2015 excluding HST and DRC and any capital contributions. Table 3 is the actual average monthly A/R outstanding from May 2014 to April 2015 including HST and DRC. See IR #2 part c) above. Table 4 is the total cash received by payment method between May 2014 and April 2015 from all sources which includes HST, DRC and a small component of capital contributions. The source for Table 4 was the bank statement.

8. Energy Probe-3-Collections

Ref: Page 31

a) Does NPEI have a finer break down of the aging category of 0 to 30 days, such as 0 to 16 days and 17 to 30 days? If yes, please provide the average accounts receivable for these periods.
b) What is NPEI's policy with respect to the write-off of bad debts? For example, how often does NPEI write off bad debts?
c) How has the average accounts receivable for > 180 days been adjusted to reflect the removal of bad debts?

d) Please explain why 16 days was used as the midpoint of the 1 to 30 aging category rather than 15 days?

NPEI Response

a) Please see the Table in IR#2 b).
b) NPEI issues a customer a Reminder Notice twenty six days after the bill date. Ten days after the reminder notice is issued and if there is still no payment received or payment arrangements made by the customer, NPEI issues a 48 hour disconnect notice. After thirty eight days, NPEI waits another five day grace period before disconnection is completed if there is no payment received or payment arrangement made. At forty three days after the bill date NPEI disconnects the service, finalizing the account and sends the receivable to a third party.

   Write-offs are completed in the first quarter of every year for balances owing on December 31st of the preceding year. Accounts which are finalized are included on the write-off listing. Balances are reviewed for payments received in the first quarter from the third party and adjusted prior to the finalization of the write-off listing. Write-offs are approved by NPEI's Finance committee and then NPEI's Board of Directors. After approval, NPEI prepares the write-off journal and reviews again for any payments received from the third party and adjusts the write-off journal. The journal is usually posted in August or September each year.
c) The average accounts receivable for >180 days have been adjusted for the removal of bad debts in October 2014. Please see the table in IR#2 d) above where the balance > 180 days decreases from $611,962.59 in September to $293,429.25 in October.
d) The midpoint of "current 0 -30" should be 15 days and not 16 days. Elenchus corrected the model which has been updated see Appendix D. Using 15 days instead of 16 days reduces the WCA by 0.31%, everything else remaining equal. Extending the same logic to the other ranges, the midpoint of the 31 to 60 day range should then be 45.5 days and not 45, for the 61 to 90 days, the midpoint should be 75.5 days and not 75, for the 91 to 180 days, the midpoint should be 135.5 days and not 135 and for the 181 to 365 days, the midpoint should be 273 days and not 270. Changing the midpoints for all categories reduces the WCA by 0.26% everything else remaining equal. Elenchus has updated the model to reflect this change. The collections lag changes from 30.00 days to 29.24 days. NPEI has filed an updated lead/lag report incorporating this change. Please see Appendix D.

9. Energy Probe-4-Brinks deposits and cash payments

Ref: Page 32

a) Does the Brinks Deposit amount shown in Table 4 include payments received in cash and by cheque?

b) What efforts has NPEI made to switch customers from payments by cash and cheque to the other form of payments shown in Table 4?

NPEI Response

a) Yes the Brinks deposit includes payments received in cash and by cheque.
b) NPEI held two contests, one in 2013 and one in 2014 to sign customers up to pre-authorized payments (PAP) and equal billing. Customers in arrears are encouraged to use sign up for PAP and equal billing. In October 2015, the electronic PAP form was updated to be more customer-friendly.

10. Energy Probe-5-Pole rental revenue & Apprenticeship Tax Credit

Ref: Page 33

a) Please explain why the collection lag for pole rental revenue is 55.01 days.

b) Please explain why the collection lag for the apprenticeship tax credit is 182.5 days. In particular, when does NPEI file its PILs tax return?

c) Please confirm that NPEI only bills for pole rental once a year, following the end of the fiscal year. If this cannot be confirmed, please explain when NPEI bills for pole rental and for what period this bill is for.

NPEI Response

a) For sources of other revenue that relate to items billed by NPEI that are not included on monthly electric bills (i.e. Pole Rental Revenue, Sale of Scrap Material, Transformer Rental Revenue, Lawyer's Letter Fees and Project Billing Revenue), NPEI used an analysis of sundry accounts receivable ("SARs") aging over the study period of May 2014 to April 2015 to calculate the collection lag. The table below provides the details of the calculation of 55.01 days.

SARs Aging						
	Current	**31-60**	**61-90**	**91-180**	**> 180 days**	**Total**
May-14	474,942	43,790	605	220,342	34,025	773,704
Jun-14	53,239	17,044	16,449	322	64,628	151,681
Jul-14	19,793	45,832	9,967	30,500	50,389	156,481
Aug-14	100,268	18,208	23,639	33,068	40,852	216,035
Sep-14	269,784	3,110	34	34,508	26,259	333,694
Oct-14	20,754	67,322	373	34	33,862	122,345
Nov-14	716,145	5,227	17,135	51	16,932	755,491
Dec-14	566,338	218,537	5,227	34	16,932	807,068
Jan-15	671	532,600	185,943	5,260	16,932	741,407
Feb-15	20,122	163,386	20,305	5,617	16,966	226,396
Mar-15	103,226	19,848	38,550	46,161	16,966	224,751
Apr-15	321,398	74,755	19,048	32,156	22,193	469,549
	2,666,680	1,209,658	337,274	408,052	356,937	4,978,600
					Average	414,883
Aging Category	**Mid Point**	**Average A/R $**	**Weight**	**Collection Lag**		
Current	16	222,223	53.56%	8.57		
31-60	45	100,805	24.30%	10.93		
61-90	75	28,106	6.77%	5.08		
91-180	135	34,004	8.20%	11.06		
> 180	270	29,745	7.17%	19.36		
		414,883	100.00%	55.01		

In calculating the SARs collection lag, NPEI used the same method and mid-points as was used in the electric bill collection lag calculation. As indicated in the response to IR# 8 Energy Probe-3, the mid-points used were not correct. Upon correcting for the mid-points of the aging categories, the weighted-average SARs collection lag is reduced from 55.01 days to 54.88 days. The corrected SARs aging calculation is given below.

SARs Aging						
	Current	**31-60**	**61-90**	**91-180**	**> 180 days**	**Total**
May-14	474,942	43,790	605	220,342	34,025	773,704
Jun-14	53,239	17,044	16,449	322	64,628	151,681
Jul-14	19,793	45,832	9,967	30,500	50,389	156,481
Aug-14	100,268	18,208	23,639	33,068	40,852	216,035
Sep-14	269,784	3,110	34	34,508	26,259	333,694
Oct-14	20,754	67,322	373	34	33,862	122,345
Nov-14	716,145	5,227	17,135	51	16,932	755,491
Dec-14	566,338	218,537	5,227	34	16,932	807,068
Jan-15	671	532,600	185,943	5,260	16,932	741,407
Feb-15	20,122	163,386	20,305	5,617	16,966	226,396
Mar-15	103,226	19,848	38,550	46,161	16,966	224,751
Apr-15	321,398	74,755	19,048	32,156	22,193	469,549
	2,666,680	1,209,658	337,274	408,052	356,937	4,978,600
					Average	414,883
Aging Category	**Mid Point**	**Average A/R $**	**Weight**	**Collection Lag**		
Current 0-30	15.0	222,223	53.56%	8.03		
Overdue 31-60	45.5	100,805	24.30%	11.06		
Overdue 61-90	75.5	28,106	6.77%	5.11		
Overdue 91-180	135.5	34,004	8.20%	11.11		
Overdue > 181	273.0	29,745	7.17%	19.57		
		414,883	100.00%	54.88		

NPEI has incorporated this correction into the revised Lead/Lag Report. NPEI notes that this correction has no impact to the final WCA calculation to 2 decimal places.

b) NPEI's tax return is prepared by its audit firm and filed on June 30th of each year. NPEI is eligible for its apprenticeship tax credit once the tax return is filed with the Ministry of Finance which is the 30th of June. The apprenticeship tax credit relates to the preceding fiscal year where the service period is 365 days divided by 2 which is 182.5 days.

c) Confirmed, NPEI bills for pole rental revenue once per year following the end of the fiscal year.

11. Energy Probe-6-Cost of Power

Ref: Page 34

a) Please show the calculation of the cost of power expense lead in Table 8 assuming the use of the 30.39 days for the IESO.

b) Please provide all the data and analysis used to calculate the IESO expense lead times of 30.39 days and 28.99 days noted in the evidence.

c) Please explain why the IESO reduced NPEIs trading limit by $1.7 million.

d) What happens when a margin call warning is issued? Is NPEI required to make a payment?

e) Does the reduction in the trading limit by $1.7 million primarily affect NPEI in the summer months?

f) Based on the analysis that reduced the IESO expense lead days from 30.39 to 28.99, please indicate which months were impacted and which months were not.

g) Please update the IESO expense lead to reflect the most recent 12 months that are now available. Please show all calculations and assumptions used.

NPEI Response

a) See NPEI's response to IR#3 Board Staff-3 b).

b) Details of the calculation of the IESO expense lead time of 30.39 days are included at Appendix E.

In order to analyze the impact of the revised trading limit, NPEI compared its actual daily market exposure over the study period to the new trading limit. NPEI assumed that a prepayment of $2.5 million would be made whenever a margin call warning was reached. Details of the resulting expense lead of 28.99 days are provided at Appendix F.

c) To the best of NPEI's knowledge, the revised trading limit was a result of an annual price review performed by the IESO in accordance with market rules. Based on the IESO's annual review performed on April 21, 2015, the IESO's price basis changed from $75 per MWh to $94 per MWh, which is an increase of 25.3%. When the price basis changes by more than 15%, the IESO recalculates the prudential support obligation of all market participants. In NPEI's case, this resulted in an increase in NPEI's Default Protection Amount from $8,935,128 to $10,675,157. Based on the Letter of Credit that NPEI has posted with the IESO of $11,910,187, NPEI's trading limit decreased from $18,122,503 to $16,382,474.

The IESO's communication about the annual review, and NPEI's Prudential Support Obligation – Schedule A (before and after the reduction) are all included in Appendix G.

d) When the IESO issues NPEI a margin call warning, NPEI's market exposure has reached 70% of its trading limit with the IESO. NPEI is not required to make a payment. However, if a margin call is issued to NPEI by the IESO (i.e. market exposure is reached or exceeds NPEI's trading limit), NPEI would be required to make a payment equivalent to 30% of the trading limit (30% X $16,382,474 = $4,914,743) within 48 hours. The daily market exposure varies due to price including global adjustment and to weather. In the summer months, NPEI's daily exposure could be between $700K and $800K. Therefore using $4,914,743 / $800,000 a margin call could be issued within 6 days of the margin call warning.

Taking weekends and statutory holidays into account it could be 3 to 4 days from the date of the margin call warning. NPEI manages its cash flow to ensure it receives the Good Payment History reduction shown on the Prudential Support Obligation shown in Appendix G. The Good Payment History reduction enables NPEI to maintain its trading limit and its prudential support obligation with the IESO. A reduced trading limit would create additional margin call warnings and margin calls whereby NPEI would be prepaying a substantial amount of its cost of power.

As can be seen in NPEI's Prudential Support Obligation – Schedule A in Appendix G, the calculation of NPEI's prudential support includes a $14 million reduction for 6 years of good payment history. In order to maintain its good payment credit, and avoid any risk associated with reaching or exceeding its trading limit, NPEI's procedure is to make a prepayment when a margin call warning is issued.

e) No, since the trading limit was revised in June 2015, NPEI has received a total of 12 margin call warnings, with one or more occurring each month from June to October, 2015.

f) The following months were not impacted: October and November 2014; April 2015. The following months were impacted: May, June, July, August, September and December 2014; January, February and March 2015.

g) Based on the most recent 12 months available (November 2014 to October 2015), the IESO expense lead is 28.13 days. Details are included in Appendix H.

12. Energy Probe-7-Interest expense payments

Ref: Page 35

a) Please provide all the calculations and assumptions used for each of the debt instruments used to calculate the 4.38 days for interest on long term debt, including the payment frequency of each loan and the amount of interest for each loan.

b) Please provide a copy of each of the loan agreements that shows the payment frequency. Please highlight this part of each of the loan agreements.

c) Is the interest that is paid monthly, quarterly, etc., paid on past balances or paid in advance for the following periods? Please explain fully.

NPEI Response

a) Please see the tables below.
b) Please see Appendix I.
c) See the amortization schedules for the Scotiabank loan and the TD loan for $9.0M included in part b)'s appendix I. All of the interest only loans including the shareholder loans interest paid in the month are for the current month's interest expense.

Long Term Debt											
Date of Debt Issuance (date)	Principal ($)	Interest Rate(%)	Interest ($)	Total ($)	Service Lag (Days)	Payment Lag (Days)	Total Lag (Days)	Weighting Factor (%)	Weighted Lead	Debt holder	Payment date
4/1/2000	22,000,000	4.77%	1,170,399.96	1,170,399.96	15.21	-13.58	1.63	48.64%	0.79	City of Niagara Falls	End of month
4/1/2000	3,605,090	4.77%	191,790.72	191,790.72	15.21	-8.83	6.38	7.97%	0.51	Niagara Falls Hydro Holding	End of month
7/19/2009	4,188,358	0	221,645	221,644.68	15.21	-10.67	4.54	0	0.42	TD Term loan, principle repayments	20th of the month
9/30/2010	2,362,500	0	133,256	133,255.57	15.21	-0.92	14.29	0	0.79	Scotiabank Smart meter loan, principle repayments	Last day of the month
6/27/2012	10,000,000	2.80%	279,999.99	279,999.99	15.21	-8.75	6.46	11.64%	0.75	TD term loan only interest repayments	21st or 23rd of the month
3/12/2013	10,000,000	2.93%	293,300.00	293,300.00	15.21	-8.75	6.46	12.19%	0.79	TD term loan only interest repayments	21st or 23rd of the month
30/11/2014	10,000,000	2.66%	116,004.65	116,004.65	15.21	-8.33	6.88	4.82%	0.33	TD term loan only interest repayments	21st or 23rd of the month
				-							
Total	**62,155,948**	**0**	**2,406,395.57**	**2,406,395.57**	**106.4583333**	**-59.83**	**46.64**	**100.00%**	**4.380**		

Principal O/S		Service start date	Service end date	payment date	Total Expense	Amount ($)	Weighting Factor (%)	Weighted Lead	Monthly Mid-point	Service end date	payment date	Payment Lead
	May-14											
22,000,000.00	City of Niagara Falls	5/1/2014	5/31/2014	5/9/2014	-6.50	97,533.33	50.75%	-3.30	15.5	5/31/2014	5/9/2014	-22
3,605,090.00	Niagara Falls Hydro Holding	5/1/2014	5/31/2014	5/23/2014	7.50	15,982.56	8.32%	0.62	15.5	5/31/2014	5/23/2014	-8
5,173,265.71	TD Term loan, principle repayments	5/1/2014	5/31/2014	5/20/2014	4.50	19,751.56	10.28%	0.46	15.5	5/31/2014	5/20/2014	-11
2,887,500.00	Scotiabank Smart meter loan, principle repayments	5/1/2014	5/31/2014	5/30/2014	14.50	11,795.24	6.14%	0.89	15.5	5/31/2014	5/30/2014	-1
10,000,000.00	TD term loan only interest repayments	5/1/2014	5/31/2014	5/21/2014	5.50	23,013.70	11.97%	0.66	15.5	5/31/2014	5/21/2014	-10
10,000,000.00	TD term loan only interest repayments	5/1/2014	5/31/2014	5/21/2014	5.50	24,106.85	12.54%	0.69	15.5	5/31/2014	5/21/2014	-10
-	TD term loan only interest repayments											
53,665,855.71						**192,183.24**	**100.00%**	**0.03**				
	Jun-14											
22,000,000.00	City of Niagara Falls	6/1/2014	6/30/2014	6/20/2014	5.00	97,533.33	50.18%	2.51	15	6/30/2014	6/20/2014	-10
3,605,090.00	Niagara Falls Hydro Holding	6/1/2014	6/30/2014	6/20/2014	5.00	15,982.56	8.22%	0.41	15	6/30/2014	6/20/2014	-10
5,099,947.08	TD Term loan, principle repayments	6/1/2014	6/30/2014	6/17/2014	2.00	20,123.29	10.35%	0.21	15	6/30/2014	6/17/2014	-13
2,850,000.00	Scotiabank Smart meter loan, principle repayments	6/1/2014	6/30/2014	6/30/2014	15.00	12,030.12	6.19%	0.93	15	6/30/2014	6/30/2014	0
10,000,000.00	TD term loan only interest repayments	6/1/2014	6/30/2014	6/23/2014	8.00	23,780.82	12.24%	0.98	15	6/30/2014	6/23/2014	-7
10,000,000.00	TD term loan only interest repayments	6/1/2014	6/30/2014	6/23/2014	8.00	24,910.41	12.82%	1.03	15	6/30/2014	6/23/2014	-7
-	TD term loan only interest repayments											0
53,555,037.08						**194,360.53**	**100.00%**	**6.06**				
	Jul-14											
22,000,000.00	City of Niagara Falls	7/1/2014	7/31/2014	7/4/2014	-11.50	97,533.33	50.98%	-5.86	15.5	7/31/2014	7/4/2014	-27
3,605,090.00	Niagara Falls Hydro Holding	7/1/2014	7/31/2014	7/25/2014	9.50	15,982.56	8.35%	0.79	15.5	7/31/2014	7/25/2014	-6
5,025,703.32	TD Term loan, principle repayments	7/1/2014	7/31/2014	7/16/2014	0.50	19,198.16	10.03%	0.05	15.5	7/31/2014	7/16/2014	-15
2,812,500.00	Scotiabank Smart meter loan, principle repayments	7/1/2014	7/31/2014	7/30/2014	14.50	11,488.87	6.00%	0.87	15.5	7/31/2014	7/30/2014	-1
10,000,000.00	TD term loan only interest repayments	7/1/2014	7/31/2014	7/21/2014	5.50	23,013.70	12.03%	0.66	15.5	7/31/2014	7/21/2014	-10
10,000,000.00	TD term loan only interest repayments	7/1/2014	7/31/2014	7/21/2014	5.50	24,106.85	12.60%	0.69	15.5	7/31/2014	7/21/2014	-10
-	TD term loan only interest repayments											0
53,443,293.32						**191,323.47**	**100.00%**	**-2.79**				
	Aug-14											
22,000,000.00	City of Niagara Falls	8/1/2014	8/31/2014	8/29/2014	13.50	97,533.33	50.51%	6.82	15.5	8/31/2014	8/29/2014	-2
3,605,090.00	Niagara Falls Hydro Holding	8/1/2014	8/31/2014	8/29/2014	13.50	15,982.56	8.28%	1.12	15.5	8/31/2014	8/29/2014	-2
4,951,810.70	TD Term loan, principle repayments	8/1/2014	8/31/2014	8/20/2014	4.50	19,549.30	10.12%	0.46	15.5	8/31/2014	8/20/2014	-11
2,775,000.00	Scotiabank Smart meter loan, principle repayments	8/1/2014	8/31/2014	8/29/2014	13.50	11,335.68	5.87%	0.79	15.5	8/31/2014	8/29/2014	-2
10,000,000.00	TD term loan only interest repayments	8/1/2014	8/31/2014	8/21/2014	5.50	23,780.82	12.32%	0.68	15.5	8/31/2014	8/21/2014	-10
10,000,000.00	TD term loan only interest repayments	8/1/2014	8/31/2014	8/21/2014	5.50	24,910.41	12.90%	0.71	15.5	8/31/2014	8/21/2014	-10
-	TD term loan only interest repayments											
53,331,900.70						**193,092.10**	**100.00%**	**10.57**				

	Sep-14											
22,000,000.00	City of Niagara Falls	9/1/2014	9/30/2014	9/11/2014	-4.00	97,533.33	50.43%	-2.02	15	9/30/2014	9/11/2014	-19
3,605,090.00	Niagara Falls Hydro Holding	9/1/2014	9/30/2014	9/26/2014	11.00	15,982.56	8.26%	0.91	15	9/30/2014	9/26/2014	-4
4,877,630.64	TD Term loan, principle repayments	9/1/2014	9/30/2014	9/22/2014	7.00	19,261.87	9.96%	0.70	15	9/30/2014	9/22/2014	-8
2,737,500.00	Scotiabank Smart meter loan, principle repayments	9/1/2014	9/30/2014	9/30/2014	15.00	11,928.00	6.17%	0.93	15	9/30/2014	9/30/2014	0
10,000,000.00	TD term loan only interest repayments	9/1/2014	9/30/2014	9/22/2014	7.00	23,780.82	12.30%	0.86	15	9/30/2014	9/22/2014	-8
10,000,000.00	TD term loan only interest repayments	9/1/2014	9/30/2014	9/22/2014	7.00	24,910.41	12.88%	0.90	15	9/30/2014	9/22/2014	-8
-	TD term loan only interest repayments											
53,220,220.64						**193,396.99**	**100.00%**	**2.28**				
	Oct-14											
22,000,000.00	City of Niagara Falls	10/1/2014	10/31/2014	10/24/2014	8.50	97,533.33	51.33%	4.36	15.5	10/31/2014	10/24/2014	-7
3,605,090.00	Niagara Falls Hydro Holding	10/1/2014	10/31/2014	10/24/2014	8.50	15,982.56	8.41%	0.71	15.5	10/31/2014	10/24/2014	-7
4,802,549.99	TD Term loan, principle repayments	10/1/2014	10/31/2014	10/20/2014	4.50	18,361.27	9.66%	0.43	15.5	10/31/2014	10/20/2014	-11
2,700,000.00	Scotiabank Smart meter loan, principle repayments	10/1/2014	10/31/2014	10/30/2014	14.50	11,029.32	5.80%	0.84	15.5	10/31/2014	10/30/2014	-1
10,000,000.00	TD term loan only interest repayments	10/1/2014	10/31/2014	10/21/2014	5.50	23,013.70	12.11%	0.67	15.5	10/31/2014	10/21/2014	-10
10,000,000.00	TD term loan only interest repayments	10/1/2014	10/31/2014	10/21/2014	5.50	24,106.85	12.69%	0.70	15.5	10/31/2014	10/21/2014	-10
-	TD term loan only interest repayments											
53,107,639.99						**190,027.03**	**100.00%**	**7.72**				
	Nov-14											
22,000,000.00	City of Niagara Falls	11/1/2014	11/30/2014	11/21/2014	6.00	97,533.33	49.45%	2.97	15	11/30/2014	11/21/2014	-9
3,605,090.00	Niagara Falls Hydro Holding	11/1/2014	11/30/2014	11/21/2014	6.00	15,982.56	8.10%	0.49	15	11/30/2014	11/21/2014	-9
4,727,789.34	TD Term loan, principle repayments	11/1/2014	11/30/2014	11/20/2014	5.00	18,681.26	9.47%	0.47	15	11/30/2014	11/20/2014	-10
2,662,500.00	Scotiabank Smart meter loan, principle repayments	11/1/2014	11/30/2014	11/28/2014	13.00	10,513.59	5.33%	0.69	15	11/30/2014	11/28/2014	-2
10,000,000.00	TD term loan only interest repayments	11/1/2014	11/30/2014	11/21/2014	6.00	23,780.82	12.06%	0.72	15	11/30/2014	11/21/2014	-9
10,000,000.00	TD term loan only interest repayments	11/1/2014	11/30/2014	11/21/2014	6.00	24,910.41	12.63%	0.76	15	11/30/2014	11/21/2014	-9
10,000,000.00	TD term loan only interest repayments	11/1/2014	11/30/2014	11/21/2014	6.00	5,836.71	2.96%	0.18	15	11/30/2014	11/21/2014	-9
62,995,379.34						**197,238.68**	**100.00%**	**6.28**				
	Dec-14											
22,000,000.00	City of Niagara Falls	12/1/2014	12/31/2014	12/19/2014	3.50	97,533.33	46.06%	1.61	15.5	12/31/2014	12/19/2014	-12
3,605,090.00	Niagara Falls Hydro Holding	12/1/2014	12/31/2014	12/19/2014	3.50	15,982.56	7.55%	0.26	15.5	12/31/2014	12/19/2014	-12
4,652,144.63	TD Term loan, principle repayments	12/1/2014	12/31/2014	12/22/2014	6.50	17,797.21	8.40%	0.55	15.5	12/31/2014	12/22/2014	-9
2,625,000.00	Scotiabank Smart meter loan, principle repayments	12/1/2014	12/31/2014	12/30/2014	14.50	11,437.81	5.40%	0.78	15.5	12/31/2014	12/30/2014	-1
10,000,000.00	TD term loan only interest repayments	12/1/2014	12/31/2014	12/22/2014	6.50	23,013.70	10.87%	0.71	15.5	12/31/2014	12/22/2014	-9
10,000,000.00	TD term loan only interest repayments	12/1/2014	12/31/2014	12/22/2014	6.50	24,106.85	11.38%	0.74	15.5	12/31/2014	12/22/2014	-9
10,000,000.00	TD term loan only interest repayments	12/1/2014	12/31/2014	12/22/2014	6.50	21,887.67	10.34%	0.67	15.5	12/31/2014	12/22/2014	-9
62,882,234.63						**211,759.13**	**100.00%**	**5.32**				

	Jan-15											
22,000,000.00	City of Niagara Falls	1/1/2015	1/31/2015	1/23/2015	7.50	97,533.33	45.61%	3.42	15.5	1/31/2015	1/23/2015	-8
3,605,090.00	Niagara Falls Hydro Holding	1/1/2015	1/31/2015	1/23/2015	7.50	15,982.56	7.47%	0.56	15.5	1/31/2015	1/23/2015	-8
4,576,798.91	TD Term loan, principle repayments	1/1/2015	1/31/2015	1/20/2015	4.50	18,096.21	8.46%	0.38	15.5	1/31/2015	1/20/2015	-11
2,587,500.00	Scotiabank Smart meter loan, principle repayments	1/1/2015	1/31/2015	1/30/2015	14.50	10,922.09	5.11%	0.74	15.5	1/31/2015	1/30/2015	-1
10,000,000.00	TD term loan only interest repayments	1/1/2015	1/31/2015	1/21/2015	5.50	23,780.82	11.12%	0.61	15.5	1/31/2015	1/21/2015	-10
10,000,000.00	TD term loan only interest repayments	1/1/2015	1/31/2015	1/21/2015	5.50	24,910.41	11.65%	0.64	15.5	1/31/2015	1/21/2015	-10
10,000,000.00	TD term loan only interest repayments	1/1/2015	1/31/2015	1/21/2015	5.50	22,617.26	10.58%	0.58	15.5	1/31/2015	1/21/2015	-10
62,769,388.91						**213,842.68**	**100.00%**	**6.94**				
	Feb-15											
22,000,000.00	City of Niagara Falls	2/1/2015	2/28/2015	2/13/2015	-1.00	97,533.33	45.93%	-0.46	14	2/28/2015	2/13/2015	-15
3,605,090.00	Niagara Falls Hydro Holding	2/1/2015	2/28/2015	2/20/2015	6.00	15,982.56	7.53%	0.45	14	2/28/2015	2/20/2015	-8
4,501,160.11	TD Term loan, principle repayments	2/1/2015	2/28/2015	2/20/2015	6.00	17,803.12	8.38%	0.50	14	2/28/2015	2/20/2015	-8
2,550,000.00	Scotiabank Smart meter loan, principle repayments	2/1/2015	2/28/2015	2/27/2015	13.00	9,722.14	4.58%	0.60	14	2/28/2015	2/27/2015	-1
10,000,000.00	TD term loan only interest repayments	2/1/2015	2/28/2015	2/23/2015	9.00	23,780.82	11.20%	1.01	14	2/28/2015	2/23/2015	-5
10,000,000.00	TD term loan only interest repayments	2/1/2015	2/28/2015	2/23/2015	9.00	24,910.41	11.73%	1.06	14	2/28/2015	2/23/2015	-5
10,000,000.00	TD term loan only interest repayments	2/1/2015	2/28/2015	2/23/2015	9.00	22,617.26	10.65%	0.96	14	2/28/2015	2/23/2015	-5
62,656,250.11						**212,349.64**	**100.00%**	**4.11**				
	Mar-15											
22,000,000.00	City of Niagara Falls	3/1/2015	3/31/2015	3/12/2015	-3.50	97,533.33	47.73%	-1.67	15.5	3/31/2015	3/12/2015	-19
3,605,090.00	Niagara Falls Hydro Holding	3/1/2015	3/31/2015	3/12/2015	-3.50	15,982.56	7.82%	-0.27	15.5	3/31/2015	3/12/2015	-19
4,423,532.68	TD Term loan, principle repayments	3/1/2015	3/31/2015	3/20/2015	4.50	15,814.49	7.74%	0.35	15.5	3/31/2015	3/20/2015	-11
2,512,500.00	Scotiabank Smart meter loan, principle repayments	3/1/2015	3/31/2015	3/30/2015	14.50	10,605.50	5.19%	0.75	15.5	3/31/2015	3/30/2015	-1
10,000,000.00	TD term loan only interest repayments	3/1/2015	3/31/2015	3/23/2015	7.50	21,479.45	10.51%	0.79	15.5	3/31/2015	3/23/2015	-8
10,000,000.00	TD term loan only interest repayments	3/1/2015	3/31/2015	3/23/2015	7.50	22,499.73	11.01%	0.83	15.5	3/31/2015	3/23/2015	-8
10,000,000.00	TD term loan only interest repayments	3/1/2015	3/31/2015	3/23/2015	7.50	20,428.49	10.00%	0.75	15.5	3/31/2015	3/23/2015	-8
62,541,122.68						**204,343.55**	**100.00%**	**1.52**				
	Apr-15											
22,000,000.00	City of Niagara Falls	4/1/2015	4/30/2015	4/17/2015	2.00	97,533.33	45.90%	0.92	15	4/30/2015	4/17/2015	-13
3,605,090.00	Niagara Falls Hydro Holding	4/1/2015	4/30/2015	4/17/2015	2.00	15,982.56	7.52%	0.15	15	4/30/2015	4/17/2015	-13
4,347,297.70	TD Term loan, principle repayments	4/1/2015	4/30/2015	4/20/2015	5.00	17,206.94	8.10%	0.40	15	4/30/2015	4/20/2015	-10
2,475,000.00	Scotiabank Smart meter loan, principle repayments	4/1/2015	4/30/2015	4/30/2015	15.00	10,447.21	4.92%	0.74	15	4/30/2015	4/30/2015	0
10,000,000.00	TD term loan only interest repayments	4/1/2015	4/30/2015	4/21/2015	6.00	23,780.82	11.19%	0.67	15	4/30/2015	4/21/2015	-9
10,000,000.00	TD term loan only interest repayments	4/1/2015	4/30/2015	4/21/2015	6.00	24,910.41	11.72%	0.70	15	4/30/2015	4/21/2015	-9
10,000,000.00	TD term loan only interest repayments	4/1/2015	4/30/2015	4/21/2015	6.00	22,617.26	10.64%	0.64	15	4/30/2015	4/21/2015	-9
62,427,387.70						**212,478.53**	**100.00%**	**4.22**				

13. Energy Probe-8-PILS

Ref: Pages 35-36

a) Please explain why NPEI has not requested a refund of the credit balance associated with the PILs with the Ministry of Finance.
b) Please calculate the expense lead days associated with PILs if NPEI did not have a credit balance with the Ministry of Finance.
c) Please confirm that if NPEI received a refund of the credit balance on deposit at the Ministry of Finance, it would have more cash on hand to deal with its working capital requirements.

NPEI Response

a) NPEI has not requested a refund because it has allowed NPEI to avoid certain charges and provides a net benefit to the customer.

If NPEI received the refund from the Ministry of Finance in August of 2014 and deposited the refund into its bank account NPEI would have earned interest for a twelve month period of $11,832. The credit balance with the Ministry was sufficient to cover the 2014 and 2015 installments owing.

In June of 2015, NPEI underwent a PILS audit for the periods 2011 and 2012. As a result, NPEI owed additional taxes for 2011 and 2012 in the amount of $644,251. This reassessment was applied back to the 2011 and 2012 tax years. The Ministry of Finance was able to use the credit that became available in July 2014 to apply back to 2011 and 2012. Had NPEI taken the credit in July of 2014, NPEI would have had approximately $150,000 in interest and would have had to pay this in 2015.

NPEI has been able to manage its cash flow during 2014 and 2015 without having to receive the refund from PILS.

The interest payment of $150,000 is 12 times the interest that would have been earned.

b) The expense lead would be 36.22 days (15.22 service lead plus 21 payment days).

c) If NPEI had received the refund in August 2014, NPEI would have had more cash on hand between August of 2014 and December 2014. Installments for 2015 would have begun in January 2015 through to December 2015. However, as a result of the audit the interest owing due to the reassessment would have resulted in NPEI having a much lower net cash position had the company not had that credit with the Ministry of Finance. NPEI estimates it has a credit balance of approximately $700,000 as of October 2015.

14. Energy Probe-9-Mearie Benefits

Ref: Page 37

Please show the calculation of the payment lead of -29.91 days for Benefits - Mearie. In particular, please provide the payment dates to Mearie for each of the 12 months used in the analysis that result in the payment lead of -29.91 days.

NPEI Response

Please see the table below:

Vendor Name	Invoice #	Invoice Date	Cheque #	Service Start Date	Service End Date	Cheque Date	Mid Point	Payment Lead	Total Lead	Invoice Amc	Weight Factor	Weighted Lead	Weighted Payment Lead
The MEARIE Group	May Premiums	4/24/2014	42456	5/1/2014	5/31/2014	4/29/2014	15.50	-32.00	-16.50	74,186.74	8.12%	(1.34)	-2.59883
The MEARIE Group	June Premiums	6/1/2014	43297	6/1/2014	6/30/2014	5/30/2014	15.00	-31.00	-16.00	74,355.90	8.14%	(1.30)	-2.52336
The MEARIE Group	July Premiums	6/24/2014	43955	7/1/2014	7/31/2014	6/27/2014	15.50	-34.00	-18.50	75,091.51	8.22%	(1.52)	-2.79493
The MEARIE Group	August Premiums	8/1/2014	44805	8/1/2014	8/31/2014	8/1/2014	15.50	-30.00	-14.50	79,264.18	8.68%	(1.26)	-2.60315
The MEARIE Group	September Premiums	8/22/2014	45634	9/1/2014	9/30/2014	8/29/2014	15.00	-32.00	-17.00	76,434.72	8.37%	(1.42)	-2.67758
The MEARIE Group	October Premiums	10/1/2014	46433	10/1/2014	10/31/2014	10/3/2014	15.50	-28.00	-12.50	75,912.09	8.31%	(1.04)	-2.32686
The MEARIE Group	November Premiums	10/24/2014	47184	11/1/2014	11/30/2014	10/31/2014	15.00	-30.00	-15.00	78,594.10	8.60%	(1.29)	-2.58115
The MEARIE Group	December Premiums	11/26/2014	48001	12/1/2014	12/31/2014	12/5/2014	15.50	-26.00	-10.50	75,302.26	8.24%	(0.87)	-2.1433
The MEARIE Group	January Premiums	12/19/2014	48753	1/1/2015	1/31/2015	1/2/2015	15.50	-29.00	-13.50	77,966.50	8.54%	(1.15)	-2.47518
The MEARIE Group	February Premiums	2/1/2015	49557	2/1/2015	2/28/2015	1/30/2015	14.00	-29.00	-15.00	76,033.91	8.32%	(1.25)	-2.41383
The MEARIE Group	March Premiums	2/21/2015	50262	3/1/2015	3/31/2015	3/2/2015	15.50	-29.00	-13.50	75,472.73	8.26%	(1.12)	-2.39601
The MEARIE Group	April Premiums	3/24/2015	50987	4/1/2015	4/30/2015	4/1/2015	15.00	-29.00	-14.00	74,864.30	8.20%	(1.15)	-2.3767
										913,478.94	100.00%	(14.70)	-29.9109

15. Energy Probe-10-Property taxes

Ref: Page 37

a) Please provide the dates and amounts paid for property taxes for the 2015 calendar year.

b) Please provide the dates and amounts paid for OEB cost assessments. Please explain why this is a prepaid expense.

NPEI Response

a) The table below shows the dates and amounts of property tax payments for the 2015 calendar year.

Vendor	Reference	Cheque Date	Amount
City of Niagara Falls	2015 Interim Payment in Lieu of Property Tax	2/6/2015	76,518.68
TOWN OF LINCOLN	1st&2nd Install-4299 Fly Rd	2/13/2015	151.19
TOWN OF LINCOLN	1st&2nd Install-Red Maple Ave	2/13/2015	254.39
TOWN OF LINCOLN	1st&2nd Install-3897 Greenlane	2/13/2015	93.68
Township of West Lincoln	1st&2nd Install-RR#20	2/13/2015	214.81
Township of West Lincoln	1st Install-2676 Clifford St	2/13/2015	19,590.26
City of Niagara Falls	1st Install Montgomery St	2/20/2015	2,159.07
Ontario Electricity Financial Corp	2015 Interim Payment in Lieu of Property Tax	3/26/2015	8,268.35
Township of West Lincoln	2nd Install-2676 Clifford St	4/9/2015	19,590.27
City of Niagara Falls	2nd Install Montgomery St	4/9/2015	2,158.00
TOWN OF PELHAM	1st&2nd install-1582 Pelham St	6/18/2015	92.00
TOWN OF PELHAM	1st&2nd install-WS-Station St	6/18/2015	505.48
TOWN OF PELHAM	1st&2nd install-Pelham St	6/18/2015	29.93
TOWN OF LINCOLN	1st&2nd install-Red Maple	7/15/2015	815.26
TOWN OF LINCOLN	1st&2nd install-Fly Road	7/15/2015	461.72
TOWN OF LINCOLN	1st&2nd install-Greenlane	7/15/2015	282.84
Township of West Lincoln	3rd&4th Install-RR#20	7/22/2015	646.83
Township of West Lincoln	3rd Install 2676 Clifford ST	7/22/2015	19,903.84
City of Niagara Falls	Final pymt In-Lieu of Property Taxes	8/12/2015	78,247.25
City of Niagara Falls	3rd Install Montgomery St	8/19/2015	3,103.27
Township of West Lincoln	4th Install Clifford St	9/30/2015	19,903.84
Ontario Electricity Financial Corp	2015 Payment in Lieu of Property Tax	10/8/2015	7,788.63
City of Niagara Falls	4th install-Montgomery St.	10/15/2015	3,102.00
			263,881.59

Details of the dates and amounts of property taxes paid in the study period (May 2014 to April 2015) that were used in the Lead/Lag study are included in Appendix J.

b) The table below shows the dates and amounts of quarterly OEB cost assessments for the 2015 calendar year.

Vendor	Reference	Cheque Date	Amount
Ontario Energy Board	Assessment - Jan 1 to Mar 31, 2015	1/16/2015	40,580.00
Ontario Energy Board	Assessment - Apr 1 to June 30, 2015	4/17/2015	41,298.00
Ontario Energy Board	Assessment - July 1 to Sept 30, 2015	7/15/2015	41,298.00
Ontario Energy Board	Assessment - Oct 1 to Dec 31, 2015	10/15/2015	41,243.00
			164,419.00

Details of the dates and amounts of quarterly cost assessments paid in the study period (May 2014 to April 2015) that were used in the Lead/Lag study are included in Appendix J.

These are prepaid expenses since the invoice is issued and paid during the first month of each quarter, but the costs assessed relate to a three month period. Therefore, NPEI records the invoice as a prepaid expense and then records one third of the invoice amount as expense each month during the quarter.

NPEI notes that the quarterly invoices that are recorded as prepaid relate to the recovery of the OEB's costs under subsection 26. (1) of the Ontario Energy Board Act, 1998, and the OEB's invoices explicitly indicate that the costs relate to a three month period.

16. Energy Probe-11-Prepaid expenses

Ref: Pages 37-38

With respect to the annual prepaid expenses:

a) Please break down the $1,147,164 amount shown in Table 11 into each of the components noted on page 37.

b) Please confirm that each of the annual prepaid expenses is based on annual costs that begin on May 1, and do not reflect any annual costs that are based on a calendar year. If this cannot be confirmed, please explain which expenses are based on pre-payment of annual costs that start to be incurred on January 1.

c) Please provide all the data and calculations used to calculate the expense lead of -292.67 for annual prepaids shown in Table 11, including, but not limited to, the amount of the expense and the payment dates for each of the items noted on page 37.

NPEI Response

a) As noted in NPEI's response to IR#5 Board Staff-5, NPEI has corrected the prepaid expenses to include $27,915 of costs relating to NPEI's 2015 COS Application (i.e. 1/5 of the actual costs paid during the study period May 2014 to April 2015), instead of the $78,650 that was originally used (1/5 of the Board-approved amount). The revised amount of annual and 2015 COS prepaid expenses is $1,096,430 (See Table 11 in the updated Lead/Lag study).

The table below summarizes the amounts originally filed and as corrected.

Prepaid Expenses - Annual and 2015 COS		Original Table 11	Revised Table 11
Regulatory Expenses for 2015 COS Rate Application		78,650	27,915
LEAP		37,100	37,100
Insurance		283,556	283,556
Other annual Prepaid Expenses		747,859	747,859
Total Annual and 2015 COS Prepaids		1,147,164	1,096,430

Details are provided in Appendix C.

b) Confirmed. All prepaid expenses used in the analysis were paid between May 2014 and April 2015.

c) Details are provided in Appendix C.

17. Energy Probe-12-HST

Ref: Pages 38-39

a) Please confirm that payroll and benefits have not been included in the calculation of the HST lag days.

b) Please confirm that the negative weighted lead days shown in Table 12 indicate that NPEI receives its revenue on average 20.28 days before it has to submit it to Revenue Canada at the end of the following month. If this cannot be confirmed, please explain fully.

c) Please confirm that the negative weighted lead days shown in Table 13 indicate that NPEI has to pay the HST on these expenses on average 18.60 days prior to receiving credit for these payments when it remits the net HST balance owing to Revenue Canada at the end of the following month. If this cannot be confirmed, please explain fully.

NPEI Response

a) Confirmed, payroll and benefits have not been included in the calculation of the HST lag days.

b) NPEI has corrected the Lead/Lag Report to reflect a weighted lead of -10.45 days for HST on all sources of revenues subject to HST. This reflects the fact that NPEI receives the HST on average 10.45 days before NPEI remits the HST revenue to Revenue Canada.

For example a customer's service period is from September 1st to 30th. The bill date is October 16th and the due date is November 4th, NPEI will record the HST revenue in October and pay the HST to Revenue Canada on November 30th. The period from September 15th, which is the mid-point of the HST service period, to November 30th is 75 days. The revenue lag for sources of revenue from all customer classes is updated to 64.22 days. Therefore, for revenue from customers, NPEI receives the HST payment on average 64.22 - 75 = - 10.78 days prior to remitting the HST to Revenue Canada.

For revenue from other sources, the revenue lag is 114.17 days as shown in Table 7 of the Lead/Lag report in Appendix D. Therefore, NPEI receives the HST payment on revenue from other sources on average 39.17 days after the HST has been remitted to Revenue Canada (114.17 - 75 = 39.17).

The table below shows the calculation of the weighted average HST lead for all revenues subject to HST of -10.45 days.

HST Expense Lead - Revenues					
Revenue	Amount ($)	HST (13%)	Lead (Lag) Days	Weighting Factor	Weighted Lead (Days)
From All Customers	164,532,857	21,389,271	-10.78	99.33%	-10.71
From Other Sources	1,103,577	143,465	39.17	0.67%	0.26
Total	**165,636,435**	**21,532,737**	**28.39**	**100.00%**	**-10.45**

c) NPEI has corrected the Lead/Lag Report to reflect a weighted lead of 43.63 days for HST on all expenses subject to the HST ITC. This reflects the fact that NPEI pays the HST on average 43.63 days before NPEI receives the Input Tax Credit ("ITC") on its HST remittance.

For the IESO power bill; using an example, the power bill from September 1st to 30th is received by NPEI on October 15th and paid by NPEI on October 16th. The HST ITC for September's power bill is claimed on the November 30th remittance to Revenue Canada. The period from September 15th, which is the mid-point of the HST service period, to November 30th is 75 days. The period from September 15th, which is the mid-point of the HST service period, to October 16th when the HST is paid is 31 days. Therefore, in this example, NPEI pays the HST on the power bill 75 – 31 = 44 days prior to receiving the ITC on its HST remittance.

The weighted average of the HST expense lead for all components of the Cost of Power (i.e. IESO, Hydro One and Niagara West) is 43.58 days. Details are provided in the table below.

Vendor	Service Month	Payment Date	ITC Claim Date	# Days from Payment to Claim date	HST Amount	Weighting Factor	Weighted Lead days
IESO	May-14	6/13/2014	7/31/2014	48	1,226,174.64	7.2%	3.47
	Jun-14	7/16/2014	8/29/2014	44	1,444,808.24	8.5%	3.74
	Jul-14	8/18/2014	9/30/2014	43	1,441,752.11	8.5%	3.65
	Aug-14	9/16/2014	10/31/2014	45	1,522,938.31	9.0%	4.04
	Sep-14	10/16/2014	11/28/2014	43	1,340,720.95	7.9%	3.40
	Oct-14	11/17/2014	12/29/2014	42	1,341,922.14	7.9%	3.32
	Nov-14	12/15/2014	1/30/2015	46	1,206,218.23	7.1%	3.27
	Dec-14	1/16/2015	2/27/2015	42	1,429,249.60	8.4%	3.54
	Jan-15	2/17/2015	3/31/2015	42	1,317,395.25	7.8%	3.26
	Feb-15	4/17/2015	5/28/2015	41	1,374,674.93	8.1%	3.32
	Mar-15	3/16/2015	4/30/2015	45	1,528,197.42	9.0%	4.05
	Apr-15	5/15/2015	6/30/2015	46	1,404,821.13	8.3%	3.81
Hydro One	Mar-14	5/9/2014	6/30/2014	52	27,977.57	0.2%	0.09
	Apr-14	6/13/2014	7/31/2014	48	24,907.97	0.1%	0.07
	May-14	7/14/2014	8/29/2014	46	24,773.73	0.1%	0.07
	Jun-14	8/15/2014	9/30/2014	46	28,668.65	0.2%	0.08
	Jul-14	9/5/2014	9/30/2014	25	29,818.28	0.2%	0.04
	Aug-14	10/31/2014	11/28/2014	28	30,049.56	0.2%	0.05
	Sep-14	11/21/2014	12/29/2014	38	22,050.56	0.1%	0.05
	Oct-14	12/19/2014	1/30/2015	42	28,424.76	0.2%	0.07
	Nov-14	1/16/2015	1/30/2015	14	34,541.48	0.2%	0.03
	Dec-14	2/13/2015	3/31/2015	46	36,708.06	0.2%	0.10
	Jan-15	3/19/2015	3/31/2015	12	38,348.91	0.2%	0.03
	Feb-15	4/9/2015	4/30/2015	21	36,895.79	0.2%	0.05
NWTC	Mar-14	5/16/2014	5/31/2014	15	3,448.65	0.0%	0.00
	Apr-14	6/20/2014	6/30/2014	10	2,915.34	0.0%	0.00
	May-14	8/1/2014	7/31/2014	-1	3,009.60	0.0%	(0.00)
	Jun-14	8/22/2014	8/29/2014	7	3,317.07	0.0%	0.00
	Jul-14	9/19/2014	9/30/2014	11	3,488.70	0.0%	0.00
	Aug-14	10/17/2014	10/31/2014	14	3,120.93	0.0%	0.00
	Sep-14	11/28/2014	11/28/2014	0	2,870.54	0.0%	-
	Oct-14	1/2/2015	12/29/2014	-4	2,555.51	0.0%	(0.00)
	Nov-14	1/30/2015	1/30/2015	0	2,195.84	0.0%	-
	Dec-14	1/30/2015	1/30/2015	0	2,647.78	0.0%	-
	Jan-15	3/26/2015	3/31/2015	5	2,032.48	0.0%	0.00
	Feb-15	4/17/2015	4/30/2015	13	3,497.16	0.0%	0.00
					16,977,137.87	100.0%	43.58

For the HST lead on OM&A expenses, NPEI determined the number of days from the mid-point of each service month until the HST remittance date when the ITCs were claimed to determine the HST lead on OM&A for each month in the study period. These lead days were then weighted using the amount of OM&A by month that attracts HST. The weighted average of the HST expense lead for the OM&A is 44.77 days. Details are provided in the table below.

Service Month	# days in service month	Mid-point of service month	# days from end of service month to ITC claim date	Total Lead days	OM&A by month	HST	Weighting Factor	Weighted Lead days
May-14	31	15.5	30	45.50	541,709.65	70,422.25	9.62%	4.38
Jun-14	30	15	31	46.00	443,559.64	57,662.75	7.87%	3.62
Jul-14	31	15.5	29	44.50	434,272.61	56,455.44	7.71%	3.43
Aug-14	31	15.5	30	45.50	471,619.34	61,310.51	8.37%	3.81
Sep-14	30	15	31	46.00	517,670.87	67,297.21	9.19%	4.23
Oct-14	31	15.5	28	43.50	438,223.45	56,969.05	7.78%	3.38
Nov-14	30	15	29	44.00	471,960.71	61,354.89	8.38%	3.69
Dec-14	31	15.5	30	45.50	503,866.73	65,502.67	8.94%	4.07
Jan-15	31	15.5	27	42.50	348,471.64	45,301.31	6.19%	2.63
Feb-15	28	14	31	45.00	380,819.00	49,506.47	6.76%	3.04
Mar-15	31	15.5	30	45.50	541,284.35	70,366.97	9.61%	4.37
Apr-15	30	15	28	43.00	539,953.67	70,193.98	9.58%	4.12
					5,633,411.66	732,343.52	100.00%	44.77

NPEI notes that the OM&A expense by month in the table above includes prepaid expenses. The HST on prepaid expenses is paid when the invoice is received, not when the expense is recognized. However, NPEI assumes in the table above that the amount of prepaid expense recognized each month is fairly consistent, and therefore excluding prepaid expenses from the OM&A by month would not significantly impact the weighting factors.

Using an HST lead on Cost of Power of 43.58 days and an HST lead on OM&A of 44.77 days results in a weighted average lead on Cost of Power and OM&A of 43.63 days, as shown in the table below.

	Rate Application	HST %	Test Year HST	HST Lead Time	HST Lead	HST working Capital
Cost of Power	144,149,669	13.0%	18,739,457	43.58	11.94%	2,237,634
OM&A	5,844,020	13.0%	759,723	44.77	12.27%	93,182
HST (Expenses)			19,499,180	43.63	11.95%	2,330,815

Please see Table 12 in the updated lead/lag report in Appendix D.

18. Energy Probe-13-reconcile Table 12 to Table 7

Ref: Pages 33 & 39

Please explain why the Amounts shown in Table 12 do not match the Amounts shown in Table 7.

NPEI Response

Table 12 used the test year revenue to calculate the HST and to calculate the Weighted Lead Days. NPEI should have used the revenues from Table 7 to calculate the Weighted Lead days and applied this number of days to the Test year HST. Please see the Table updated below. Note of the $1,746,806.98 of revenue from other sources only $1,103,577 attracts HST. Bank Interest revenue, revenues from non-payment of account-late payment charges on hydro sales and apprenticeship tax credit revenues are excluded.

HST Expense Lead - Revenues					
Revenue	Amount ($)	HST (13%)	Lead (Lag) Days	Weighting Factor	Weighted Lead (Days)
From All Customers	164,532,857	21,389,271	-10.78	99.33%	-10.71
From Other Sources	1,103,577	143,465	39.17	0.67%	0.26
Total	**165,636,435**	**21,532,737**	**28.39**	**100.00%**	**-10.45**

19. Energy Probe-14-HST on receivables

Ref: Page 40

a) Please explain why the HST associated with receivables results in an increase in the working capital allowance for NPEI.

b) Has Elenchus reviewed other lead lag studies, and if so, is it aware of any other electricity distributors in Ontario where the HST on receivables increases the working capital allowance?
c) Why is the HST receivables which is based on revenues received, shown as expense in Table 14? In other words, shouldn't the receivables amount of $22,603,800 be shown as a negative number since it is a revenue and not an expense?

NPEI Response

a) The HST associated with receivables should be a negative value in the calculation of WCA. See NPEI's response to IR#17 – Energy Probe 12 a).
b) Elenchus has reviewed other lead lag studies and there was an error in the model which has been corrected.
c) Yes the $22,603,800 has been updated to be shown as a negative number. The sign on the Expense Lead Days was backwards in the model.

20. Energy Probe-15-Authors and experience

Ref: Appendix A

a) Please provide the CV's associated with the author(s) of the Elenchus lead lag study.
b) For each author, please indicate their relevant experience in preparing lead lag studies, including any testimony provided in front of regulatory agencies.

NPEI Response

a) Attached are the CVs for Andrew Frank and Michael Roger. Please see Appendix K.

b) Both Andrew and Michael prepared the lead lag study filed with the Ontario Energy Board by Veridian Connections Inc. in proceeding EB-2013-0174.

LRAMVA

21. OEB Board Staff-IR#6-LRAMVA-CDM savings reference 2011 COS

Ref: LRAMVA Application, page 7

On Table 2, NPEI shows the CDM savings for each class that were assumed in the load forecast for its 2011 cost of service application. Please provide an evidentiary reference from NPEI's cost of service application that confirms the amounts summarized in Table 2.

NPEI Response

The total CDM energy savings of 5.8 million kWh assumed in the load forecast in NPEI's 2011 COS Application (EB-2010-0138) can be found in *the Decision on Partial Settlement and Procedural Order No. 3* dated May 16, 2011 (See Issue 3.1 of the Approved Partial Settlement Agreement, page 18 of 102). The evidence in NPEI's 2011 COS Application does not include a breakdown of the 5.8 million kWh by rate class.

In order to determine the allocation by rate class, NPEI increased the total 2011 billed consumption in the 2011 load forecasting model by 5.8 million kWh. The table below shows the resulting differences in billed consumption by rate class as allocated in the load forecasting model.

	2011 Rate Application as Approved	2011 with CDM Baseline of 5.8 GWh Added Back	Difference
Billed kWh	1,223,308,130	1,229,108,130	5,800,000
By Class			
Residential			
Customers	46,900	46,900	
kWh	462,790,265	465,082,407	2,292,141
GS<50			
Customers	4,352	4,352	
kWh	122,331,880	122,937,775	605,894
GS>50			
Customers	848	848	
kWh	628,090,148	630,992,113	2,901,964
kW	1,818,411	1,826,812	8,402
Large User			
Customers	0	0	0
kWh	0	0	0
kW	0	0	0
Sentinels			
Connections	560	560	
kWh	292,817	292,817	0
kW	809	809	0
Streetlights			
Connections	12,408	12,408	
kWh	7,467,591	7,467,591	0
kW	20,107	20,107	0
USL			
Connections	465	465	
kWh	2,335,428	2,335,428	0
Total of Above			
Customer/Connections	65,533	65,533	
kWh	1,223,308,130	1,229,108,130	5,800,000
kW from applicable classes	1,839,327	1,847,729	8,402
Total from Model			
Customer/Connections	65,533	65,533	
kWh	1,223,308,130	1,229,108,130	5,800,000
kW from applicable classes	1,839,327	1,847,729	8,402
Check should all be zero			
Customer/Connections	0	0	0
kWh	0	0	0
kW from applicable classes	0	0	0

22. OEB Board Staff-IR#7-LRAMVA-reconciliation of total annual savings

Ref: LRAMVA Application, pages 33 – 51

OEB staff is unable to reconcile the total annual savings shown in the bottom row of Table A, including adjustments, with the annual savings shown in Table C.

a) Please explain how NPEI translated the kW and kWh savings in Table A in to the "Current year load losses" amounts shown per class in table C.
b) As an example, please provide a derivation showing the steps that were used to calculate the total 4,421,324 kWh savings for 2012.

NPEI Response

a) The kW and kWh values by program in Tables A-1 to A-6 were multiplied by the appropriate rate class allocations in Tables B-1 to B-4 to calculate the load impact values for each program in Tables B-6 to B-9. The "current year load losses in Table C-2 are the sum of the load impacts by rate class for each year found at the bottom of Tables B-6 to B-9.

b) The total 2012 current year load losses of 4,421,324 is the sum of the 1,969,867 kWh for the Residential rate class, the 2,427,588 kWh for the GS < 50 kW rate class, and the 23,869 kW for the GS 50 to 4,999 kW rate class. We recognize now that there should not be a sum of these kWh and kW values shown, given that the units are not commensurate; that sum is not carried forward into any calculations.

   The 1,969,867 kWh for the Residential rate class is the total of the load losses for all programs with CDM impacts in that rate class found in Table B-7 and the same is true for the other rate classes. The load loss values for each program are the product of the sum of the persistence of 2011 results in 2012 found in Table A-1, the 2012 results found in Table A-2, and the persistence of 2011 adjustments in 2012 found in Table A-4 multiplied by the allocation of 2012 CDM program impacts by rate class found in Table B-2.

   In response to IR# 24 OEB Board Staff-9, IndEco has prepared a sample set of calculations of the 2012 CDM impact on load for the Residential rate class to demonstrate the calculation methodology.

23. OEB Board Staff-IR#8-LRAMVA-% Allocators in Retrofit program

Ref: LRAMVA Application, pages 41 - 43

OEB staff notes that the percentage allocators for all applicable classes participating in the Retrofit initiative of the Business Program category do not sum to 100%. The allocators sum to 99% in 2011 and 2012, 114% in 2013, and 105% in 2014.

a) Please explain why the allocators do not add up to 100% for the Retrofit initiative.
b) Please explain how the final savings are allocated between the classes when the allocators sum to a value greater than 100%.

NPEI Response

a) Rate class allocation percentage totals may not add up to 100% in cases were kWh savings are allocated to rate classes billed by kWh and kW demand reductions are allocated to rate classes billed by kW. This allocation methodology was used for the Retrofit Program.

b) The total kWh results for the Retrofit initiative in a given year were multiplied by the percentage allocations for rate classes billed by kWh, because the allocation percentages for rate classes billed by kWh were calculated based on kWh energy savings. The total kW results for the Retrofit initiative in a given year were multiplied by the percentage allocation for the rate class billed by kW, because the allocation percentages for the rate class billed by kW was calculated based on kW demand reduction.

24. OEB Board Staff-IR#9-LRAMVA-Live Excel version

Please provide a live Excel version of the model used to perform the calculations shown in Tables A, B and C of the IndEco report. If errors were identified in the review of interrogatories, please reflect any changes in the model that is provided.

NPEI Response

The model used to perform the calculations is a proprietary model developed by IndEco. The tables and descriptions in the report provide a traceable description of how the results were derived. IndEco has prepared a sample set of calculations of the CDM impact on load for the Residential rate class in 2012 to demonstrate the calculation methodology. See Appendix L.

25. VECC-1-Demand Response 3 program

Ref: Application Page 7 of 59

NPEI states "As indicated in the IndEco Report (Attachment A, page 3), NPEI's CDM results as provided by the OPA include the calculation of demand reduction due to the Demand Response 3 ("DR3") program in a manner that is consistent with other recent LRAMVA dispositions applications, which have been accepted by the Board."

Ref: **IndEco Report Page 3**

IndEco states "In the case of demand response programs, in particular Demand Response 3 (DR3), the demand reduction may only apply to certain months in the year. These considerations have been factored into the lost revenue calculations.

There have been arguments advanced around the uncertainty regarding the impact of DR3 program results on LDC revenues. However, the OEB has considered these arguments and has been consistent in recent rate cases in ruling that the IESO's analyses with respect to CDM results may be used to estimate lost revenues, including those related to DR3 programs."

a) With respect to Demand Response 3 programs, please explain how "the demand reduction may only apply to certain months in the year" has been determined and factored into the lost revenue calculations".

b) Please provide and explain IndEco's previous position (prior to the PowerStream Decision EB-2014-0108) on the treatment of Demand Response 3 programs and provide the resulting impact on Demand Response 3 lost revenue calculations.

c) Please confirm that the kW savings values reported for the Demand Response 3 program are contracted values and not actual demand reductions in each year.

d) Does NPEI have any record as to how much actual demand reduction was achieved in each year due to the Demand Response 3 program? If so, how much was the actual demand reduction in each year and was the demand reduction coincident with the peak interval used to establish the customers' billing demands?

e) If No to (d), does NPEI have the ability to track how much actual demand reduction was achieved in each year due to the Demand Response 3 program and if the demand reduction was coincident with the peak interval used to establish the customers' billing demands.

NPEI Response

a) For DR 3, the kW values provided by the IESO were multiplied by 3, based on the methodology used in PowerStream's 2015 rate decision, EB-2014-0108, that was approved by the Board.

b) IndEco's previous position on the treatment of Demand Response 3 in lost revenue calculations was:
"For other programs, in particular demand response programs, the customer's monthly peak may not correspond to the system's peak. Further, even if they are coincident, if a demand response event is called, and the customer's monthly peak is shaved, it is likely that the customer's second highest peak in the month is only slightly less than their highest peak. Thus, the impact on distribution revenues of the demand response program is likely to be minimal, and is assumed to have zero impact on lost load.

Thus, no distribution revenues are estimated to be lost from large general service customers' participation in demand response programs." (North Bay Hydro 2015 COS application EB-2014-0099, Exhibit 3)

Eliminating the impact of DR 3 programs in the lost revenue calculations would reduce the total lost revenue value from $467,812.35 to $449,749.65 and the carrying charges from $14,991.84 to $14,330.29.

c) The IESO reported kW values for DR 3 in the 2011-2014 final results report 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."

d) Due to contractual privacy agreements between the IESO and the DR 3 participants, NPEI is not informed of the actual demand reductions from the program in NPEI's service territory in each year.

e) NPEI is not able to track the actual demand reduction from the DR 3 program.

26. VECC-2-Bill Impacts

a) Please provide bill impacts for each rate class that combine the impacts of EB-2015-0090 and EB-2015-0328, (including residential consumption at the lowest 10th percentile), and include the removal of the Debt Retirement Charge in 2016, the removal of the Ontario Clean Energy

Benefit in 2016 and the addition of the Ontario Energy Support Program (OESP) starting January 1, 2016 that will be funded by all electricity ratepayers.

NPEI Response

NPEI has included in Appendix M the following updated models resulting from the update to WCA of 12.61%;

1. RRWF
2. PILS
3. Cost Allocation- Sheet I5.1-Misc Data, O1 Revenue to Cost & O2 Fixed Charge|Floor|Ceiling
4. Revenue-to-cost ratios table
5. Fixed versus variable split rate design and updated rates

The excel models for the RRWF, PILS, and Cost Allocation were uploaded in the e-filing service.

Sheet 15. Rev2Cost_GDPIPI of the 2016_IRM_RateGen_Model_version1.0 updated for 12.61% WCA and Bill Impacts are provided in Appendix N.

Appendix A – Revenue-to-Cost Ratios In Settlement Agreement

The following table provides the agreed upon revenue-to-cost ratios, which includes moving the GS>50 kW class to 120% in the 2015 Test Year, and bringing all of the classes that are below 100% up to the same percentage, 91.65%.

Revenue-to-Cost Ratios

Class	Previously Approved Ratios Most Recent Year 2014	Status Quo Ratios	2015 Proposed Ratios	Policy Range
	%	%	%	%
Residential	85.00	80.65	91.65	85 - 115
GS < 50 kW	109.09	120.11	120.00	80 - 120
GS > 50 kW	145.83	161.63	120.00	80 - 120
Street Lighting	70.00	87.23	91.65	70 - 120
Sentinel Lighting	70.00	70.99	91.65	80 - 120
Unmetered Scattered Load (USL)	101.51	119.83	119.83	80 - 120

Evidence: Cost Allocation	
Application:	E1/T2/S10, E7/T1/S1, E7/T1/S2, E7/T1/S4, E7/T1/S3
Interrogatories:	IRR#16-SEC#6, IRR#17-SEC#7, IRR#96-3-VECC-13, IRR#149-7-Staff-43, IRR#150-7-Staff-44, IRR#152-7-Energy Probe-38, IRR#153-7-Energy Probe-39, IRR#154-7-VECC-41, IRR#156-7-VECC-43, IRR#157-7-VECC-44, IRR#158-7-VECC-45, 7-Energy Probe-59TC, 2-VECC-55TC
Undertakings:	JT1.8, JT1.15
Transcript:	• Page 67 line 16 to page 67 line 27 • Page 81 line 14 to page 84 line 3 • Page 87 line 25 to page 88 line 16
Appendices:	Appendix 3.2-A Cost Allocation Model (in Excel) OEB Appendix 2-P
Supporting Parties:	NPEI, Energy Probe, SEC, VECC
Opposing Parties:	None

Appendix B – NPEI Decision and Order Findings

Fixed Variable Split for the Residential Class

proposed to recover 65% of revenues from the fixed monthly service charge and 35% from the variable charge from energy consumed.

After the oral hearing, NPEI revised its proposal from 65%-35% to the current fixed-variable rate split of 58%-42% based on an analysis filed as an undertaking response. Energy Probe, VECC and SEC supported the revised proposal. OEB staff did not oppose the revised proposal, but noted that OEB policy is moving in the direction of increasing fixed charges among the residential class.[2]

Findings

The Board finds it appropriate to maintain the current fixed-variable rate split for the residential customer class. The Board directs NPEI to maintain the current 58%-42% fixed-variable split pending any new policies issued by the OEB regarding distribution rate design for residential customers.

NPEI indicated that it had not sought customer feedback regarding its original proposal to change the residential fixed-variable rate split. In response to questions from the Board during the oral hearing, NPEI clarified that its consumer engagement evidence included a customer survey, yet the survey was conducted before the Application was prepared. The Board would find it useful if customer engagement activities encompassed any proposed changes included in an application, especially changes directly affecting customers.

Working Capital Allowance

The working capital allowance (WCA), is the cash required by the utility because of the time lag between when money is spent to provide distribution services and when money is received in payment for those services from customers.

In its Application, NPEI requested a 13% WCA of eligible controllable expenses, taxes and the cost of power. NPEI submitted that 13% was consistent with the OEB's Filing Requirements.[3] The 13% WCA proposal resulted in $20.8 million being added to rate base.

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[2] In the time since the OEB staff submission, the policy has been confirmed in *EB-2012-0410, A New Distribution Rate Design for Residential Electricity Customers, issued April 2, 2015*
[3] Filing Requirements For Electricity Distribution Rate Applications - 2014 Edition for 2015 Rates Applications

Appendix C – Annual Prepaids

Annual Prepaid Expenses

Invoice Date	Amount	Vendor Name	Description	Cheque Date	Start Date	End Date	Service Period	Service Lead	Payment Lead	Total Lead	Weight Factor %	Weighted Lead (Days)	Weighted Service Lead	Weighted Payment Lead
6/30/2014	165.66	GEOTRUST	Sync email-phone yrly SSL cert	8/15/14	6/1/2014	5/31/2015	365	182.50	-289	(106.50)	0.01%	(0.01)	0.03	(0.04)
1/21/2015	195.00	WEST LINCOLN CHAMBER COMMERCE	2015 membership dues	1/23/15	1/1/2015	12/31/2015	365	182.50	-342	(159.50)	0.02%	(0.03)	0.03	(0.06)
11/30/2014	200.00	Niagara Falls Tourism	GeneralMembershipNov'14/Oct'15	12/19/14	11/1/2014	10/31/2015	365	182.50	-316	(133.50)	0.02%	(0.02)	0.03	(0.05)
1/29/2015	462.00	JBM Office Systems LTD	WL-Annual Mail Machine mtnce	1/30/15	3/1/2015	2/28/2016	365	182.50	-394	(211.50)	0.04%	(0.08)	0.07	(0.15)
7/17/2014	475.00	Employers' Advocacy Council	2014 fees	7/18/14	5/1/2014	4/30/2015	365	182.50	-286	(103.50)	0.04%	(0.04)	0.07	(0.11)
3/4/2015	475.00	Employers' Advocacy Council	2015Membership Fee	3/6/15	5/1/2015	4/30/2016	366	183.00	-421	(238.00)	0.04%	(0.09)	0.07	(0.17)
2/23/2015	535.00	LINCOLN CHAMBER OF COMMERCE	2015 Membership dues	3/13/15	1/1/2015	12/31/2015	365	182.50	-293	(110.50)	0.04%	(0.05)	0.08	(0.13)
7/31/2014	664.50	SolarWinds Inc.	ipMonitor-yr Renewal	9/12/14	9/1/2014	8/31/2015	365	182.50	-353	(170.50)	0.06%	(0.09)	0.10	(0.19)
5/14/2014	725.00	GEMSYS Money Handling Systems Inc.	Yrly chq encoder mtnce	5/16/14	4/1/2014	3/31/2015	365	182.50	-319	(136.50)	0.06%	(0.08)	0.11	(0.19)
4/24/2015	725.00	GEMSYS Money Handling Systems Inc.	Yrly support fee:Apr-Mar	4/30/15	4/1/2015	3/31/2016	366	183.00	-336	(153.00)	0.06%	(0.09)	0.11	(0.20)
7/31/2014	793.35	CLEO Communications	VLSR VL Trader Renwal gold	9/12/14	8/1/2014	7/31/2015	365	182.50	-322	(139.50)	0.07%	(0.09)	0.12	(0.21)
10/31/2014	871.46	NEOPOST	Contract Dec'14-Dec'15	11/28/14	12/1/2014	11/30/2015	365	182.50	-367	(184.50)	0.07%	(0.13)	0.13	(0.26)
11/19/2014	930.00	Greater Niagara Chamber of Commerce	2015 member fees	11/21/14	12/1/2014	11/30/2015	365	182.50	-374	(191.50)	0.08%	(0.15)	0.14	(0.29)
1/7/2015	948.00	The Chamber of Comm. NF, CA	2015 membership dues	1/9/15	1/1/2015	12/31/2015	365	182.50	-356	(173.50)	0.08%	(0.14)	0.14	(0.28)
1/31/2015	950.00	Greater Niagara Chamber of Commerce	2014-2015BusinessDirectoryAd	2/6/15	1/1/2015	12/31/2015	365	182.50	-328	(145.50)	0.08%	(0.11)	0.14	(0.26)
3/30/2015	951.90	Orkin Canada Corporation	NF-Mar pest control	4/1/15	6/1/2015	5/31/2016	366	183.00	-426	(243.00)	0.08%	(0.19)	0.14	(0.34)
1/31/2015	995.00	The Canadian Public Relations Society, Inc.	2015 CPRS membership- Forcier	2/13/15	1/1/2015	12/31/2015	365	182.50	-321	(138.50)	0.08%	(0.11)	0.15	(0.26)
12/19/2014	1,397.25	SkyComp	Programming	1/2/15	12/1/2014	11/30/2015	365	182.50	-332	(149.50)	0.12%	(0.17)	0.21	(0.38)
1/7/2015	1,500.00	Cansel	2015 mapping subscription	1/9/15	1/1/2015	12/31/2015	365	182.50	-356	(173.50)	0.12%	(0.22)	0.23	(0.44)
6/4/2014	1,500.00	Canadian Distributer for ALLDATA	1yr sub.-Jun/14-may/15	6/13/14	6/1/2014	5/31/2015	365	182.50	-352	(169.50)	0.12%	(0.21)	0.23	(0.44)
2/28/2015	1,536.02	CDW Canada Inc.	Programming	3/26/15	5/1/2015	4/30/2016	366	183.00	-401	(218.00)	0.13%	(0.28)	0.23	(0.51)
9/18/2014	1,540.77	ITbrotherhood.com	ITbrotherhood-WMware yrly mtnc	9/19/14	11/16/2014	11/15/2015	365	182.50	-422	(239.50)	0.13%	(0.31)	0.23	(0.54)
1/7/2015	1,655.58	Pitney Bowes	2015 DM800 Config	1/9/15	1/1/2015	12/31/2015	365	182.50	-356	(173.50)	0.14%	(0.24)	0.25	(0.49)
12/19/2014	1,673.46	BELL CANADA	Programming	12/19/14	12/1/2014	11/30/2015	365	182.50	-346	(163.50)	0.14%	(0.23)	0.25	(0.48)
8/31/2014	1,679.28	Fire Monitoring of Canada Inc.	Stn17 Fire monitor sep14-aug15	9/5/14	9/1/2014	8/31/2015	365	182.50	-360	(177.50)	0.14%	(0.25)	0.25	(0.50)
12/31/2014	1,798.00	Care Pack Sales	Yrly Post Warranty Service	2/13/15	1/1/2015	12/31/2015	365	182.50	-321	(138.50)	0.15%	(0.21)	0.27	(0.48)
7/25/2014	1,981.20	Fire Monitoring of Canada Inc.	WL-Fire Mointor Aug/14-Jul/15	8/1/14	8/1/2014	7/31/2015	365	182.50	-364	(181.50)	0.16%	(0.30)	0.30	(0.60)
10/31/2014	2,280.00	Northrop Grumman - CIS	Versaprobe warrenty 1yr	11/21/14	1/1/2015	12/31/2015	365	182.50	-405	(222.50)	0.19%	(0.42)	0.34	(0.76)
4/15/2015	2,286.90	ITbrotherhood.com	Dell Poweredge yrly support	4/17/15	5/1/2015	4/30/2016	366	183.00	-379	(196.00)	0.19%	(0.37)	0.35	(0.72)
4/15/2015	2,286.90	ITbrotherhood.com	Pwr edge-yr warranty extension	4/17/15	5/1/2015	4/30/2016	366	183.00	-379	(196.00)	0.19%	(0.37)	0.35	(0.72)
9/30/2014	2,465.00	ITbrotherhood.com	Sep 14-Sep 15 server mtnce	10/3/14	10/1/2014	9/30/2015	365	182.50	-362	(179.50)	0.20%	(0.37)	0.37	(0.74)
1/7/2015	2,678.00	ITbrotherhood.com	2015 Power vault support	1/9/15	12/1/2014	11/30/2015	365	182.50	-325	(142.50)	0.22%	(0.32)	0.40	(0.72)
9/22/2014	2,690.00	ITbrotherhood.com	HydroNexus warranty 9/14-9/15	10/3/14	9/1/2014	8/31/2015	365	182.50	-332	(149.50)	0.22%	(0.33)	0.41	(0.74)
7/31/2014	3,030.83	Forsythe International, Inc.	Programming	8/29/14	7/1/2014	6/30/2015	365	182.50	-305	(122.50)	0.25%	(0.31)	0.46	(0.77)
3/31/2015	3,044.00	Receiver General for Canada	Yrly radio License Apr15-Mar16	5/15/15	4/1/2015	3/31/2016	366	183.00	-321	(138.00)	0.25%	(0.35)	0.46	(0.81)
10/27/2014	3,449.19	Association of Energy Services Professionals	Nov'14-Nov'15 Bronze level mem	11/14/14	11/1/2014	10/31/2015	365	182.50	-351	(168.50)	0.29%	(0.48)	0.52	(1.00)
3/31/2015	3,689.28	CDW Canada Inc.	Programming	4/17/15	5/1/2015	4/30/2016	366	183.00	-379	(196.00)	0.31%	(0.60)	0.56	(1.16)
9/10/2014	3,816.88	CDW Canada Inc.	Programming	9/19/14	10/1/2014	9/30/2015	365	182.50	-376	(193.50)	0.32%	(0.61)	0.58	(1.19)
3/17/2015	3,868.76	ITbrotherhood.com	ND & PowerEdge 3/15-3/16	3/19/15	4/1/2015	3/31/2016	366	183.00	-378	(195.00)	0.32%	(0.62)	0.59	(1.21)
12/31/2014	3,945.75	Essex Energy Corporation	2015 DESS user mtnce	1/30/15	1/1/2015	12/31/2015	365	182.50	-335	(152.50)	0.33%	(0.50)	0.60	(1.09)
10/31/2014	4,966.87	Oracle Canada ULC	Programming	11/21/14	12/1/2014	11/30/2015	365	182.50	-374	(191.50)	0.41%	(0.79)	0.75	(1.54)
2/4/2015	5,400.00	SilverBlaze Solutions Inc.	2015Apollo WE Software Renewal	2/6/15	4/1/2015	3/31/2016	366	183.00	-419	(236.00)	0.45%	(1.05)	0.82	(1.87)
6/23/2014	6,000.00	Erth Business Technologies Inc	Yrly Hub mtnce:May/14-Apr/15	7/4/14	5/1/2014	4/30/2015	365	182.50	-300	(117.50)	0.50%	(0.58)	0.91	(1.49)
7/23/2014	6,311.36	Forsythe International, Inc.	Programming	8/8/14	8/1/2014	7/31/2015	365	182.50	-357	(174.50)	0.52%	(0.91)	0.95	(1.87)
12/19/2014	6,704.93	BELL CANADA	Programming	12/19/14	12/1/2014	11/30/2015	365	182.50	-346	(163.50)	0.56%	(0.91)	1.01	(1.92)
10/28/2014	6,880.00	ITbrotherhood.com	Programming	10/31/14	12/1/2014	9/30/2015	304	152.00	-334	(182.00)	0.57%	(1.04)	0.87	(1.90)
10/23/2014	7,770.00	Eaton Power Quality Company	Pwrware Oct/14-Sept/15	12/12/14	10/1/2014	9/30/2015	365	182.50	-292	(109.50)	0.64%	(0.70)	1.17	(1.88)
3/24/2015	8,142.00	Receiver General for Canada	2015 Radio Authorization	3/24/15	4/1/2015	3/31/2016	366	183.00	-373	(190.00)	0.67%	(1.28)	1.23	(2.51)
12/17/2014	8,900.00	Utilities Standards Forum	2015 Membership fee	12/19/14	1/1/2015	12/31/2015	365	182.50	-377	(194.50)	0.74%	(1.43)	1.34	(2.78)
9/10/2014	9,020.00	AEGISYS ONT CORP 1468625	2014 Maintenance contract	10/3/14	10/1/2014	9/30/2015	365	182.50	-362	(179.50)	0.75%	(1.34)	1.36	(2.70)
10/30/2014	9,477.00	Storage Clarity	Programming	10/31/14	8/1/2014	7/31/2015	365	182.50	-273	(90.50)	0.78%	(0.71)	1.43	(2.14)
6/24/2014	10,000.00	Burlington Electricity Services Inc	Yrly GridSmart membership	6/27/14	7/1/2014	6/30/2015	365	182.50	-368	(185.50)	0.83%	(1.54)	1.51	(3.05)
2/17/2015	11,376.00	Supremex Inc.	Envelopes	3/6/15	2/1/2015	10/31/2015	273	136.50	-239	(102.50)	0.94%	(0.97)	1.29	(2.25)
6/24/2014	12,378.40	IBM Canada Ltd	Programming	6/27/14	8/1/2014	7/31/2015	365	182.50	-399	(216.50)	1.02%	(2.22)	1.87	(4.09)
4/8/2015	12,500.00	Harris Computer Systems	NS Core Automation Bundle	4/9/15	3/1/2015	12/31/2015	306	153.00	-266	(113.00)	1.03%	(1.17)	1.58	(2.75)
10/28/2014	12,507.00	ITbrotherhood.com	Programming	11/7/14	10/1/2014	5/31/2015	243	121.50	-205	(83.50)	1.04%	(0.86)	1.26	(2.12)
10/8/2014	15,875.64	Tele-works Inc.	yrly support-Dec/14-Nov/15	11/30/14	12/1/2014	11/30/2015	365	182.50	-365	(182.50)	1.31%	(2.40)	2.40	(4.80)
4/29/2015	17,172.00	Emerson/Liebert	Programming	4/30/15	4/1/2015	3/31/2016	366	183.00	-336	(153.00)	1.42%	(2.17)	2.60	(4.78)
5/30/2014	18,883.80	BDO Canada LLP	GP Business Ready 1yr	5/30/14	8/1/2014	7/31/2015	365	182.50	-427	(244.50)	1.56%	(3.82)	2.85	(6.67)
1/31/2015	25,006.80	Electric Safety Authority	2015 Regulatory Oversight Cost	2/20/15	1/1/2015	12/31/2015	365	182.50	-314	(131.50)	2.07%	(2.72)	3.78	(6.50)
12/3/2014	26,955.02	Harris Computer Systems	2015 Metersense Support	12/5/14	1/1/2015	12/31/2015	365	182.50	-391	(208.50)	2.23%	(4.65)	4.07	(8.72)
4/1/2015	30,265.60	BELL CANADA	Programming	4/1/15	4/1/2015	3/31/2016	366	183.00	-365	(182.00)	2.51%	(4.56)	4.58	(9.14)
4/14/2015	59,551.41	IESO	LC Fee	4/14/15	4/14/2015	4/13/2016	366	183.00	-365	(182.00)	4.93%	(8.97)	9.02	(17.99)
11/17/2014	77,100.00	Electricity Distributors Assoc.	LDC Membership Jan/15-Dec/15	11/21/14	1/1/2015	12/31/2015	365	182.50	-405	(222.50)	6.38%	(14.20)	11.65	(25.85)
12/3/2014	123,778.69	Harris Computer Systems	2015 Mtnce Support	12/5/14	1/1/2015	12/31/2015	365	182.50	-391	(208.50)	10.25%	(21.36)	18.70	(40.06)
3/31/2015	148,081.20	Intergraph Canada Ltd.	G/technology 5/01/15-4/30/16	4/9/15	5/1/2015	4/30/2016	366	183.00	-387	(204.00)	12.26%	(25.01)	22.43	(47.44)
	747,858.64													

5/20/2014	1,890.00	Aird & Berlis LLP	2015 Cost of Service Rate App	5/23/14	6/1/2015	4/30/2020	1796	898	-2169	(1,271.00)	0.16%	(1.99)	1.40	(3.39)
6/30/2014	15,000.00	Kinectrics Inc.	Rate App	7/25/14	6/1/2015	4/30/2020	1796	898	-2106	(1,208.00)	1.24%	(15.00)	11.15	(26.15)
6/30/2014	54.00	Aird & Berlis LLP	Jun serv- 2015 Rate ap	7/25/14	[illegible]	4/30/2020	1796	898	-2106	(1,208.00)	0.00%	(0.05)	0.04	(0.09)

Annual Prepaid Expenses

Invoice Date	Amount	Vendor Name	Description	Cheque Date	Start Date	End Date	Service Period	Service Lead	Payment Lead	Total Lead	Weight Factor %	Weighted Lead (Days)	Weighted Service Lead	Weighted Payment Lead
6/18/2014	1,728.00	Aird & Berlis LLP	Legal Fees for 2015 Rate App	6/20/14	6/1/2015	4/30/2020	1796	898	-2141	(1,243.00)	0.14%	(1.78)	1.28	(3.06)
8/21/2014	1,613.50	Aird & Berlis LLP	Prof.serv.-2015 COS rate appl	8/22/14	6/1/2015	4/30/2020	1796	898	-2078	(1,180.00)	0.13%	(1.58)	1.20	(2.78)
9/30/2014	10,000.00	Kinectrics Inc.	Rate App	8/29/14	6/1/2015	4/30/2020	1796	898	-2071	(1,173.00)	0.83%	(9.71)	7.43	(17.14)
9/30/2014	8,036.93	Aird & Berlis LLP	Aird&Berlis: 2015 COS Appl.	10/3/14	6/1/2015	4/30/2020	1796	898	-2036	(1,138.00)	0.67%	(7.57)	5.97	(13.54)
9/30/2014	25,000.00	Kinectrics Inc.	Rate App	11/28/14	6/1/2015	4/30/2020	1796	898	-1980	(1,082.00)	2.07%	(22.39)	18.58	(40.97)
10/31/2014	5,687.09	Aird & Berlis LLP	Sep- 2015 Cost of Service Ap	11/14/14	6/1/2015	4/30/2020	1796	898	-1994	(1,096.00)	0.47%	(5.16)	4.23	(9.39)
11/19/2014	503.00	Aird & Berlis LLP	Oct services	11/21/14	6/1/2015	4/30/2020	1796	898	-1987	(1,089.00)	0.04%	(0.45)	0.37	(0.83)
11/28/2014	25,000.00	Kinectrics Inc.	Rate App	11/28/14	6/1/2015	4/30/2020	1796	898	-1980	(1,082.00)	2.07%	(22.39)	18.58	(40.97)
12/31/2014	5,628.89	Aird & Berlis LLP	2015 Cost of Serv Rate Ap	1/23/15	6/1/2015	4/30/2020	1796	898	-1924	(1,026.00)	0.47%	(4.78)	4.18	(8.96)
2/28/2015	12,534.43	Aird & Berlis LLP	Aird&Berlis-2015 COS rate app	3/12/15	6/1/2015	4/30/2020	1796	898	-1876	(978.00)	1.04%	(10.15)	9.32	(19.46)
3/30/2015	15,435.65	Aird & Berlis LLP	2015 Cost of Service Rate	4/1/15	6/1/2015	4/30/2020	1796	898	-1856	(958.00)	1.28%	(12.24)	11.47	(23.71)
3/31/2015	11,464.79	Aird & Berlis LLP	2015 Cost of Service rate app	4/22/15	6/1/2015	4/30/2020	1796	898	-1835	(937.00)	0.95%	(8.89)	8.52	(17.41)
	139,576.28													
1/7/2015	37,100.00	Project Share	2015 LEAP	1/9/15	1/1/2015	12/31/2015	365	182.5	-356	(173.50)	3.07%	(5.33)	5.60	(10.93)
	37,100.00													
11/30/2014	191,742.73	The MEARIE Group	2014 Insurance Premiums	12/5/14	1/1/2015	12/31/2015	365	182.50	-391	(208.50)	15.87%	(33.09)	28.97	(62.06)
1/9/2015	25,014.96	Olsen-Sottile Insurance Brokers Inc	2015 Boiler&Machine 9150388612	1/9/15	1/1/2015	12/31/2015	365	182.50	-356	(173.50)	2.07%	(3.59)	3.78	(7.37)
1/9/2015	61,914.24	Olsen-Sottile Insurance Brokers Inc	2015 Commercial- FC33769	1/9/15	1/1/2015	12/31/2015	365	182.50	-356	(173.50)	5.12%	(8.89)	9.35	(18.24)
1/9/2015	4,883.76	Olsen-Sottile Insurance Brokers Inc	2015Crime/Brd Accident CP98211	1/9/15	1/1/2015	12/31/2015	365	182.50	-356	(173.50)	0.40%	(0.70)	0.74	(1.44)
	283,555.69													
	1,208,090.61										100.00%	(292.67)	263.74	(556.41)

Appendix D – Updated Lead/Lag Report

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Working Capital Requirement

A Report Prepared by
Elenchus Research Associates Inc.

On Behalf of
Niagara
Peninsula
Energy Inc.

14/12/2015

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1 INTRODUCTION

Niagara Peninsula Energy Inc. ("NPEI") has been ordered by the Ontario Energy Board ("Board" or "OEB") to conduct a lead-lag study.

NPEI retained Elenchus Research Associates in order to assist with conducting a Working Capital Allowance ("WCA") study.

This report documents the data inputs and results of the WCA conducted on behalf of NPEI.

In this WCA study the 12 months period May 2014 to April 2015 has been used as this represents a typical 12 month period of operation for NPEI and the last full year of available data. Prior to May 2014, NPEI performed water billing and collection activities on behalf of the City of Niagara Falls. NPEI ceased these activities April 30, 2014. Therefore, the period May 1, 2014 to April 30, 2015 was used as it is more representative of the 2015 Test Year.

Working capital is the amount of funds required to finance the day-to-day operations of a regulated utility which is determined by a lead/lag study and are included as part of the rate base for determining distribution rates.

A lead/lag study analyzes two time periods:

1. Lag is the time between one event and another. In this lead/lag study, lag is the number of days between the date that a service is rendered and the date that payment is received and generally refers to revenue.
2. Lead refers to the number of days between the date NPEI receives goods and services and the date that NPEI pays for them and generally refers to an expense. A pre-paid expense would be a negative lead or an expense lag.

Both the overall revenue lag and expense lead, in number of days, are developed by weighting the lag or lead from individual sources based on relative dollar magnitude. A net lag is then calculated using the lag minus the lead. The working capital requirements is then determined by using the net lag divided by 365, and multiplied by the annual budgeted costs as seen in the formula below.

$$\text{Working Capital Requirement} = \text{2015 Budgeted Costs}^{*} \times \frac{\text{Net (Lead)/Lag}}{365}$$

* Budgeted Costs include: Cost of Power, OM&A, Interest Expense, PILs, HST and Debt Retirement Charge

The working capital requirement is expressed as a percent of the total Operations, Maintenance and Administration (OM&A) costs plus the cost of power to determine the WCA for 2015. The final working capital requirement to be included in rate base for 2015 is derived by multiplying the proposed WCA by the 2015 forecast OM&A and cost of power.

When a service is provided to a company or is provided by the company over a period of time, the service is deemed to have been provided or received evenly over the midpoint of the period, unless specific information regarding the provision or receipt of the service is available. If both the service start ("A") and end date ("B") are known, the midpoint of a service period can be calculated as follows:

Mid-Point = [(B)-(A) +1]/2

If the start and end date are unknown and the service is evenly distributed over the period, the formula uses the number of days (C) in the period:

Mid-Point = (C)/2

2 REVENUE LAG

Revenue lag refers to the number of days between the date NPEI provides service to its customers and the date that payment is received and funds are available to the company. Revenue lag consists of the following four components:

1. Service Lag – The time between when the service is provided and meters are read;
2. Billing Lag – The time between when the meters are read and invoices are sent;
3. Collection Lag – The time between when the invoices are sent and payment is received; and
4. Payment Processing Lag – The time between when the payment is received and processed.

NPEI's revenues are from customers and from other sources:

- Revenues from customers. This includes revenues from residential, General Service below 50 kW, General Service above 50 kW, unmetered scattered load, sentinel lighting and street lighting
- Revenues for other sources. This includes mainly Pole Rentals; Non-payment of account, i.e. Late payment charges; Account setup charge/Change of Occupancy charges; Apprenticeship tax credit; and miscellaneous billable services.

2.1 SERVICE LAG

Meters for all customers are read monthly.

Based on the meter reading information and the average number of customers for the study period in each customer class, the weighted average service lag is 15.21 days. Table 1 shows the details.

Table 1 2014-2015 Service Lag

Service Lag - All Classes -By Customer Count					
Customer Type	Avg # Cust	Customer Weight	Frequency of Meter Read	Mid point of service period (Days)	Service Lag
	a)		b)	c)	
Residential	46,716.0	89.45	Monthly	15.21	13.60
GS<50	4,319.0	8.27	Monthly	15.21	1.26
GS>50	815.0	1.56	Monthly	15.21	0.24
Unmetered Scattered Load	17.0	0.03	Monthly	15.21	0.00
Streetlighting	5.0	0.01	Monthly	15.21	0.00
Sentinel Lights	351.0	0.67	Monthly	15.21	0.10
Total	**52,223**	**100.00**			**15.21**

2.2 BILLING LAG

The time between when the meters are read and the bills are delivered is dependent on the availability of the pricing information provided by the Retailers and by the Independent Electricity System Operator (IESO). Typically the pricing information is available by the Independent Electricity System Operator on the 10th business day after the read date. To determine the billing lag, NPEI queried the billing system from May 1, 2014 to April 30, 2015 to obtain by rate class the Bill From Date; Bill To Date; Bill Date; Due Date; Cycle #; and total dollars billed. The difference between the Bill Date and the Bill to Date was calculated to obtain the number of bill days. These bill days were then weighted over all billing journals queried to obtain a weighted number of bill days.

The weighted average billing lag is 17.98 days. Table 2 shows the details.

Table 2 2014-2015 Billing Lag

Billing Lag					
Customer Type	Avg # Cust	Sales ($)	Weight By Sales	Number of Days between Billing Date and End of Service Period	Weighted Lag
	a)	b)		c)	
Residential	46,716.0	65,519,480	39.82%	17.34	6.90
GS<50	4,319.0	19,509,321	11.86%	18.80	2.23
GS>50	815.0	78,227,698	47.55%	18.32	8.71
Unmetered Scattered Load	17.0	182,051	0.11%	18.22	0.02
Streetlighting	5.0	1,009,735	0.61%	16.65	0.10
Sentinel Lights	351.0	84,571	0.05%	17.64	0.01
Total	**52,223.0**	**164,532,857**	**100.00%**		**17.98**

2.3 COLLECTION LAG

The average collection lag was derived from accounts receivable aging summary for the period May 2014 to April 2015. The weighted average collection lag is 29.24 days. Table 3 shows the details.

Table 3 2014 -2015 Collection Lag

Aging Categories	Mid Point	Average A/R $	Weight	Collection Lag
Current 0-30	15	$ 9,712,733	91.07%	13.66
Overdue 31-60	45.5	$ 220,467	2.07%	0.94
Overdue 61-90	75.5	$ 93,250	0.87%	0.66
Overdue 91-180	135.5	$ 184,090	1.73%	2.34
Overdue > 181	273	$ 454,631	4.26%	11.64
		10,665,170.68	100.00%	29.24

2.4 PAYMENT PROCESSING LAG

Payments from customers are mainly in the following forms: PAP (Preauthorized Payment Plan) sales, EDI (Electronic Data Interchange-Electronic payments (internet banking)), and Brinks deposit. The weighted average for all these form of payments is a processing lag of 1.8 days. Table 4 below shows the details.

Table 4 2014 -2015 Payment Processing Lag

	Total Cash $	% of Total	# of Processing Days	Weighted # of Processing Days
Preauthorized Payment Plan	43,723,096	23.00%	0.50	0.11
Payments made at Banks	3,097,034	1.63%	2.00	0.03
EDI (Internet banking)	85,128,032	44.78%	1.00	0.45
Telephone Banking	688,667	0.36%	1.00	0.00
Brinks Deposit	55,668,091	29.28%	4.07	1.19
Debit Card	1,718,016	0.90%	1.00	0.01
Paymentech (Credit Card)	94,833	0.05%	1.00	0.00
	190,117,768	100.00%		1.800

2.5 REVENUE LAG FROM CUSTOMERS

The sum of the Service lag, Billing Lag, Collection lag, and Payment and Processing lag related to revenue from customers is 64.22 days. Table 5 shows the details.

Table 5 2014 - 2015 Revenue Lag Customer Classes

Revenue Lag For All Classes	
Month	Days
Service Lag	15.21
Billing Lag	17.98
Collection Lag	29.24
Payment Processing and Bank Float Lag	1.80
TOTAL	**64.22**

2.6 REVENUE LAG OTHER SOURCES

The revenue from other sources is estimated to be 114.67 days. Revenue from other sources includes Late payment charges on hydro sales; Account setup/Change of occupancy charges; Pole rental revenues; Collection and Reconnection charges; and Apprenticeship tax credits. Revenue lag days for Other Sources reflects a longer service lag and longer collection lag especially related to pole rental revenues and the apprenticeship tax credits. This revenue from Other Sources is only 1% of the total revenue. See Table 6 below for the details.

Table 6 2014 - 2015 Revenue Lag Other Sources

Other Revenue	Revenue $ May 1 2014 to April 30, 2015	Service Lag	Billing Lag	Collection Lag	Payment Processing	Total Lag	Weighting	Revenue Lag for Other Revenue
SSS Admin Charge	144,762	15.21	17.98	29.24	1.80	64.22	8.29%	5.32
Retailer Revenue	42,629	15.21	17.98	29.24	1.80	64.22	2.44%	1.57
Microfit Charges	21,404	15.21	17.98	29.24	1.80	64.22	1.23%	0.79
Interest Charges Hydro Sales	419,706	15.21	17.98	29.24	1.80	64.22	24.03%	15.43
Collection & Reconnection Charges	213,012	15.21	17.98	29.24	1.80	64.22	12.19%	7.83
Connection During Hours	19,565	15.21	17.98	29.24	1.80	64.22	1.12%	0.72
Connection After Hours	7,695	15.21	17.98	29.24	1.80	64.22	0.44%	0.28
Connection at Pole	7,630	15.21	17.98	29.24	1.80	64.22	0.44%	0.28
Occupancy Change Charge	188,340	15.21	17.98	29.24	1.80	64.22	10.78%	6.92
Interest Revenue	109,586	15.21	1.51	0.00	0.00	16.72	6.27%	1.05
Pole Rental Revenue	268,719	182.54	16.32	54.88	1.80	255.54	15.38%	39.31
Sale of Scrap Materials	49,641	182.54	0.00	54.88	1.80	239.22	2.84%	6.80
Transformer Rental Revenue	9,625	32.66	5.19	54.88	1.80	94.53	0.55%	0.52
NSF Returned Cheque Charge	7,105	15.21	17.98	29.24	1.80	64.22	0.41%	0.26
Customer Admin Fees (Lawyer's Letters)	4,901	15.21	0.00	54.88	1.80	71.89	0.28%	0.20
Miscellaneous Service Revenues (Project Billing)	86,115	0.00	0.00	54.88	1.80	56.68	4.93%	2.79
Miscellaneous Service Revenues (Other)	32,435	15.21	0.00	0.00	0.00	15.21	1.86%	0.28
Miscellaneous Non-Operating Income (Apprenticeship tax credit)	113,937	182.50	0.00	182.50	0.00	365.00	6.52%	23.81
	1,746,807						100.00%	**114.17**

2.7 TOTAL REVENUE LAG

The total weighted average revenue lag from customers and other sources is 64.75 days. Table 7 shows the details.

Table 7 2014 - 2015 Total Revenue Lag

Service Revenue Lag Total				
Sources of Revenue	Revenue Lag	Amount $	Weighting Factor	Weighted Revenue Lag
Sources of Rev from All Customers	64.22	164,532,857.29	0.99	63.55
Revenue from Services to Retailer	0.00	-	0.00	0.00
Revenue from Other Sources	114.17	1,746,806.98	0.01	1.20
Total	**178.39**	**166,279,664.27**	**1.00**	**64.75**

3 EXPENSE LEAD

The major categories of expenses considered in this study are:

- Cost of Power
- Retailer Payments
- Long term debt
- PILs
- Debt Retirement Charge
- Payroll and Benefit
- OM&A
- HST

3.1 COST OF POWER

NPEI receives cost of power invoices from the IESO, Hydro One Networks and Niagara West Transformation Corporation ("NWTC"). Based on actual May 2014 to April 2015 invoices and payment dates, the average expense lead time for the cost of power from the IESO, Hydro One Networks and NWTS is 30.39 days, 51.23 days and 66.82 days respectively. In June 2015, the IESO reduced NPEI's trading limit by $1.7 million. NPEI obtained its daily exposure data from the IESO for the period of May 2014 to April 2015 and re-ran the study period data against the current updated trading limit to determine if there would have been an exposure to additional margin call warnings, which occur when the daily market exposure reaches 70% of the trading limit. This new trading limit is more reflective of the 2015 Test year and results in a weighted average expense lead time for the IESO of 28.99 days. Weighting the amounts paid to the providers, the weighted average expense lead time is 29.59 days. Table 8 shows the details.

Table 8 2014 - 2015 Cost of Power Expense Lead

Cost of Power Expense Lead				
Month	Amount ($) Per Rate App	Weight Factor	Expense Lead (Days)	Weighted Lead Time
IESO	140,521,891.33	97.48%	28.99	28.26
Hydro One	3,305,311.98	2.29%	51.23	1.17
NWTC	322,465.69	0.22%	66.82	0.15
	144,149,669.00	**100%**	**147.04**	**29.59**

3.2 RETAILER PAYMENTS

Retailer payments represent the difference between the Retailer's contract price and NPEI's monthly WAP (Weighted Average Price).

Based on actual payments to Retailers in the study period the weighted average lead is 37.94 days. Table 9 shows the details.

Table 9 2014 - 2015 Payment to Retailers Lead

Payments to Retailers							
	Service start date	Service end date	payment date	Expense Lead (Days)	Amount ($)	Weighting Factor (%)	Weighted Lead
May-14	01/05/2014	31/05/2014	06/17/2014	32.50	161,985.28	6.70%	2.18
Jun-14	01/06/2014	30/06/2014	07/28/2014	43.00	147,467.62	6.10%	2.62
Jul-14	01/07/2014	31/07/2014	08/28/2014	43.50	133,943.89	5.54%	2.41
Aug-14	01/08/2014	31/08/2014	09/24/2014	39.50	285,384.07	11.81%	4.66
Sep-14	01/09/2014	30/09/2014	10/24/2014	39.00	227,267.51	9.40%	3.67
Oct-14	01/10/2014	31/10/2014	11/21/2014	36.50	243,056.44	10.06%	3.67
Nov-14	01/11/2014	30/11/2014	12/22/2014	37.00	269,368.16	11.14%	4.12
Dec-14	01/12/2014	31/12/2014	01/23/2015	38.50	39,882.99	1.65%	0.64
Dec-14	01/12/2014	31/12/2014	01/26/2015	41.50	174,272.15	7.21%	2.99
Jan-15	01/01/2015	31/01/2015	02/24/2015	39.50	230,823.13	9.55%	3.77
Feb-15	01/02/2015	28/02/2015	03/19/2015	33.00	213,176.80	8.82%	2.91
Mar-15	01/03/2015	31/03/2015	04/22/2015	37.50	82,347.90	3.41%	1.28
Apr-15	01/04/2015	30/04/2015	05/20/2015	35.00	208,029.14	8.61%	3.01
Total				**496**	**$2,417,005**	**100.00%**	**37.94**

3.3 INTEREST ON LONG TERM DEBT

NPEI has a combined total of $25.6 million in promissory notes payable to its shareholder and the City of Niagara Falls. NPEI has a term loan with TD Bank in the amount of $4.2 million average outstanding balance for 2015, on which principal and interest are repaid monthly. NPEI has $30 million of interest-only loans with TD Bank where interest only is paid on a monthly basis. NPEI has a loan related to smart meters with Scotiabank in the amount of $2.4 million average outstanding balance for 2015, where principal and interest are repaid monthly. All interest payments are made at the end of each month or during the last 10 days of the months.

Based on actual payments for the study period the weighted average lead is 4.38 days.

3.4 PILS

As of June 30, 2013, NPEI has a credit balance with the Ministry of Finance related to its PILs (Payment-in-Lieu of Taxes). The credit arose from NPEI making tax installments in 2013 based on its 2012 tax return. The change in lives related to capital assets effective January 1, 2013 in accordance with directions from the OEB decreased NPEI's 2013 depreciation expense. Capital Cost Allowance ("CCA") calculated in 2013 exceeded the 2013 depreciation amount. Thereby the PILs for 2013 were substantially lower than 2012.

This credit is being used to offset any PILs payments that NPEI would need to make to the Ministry of Finance during the study period. This is expected to continue for a few more years. As a result of this credit the PILs expense lead for the study period is -562.75 days.

3.5 DEBT RETIREMENT CHARGE

NPEI collects a debt retirement charge from its customers and remits this revenue to the OEFC monthly. These payments are cleared between 10 and 15 days after month end. Based on the study period data, the weighted expense lead time is 28.26 days. The 2015 Test Year DRC amount is based on $0.007/kWh of NPEI's 2015 weather normalized load forecast, excluding losses.

3.6 PAYROLL AND BENEFITS

All NPEI employees are paid weekly. NPEI's salaried employees are paid separately from NPEI's hourly employees. Salaried payroll is transmitted to the bank on the Friday of the current pay week. Hourly payroll is transmitted to the bank on the Monday following the pay week. Both payrolls are deposited into NPEI employee's bank accounts on the Tuesday following the pay week. The payroll has a service period of 3.51 days and an average payment lead of 1.72 days for a total lead of 5.23 days.

Benefits are split by total number of lead days from the service date to the payment date. The service lead is calculated using the mid-point of the service period.

- Payroll withholding taxes are paid subsequent to the pay period. The average payment lead days are 13.04 days in the study period for a total lead number of days of 16.55
- Pension benefits (OMERS) are paid monthly and generally up to a week following the service period. The service lead was 15.21 days and the average payment lead was 5.15 days during the study period for a total of 20.36 lead days
- Dental, drug and extended health care benefits are paid to Mearie prior to the beginning of the month to which the service period relates. The average payment lag was -29.91 days in the study period. The total lead days were -14.70.
- Other benefits include EHT, WSIB and Union Dues. The average payment lead days for these other benefits was 10.7 in the study period, resulting in a total lead days of 25.91.

The weighted average expense lead for the study period is 9.64 days for Operations, Maintenance and Administration (OM&A) payroll and benefits. See Table 10 below for the details.

Table 10 2014 - 2015 OM&A Payroll and Benefits Expenses

OM&A Payroll and Benefits Expenses May 1, 2014 - April 30, 2015						
	Service Lead (days)	Payment Lead (days)	Total Lead (days)	Expenses ($)	Weighting Factor (%)	Weighted Lead
Net Payroll	3.51	1.72	5.23	4,972,510	50.60%	2.65
Withholdings	3.51	13.04	16.55	2,289,376	23.30%	3.86
Benefits-OMERS	15.21	5.15	20.36	1,617,148	16.46%	3.35
Benefits-Other	15.21	10.70	25.91	292,807	2.98%	0.77
Benefits-Mearie	15.21	-29.91	-14.70	655,632	6.67%	-0.98
Total	**52.64**	**0.71**	**53.35**	**9,827,474**	**100.00%**	**9.64**

3.7 OM&A

The OM&A total lead days are calculated based on expenses split by Vendor Terms. The nature of the expenses in these groupings is detailed below.

Annual prepaid expenses

Annual prepaid expenses include software maintenance, insurance and memberships. Also included are regulatory expenses relating to NPEI's 2015 COS Rate Application. For these expenses, the service period is the 2015 Test Year and the subsequent 4 year IRM period (i.e. June 1, 2015 to April 30, 2020).

Expenses that are prepaid annually include Kinectrics, legal expenses related to the rate application, ESA, software and hardware maintenance fees, property insurance and general insurance.

Quarterly Prepaid expenses

Expenses that are prepaid quarterly include Property tax fees for office, yard and substation properties, and OEB cost assessments.

Monthly Prepaid expenses

Monthly prepaid expenses include property maintenance and other miscellaneous prepaid expenses.

Bi-Weekly Prepaid expenses

Bi-weekly prepaid expenses consist of postage expense.

Miscellaneous OM&A (All Vendor Terms)

The miscellaneous OM&A is split by grouping of vendor terms. The major costs included are Subcontract (tree trimming, pole inspection, locates), fuel and fleet maintenance, meter reading, consulting, legal, audit, office supplies, telecommunications, and facilities maintenance.

Table 11 shows the details for OM&A expenses.

Table 11 2014 - 2015 OM&A Expense Lead

OM&A Expense Lead Based on the period May 2014-April 2015				
	Expense Lead (days)	Amount ($)	Weighting Factor	Weighted Lead
Payroll & Benefits	9.64	9,827,474	58.69%	5.66
Annual Prepaids	-292.67	1,096,430	6.55%	-19.16
Quarterly Prepaids	-31.44	458,258	2.74%	-0.86
Monthly Prepaids	-13.00	78,934	0.47%	-0.06
Bi-weekly Prepaids	-6.76	503,000	3.00%	-0.20
OM&A Expense Lead	45.18	4,780,842	28.55%	12.90
TOTAL	**-94.30**	**16,744,938**	**100.00%**	**-1.73**

Combining the Payroll and Benefits and OM&A expenses, the weighted average expense lead for the study period is -1.73 days.

3.8 HST

The following categories are subject to HST:

- Customer revenues including cost of power and other revenues
- Cost of power, and
- OM&A expenses excluding Property taxes, insurance, OEB cost assessment fees and low energy assistance program (LEAP) expenditures

HST for Revenue - HST return is remitted on the last business day of the month following the billing month therefore remittance is approximately 60 days after the service period end. Other revenues excluded from HST revenue are Non-payment of Account-Late payment charges on hydro sales; bank interest revenue and apprenticeship tax credit revenue.

HST for Expenses - HST for IESO invoice for the service month is paid before the HST remittance credit is received. The IESO invoice is paid in the middle of month following the service period. The HST input tax credit for the IESO invoice is not claimed until two months following the service period. For NWTC and Hydro One, NPEI typically receives the invoice at the end of the month following the service period, which is paid the month after. Therefore, the ITC for Hydro One and NWTC are not claimed until 2 months after the service period. This resulted in total weighted lead days for cost of power of 43.58 days during the study period.

HST weighted lead days for OM&A for the study period resulted in 44.77 days.

Table 12 shows the details of the calculations for HST for the three categories.

Table 12 2014 - 2015 HST for Revenues, Cost of Power and OM&A

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	Rate Application	HST %	Test Year HST	HST Lead Time	HST Lead Time/365 days	HST working Capital
Revenue	173,875,385.00	0.13	22,603,800.05	(10.45)	(0.0286)	(646,921.49)
Cost of Power	144,149,669.00	0.13	18,739,456.97	43.58	0.1194	2,237,633.70
OM&A	5,844,020.00	0.13	759,722.60	44.77	0.1227	93,181.50
Total						1,683,893.71
HST (Expenses)			19,499,179.57	43.63	0.1195	2,330,815.20

4 WORKING CAPITAL REQUIREMENT

Based on the revenue lag and expense lead information described above using May 2014 to April 2015 data, the 2015 working capital allowance for NPEI based on forecast 2015 expenses is $20.3 million or 12.61% of forecast cost of power and OM&A expenses. Table 13 shows the details.

Table 13 – Working Capital Requirement

Working Capital Allowance - HST Adjusted							
Budget Item Description	Revenue Lag Days	Expense Lead Days	Net Lag (Lead) Days	WCA Factor	Test Year Expenses ($)	WCA ($)	WCA (%)
Cost of Power	64.75	29.59	35.16	10%	144,149,669	13,884,477	
Retailer Expenses	64.75	37.94	26.81	7%	2,417,005	177,520	
OM&A Expenses	64.75	-1.73	66.48	18%	16,424,995	2,991,420	
Interest on Long Term Debt	64.75	4.38	60.37	17%	2,345,596	387,927	
PILs	64.75	-562.75	627.50	172%	163,430	280,964	
Debt Retirement Charges	64.75	28.26	36.48	10%	8,456,444	845,245	
Sub-Total					173,957,139	18,567,554	11.56%
HST (Receivables)			-10.45	-2.86%	-22,603,800	-646,921	
HST (Expenses)			43.63	11.95%	19,499,180	2,330,815	
Total (inc. HST)					**170,852,518**	**20,251,447**	12.61%

5 ELENCHUS' OPINION

Elenchus reviewed the methodology and data used by NPEI in calculating the working capital allowance and in Elenchus' views the methodology covers the revenue and expense items usually covered in this type of analysis and is consistent with other studies presented to the Ontario Energy Board by other distributors.

The 12.61% working capital allowance for NPEI is based on NPEI's May 2014 to April 2015 data adjusted for the lower trading limit established by the IESO for NPEI in 2015. The test year expenses are consistent with NPEI's 2015 rate submission to the Ontario Energy Board.

Appendix E – IESO Expense Lead Study Period Actual

IESO Expense Lead - May 2014 to April 2015

Service Month	# days	Service Lead Time	Document Date	Transaction Description	Payment Date	# Payment days	Total Lead Time	Document Amount	Less HST	Amount not including HST	Weighting for Month	Weighted Lead for Month	Total Weighting	Weighted Lead
May-14	31.00	15.50	6/13/2014	May Power Bill	6/13/2014	13.00	28.50	9,970,502.61	1,226,174.64	8,744,327.97	100%	28.50	7.44%	2.12
Jun-14	30.00	15.00	7/7/2014	Jun Margin Call	7/7/2014	7.00	22.00	2,000,000.00		2,000,000.00	19.17%	4.22		
Jun-14	30.00	15.00	7/15/2014	Jun Power Bill	7/16/2014	16.00	31.00	9,877,182.48	1,444,808.24	8,432,374.24	80.83%	25.06		
								11,877,182.48	1,444,808.24	10,432,374.24	100%	29.27	8.88%	2.60
Jul-14	31.00	15.50	8/6/2014	Jul Margin Call	8/6/2014	6.00	21.50	3,000,000.00		3,000,000.00	29.23%	6.29		
Jul-14	31.00	15.50	8/18/2014	July Power Bill	8/18/2014	18.00	33.50	8,703,819.77	1,441,752.11	7,262,067.66	70.77%	23.71		
								11,703,819.77	1,441,752.11	10,262,067.66	100%	29.99	8.73%	2.62
Aug-14	31.00	15.50	9/8/2014	Aug Margin Call	9/8/2014	8.00	23.50	2,000,000.00		2,000,000.00	18.45%	4.34		
Aug-14	31.00	15.50	9/15/2014	Aug Power Bill	9/16/2014	16.00	31.50	10,361,240.27	1,522,938.31	8,838,301.96	81.55%	25.69		
								12,361,240.27	1,522,938.31	10,838,301.96	100%	30.02	9.22%	2.77
Sep-14	30.00	15.00	10/16/2014	Sep Power Bill	10/16/2014	16.00	31.00	10,725,876.84	1,340,720.95	9,385,155.89	100%	31.00	7.98%	2.48
Oct-14	31.00	15.50	11/17/2014	Oct Power Bill	11/17/2014	17.00	32.50	10,887,387.04	1,341,922.14	9,545,464.90	100%	32.50	8.12%	2.64
Nov-14	30.00	15.00	12/15/2014	Nov Power Bill	12/15/2014	15.00	30.00	9,555,367.26	1,206,218.23	8,349,149.03	100%	30.00	7.10%	2.13
Dec-14	31.00	15.50	1/12/2015	Dec Margin Call	1/12/2015	12.00	27.50	2,500,000.00		2,500,000.00	24.45%	6.73		
Dec-14	31.00	15.50	1/15/2015	Dec Powerbill	1/16/2015	16.00	31.50	9,152,272.98	1,429,249.60	7,723,023.38	75.55%	23.80		
								11,652,272.98	1,429,249.60	10,223,023.38	100%	30.52	8.70%	2.65
Jan-15	31.00	15.50	2/9/2015	Margin Call	2/9/2015	9.00	24.50	1,500,000.00		1,500,000.00	16.25%	3.98		
Jan-15	31.00	15.50	2/17/2015	Jan Powerbill	2/17/2015	17.00	32.50	9,050,715.69	1,317,395.25	7,733,320.44	83.75%	27.22		
								10,550,715.69	1,317,395.25	9,233,320.44	100%	31.20	7.86%	2.45
Feb-15	28.00	14.00	3/9/2015	Margin Call	3/9/2015	9.00	23.00	1,000,000.00		1,000,000.00	9.22%	2.12		
Feb-15	28.00	14.00	3/16/2015	Feb IESO bill	3/16/2015	16.00	30.00	11,378,242.83	1,528,197.42	9,850,045.41	90.78%	27.24		
								12,378,242.83	1,528,197.42	10,850,045.41	100%	29.35	9.23%	2.71
Mar-15	31.00	15.50	4/17/2015	Mar Power Bill	4/17/2015	17.00	32.50	11,073,803.56	1,374,674.93	9,699,128.63	100%	32.50	8.25%	2.68
Apr-15	30.00	15.00	5/15/2015	April Power Bill	5/15/2015	15.00	30.00	11,386,656.80	1,404,821.13	9,981,835.67	100%	30.00	8.49%	2.55
									Total	117,544,195.18			100.00%	30.39

Appendix F – IESO Expense Lead Study Period with Revised Trading Limit

IESO Expense Lead - May 2014 to April 2015 - Revised Trading Limit

Service Month	# days	Service Lead Time	Document Date	Transaction Description	Payment Date	# Payment days	Total Lead Time	Document Amount	Less HST	Amount not including HST	Weighting for Month	Weighted Lead for Month	Total Weighting	Weighted Lead
	31.00	15.50	6/10/2014		6/10/2014	10.00	25.50	2,500,000.00		2,500,000.00	28.59%	7.29		
May-14	31.00	15.50	6/13/2014	May Power Bill	6/13/2014	13.00	28.50	7,470,502.61	1,226,174.64	6,244,327.97	71.41%	20.35		
								9,970,502.61		8,744,327.97	100.00%	27.64	7.44%	2.06
Jun-14	30.00	15.00	7/3/2014	Jun Margin Call	7/3/2014	3.00	18.00	2,500,000.00		2,500,000.00	23.96%	4.31		
Jun-14	30.00	15.00	7/16/2014	Jun Power Bill	7/16/2014	16.00	31.00	9,377,182.48	1,444,808.24	7,932,374.24	76.04%	23.57		
								11,877,182.48	1,444,808.24	10,432,374.24	100.00%	27.88	8.88%	2.47
Jul-14	31.00	15.50	8/2/2014	Jul Margin Call	8/2/2014	2.00	17.50	2,500,000.00		2,500,000.00	24.36%	4.26		
Jul-14	31.00	15.50	8/10/2014	Jul Margin Call	8/10/2014	10.00	25.50	2,500,000.00		2,500,000.00	24.36%	6.21		
Jul-14	31.00	15.50	8/18/2014	July Power Bill	8/18/2014	18.00	33.50	6,703,819.77	1,441,752.11	5,262,067.66	51.28%	17.18		
								11,703,819.77	1,441,752.11	10,262,067.66	100.00%	27.65	8.73%	2.41
Aug-14	31.00	15.50	9/3/2014	Aug Margin Call	9/3/2014	3.00	18.50	2,500,000.00		2,500,000.00	22.07%	4.08		
Aug-14	31.00	15.50	9/16/2014	Aug Power Bill	9/16/2014	16.00	31.50	9,861,240.27	1,522,938.31	8,338,301.96	77.93%	24.55		
								12,361,240.27	1,522,938.31	10,838,301.96	100.00%	28.63	9.22%	2.64
Sep-14	30.00	15.00	10/7/2014	Aug Margin Call	10/7/2014	7.00	22.00	2,500,000.00		2,500,000.00	26.64%	5.86		
Sep-14	30.00	15.00	10/16/2014	Sep Power Bill	10/16/2014	16.00	31.00	8,225,876.84	1,340,720.95	6,885,155.89	73.36%	22.74		
								10,725,876.84		9,385,155.89	100.00%	28.60	7.98%	2.28
Oct-14	31.00	15.50	11/17/2014	Oct Power Bill	11/17/2014	17.00	32.50	10,887,387.04	1,341,922.14	9,545,464.90	100.00%	32.50	8.12%	2.64
Nov-14	30.00	15.00	12/15/2014	Nov Power Bill	12/15/2014	15.00	30.00	9,555,367.26	1,206,218.23	8,349,149.03	100.00%	30.00	7.10%	2.13
Dec-14	31.00	15.50	1/6/2015	Dec Margin Call	1/6/2015	6.00	21.50	2,500,000.00		2,500,000.00	24.45%	5.26		
Dec-14	31.00	15.50	1/16/2015	Dec Powerbill	1/16/2015	16.00	31.50	9,152,272.98	1,429,249.60	7,723,023.38	75.55%	23.80		
								11,652,272.98	1,429,249.60	10,223,023.38	100.00%	29.05	8.70%	2.53
Jan-15	31.00	15.50	2/4/2015	Margin Call	2/4/2015	4.00	19.50	2,500,000.00		2,500,000.00	27.08%	5.28		
Jan-15	31.00	15.50	2/17/2015	Jan Powerbill	2/17/2015	17.00	32.50	8,050,715.69	1,317,395.25	6,733,320.44	72.92%	23.70		
								10,550,715.69	1,317,395.25	9,233,320.44	100.00%	28.98	7.86%	2.28
Feb-15	28.00	14.00	3/4/2015	Margin Call	3/4/2015	4.00	18.00	2,500,000.00		2,500,000.00	23.04%	4.15		
Feb-15	28.00	14.00	3/16/2015	Feb IESO bill	3/16/2015	16.00	30.00	9,878,242.83	1,528,197.42	8,350,045.41	76.96%	23.09		
								12,378,242.83	1,528,197.42	10,850,045.41	100.00%	27.24	9.23%	2.51
Mar-15	31.00	15.50	4/8/2015	Margin Call	4/8/2015	8.00	23.50	2,500,000.00		2,500,000.00	25.78%	6.06		
Mar-15	31.00	15.50	4/17/2015	Mar Power Bill	4/17/2015	17.00	32.50	8,573,803.56	1,374,674.93	7,199,128.63	74.22%	24.12		
								11,073,803.56		9,699,128.63	100.00%	30.18	8.25%	2.49
Apr-15	30.00	15.00	5/15/2015	April Power Bill	5/15/2015	15.00	30.00	11,386,656.80	1,404,821.13	9,981,835.67	100.00%	30.00	8.49%	2.55
									Total	117,544,195.18			100.00%	28.99

Appendix G – NPEI Prudential Support

Independent Electricity System Operator

Annual Review of Price Basis for Determining Prudential Support Obligations

Summary:

Based on the IESO's annual review performed on April 21, 2015, there are changes to the following IESO established price basis used in determining the prudential support obligations for market participants:

For metered market participants that are *distributors* = $94/MWh

For metered market participants *other than distributors* = $102.10/MWh

Date of next annual review: April 2016

Background:

For prudential calculation purposes, the IESO is required to calculate a metered market participant's minimum trading limit and default protection amount using energy prices based on the Ontario Energy Board's ("OEB's") price forecasts for electricity in Ontario for use in setting retail prices under its regulated price plan ("RPP"). The price basis for Local Distribution Companies ("Distributors") is equal to the conventional meter RPP tier 1 price ("RPCMT1") as reported by the OEB for its tiered RPP prices. The price basis for all other market participants is equal to the RPP supply cost or its equivalent as forecasted by the OEB. The IESO annually reviews each price basis referred to in Chapter 2, section 5.3.10A of the market rules, and modifies the applicable price basis if it has increased or decreased by 15% or more from the price basis used by the IESO.

Independent Electricity System Operator

Calculations:

IESO established price basis effective May 1, 2012 based on the OEB Price Report:

The IESO established its current price basis for market participants using the prices published in the RPP Price Report for the period May 1, 2012 to April 30, 2013 (published April 2, 2012):

- Distributors: RPCMT1 as reported by the OEB = $75/MWh
- All other market participants: RPP supply cost as reported by the OEB = $80.69/MWh

Annual review – April 21, 2015:

On April 20, 2015, the OEB published the Regulated Price Plan Report for the period May 1, 2015 to April 30, 2016:

- Distributors: RPCMT1 as reported by the OEB = $94/MWh
- All other market participants: RPP supply cost as reported by the OEB = 102.10/MWh

The IESO identified the 15% price range to determine if the IESO established price basis should change. The price range was determined by adjusting the established price basis 15% higher and 15% lower. The IESO must change the price basis only if the prices are equal to or greater than the higher end of the range or equal to or lesser than the lower end of the range.

Therefore, the price ranges were:

RPCMT1 **$86.25/MWh** ($75.00 x 1.15) **to $63.75/MWh** ($75.00 x 0.85)

RPP supply cost **$92.79/MWh** ($80.69 x 1.15) to **$68.59/MWh** ($80.69 x 0.85)

The RPCMT1 and RPP supply cost price basis published by the OEB on April 20, 2015 were $94.00/MWh and $102.10/MWh respectively, falling outside the 15% price range. Therefore, the IESO price basis will change to $94.00/MWh and $102.10 effective May 1, 2015.

7-Mar-14

Independent Electricity System Operator
STATION A BOX 4474
TORONTO, ON M5W 4E5

www.ieso.ca

NIAGARA PENINSULA ENERGY INC.
P.O. Box 120 7447 Pin Oak Drive
Niagara Falls, ON L2E 6S9
Canada

Market Participant ID: 102102

Prudential Support Obligation - Schedule A

Default Protection Amount	$8,935,128.00
Minimum Trading Limit as determined by IESO	$3,982,133.00
Self Assessed Trading Limit	$18,122,503.00
Trading Limit	$18,122,503.00
Maximum Net Exposure	$27,057,631.00
LDC Prudential Credit submitted by participant	$1,912,406.00
LDC Prudential Credit Reduction	$1,147,444.00
Credit Rating	
Credit Rating Agency	
Credit Rating Reduction	$0.00
Years of Good Payment History	6
Good Payment History Reduction	$14,000,000.00
Prudential Support Obligation	**$11,910,187.00**

15-Jun-15

Independent Electricity System Operator
STATION A BOX 4474
TORONTO, ON M5W 4E5

www.ieso.ca

NIAGARA PENINSULA ENERGY INC.
P.O. Box 120 7447 Pin Oak Drive
Niagara Falls, ON L2E 6S9
Canada

Market Participant ID: 102102

Prudential Support Obligation - Schedule A

Default Protection Amount	$10,675,157.00
Minimum Trading Limit as determined by IESO	$4,564,764.00
Self Assessed Trading Limit	$16,382,474.00
Trading Limit	$16,382,474.00
Maximum Net Exposure	$27,057,631.00
LDC Prudential Credit submitted by participant	$1,912,406.00
LDC Prudential Credit Reduction	$1,147,444.00
Credit Rating	
Credit Rating Agency	
Credit Rating Reduction	$0.00
Years of Good Payment History	6
Good Payment History Reduction	$14,000,000.00
Prudential Support Obligation	**$11,910,187.00**

Appendix H – IESO Expense Lead

Most Recent 12 Month Actual

IESO Expense Lead - Nov 2014 to Oct 2015

Service Month	# days	Service Lead Time	Document Date	Transaction Description	Payment Date	# Payment days	Total Lead Time	Document Amount	Less HST	Amount not including HST	Weighting for Month	Weighted Lead for Month	Total Weighting	Weighted Lead
Nov-14	30.00	15.00	12/15/2014	Nov Power Bill	12/15/2014	15.00	30.00	9,555,367.26	1,206,218.23	8,349,149.03	100.00%	30.00	6.87%	2.06
Dec-14	31.00	15.50	1/12/2015	Dec Margin Call	1/12/2015	12.00	27.50	2,500,000.00		2,500,000.00	24.45%	6.73		
Dec-14	31.00	15.50	1/15/2015	Dec Powerbill	1/16/2015	16.00	31.50	9,152,272.98	1,429,249.60	7,723,023.38	75.55%	23.80		
								11,652,272.98	1,429,249.60	10,223,023.38	100.00%	30.52	8.41%	2.57
Jan-15	31.00	15.50	2/9/2015	Margin Call	2/9/2015	9.00	24.50	1,500,000.00		1,500,000.00	16.25%	3.98		
Jan-15	31.00	15.50	2/17/2015	Jan Powerbill	2/17/2015	17.00	32.50	9,050,715.69	1,317,395.25	7,733,320.44	83.75%	27.22		
								10,550,715.69	1,317,395.25	9,233,320.44	100.00%	31.20	7.59%	2.37
Feb-15	28.00	14.00	3/9/2015	Margin Call	3/9/2015	9.00	23.00	1,000,000.00		1,000,000.00	9.22%	2.12		
Feb-15	28.00	14.00	3/16/2015	Feb IESO bill	3/16/2015	16.00	30.00	11,378,242.83	1,528,197.42	9,850,045.41	90.78%	27.24		
								12,378,242.83	1,528,197.42	10,850,045.41	100.00%	29.35	8.92%	2.62
Mar-15	31.00	15.50	4/17/2015	Mar Power Bill	4/17/2015	17.00	32.50	11,073,803.56	1,374,674.93	9,699,128.63	100.00%	32.50	7.98%	2.59
Apr-15	30.00	15.00	5/15/2015	April Power Bill	5/15/2015	15.00	30.00	11,386,656.80	1,404,821.13	9,981,835.67	100.00%	30.00	8.21%	2.46
May-15	31.00	15.50	6/8/2015	Margin Call	6/8/2015	8.00	23.50	2,500,000.00		2,500,000.00	25.34%	5.95		
May-15	31.00	15.50	6/12/2015	May Power Bill	6/12/2015	12.00	27.50	8,746,778.33	1,379,549.73	7,367,228.60	74.66%	20.53		
								11,246,778.33	1,379,549.73	9,867,228.60	100.00%	26.49	8.12%	2.15
Jun-15	30.00	15.00	7/3/2015	Margin Call	7/3/2015	3.00	18.00	2,800,000.00		2,800,000.00	27.37%	4.93		
Jun-15	30.00	15.00	7/15/2015	June Power Bill	7/15/2015	15.00	30.00	8,867,640.02	1,436,371.38	7,431,268.64	72.63%	21.79		
								11,667,640.02	1,436,371.38	10,231,268.64	100.00%	26.72	8.42%	2.25
Jul-15	31.00	15.50	7/29/2015	Margin Call	7/29/2015	-2.00	13.50	2,500,000.00		2,500,000.00	21.22%	2.86		
Jul-15	31.00	15.50	8/4/2015	Margin Call	8/4/2015	4.00	19.50	1,500,000.00		1,500,000.00	12.73%	2.48		
Jul-15	31.00	15.50	8/6/2015	Margin Call	8/6/2015	6.00	21.50	2,000,000.00		2,000,000.00	16.97%	3.65		
Jul-15	31.00	15.50	8/17/2015	July Power Bill	8/17/2015	17.00	32.50	7,432,939.40	1,648,911.67	5,784,027.73	49.08%	15.95		
								13,432,939.40	1,648,911.67	11,784,027.73	100.00%	24.95	9.69%	2.42
Aug-15	31.00	15.50	8/31/2015	Margin Call	8/31/2015	0.00	15.50	3,000,000.00		3,000,000.00	26.44%	4.10		
Aug-15	31.00	15.50	9/4/2015	Margin Call	9/4/2015	4.00	19.50	1,000,000.00		1,000,000.00	8.81%	1.72		
Aug-15	31.00	15.50	9/8/2015	Margin Call	9/8/2015	8.00	23.50	1,000,000.00		1,000,000.00	8.81%	2.07		
Aug-15	31.00	15.50	9/10/2015	Margin Call	9/10/2015	10.00	25.50	1,500,000.00		1,500,000.00	13.22%	3.37		
Aug-15	31.00	15.50	9/15/2015	Aug Power Bill	9/15/2015	15.00	30.50	6,458,888.18	1,611,112.79	4,847,775.39	42.72%	13.03		
								12,958,888.18	1,611,112.79	11,347,775.39	100.00%	24.29	9.33%	2.27
Sep-15	30.00	15.00	9/28/2015	Margin Call	9/28/2015	-2.00	13.00	1,500,000.00		1,500,000.00	13.54%	1.76		
Sep-15	30.00	15.00	10/2/2015	Margin Call	10/2/2015	2.00	17.00	1,500,000.00		1,500,000.00	13.54%	2.30		
Sep-15	30.00	15.00	10/6/2015	Margin Call	10/6/2015	6.00	21.00	1,750,000.00		1,750,000.00	15.80%	3.32		
Sep-15	30.00	15.00	10/15/2015	Sept Power Bill	10/15/2015	15.00	30.00	7,898,973.63	1,572,809.30	6,326,164.33	57.12%	17.13		
								12,648,973.63	1,572,809.30	11,076,164.33	100.00%	24.52	9.11%	2.23
Oct-15	31.00	15.50	11/6/2015	Margin Call	11/6/2015	6.00	21.50	2,100,000.00		2,100,000.00	23.50%	5.05		
Oct-15	31.00	15.50	11/16/2015	Oct Power Bill	11/16/2015	16.00	31.50	8,110,774.40	1,274,067.52	6,836,706.88	76.50%	24.10		
								10,210,774.40	1,274,067.52	8,936,706.88	100.00%	29.15	7.35%	2.14
									Total	121,579,674.13			100.00%	28.13

Appendix I – Loan Agreements

PROMISSORY NOTE

COPY

Due: April 1, 2020

FOR VALUE RECEIVED, Niagara Falls Hydro Inc. ("WiresCo") hereby promises to pay to or to the order of the City of Niagara Falls (the "City") the principal sum of twenty-two million dollars ($22,000,000.00) with interest at the rate specified herein, either upon demand by the City or on April 1, 2020 (the "Maturity Date").

Interest on the principal sum shall accrue from April 1, 2000 and be payable at a rate of seven and one-quarter percent (7¼ %) per annum, based on the interest rate for third party financing which the Ontario Energy Board or its successor may permit regulated distribution corporations to recover for rate making purposes.

Interest at the aforesaid rate shall be payable in quarterly installments, by means of an electronic funds transfer to the City, with the first of such payments commencing on June 30, 2000.

At the option of the City, on one year's prior written notice to WiresCo, the Maturity Date and any of the terms of this Promissory Note may be revised, changed or restated by the City in consultation with WiresCo.

This Promissory Note may, at the option of the City, be converted, as to some or all of the principal sum outstanding, into common shares of WiresCo at a conversion ratio of $100 per share. The foregoing conversion right may be exercised by the City at any time on 90 days prior written notice to WiresCo.

The terms of this Promissory Note are subject to the adjustment provisions of the Transfer By-law passed by the City of Niagara Falls on May 8, 2000 as By-law No.2000-97.

This Promissory Note is not assignable by the City without the consent of WiresCo.

DATED this 26th day of September, 2000.

NIAGARA FALLS HYDRO INC.

Per:

____
Authorized Signing Officer

____
Authorized Signing Officer

COPY

::ODMA\PCDOCS\CCT\59298\2

PROMISSORY NOTE

Due: April 1, 2020

FOR VALUE RECEIVED, Niagara Falls Hydro Inc. ("WiresCo") hereby promises to pay to or to the order of the Niagara Falls Hydro Holding Corporation ("HoldCo") the principal sum of Three Million Six Hundred and Five Thousand and Ninety Dollars ($3,605,090.00) with interest at the rate specified herein, either upon demand by HoldCo or on April 1, 2020 (the "Maturity Date").

Interest on the principal sum shall accrue from April 1, 2000 and be payable at a rate of seven and one-quarter percent (7¼ %) per annum, based on the interest rate for third party financing which the Ontario Energy Board or its successor may permit regulated distribution corporations to recover for rate making purposes.

Interest at the aforesaid rate shall be payable in quarterly installments, by means of an electronic funds transfer to HoldCo, with the first of such payments commencing on June 30, 2000.

At the option of HoldCo, on one year's prior written notice to WiresCo, the Maturity Date and any of the terms of this Promissory Note may be revised, changed or restated by HoldCo in consultation with WiresCo.

This Promissory Note may, at the option of HoldCo, be converted, as to some or all of the principal sum outstanding, into common shares of WiresCo at a conversion ratio of $100 per share. The foregoing conversion right may be exercised by HoldCo at any time on 90 days prior written notice to WiresCo.

The terms of this Promissory Note are subject to the adjustment provisions of the Transfer By-law passed by the City of Niagara Falls on May 8, 2000 as By-law No.2000-97.

This Promissory Note is not assignable by HoldCo without the consent of WiresCo.

This Promissory Note replaces a promissory note in the principal amount of $5,000,000.00 previously issued by WiresCo to HoldCo pursuant to the provisions of the said Transfer By-law.

DATED this 24th day of July, 2001.

NIAGARA FALLS HYDRO INC.

per: ______________________
President

per: ______________________
Treasurer

::ODMA\PCDOCS\CCT\59297\3

3,520
C.R.C

TD Commercial Banking

Commercial Banking Centre
40 King Street
St. Catharines, Ontario
L2R 3H4

Telephone No.: 905 685-7631
Fax No.: 905 685-7053

July 14, 2009

Niagara Peninsula Energy Inc.
7447 Pin Oak Drive
Niagara Falls, Ontario
L2E 6S9

Attention: Mr. Brian Wilkie - President

Dear Mr. Wilkie,

We are pleased to offer the Borrower the following credit facilities (the "Facilities"), subject to the following terms and conditions.

BORROWER	Niagara Peninsula Energy Inc. (the "Borrower")
LENDER	The Toronto-Dominion Bank (the "Bank"), through its 40 King Street branch, in St. Catharines, Ontario.
CREDIT LIMIT	1) CDN$9,000,000. as reduced pursuant to the section headed "Repayment and Reduction of Amount of Credit Facility".
TYPE OF CREDIT AND BORROWING OPTIONS	1) Committed Reducing Term Facility available at the Borrower's option by way of: • Fixed Rate Term Loan in CDN$
PURPOSE	1) Refinance maturing term loan facility.
TENOR	1) Committed.
CONTRACTUAL TERM	1) 10 years from the date of drawdown
AMORTIZATION	1) 10 years

INTEREST RATES AND FEES

Advances shall bear interest and fees as follows:

1) Committed Reducing Term Facility:
- Fixed Rate Term Loans: Cost of Funds + 0.60% per annum.

For loan facility, payments will be made in accordance with Schedule "A" attached hereto 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" attached hereto.

DRAWDOWN

1) One time drawdown

REPAYMENT AND REDUCTION OF AMOUNT OF CREDIT FACILITY

1) All amounts outstanding will be repaid on or before the Contractual Term Maturity Date. The drawdown will be repaid in equal monthly payments. The details of repayment and interest rate applicable to such drawdown will be set out in the" Rate and Payment Terms Notice" applicable to that drawdown. Any amounts repaid may not be reborrowed.

PREPAYMENT

1) Standard prepayment penalties apply.

SECURITY

The following security shall be provided, shall, unless otherwise indicated, support all present and future indebtedness and liability of the Borrower and the grantor of the security to the Bank including without limitation indebtedness and liability under guarantees, foreign exchange contracts, cash management products, and derivative contracts, shall be registered in first position, and shall be on the Bank's standard form, supported by resolutions and solicitor's opinion, all acceptable to the Bank:

a) General Security Agreement ("GSA").
b) Assignment of relative fire insurance.
c) Assignment of relative fire insurance - vehicles.
d) Assignment of relative fire insurance - liability.

All of the above security shall be referred to collectively in this Agreement as "Bank Security".

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:

a) To be drawn to retire existing maturing term loan facility.
b) Compliance with financial covenants pre and post drawdown.

REPRESENTATIONS AND WARRANTIES

All representations and warranties shall be deemed to be continually repeated 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 makes the Standard Representations and Warranties set out in Schedule "A".

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:

a) Comply with all applicable environmental regulations at all times.
b) Comply with all contractual obligations and laws, including payment of taxes, at all times.
c) Maintain adequate liability insurance.
d) File all OEB rate submissions as outlined in three year business plan.
e) 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.
f) LDC to remain in the regulated business of electricity distribution and maintain all requisite licenses to do so.
g) 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.)
h) Comply with Affiliate Relationship Code (legislated by OEB)
i) 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.

Reporting Covenants:

a) Provide Audited annual financial statements within 120 days of fiscal year end for Niagara Peninsula Energy Inc.
b) Provide annually within 120 days of fiscal year end a 1 year business plan for Niagara Peninsula Energy Inc. The Business plan will include an income statement and schedule of capital expenditures.
c) Provide unaudited quarterly financial statements within 45 days of Q1, Q2 and Q3 (Q4 not required) for Niagara Peninsula Energy Inc. Quarterly financial statement submissions to be accompanied by a Certificate of No Default, which details compliance calculations outlined under financial covenants.
d) Provide annual OEB rate submission and Service Quality Index (SQI), if applicable.

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:

a) Change its status as a Limited Distribution Company.
b) Change is ownership/control without the Bank's prior written consent.
c) Undertake further material outside investments, mergers, amalgamations or consolidations without the Bank's prior written consent.
d) Undertake additional debt or guarantees without the Bank's prior written consent.
e) Repay shareholder debt, beyond the permitted distributions outlined below, without the Bank's prior written consent.
f) Make distributions beyond (EBITDA- Cash Taxes- Unfinanced Capex (net of contributed capital) – Interest Costs- Principal, if any), on a combined basis with Niagara West Transformation Corporation, providing Debt Service Coverage test exceeds 1.25x and no other default has occurred.

PERMITTED LIENS

Permitted Liens as referred to in Schedule "A" are:
a) Purchase Money Security Interests, not to exceed $250,000.

FINANCIAL COVENANTS

The Borrower agrees at all times to:

a) Maintain a Debt Service Coverage ratio of 1.25x, defined as :

$$\frac{\text{Free Cash Flow (FCF)*}}{\text{Total Cash Interest Expense** + Mandatory Principal Payments}}$$

*Free Cash Flow (FCF) is defined as:
EBITDA less Cash taxes less 40% CAPEX (net of Contributed capital). To be calculated as the sum of the FCF of the Borrower and its pro rata share of the FCF generated by the Niagara West Transformation Corporation joint venture (net of any contra and related amounts).

** Total Cash Interest Expense is calculated as the interest expense sum of the Borrower's direct obligations and its pro rata share of the Niagara West Transformation Corporation joint venture obligations (net of accrual of any shareholder debt interest).
To be tested on a rolling 4 quarter basis.

b) 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, not subordinated to these credit facilities.

** 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.

Funded Debt and Capitalization to be calculated on a combined basis with the Borrower and its pro rata share of Niagara West Transformation Corporation.
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:

a) Any material adverse change in legislation or regulation of the electrical distribution business in Ontario.
b) Material judgements.
c) Loss of OEB License.
d) Cross Default to Niagara West Transformation Corporation.
e) Cross Default to Bank of Nova Scotia.

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 trust you will find these facilities helpful in meeting your ongoing financing requirements. We ask that if you wish to accept this offer of financing (which includes the Standard Terms and Conditions), please do so by signing and returning the attached duplicate copy of this letter to the undersigned. This offer will expire if not accepted in writing and received by the Bank on or before **July 20, 2009.**

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 16th day of July, 2009. 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.

Signature

Signature

Suzanne Wilson VP Finance
Print Name & Position

BRIAN WILKIE, PRESIDENT
Print Name & Position

SCHEDULE A
STANDARD TERMS AND CONDITIONS

1. INTEREST RATE DEFINITIONS

Prime Rate means the rate of interest per annum (based on a 365/366 day year) established and reported by the Bank to the Bank of Canada from time to time as the reference rate of interest for determination of interest rates that the Bank charges to customers of varying degrees of creditworthiness in Canada for Canadian dollar loans made by it in Canada.

The Stamping Fee rate per annum for CDN$ B/As is based on a 365/366 day year and the Stamping Fee is calculated on the Face Amount of each B/A presented to the Bank for acceptance. The Stamping Fee rate per annum for US$ B/As is based on a 360 day year and the Stamping Fee is calculated on the Face Amount of each B/A presented to the Bank for acceptance.

LIBOR means the rate of interest per annum (based on a 360 day year) as determined by the Bank (rounded upwards, if necessary to the nearest whole multiple of 1/16th of 1%) at which the Bank may make available United States dollars which are obtained by the Bank in the Interbank Euro Currency Market, London, England at approximately 11:00 a.m. (Toronto time) on the second Business Day before the first day of, and in an amount similar to, and for the period similar to the interest period of, such advance.

USBR means the rate of interest per annum (based on a 365/366 day year) established by the Bank from time to time as the reference rate of interest for the determination of interest rates that the Bank charges to customers of varying degrees of creditworthiness for US dollar loans made by it in Canada.

Any interest rate based on a period less than a year expressed as an annual rate for the purposes of the Interest Act (Canada) is equivalent to such determined rate multiplied by the actual number of days in the calendar year in which the same is to be ascertained and divided by the number of days in the period upon which it was based.

2. INTEREST CALCULATION AND PAYMENT

Interest on Prime Based Loans and USBR Loans is calculated daily and payable monthly in arrears based on the number of days the subject loan is outstanding unless otherwise provided in the Rate and Payment Terms Notice.

The Stamping Fee is calculated based on the amount and the term of the B/A and payable upon acceptance by the Bank of the B/A. The net proceeds received by the Borrower on a B/A advance will be equal to the Face Amount of the B/A discounted at the Bank's then prevailing B/A discount rate for CDN$ B/As or US$ B/As as the case may be, for the specified term of the B/A less the B/A Stamping Fee.

Interest on LIBOR Loans is calculated and payable on the earlier of contract maturity or quarterly in arrears, for the number of days in the LIBOR interest period.

L/C and L/G fees are payable at the time set out in the Letter of Credit Indemnity Agreement applicable to the issued L/C or L/G.

Interest on Fixed Rate Term Loans is compounded monthly and payable monthly in arrears unless otherwise provided in the Rate and Payment Terms Notice.

Interest is payable both before and after maturity or demand, default and judgment.

Each payment under this Agreement shall be applied first in payment of costs and expenses, then interest and fees and the balance, if any, shall be applied in reduction of principal.

For loans not secured by real property, all overdue amounts of principal and interest and all amounts outstanding in excess of the Credit Limit shall bear interest from the date on which the same became due or from when the excess was incurred, as the case may be, until the date of payment or until the date the excess is repaid at 21% per annum, or such lower interest rate if the Bank agrees to a lower interest rate in writing. Nothing in this clause shall be deemed to authorize the Borrower to incur loans in excess of the Credit Limit.

3. DRAWDOWN PROVISIONS

Prime Based and USBR Loans
There is no minimum amount of drawdown by way of Prime Based Loans and USBR Loans, except as stated in the section of the Agreement titled "Business Credit Services Agreement", if that section of the Agreement has not been deleted. The Borrower shall provide the Bank with 3 Business Days' notice of a requested Prime Based Loan or USBR Loan over $1,000,000.

B/As
The Borrower shall advise the Bank of the requested term or maturity date for B/As issued hereunder. The Bank shall have the discretion to restrict the term or maturity dates of B/As. In no event shall the term of the B/A exceed the Contractual Term Maturity Date. The minimum amount of a drawdown by way of B/As is $1,000,000 and in multiples of $100,000 thereafter. The Borrower shall provide the Bank with 3 Business Days' notice of a requested B/A drawdown.

The Borrower shall pay to the Bank the full amount of the B/A at the maturity date of the B/A.

The Borrower appoints the Bank as its attorney to and authorizes the Bank to (i) complete, sign, endorse, negotiate and deliver B/As on behalf of the Borrower in handwritten form, or by facsimile or mechanical signature or otherwise, (ii) accept such B/As, and (iii) purchase, discount, and/or negotiate B/As.

LIBOR
The Borrower shall advise the Bank of the requested LIBOR contract maturity period. The Bank shall have the discretion to restrict the LIBOR contract maturity. In no event shall the term of the LIBOR contract exceed the Contractual Term Maturity Date. The minimum amount of a drawdown by way of a LIBOR Loan is $1,000,000, and shall be in multiples of $100,000 thereafter. The Borrower will provide the Bank with 3 Business Days' notice of a requested LIBOR Loan.

L/C and/or L/G
The Bank shall have the discretion to restrict the maturity date of L/Gs or L/Cs.

B/A - Prime Conversion
The Borrower will provide the Bank with at least 3 Business Days' notice of its intention either to convert a B/A to a Prime Based Loan or vice versa, failing which, the Bank may decline to accept such additional B/As or may charge interest on the amount of Prime Based Loans resulting from maturity of B/As at the rate of 115% of the rate applicable to Prime Based Loans for the 3 Business Day period immediately following such maturity. Thereafter, the rate shall revert to the rate applicable to Prime Based Loans.

Notice
Prior to each drawdown and at least 10 days prior to each Rate Term Maturity, the Borrower will advise the Bank of its selection of drawdown options from those made available by the Bank. The Bank will, after each drawdown, other than drawdowns by way of BA, LIBOR Loan or under the operating loan, send a Rate and Payment Terms Notice to the Borrower.

4. PREPAYMENT

(a) 10% Prepayment Option Chosen. If the Borrower has elected a 10% Prepayment Option for a Facility the following shall apply to all Fixed Rate Loans made under that Facility. Each calendar year, ("Year"), the Borrower may prepay in one lump sum, once each Year, an amount outstanding under a Fixed Rate

Term Loan not exceeding 10% of the original amount of the Fixed Rate Term Loan being prepaid, upon payment of all interest accrued to the date of prepayment ("Prepayment Date") without paying any prepayment charge, provided that an Event of Default has not occurred. This privilege is not cumulative from Year to Year.

(b) 10% Prepayment Option Not Chosen or Borrower Prepaying More than 10%. During each Year, the Borrower may, provided that an Event of Default has not occurred:

if it has not chosen the 10% Prepayment Option, prepay all or any part of the principal then outstanding under Fixed Rate Term Loans, or,
if it has chosen the 10% Prepayment Option, prepay more than 10% of the original amount of the Fixed Rate Term Loan being prepaid, in any Year,

in either case, upon payment of all interest accrued to the Prepayment Date and prepayment charges equal to the greater of:

(a) three months' interest on the amount of the prepayment (and in the case where the Borrower has chosen the 10% Prepayment Option, the amount of prepayment is the amount of prepayment exceeding the 10% limit) using the interest rate applicable to the Fixed Rate Term Loan being prepaid; and

(b) the Interest Rate Differential, being the amount by which:

the total amount of interest on the amount of the prepayment using the interest rate applicable to the Fixed Rate Term Loan being prepaid calculated for the period of time equal to the Remaining Term, exceeds
the total amount of interest on the amount being prepaid using the interest rate applicable to a fixed rate term loan that the Bank would make to a borrower for a comparable facility on the Prepayment Date, calculated for the period of time from the Prepayment Date until the Rate Term Maturity Date for the Fixed Rate Term Loan being prepaid ("Remaining Term").

5. STANDARD DISBURSEMENT CONDITIONS

The obligation of the Bank to permit any drawdowns hereunder at any time is subject to the following conditions precedent:

a) The Bank shall have received the following documents which shall be in form and substance satisfactory to the Bank:
   i) A copy of a duly executed resolution of the Board of Directors of the Borrower empowering the Borrower to enter into this Agreement;
   ii) A copy of any necessary government approvals authorizing the Borrower to enter into this Agreement;
   iii) All of the Bank Security and supporting resolutions and solicitors' letter of opinion required hereunder;
   iv) The Borrower's compliance certificate certifying compliance with all terms and conditions hereunder;
   v) all operation of account documentation; and
   vi) For drawdowns under the Facility by way of L/C or L/G, the Bank's standard form Letter of Credit Indemnity Agreement

b) The representations and warranties contained in this Agreement are correct.

c) No event has occurred and is continuing which constitutes an Event of Default or would constitute an Event of Default, but for the requirement that notice be given or time elapse or both.

d) The Bank has received the arrangement fee payable hereunder (if any) and the Borrower has paid all legal and other expenses incurred by the Bank in connection with the Agreement or the Bank Security.

6. STANDARD REPRESENTATIONS AND WARRANTIES

The Borrower hereby represents and warrants, which representations and warranties shall be deemed to be continually repeated so long as any amounts remain outstanding and unpaid under this Agreement or so long as any commitment under this Agreement remains in effect, that:

a) The Borrower is a duly incorporated corporation, a limited partnership, partnership, or sole proprietorship, duly organized, validly existing and in good standing under the laws of the jurisdiction where the Branch/Centre is located and each other jurisdiction where the Borrower has property or assets or carries on business and the Borrower has adequate corporate power and authority to carry on its business, own property, borrow monies and enter into agreements therefore, execute and deliver the Agreement, the Bank Security, and documents required hereunder, and observe and perform the terms and provisions of this Agreement.

b) There are no laws, statutes or regulations applicable to or binding upon the Borrower and no provisions in its charter documents or in any by-laws, resolutions, contracts, agreements, or arrangements which would be contravened, breached, violated as a result of the execution, delivery, performance, observance, of any terms of this Agreement.

c) No Event of Default has occurred nor has any event occurred which, with the passage of time or the giving of notice, would constitute an Event of Default under this Agreement or which would constitute a default under any other agreement.

d) There are no actions, suits or proceedings, including appeals or applications for review, or any knowledge of pending actions, suits, or proceedings against the Borrower and its subsidiaries, before any court or administrative agency which would result in any material adverse change in the property, assets, financial condition, business or operations of the Borrower.

e) All material authorizations, approvals, consents, licenses, exemptions, filings, registrations and other requirements of governmental, judicial and public bodies and authorities required to carry on its business have been or will be obtained or effected and are or will be in full force and effect.

f) The financial statements and forecasts delivered to the Bank fairly present the present financial position of the Borrower, and have been prepared by the Borrower and its auditors in accordance with Canadian Generally Accepted Accounting Principles consistently applied.

g) All of the remittances required to be made by the Borrower to the federal government and all provincial and municipal governments have been made, are currently up to date and there are no outstanding arrears. Without limiting the foregoing, all employee source deductions (including income taxes, Employment Insurance and Canada Pension Plan), sales taxes (both provincial and federal), corporate income taxes, corporate capital taxes, payroll taxes and Workers' Compensation dues are currently paid and up to date.

7. STANDARD 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:

a) Pay all amounts of principal, interest and fees on the dates, times and place specified herein, under the Rate and Payment Terms Notice, and under any other agreement between the Bank and the Borrower.

b) Advise the Bank of any change in the amount and the terms of any credit arrangement made with other lenders or any action taken by another lender to recover amounts outstanding with such other lender.

c) Advise promptly after the happening of any event which will result in a material adverse change in the financial condition, business, operations, or prospects of the Borrower or the occurrence of any Event of Default or default under this Agreement or under any other agreement for borrowed money.

d) Do all things necessary to maintain in good standing its corporate existence and preserve and keep all material agreements, rights, franchises, licenses, operations, contracts or other arrangements in full force and effect.

e) Take all necessary actions to ensure that the Bank Security and its obligations hereunder will rank ahead of all other indebtedness of and all other security granted by the Borrower.

f) Pay all taxes, assessments and government charges unless such taxes, assessments, or charges are being contested in good faith and appropriate reserves shall be made with funds set aside in a separate trust fund.

g) Provide the Bank with information and financial data as it may request from time to time.

h) Maintain property, plant and equipment in good repair and working condition.

i) Inform the Bank of any actual or probable litigation and furnish the Bank with copies of details of any litigation or other proceedings, which might affect the financial condition, business, operations, or prospects of the Borrower.

j) Provide such additional security and documentation as may be required from time to time by the Bank or its solicitors.

k) Continue to carry on the business currently being carried on by the Borrower its subsidiaries and each of the Guarantors at the date hereof.

l) Maintain adequate insurance on all of its assets, undertakings, and business risks.

m) Permit the Bank or its authorized representatives full and reasonable access to its premises, business, financial and computer records and allow the duplication or extraction of pertinent information therefrom and

n) Comply with all applicable laws.

8. STANDARD 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 not and will ensure that its subsidiaries and each of the Guarantors will not:

a) Create, incur, assume, or suffer to exist, any mortgage, deed of trust, pledge, lien, security interest, assignment, charge, or encumbrance (including without limitation, any conditional sale, or other title retention agreement, or finance lease) of any nature, upon or with respect to any of its assets or undertakings, now owned or hereafter acquired, except for those Permitted Liens, if any, set out in the Letter.

b) Create, incur, assume or suffer to exist any other indebtedness for borrowed money (except for indebtedness resulting from Permitted Liens, if any) or guarantee or act as surety or agree to indemnify the debts of any other Person.

c) Merge or consolidate with any other Person, or acquire all or substantially all of the shares, assets or business of any other Person.

d) Sell, lease, assign, transfer, convey or otherwise dispose of any of its now owned or hereafter acquired assets (including, without limitation, shares of stock and indebtedness of subsidiaries, receivables and leasehold interests), except for inventory disposed of in the ordinary course of business.

e) Terminate or enter into a surrender of any lease of any property mortgaged under the Bank Security.

f) Cease to carry on the business currently being carried on by each of the Borrower, its subsidiaries, and the Guarantors at the date hereof.

g) Permit any change of ownership or change in the capital structure of the Borrower.

9. ENVIRONMENTAL

The Borrower represents and warrants (which representation and warranty shall continue throughout the term of this Agreement) that the business of the Borrower, its subsidiaries and each of the Guarantors is being operated in compliance with applicable laws and regulations respecting the discharge, omission, spill or disposal of any hazardous materials and that any and all enforcement actions in respect thereto have been clearly conveyed to the Bank.

The Borrower shall, at the request of the Bank from time to time, and at the Borrower's expense, obtain and provide to the Bank an environmental audit or inspection report of the property from auditors or inspectors acceptable to the Bank.

The Borrower hereby indemnifies the Bank, its officers, directors, employees, agents and shareholders, and agrees to hold each of them harmless from all loss, claims, damages and expenses (including legal and audit expenses) which may be suffered or incurred in connection with the Indebtedness under this Agreement or in connection with the Bank Security.

10. STANDARD 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 following Events of Default:

a) Non-payment of principal outstanding under this Agreement when due or non-payment of interest or fees outstanding under this Agreement within 3 Business Days of when due.

b) If any representation, warranty or statement made hereunder or made in connection with the execution and delivery of this Agreement or the Bank Security is false or misleading at any time.

c) If there is a breach or non-performance or non-observance of any term or condition of this Agreement or the Bank Security and, if such default is capable to being remedied, the default continues unremedied for 5 Business Days after the occurrence.

d) If the Borrower, any one of its subsidiaries, or, if any of the Guarantors makes a general assignment for the benefit of creditors, files or presents a petition, makes a proposal or commits any act of bankruptcy, or if any action is taken for the winding up, liquidation or the appointment of a liquidator, trustee in bankruptcy, custodian, curator, sequestrator, receiver or any other officer with similar powers or if a judgment or order shall be entered by any court approving a petition for reorganization, arrangement or composition of or in respect of the Borrower, any of its subsidiaries, or any of the Guarantors or if the Borrower, any of its subsidiaries, or any of the Guarantors is insolvent or declared bankrupt.

e) If there exists a voluntary or involuntary suspension of business of the Borrower, any of its subsidiaries, or any of the Guarantors.

f) If action is taken by an encumbrancer against the Borrower, any of its subsidiaries, or any of the Guarantors to take possession of property or enforce proceedings against any assets.

g) If any final judgment for the payment of monies is made against the Borrower, any of its subsidiaries, or any of the Guarantors and it is not discharged within 30 days from the imposition of such judgment.

h) If there exists an event, the effect of which with lapse of time or the giving of notice, will constitute an event of default or a default under any other agreement for borrowed money in excess the Cross Default Threshold entered into by the Borrower, any of its subsidiaries, or any of the Guarantors.

i) If the Bank Security is not enforceable or if any party to the Bank Security shall dispute or deny any liability or any of its obligations under the Bank Security.

j) If, in the Bank's determination, a material adverse change occurs in the financial condition, business operations or prospects of the Borrower, any of the Borrower's subsidiaries, or any of the Guarantors.

11. ACCELERATION

If the Bank accelerates the payment of principal and interest hereunder, the Borrower shall immediately pay to the Bank all amounts outstanding hereunder, including without limitation, the amount of unmatured B/As and LIBOR Loans and the amount of all drawn and undrawn L/Gs and L/Cs. All cost to the Bank of unwinding LIBOR Loans and all loss suffered by the Bank in re-employing amounts repaid will be paid by the Borrower.

The Bank may demand the payment of principal and interest under the Operating Loan (and any other uncommitted facility) hereunder and cancel any undrawn portion of the Operating Loan (and any other uncommitted facility) hereunder, at any time whether or not an Event of Default has occurred.

12. CURRENCY INDEMNITY
US$ loans must be repaid with US$ and CDN$ loans must be repaid with CDN$ and the Borrower shall indemnify the Bank for any loss suffered by the Bank if US$ loans are repaid with CDN$ or vice versa, whether such payment is made pursuant to an order of a court or otherwise.

13. TAXATION ON PAYMENTS
All payments made by the Borrower to the Bank will be made free and clear of all present and future taxes (excluding the Bank's income taxes), withholdings or deductions of whatever nature. If these taxes, withholdings or deductions are required by applicable law and are made, the Borrower, shall, as a separate and independent obligation, pay to the Bank all additional amounts as shall fully indemnify the Bank from any such taxes, withholdings or deductions.

14. REPRESENTATION
No representation or warranty or other statement made by the Bank concerning any of the credit facilities shall be binding on the Bank unless made by it in writing as a specific amendment to this Agreement.

15. ADDED COST
If the introduction of or any change in any present or future law, regulation, treaty, official or unofficial directive, or regulatory requirement, (whether or not having the force of law) or in the interpretation or application thereof, relates to:

i) the imposition or exemption of taxation of payments due to the Bank or on reserves or deemed reserves in respect of the undrawn portion of any Facility or loan made available hereunder; or,

ii) any reserve, special deposit, regulatory or similar requirement against assets, deposits, or loans or other acquisition of funds for loans by the Bank; or,

iii) the amount of capital required or expected to be maintained by the Bank as a result of the existence of the advances or the commitment made hereunder;

and the result of such occurrence is, in the sole determination of the Bank, to increase the cost of the Bank or to reduce the income received or receivable by the Bank hereunder, the Borrower shall, on demand by the Bank, pay to the Bank that amount which the Bank estimates will compensate it for such additional cost or reduction in income and the Bank's estimate shall be conclusive, absent manifest error.

16. EXPENSES
The Borrower shall pay, within 5 Business Days following notification, all fees and expenses (including but not limited to all legal fees) incurred by the Bank in connection with the preparation, registration and ongoing administration of this Agreement and the Bank Security and with the enforcement of the Bank's rights and remedies under this Agreement and the Bank Security whether or not any amounts are advanced under the Agreement. These fees and expenses shall include, but not be limited, to all outside counsel fees and expenses and all in-house legal fees and expenses, if in-house counsel are used, and all outside professional advisory fees and expenses. The Borrower shall pay interest on unpaid amounts due pursuant to this paragraph at the All-In Rate plus 2% per annum.

17. NON WAIVER
Any failure by the Bank to object to or take action with respect to a breach of this Agreement or any Bank Security or upon the occurrence of an Event of Default shall not constitute a waiver of the Bank's right to take action at a later date on that breach. No course of conduct by the Bank will give rise to any reasonable expectation which is in any way inconsistent with the terms and conditions of this Agreement and the Bank Security or the Bank's rights thereunder.

18. EVIDENCE OF INDEBTEDNESS
The Bank shall record on its records the amount of all loans made hereunder, payments made in respect thereto, and all other amounts becoming due to the Bank under this Agreement. The Bank's records constitute, in the absence of manifest error, conclusive evidence of the indebtedness of the Borrower to the Bank pursuant to this Agreement.

The Borrower will sign the Bank's standard form Letter of Credit Indemnity Agreement for all L/Cs and L/Gs issued by the Bank.

With respect to chattel mortgages taken as Bank Security, this Agreement is the Promissory Note referred to in same chattel mortgage, and the indebtedness incurred hereunder is the true indebtedness secured by the chattel mortgage.

19. ENTIRE AGREEMENTS
This Agreement replaces any previous letter agreements dealing specifically with terms and conditions of the credit facilities described in the Letter. Agreements relating to other credit facilities made available by the Bank continue to apply for those other credit facilities. This Agreement, and if applicable, the Letter of Credit Indemnity Agreement, are the entire agreements relating to the Facilities described in this Agreement.

20. ASSIGNMENT
The Bank may assign or grant participation in all or part of this Agreement or in any loan made hereunder without notice to and without the Borrower's consent.

The Borrower may not assign or transfer all or any part of its rights or obligations under this Agreement.

21. RELEASE OF INFORMATION
The Borrower hereby irrevocably authorizes and directs the Borrower's accountant, (the "Accountant") to deliver all financial statements and other financial information concerning the Borrower to the Bank and agrees that the Bank and the Accountant may communicate directly with each other.

22. FX CLOSE OUT
The Borrower hereby acknowledges and agrees that in the event any of the following occur: (i) Default by the Borrower under any forward foreign exchange contract ("FX Contract"); (ii) Default by the Borrower in payment of monies owing by it to anyone, including the Bank; (iii) Default in the performance of any other obligation of the Borrower under any agreement to which it is subject; or (iv) the Borrower is adjudged to be or voluntarily becomes bankrupt or insolvent or admits in writing to its inability to pay its debts as they come due or has a receiver appointed over its assets, the Bank shall be entitled without advance notice to the Borrower to close out and terminate all of the outstanding FX Contracts entered into hereunder, using normal commercial practices employed by the Bank, to determine the gain or loss for each terminated FX contract. The Bank shall then be entitled to calculate a net termination value for all of the terminated FX Contracts which shall be the net sum of all the losses and gains arising from the termination of the FX Contracts which net sum shall be the "Close Out Value" of the terminated FX Contracts. The Borrower acknowledges that it shall be required to forthwith pay any positive Close Out Value owing to the Bank and the Bank shall be required to pay ant negative Close Out Value owing to the Borrower, subject to any rights of set-off to which the Bank is entitled or subject.

23. SET-OFF
In addition to and not in limitation of any rights now or hereafter granted under applicable law, the Bank may at any time and from time to time without notice to the Borrower or any other Person, any notice being expressly waived by the Borrower, set-off and compensate and apply any and all deposits, general or special, time or demand, provisional or final, matured or unmatured, in any currency, and any other indebtedness or amount payable by the Bank (irrespective of the place of payment or booking office of the obligation), to or for the credit of or for the Borrower's account, including without limitation, any amount owed by the Bank to the Borrower under any FX Contract or other treasury or derivative product, against and on account of the indebtedness and liability under this Agreement notwithstanding that any of them are contingent or unmatured or in a different currency than the indebtedness and liability under this Agreement.

When applying a deposit or other obligation in a different currency than the indebtedness and liability under this Agreement to the indebtedness and liability under this Agreement, the Bank will convert the deposit or other obligation to the currency of the indebtedness and liability under this Agreement using the Bank's noon spot rate of exchange for the conversion of such currency.

24. USE OF INFORMATION

The word "Information" means the Borrower's business and credit information and the Guarantor's personal, business and credit information. It includes information provided to the Bank by the Borrower and Guarantors, including through the products and services the Borrower and Guarantor(s) uses, and information obtained from others.

The Borrower and the Guarantor agree to the use of its Information as follows:
Use of Information - The Bank may use Information to establish and serve the Borrower as its customer, determine whether any products or services of the TD Bank Financial Group are suitable for the Borrower and offer them to the Borrower, or when required or permitted by law. The Bank may share Information within the TD Bank Financial Group where permitted by law;
Collection and Use of Credit Information - THE BANK MAY OBTAIN INFORMATION FROM PARTIES OUTSIDE THE TD BANK FINANCIAL GROUP, INCLUDING THROUGH A CREDIT CHECK, AND VERIFY INFORMATION WITH THEM. THE BORROWER AND THE GUARANTOR AUTHORIZE THOSE PARTIES TO GIVE THE BANK INFORMATION. The Bank may disclose Information to other lenders and credit bureaus.

The Borrower and the Guarantor may obtain the Bank's Privacy Code - "Protecting Your Privacy" or review its options for refusing or withdrawing this consent, including its option not to be contacted about offers of products or services, by contacting the Branch or calling the Bank at 1-800-9TD BANK.

25. MISCELLANEOUS

i) The Borrower has received a signed copy of this Agreement;

ii) If more than one Person, firm or corporation signs this Agreement as the Borrower, each party is jointly and severally liable hereunder, and the Bank may require payment of all amounts payable under this Agreement from any one of them, or a portion from each, but the Bank is released from any of its obligations by performing that obligation to any one of them;

iii) Accounting terms will (to the extent not defined in this Agreement) be interpreted in accordance with accounting principles established from time to time by the Canadian Institute of Chartered Accountants (or any successor) consistently applied, and all financial statements and information provided to the Bank will be prepared in accordance with those principles;

iv) This Agreement is governed by the law of the Province or Territory where the Branch/Centre is located.

v) Unless stated otherwise, all amounts referred to herein are in Canadian dollars

26. DEFINITIONS

Capitalized Terms used in this Agreement shall have the following meanings:

"All-In Rate" means the greater of the Interest Rate that the Borrower pays for Prime Based Loans (which for greater certainty includes the percent per annum added to the Prime Rate) or the highest fixed rate paid for Fixed Rate Term Loans.

"Agreement" means the agreement between the Bank and the Borrower set out in the Letter and this Schedule "A" - Standard Terms and Conditions.

"Business Day" means any day (other than a Saturday or Sunday) that the Branch/Centre is open for business.

"Branch/Centre" means The Toronto-Dominion Bank branch or banking centre noted on the first page of the Letter, or such other branch or centre as may from time to time be designated by the Bank.

"Contractual Term Maturity Date" means the date set out in the Letter under the heading "Contractual Term".

"Face Amount" means, in respect of:

(i) a B/A, the amount payable to the holder thereof on its maturity;
(ii) A L/C or L/G, the maximum amount payable to the beneficiary specified therein or any other Person to whom payments may be required to be made pursuant to such L/C or L/G.

"Fixed Rate Term Loan" means any drawdown in Canadian dollars under a Credit Facility at an interest rate which is fixed for a Rate Term at such rate as is determined by the Bank as its sole discretion.

"Inventory Value" means, at any time of determination, the total value (based on the lower of cost or market) of the Borrower's inventories that are subject to the Bank Security (other than (i) those inventories supplied by trade creditors who at that time have not been fully paid therefore and would have a right to repossess all or part of such inventories if the Borrower were then either bankrupt or in receivership, (ii) those inventories comprising work in process and (iii) those inventories that the Bank may from time to time designate in its sole discretion) minus the total amount of any claims, liens or encumbrances on those inventories having or purporting to have priority over the Bank.

"Letter" means the letter from the Bank to the Borrower to which this Schedule "A" - Standard Terms and Conditions is attached.

"Letter of Credit" or *"L/C"* means a documentary letter of credit or similar instrument in form and substance satisfactory to the Bank.

"Letter of Guarantee" or *"L/G"* means a stand-by letter of guarantee or similar instrument in form and substance satisfactory to the Bank.

"Person" includes any individual, sole proprietorship, corporation, partnership, joint venture, trust, unincorporated association, association, institution, entity, party, or government (whether national, federal, provincial, state, municipal, city, county, or otherwise and including any instrumentality, division, agency, body, or department thereof).

"Purchase Money Security Interest" means a security interest on equipment which is granted to a lender or to the seller of such equipment in order to secure the purchase price of such equipment or a loan to acquire such equipment, provided that the amount secured by the security interest does not exceed the cost of the equipment, the Borrower provides written notice to the Bank prior to the creation of the security interest, and the creditor under the security interest has, if requested by the Bank, entered into an inter-creditor agreement with the Bank, in a format acceptable to the Bank.

"Rate Term" means that period of time as selected by the Borrower from the options offered to it by the Bank, during which a Fixed Rate Term Loan will bear a particular interest rate. If no Rate Term is selected, the Borrower will be deemed to have selected a Rate Term of 1 year.

"Rate Term Maturity" means the last day of a Rate Term which day may never exceed the Contractual Term Maturity Date.

"Rate and Payment Terms Notice" means the notice sent by the Bank setting out the interest rate and payment terms for a particular drawdown.

"Receivable Value" means, at any time of determination, the total value of those of the Borrower's trade accounts receivable that are subject to the Bank Security other than (i) those accounts then outstanding for 90 days, (ii) those accounts owing by Persons, firms or corporations affiliated with the Borrower, (iii) those accounts that the Bank may from time to time designate in its sole discretion, (iv) those accounts subject to any claim, liens, or encumbrance having or purporting to have priority over the Bank, (v) those accounts which are subject to a claim of set-off by the obligor under such account, MINUS the total amount of all claims, liens, or encumbrances on those receivables having or purporting to have priority over the Bank.

"Receivables/Inventory Summary" means a summary of the Customer's trade account receivables and inventories, in form as the Bank may require and certified by a senior officer/representative of the Borrower.

"US$ Equivalent" means, on any date, the equivalent amount in United States Dollars after giving effect to a conversion of a specified amount of Canadian Dollars to United States Dollars at the Bank's noon spot rate of exchange for Canadian Dollars to United States Dollars established by the Bank for the day in question.

TD Commercial Banking

Commercial Banking Centre
40 King Street
St. Catharines, Ontario
L2R 3H4

Telephone No.: 905 685-7631
Fax No.: 905 685-7053

December 20, 2010

Niagara Peninsula Energy Inc.
7447 Pin Oak Drive
Niagara Falls, Ontario
L2E 6S9

Attention: Mr. Brian Wilkie, President

Dear Mr. 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.

BORROWER

Niagara Peninsula Energy Inc. (the "Borrower")

LENDER

The Toronto-Dominion Bank (the "Bank"), through its 40 King Street branch, in St. Catharines, Ontario.

FINANCIAL COVENANTS

The Borrower agrees at all times to:

a) Maintain a Debt Service Coverage ratio of 1.25x defined as:

$$\frac{\text{Free Cash Flow (FCF)}^{*}}{\text{Total Cash Interest Expenses}^{**} + \text{Mandatory principal payments}}$$

* *Free Cash Flow (FCF) is defined as:*
EBITDA less Cash Taxes less 40% of CAPEX (net of contributed capital)
** Total Cash Interest Expense is calculated as the interest expense sum of the Borrower's direct obligations.
To be tested on a rolling 4 quarter basis.

b) 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, not subordinated to these credit facilities.
** 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.

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.

Unless otherwise stated, the amendments outlined above are in addition to the Terms and Conditions of the existing Agreement. All other terms and conditions remain unchanged. We ask that you acknowledge your agreement to these amendments by signing and returning the attached duplicate copy of this Amending Agreement to the undersigned. The amendments will not come into force unless the duplicate of this Amending Agreement is received by the Bank on or before **January 20, 2011.**

Yours truly,

THE TORONTO-DOMINION BANK

David Drosky
Manager

Greg Hoekman
Manager Commercial Credit

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TO THE TORONTO-DOMINION BANK:

Niagara Peninsula Energy Inc. hereby accepts the foregoing offer this 5th day of Jan, 20 11. The Borrower confirms that, except as may be set out above, the credit facility(ies) detailed herein shall not be used by or on behalf of any third party.

X ______________________
Brian Wilkie, President

____
Suzanne Wilson, VP Finance

TD Commercial Banking

St. Catharines
40 King St
St Catharines, ON
L2R 3H4
Telephone No.: (905) 685 7631
Fax No.: (905) 685 7053

June 21, 2012

NIAGARA PENINSULA ENERGY INC.
7447 Pin Oak Drive
Niagara Falls, Ontario
L2E 6S9

Attention: Brian Wilkie, President

Dear Mr. 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 Agreement dated December 20, 2010.

BORROWER
NIAGARA PENINSULA ENERGY INC. (the "Borrower")

LENDER
The Toronto-Dominion Bank (the "Bank"), through its 40 King St. branch in St Catharines, Ontario.

CREDIT LIMIT

2) CDN$10,000,000.

TYPE OF CREDIT AND BORROWING OPTIONS

2) Committed Term Facility (Single Draw) available at the Borrower's option by way of:
- Fixed Rate Term Loan in CAD$

PURPOSE
2) General purposes including repatriation of funds previously utilized for past years capital expenditures.

TENOR
2) Committed

CONTRACTUAL TERM
2) Up to 60 months from the date of drawdown.

RATE TERM
(FIXED RATE
TERM LOAN)

2) Fixed rate: Up to 60 months but never to exceed the Contractual Term Maturity Date

INTEREST RATES
AND FEES

Advances shall bear interest and fees as follows:

2) Committed Term Facility:
- Fixed Rate Term Loans: Cost of Funds (COF) + 0.35% 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

2) 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

2) Interest only monthly for up to 5 years with full principal repayment at end of contractual term.

PREPAYMENT

2) 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:

a) Acknowledgement from BNS as per Intercreditor Agreement dated July 31, 2009 - Section 16.

b) Executed Loan Amending Agreement.

c) To be in compliance with financial covenants pre and post advance, based on the most recent financial reporting including confirmation of compliance with BNS covenants pre and post advance.

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) 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) Comply with Affiliate Relationship Code (legislated by OEB).

1,2) Comply with all applicable environmental regulations at all times.

1,2) Comply with all contractual obligations and laws, including payment of taxes, at all times.

1,2) 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) File all OEB rate submissions as outlined in three year business plan.

1,2) LDC to remain in the regulated business of electricity distribution and maintain all requisite licenses to do so.

1,2) Maintain adequate liability insurance.

1,2) Provide Audited annual financial statements within 120 days of fiscal year end for Niagara Peninsula Energy Inc. To be accompanied by a Certificate of No Default, which details compliance calculations outlined under financial conditions (provide annually).

1,2) Provide annual OEB rate submission and Service Quality Index (SQI), if applicable.

1,2) 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) Provide unaudited quarterly financial statements within 45 days of Q1, Q2 and Q3 (Q4 not required) for Niagara Peninsula Energy Inc.

1,2) 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) Change its ownership/control without the Bank's prior written consent.

1,2) Change its status as a Limited Distribution Company.

1,2) Make distributions beyond (EBITDA - Cash Taxes - Unfinanced Capex (net of contributed capital) - Interest Costs - Principal, if any), providing Debt Service Coverage test exceeds 1.25x and no other default has occurred.

1,2) Repay shareholder debt, beyond the permitted distributions outlined below, without the Bank's prior written consent.

1,2) Undertake additional debt or guarantees without the Bank's prior written consent.

1,2) 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) 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, 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.

1,2) Maintain a Debt Service Coverage ratio of 1.25x defined as:

$$\frac{\text{Free Cash Flow (FCF) *}}{\text{Total Cash Interest Expenses** + Mandatory principal payments}}$$

* Free Cash Flow (FCF) is defined as:
EBITDA less Cash taxes less 40% CAPEX (net of Contributed capital).

** Total Cash Interest Expense is calculated as the interest expense sum of the Borrower's direct obligations

To be tested on a rolling four quarter basis.

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) Any material adverse change in legislation or regulation of the electrical distribution business in Ontario.

1,2) Cross Default to Bank of Nova Scotia.

1,2) Loss of OEB License.

1,2) 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.

Unless otherwise stated, the amendments outlined above are in addition to the Terms and Conditions of the existing Agreement. All other terms and conditions remain unchanged.

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 **June 27, 2012.**

Yours truly,

THE TORONTO-DOMINION BANK

David Drosky
Manager

Greg Hoekman
Manager Commercial Credit

4

TO THE TORONTO-DOMINION BANK:

NIAGARA PENINSULA ENERGY INC. hereby accepts the foregoing offer this 22 day of June, 2012. 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

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TD Commercial Banking

40 King St
St Catharines, ON
L2R 3H4

Telephone No.: (905) 685 7631
Fax No.: (905) 685 7053

November 22, 2013

NIAGARA PENINSULA ENERGY INC.
7447 Pin Oak Drive
Niagara Falls, Ontario
L2E 6S9

Attention: Brian Wilkie, President

Dear Mr. 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 Agreement(s) dated December 20, 2010 and June 21, 2012.

BORROWER

NIAGARA PENINSULA ENERGY INC. (the "Borrower")

LENDER

The Toronto-Dominion Bank (the "Bank"), through its 40 King Street branch, in St Catharines, Ontario.

CREDIT LIMIT

3) CAD$10,000,000.

TYPE OF CREDIT AND BORROWING OPTIONS

3) Committed Term Facility (Single Draw) available at the Borrower's option by way of:
- Fixed Rate Term Loan in CAD$

PURPOSE

3) Repatriation of funds previously utilized for past years capital expenditures.

TENOR

3) Committed

CONTRACTUAL TERM

3) Up to 60 months from the date of drawdown

RATE TERM (FIXED RATE TERM LOAN)

3) Fixed rate. Up to 60 months but never to exceed the Contractual Term Maturity Date

INTEREST RATES AND FEES

Advances shall bear interest and fees as follows:

3) Committed Term Facility:

- Fixed Rate Term Loans: Cost of Funds (COF) + 0.32% 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

3) 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

3) Interest only monthly for up to 5 years with full principal repayment at the end of contractual term.

PREPAYMENT

3) 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 both the TD Bank and Bank of Nova Scotia deals, 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) 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) Comply with Affiliate Relationship Code (legislated by OEB).

1,2,3) Comply with all applicable environmental regulations at all times.

1,2,3) Comply with all contractual obligations and laws, including payment of taxes, at all times.

1,2,3) 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) File all OEB rate submissions as outlined in three year business plan.

1,2,3) LDC to remain in the regulated business of electricity distribution and maintain all requisite licenses to do so.

1,2,3) Maintain adequate liability insurance.

1,2,3) Provide Audited annual financial statements within 120 days of fiscal year end for Niagara Peninsula Energy Inc.

1,2,3) Provide annual OEB rate submission and Service Quality Index (SQI), if applicable.

1,2,3) 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) Provide unaudited quarterly financial statements within 45 days of Q1, Q2 and Q3 (Q4 not required) for Niagara Peninsula Energy Inc.

1,2,3) 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) Change its ownership/control without the Bank's prior written consent.

1,2,3) Change its status as a Limited Distribution Company.

1,2,3) 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** (~~1.25x~~) and no other default has occurred. ✓

1,2,3) Repay shareholder debt, beyond the permitted distributions outlined below, without the Bank's prior written consent.

1,2,3) Undertake additional debt or guarantees without the Bank's prior written consent.

1,2,3) 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) Maintain a Minimum Debt Service Coverage Ratio of **1.20x** (~~1.25x~~) defined as: ✓

$$\frac{\text{EBITDA*} - \text{Cash Taxes (PILS)} - 40\% \text{ of Capital Expenditures (net of contributed capital)}}{\text{Mandatory Principal + Interest}}$$

*EBITDA is defined as Earnings before Interest, Income Taxes, Depreciation and Amortization

To be tested on a rolling four quarter basis.

1,2,3) Maintain a Notional Minimum Debt Service Coverage Ratio of 1.20x defined as:

$$\frac{\text{EBITDA*} - \text{Cash Taxes (PILS)} - 40\% \text{ of Capital Expenditures (net of contributed capital)}}{\text{Principal** + Interest}}$$

*EBITDA is defined as Earnings before Interest, Income Taxes, Depreciation and Amortization

3

** 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) 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) Any material adverse change in legislation or regulation of the electrical distribution business in Ontario.

1,2,3) Cross Default to Bank of Nova Scotia.

1,2,3) Loss of OEB License.

1,2,3) 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 **December 4, 2013**

Yours truly,

THE TORONTO-DOMINION BANK

David Drosky
Manager

Greg Hoekman
Manager Commercial Credit

4

TO THE TORONTO-DOMINION BANK:

NIAGARA PENINSULA ENERGY INC. hereby accepts the foregoing offer this 26th day of November 2013. The Borrower confirms that, except as may be set out above, the credit facilities detailed herein shall not be used by or on behalf of any third party.

Brian Wilkie - President

Suzanne Wilson – VP Finance

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:

$$\frac{\text{EBITDA* - Cash Taxes (PILS) - 40\% of Capital Expenditures (net of contributed capital)}}{\text{Principal** + Interest}}$$

*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	Greg Hoekman
Manager	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

S. Wilson

Suzanne Wilson – VP Finance

Schedule A

Scotiabank

Trade date:	19-Nov-09	
Advance date:	30-Sep-10	
Amount of fixed rate advance:	4,500,000.00	
Term:	5 years	
Day Count:	Act/365	
New customer loan rate:	**4.97%**	**Monthly**
Prepayments:	**Not permitted except subject to break costs as calculated by Global Capital Markets**	
Lending branch:	Ontario BSC 87866	
Borrower:	Niagara Peninsula Energy	

Period Start	Period End (and payment)	Outstanding Principal	Principal Payment	All-in Deposit Interest at	Total Payment
	30-Sep-10		4,500,000.00		
30-Sep-10	29-Oct-10	-4,500,000.00	37,500.00	17,769.45	55,269.45
29-Oct-10	30-Nov-10	-4,462,500.00	37,500.00	19,444.27	56,944.27
30-Nov-10	30-Dec-10	-4,425,000.00	37,500.00	18,075.82	55,575.82
30-Dec-10	31-Jan-11	-4,387,500.00	37,500.00	19,117.48	56,617.48
31-Jan-11	28-Feb-11	-4,350,000.00	37,500.00	16,584.82	54,084.82
28-Feb-11	30-Mar-11	-4,312,500.00	37,500.00	17,616.27	55,116.27
30-Mar-11	29-Apr-11	-4,275,000.00	37,500.00	17,463.08	54,963.08
29-Apr-11	30-May-11	-4,237,500.00	37,500.00	17,886.89	55,386.89
30-May-11	30-Jun-11	-4,200,000.00	37,500.00	17,728.60	55,228.60
30-Jun-11	29-Jul-11	-4,162,500.00	37,500.00	16,436.74	53,936.74
29-Jul-11	30-Aug-11	-4,125,000.00	37,500.00	17,973.70	55,473.70
30-Aug-11	30-Sep-11	-4,087,500.00	37,500.00	17,253.73	54,753.73
30-Sep-11	31-Oct-11	-4,050,000.00	37,500.00	17,095.44	54,595.44
31-Oct-11	30-Nov-11	-4,012,500.00	37,500.00	16,390.79	53,890.79
30-Nov-11	30-Dec-11	-3,975,000.00	37,500.00	16,237.60	53,737.60
30-Dec-11	30-Jan-12	-3,937,500.00	37,500.00	16,620.57	54,120.57
30-Jan-12	29-Feb-12	-3,900,000.00	37,500.00	15,931.23	53,431.23
29-Feb-12	30-Mar-12	-3,862,500.00	37,500.00	15,778.05	53,278.05

450,000
205,358.23

30-Mar-12	30-Apr-12	-3,825,000.00	37,500.00	16,145.69	53,645.69
30-Apr-12	30-May-12	-3,787,500.00	37,500.00	15,471.68	52,971.68
30-May-12	29-Jun-12	-3,750,000.00	37,500.00	15,318.49	52,818.49
29-Jun-12	30-Jul-12	-3,712,500.00	37,500.00	15,670.82	53,170.82
30-Jul-12	30-Aug-12	-3,675,000.00	37,500.00	15,512.53	53,012.53
30-Aug-12	28-Sep-12	-3,637,500.00	37,500.00	14,363.64	51,863.64
28-Sep-12	30-Oct-12	-3,600,000.00	37,500.00	15,686.14	53,186.14
30-Oct-12	30-Nov-12	-3,562,500.00	37,500.00	15,037.65	52,537.65
30-Nov-12	31-Dec-12	-3,525,000.00	37,500.00	14,879.36	52,379.36
31-Dec-12	30-Jan-13	-3,487,500.00	37,500.00	14,246.20	51,746.20
30-Jan-13	28-Feb-13	-3,450,000.00	37,500.00	13,623.25	51,123.25
28-Feb-13	28-Mar-13	-3,412,500.00	37,500.00	13,010.51	50,510.51
28-Mar-13	30-Apr-13	-3,375,000.00	37,500.00	15,165.31	52,665.31
30-Apr-13	30-May-13	-3,337,500.00	37,500.00	13,633.46	51,133.46
30-May-13	28-Jun-13	-3,300,000.00	37,500.00	13,030.93	50,530.93
28-Jun-13	30-Jul-13	-3,262,500.00	37,500.00	14,215.56	51,715.56
30-Jul-13	30-Aug-13	-3,225,000.00	37,500.00	13,613.03	51,113.03
30-Aug-13	30-Sep-13	-3,187,500.00	37,500.00	13,454.74	50,954.74
30-Sep-13	30-Oct-13	-3,150,000.00	37,500.00	12,867.53	50,367.53
30-Oct-13	29-Nov-13	-3,112,500.00	37,500.00	12,714.35	50,214.35
29-Nov-13	30-Dec-13	-3,075,000.00	37,500.00	12,979.87	50,479.87
30-Dec-13	30-Jan-14	-3,037,500.00	37,500.00	12,821.58	50,321.58
30-Jan-14	28-Feb-14	-3,000,000.00	37,500.00	11,846.30	49,346.30
28-Feb-14	31-Mar-14	-2,962,500.00	37,500.00	12,505.00	50,005.00
31-Mar-14	30-Apr-14	-2,925,000.00	37,500.00	11,948.42	49,448.42
30-Apr-14	30-May-14	-2,887,500.00	37,500.00	11,795.24	49,295.24
30-May-14	30-Jun-14	-2,850,000.00	37,500.00	12,030.12	49,530.12
30-Jun-14	30-Jul-14	-2,812,500.00	37,500.00	11,488.87	48,988.87
30-Jul-14	29-Aug-14	-2,775,000.00	37,500.00	11,335.68	48,835.68
29-Aug-14	30-Sep-14	-2,737,500.00	37,500.00	11,928.00	49,428.00
30-Sep-14	30-Oct-14	-2,700,000.00	37,500.00	11,029.32	48,529.32
30-Oct-14	28-Nov-14	-2,662,500.00	37,500.00	10,513.59	48,013.59
28-Nov-14	30-Dec-14	-2,625,000.00	37,500.00	11,437.81	48,937.81
30-Dec-14	30-Jan-15	-2,587,500.00	37,500.00	10,922.09	48,422.09
30-Jan-15	27-Feb-15	-2,550,000.00	37,500.00	9,722.14	47,222.14
27-Feb-15	30-Mar-15	-2,512,500.00	37,500.00	10,605.50	48,105.50
30-Mar-15	30-Apr-15	-2,475,000.00	37,500.00	10,447.21	47,947.21
30-Apr-15	29-May-15	-2,437,500.00	37,500.00	9,625.12	47,125.12
29-May-15	30-Jun-15	-2,400,000.00	37,500.00	10,457.42	47,957.42
30-Jun-15	30-Jul-15	-2,362,500.00	37,500.00	9,650.65	47,150.65
30-Jul-15	31-Aug-15	-2,325,000.00	37,500.00	10,130.63	47,630.63
31-Aug-15	30-Sep-15	-2,287,500.00	2,287,500.00	9,344.28	2,296,844.28

450,000
184,041.48
450,000
162,554
(22,349.68)
450,000
140,479.93
2,350,000
90,905.04

TD Commercial Banking

COMMERCIAL LOAN AMORTIZATION SCHEDULE

	Enter values
Loan amount	$ 9,000,000.00
Annual Interest Rate	4.58 %
Monthly Equivalent Rate	4.58 %
Rate Term in months	120
Amortization period in months	120
Number of payments per year	12
Start Date	20-Jul-09
First Payment Date	20-Aug-09
Rate Term Maturity Date	20-Jul-19

Client Name:	NIAGARA PENINSULA ENERGY INC.
Sales Branch:	3524
Loan Number:	9315069-12

Loan summary	
Scheduled payment actual	$ 93,441.92
Payment frequency	monthly
Scheduled number of payments	120
Total interest	$ 2,243,398.24
Balance at End of Rate Term	$ 30,367.84

This Schedule has been provided to you at your request for your convenience. While every reasonable effort has been made to ensure accurate calculations, we cannot guarantee them. The information contained herein is based on certain assumptions and is for illustration purposes only. It is not to be relied on. The terms and conditions of the lending agreements you sign with TD shall govern your payment obligations and if there is any inconsistency between the information contained in this schedule and the terms and conditions of the lending agreements, the lending agreements shall govern. Any legal or tax issues should be confirmed by your own legal or tax advisors.

No.	Payment Date	Beginning Balance	Scheduled Payment	Principal	Interest	Ending Balance	Cumulative Interest	Days
1	8/20/2009	9,000,000.00	93,441.92	58,433.15	35,008.77	8,941,566.85	35,008.77	31
2	9/20/2009	8,941,566.85	93,441.92	58,660.45	34,781.47	8,882,906.40	69,790.24	31
3	10/20/2009	8,882,906.40	93,441.92	60,003.25	33,438.67	8,822,903.14	103,228.90	30
4	11/20/2009	8,822,903.14	93,441.92	59,122.04	34,319.88	8,763,781.11	137,548.79	31
5	12/20/2009	8,763,781.11	93,441.92	60,451.69	32,990.23	8,703,329.42	170,539.02	30
6	1/20/2010	8,703,329.42	93,441.92	59,587.16	33,854.76	8,643,742.26	204,393.78	31
7	2/20/2010	8,643,742.26	93,441.92	59,818.95	33,622.97	8,583,923.31	238,016.75	31
8	3/20/2010	8,583,923.31	93,441.92	63,282.95	30,158.97	8,520,640.36	268,175.72	28
9	4/20/2010	8,520,640.36	93,441.92	60,297.80	33,144.12	8,460,342.57	301,319.85	31
10	5/20/2010	8,460,342.57	93,441.92	61,593.95	31,847.97	8,398,748.62	333,167.82	30
11	6/20/2010	8,398,748.62	93,441.92	60,771.94	32,669.98	8,337,976.68	365,837.80	31
12	7/20/2010	8,337,976.68	93,441.92	62,054.58	31,387.34	8,275,922.10	397,225.14	30
13	8/20/2010	8,275,922.10	93,441.92	61,249.72	32,192.20	8,214,672.39	429,417.35	31
14	9/20/2010	8,214,672.39	93,441.92	61,487.97	31,953.95	8,153,184.42	461,371.30	31
15	10/20/2010	8,153,184.42	93,441.92	62,750.21	30,691.71	8,090,434.21	492,063.01	30
16	11/20/2010	8,090,434.21	93,441.92	61,971.24	31,470.68	8,028,462.97	523,533.69	31
17	12/20/2010	8,028,462.97	93,441.92	63,219.71	30,222.21	7,965,243.27	553,755.91	30
18	1/20/2011	7,965,243.27	93,441.92	62,458.21	30,983.71	7,902,785.05	584,739.61	31
19	2/20/2011	7,902,785.05	93,441.92	62,701.17	30,740.75	7,840,083.88	615,480.36	31
20	3/20/2011	7,840,083.88	93,441.92	65,896.38	27,545.54	7,774,187.51	643,025.91	28
21	4/20/2011	7,774,187.51	93,441.92	63,201.40	30,240.52	7,710,986.11	673,266.43	31
22	5/20/2011	7,710,986.11	93,441.92	64,414.81	29,027.11	7,646,571.30	702,293.54	30
23	6/20/2011	7,646,571.30	93,441.92	63,697.81	29,744.11	7,582,873.50	732,037.66	31
24	7/20/2011	7,582,873.50	93,441.92	64,897.08	28,544.84	7,517,976.42	760,582.50	30
25	8/20/2011	7,517,976.42	93,441.92	64,198.02	29,243.90	7,453,778.40	789,826.40	31
26	9/20/2011	7,453,778.40	93,441.92	64,447.74	28,994.18	7,389,330.66	818,820.58	31
27	10/20/2011	7,389,330.66	93,441.92	65,625.65	27,816.27	7,323,705.01	846,636.85	30
28	11/20/2011	7,323,705.01	93,441.92	64,953.71	28,488.21	7,258,751.30	875,125.06	31
29	12/20/2011	7,258,751.30	93,441.92	66,117.20	27,324.72	7,192,634.10	902,449.78	30
30	1/20/2012	7,192,634.10	93,441.92	65,463.56	27,978.36	7,127,170.55	930,428.15	31
31	2/20/2012	7,127,170.55	93,441.92	65,718.20	27,723.72	7,061,452.34	958,151.86	31
32	3/20/2012	7,061,452.34	93,441.92	67,745.97	25,695.95	6,993,706.37	983,847.81	29
33	4/20/2012	6,993,706.37	93,441.92	66,237.36	27,204.56	6,927,469.01	1,011,052.37	31
34	5/20/2012	6,927,469.01	93,441.92	67,364.27	26,077.65	6,860,104.74	1,037,130.02	30
35	6/20/2012	6,860,104.74	93,441.92	66,757.05	26,684.87	6,793,347.69	1,063,814.89	31
36	7/20/2012	6,793,347.69	93,441.92	67,869.15	25,572.77	6,725,478.53	1,089,387.65	30
37	8/20/2012	6,725,478.53	93,441.92	67,280.73	26,161.19	6,658,197.80	1,115,548.84	31
38	9/20/2012	6,658,197.80	93,441.92	67,542.44	25,899.48	6,590,655.36	1,141,448.32	31

738,086.18
383,217.04
772,612
348,691.04
807,829.81
313,473.23

o.	Payment Date	Beginning Balance	Scheduled Payment	Principal	Interest	Ending Balance	Cumulative Interest	Days
39	10/20/2012	6,590,655.36	93,441.92	68,632.17	24,809.75	6,522,023.20	1,166,258.08	30
40	11/20/2012	6,522,023.20	93,441.92	68,072.14	25,369.78	6,453,951.05	1,191,627.85	31
41	12/20/2012	6,453,951.05	93,441.92	69,146.77	24,295.15	6,384,804.28	1,215,923.00	30
42	1/20/2013	6,384,804.28	93,441.92	68,605.91	24,836.01	6,316,198.37	1,240,759.01	31
43	2/20/2013	6,316,198.37	93,441.92	68,872.77	24,569.15	6,247,325.60	1,265,328.16	31
44	3/20/2013	6,247,325.60	93,441.92	71,492.41	21,949.51	6,175,833.19	1,287,277.67	28
45	4/20/2013	6,175,833.19	93,441.92	69,418.77	24,023.15	6,106,414.41	1,311,300.81	31
46	5/20/2013	6,106,414.41	93,441.92	70,455.03	22,986.89	6,035,959.38	1,334,287.70	30
47	6/20/2013	6,035,959.38	93,441.92	69,962.86	23,479.06	5,965,996.52	1,357,766.76	31
48	7/20/2013	5,965,996.52	93,441.92	70,983.62	22,458.30	5,895,012.89	1,380,225.05	30
49	8/20/2013	5,895,012.89	93,441.92	70,511.13	22,930.79	5,824,501.77	1,403,155.85	31
50	9/20/2013	5,824,501.77	93,441.92	70,785.41	22,656.51	5,753,716.36	1,425,812.36	31
51	10/20/2013	5,753,716.36	93,441.92	71,782.72	21,659.20	5,681,933.64	1,447,471.56	30
52	11/20/2013	5,681,933.64	93,441.92	71,339.98	22,101.94	5,610,593.66	1,469,573.50	31
53	12/20/2013	5,610,593.66	93,441.92	72,321.49	21,120.43	5,538,272.17	1,490,693.93	30
54	1/20/2014	5,538,272.17	93,441.92	71,898.80	21,543.12	5,466,373.37	1,512,237.05	31
55	2/20/2014	5,466,373.37	93,441.92	72,178.48	21,263.44	5,394,194.89	1,533,500.49	31
56	3/20/2014	5,394,194.89	93,441.92	74,489.82	18,952.10	5,319,705.07	1,552,452.59	28
57	4/20/2014	5,319,705.07	93,441.92	72,749.00	20,692.92	5,246,956.07	1,573,145.51	31
58	5/20/2014	5,246,956.07	93,441.92	73,690.36	19,751.56	5,173,265.71	1,592,897.07	30
59	6/20/2014	5,173,265.71	93,441.92	73,318.63	20,123.29	5,099,947.08	1,613,020.36	31
60	7/20/2014	5,099,947.08	93,441.92	74,243.76	19,198.16	5,025,703.32	1,632,218.52	30
61	8/20/2014	5,025,703.32	93,441.92	73,892.62	19,549.30	4,951,810.70	1,651,767.82	31
62	9/20/2014	4,951,810.70	93,441.92	74,180.05	19,261.87	4,877,630.64	1,671,029.68	31
63	10/20/2014	4,877,630.64	93,441.92	75,080.65	18,361.27	4,802,549.99	1,689,390.95	30
64	11/20/2014	4,802,549.99	93,441.92	74,760.66	18,681.26	4,727,789.34	1,708,072.22	31
65	12/20/2014	4,727,789.34	93,441.92	75,644.71	17,797.21	4,652,144.63	1,725,869.43	30
66	1/20/2015	4,652,144.63	93,441.92	75,345.71	18,096.21	4,576,798.91	1,743,965.63	31
67	2/20/2015	4,576,798.91	93,441.92	75,638.80	17,803.12	4,501,160.11	1,761,768.75	31
68	3/20/2015	4,501,160.11	93,441.92	77,627.43	15,814.49	4,423,532.68	1,777,583.24	28
69	4/20/2015	4,423,532.68	93,441.92	76,234.98	17,206.94	4,347,297.70	1,794,790.18	31
70	5/20/2015	4,347,297.70	93,441.92	77,077.02	16,364.90	4,270,220.67	1,811,155.07	30
71	6/20/2015	4,270,220.67	93,441.92	76,831.35	16,610.57	4,193,389.33	1,827,765.65	31
72	7/20/2015	4,193,389.33	93,441.92	77,656.39	15,785.53	4,115,732.93	1,843,551.17	30
73	8/20/2015	4,115,732.93	93,441.92	77,432.28	16,009.64	4,038,300.65	1,859,560.81	31
74	9/20/2015	4,038,300.65	93,441.92	77,733.48	15,708.44	3,960,567.17	1,875,269.25	31
75	10/20/2015	3,960,567.17	93,441.92	78,532.83	14,909.09	3,882,034.34	1,890,178.34	30
76	11/20/2015	3,882,034.34	93,441.92	78,341.34	15,100.58	3,803,693.00	1,905,278.92	31
77	12/20/2015	3,803,693.00	93,441.92	79,123.36	14,318.56	3,724,569.64	1,919,597.48	30
78	1/20/2016	3,724,569.64	93,441.92	78,953.85	14,488.07	3,645,615.79	1,934,085.55	31
79	2/20/2016	3,645,615.79	93,441.92	79,260.97	14,180.95	3,566,354.81	1,948,266.49	31
80	3/20/2016	3,566,354.81	93,441.92	80,464.30	12,977.62	3,485,890.52	1,961,244.12	29
81	4/20/2016	3,485,890.52	93,441.92	79,882.28	13,559.64	3,406,008.23	1,974,803.75	31
82	5/20/2016	3,406,008.23	93,441.92	80,620.40	12,821.52	3,325,387.83	1,987,625.27	30
83	6/20/2016	3,325,387.83	93,441.92	80,506.62	12,935.30	3,244,881.22	2,000,560.58	31
84	7/20/2016	3,244,881.22	93,441.92	81,226.94	12,214.98	3,163,654.27	2,012,775.55	30
85	8/20/2016	3,163,654.27	93,441.92	81,135.74	12,306.18	3,082,518.54	2,025,081.74	31
86	9/20/2016	3,082,518.54	93,441.92	81,451.35	11,990.57	3,001,067.19	2,037,072.31	31
87	10/20/2016	3,001,067.19	93,441.92	82,144.75	11,297.17	2,918,922.44	2,048,369.48	30
88	11/20/2016	2,918,922.44	93,441.92	82,087.71	11,354.21	2,836,834.73	2,059,723.69	31
89	12/20/2016	2,836,834.73	93,441.92	82,762.99	10,678.93	2,754,071.74	2,070,402.62	30
90	1/20/2017	2,754,071.74	93,441.92	82,728.96	10,712.96	2,671,342.78	2,081,115.58	31
91	2/20/2017	2,671,342.78	93,441.92	83,050.76	10,391.16	2,588,292.02	2,091,506.74	31
92	3/20/2017	2,588,292.02	93,441.92	84,348.15	9,093.77	2,503,943.87	2,100,600.51	28
93	4/20/2017	2,503,943.87	93,441.92	83,701.92	9,740.00	2,420,241.95	2,110,340.51	31
94	5/20/2017	2,420,241.95	93,441.92	84,331.20	9,110.72	2,335,910.75	2,119,451.23	30
95	6/20/2017	2,335,910.75	93,441.92	84,355.55	9,086.37	2,251,555.20	2,128,537.60	31
96	7/20/2017	2,251,555.20	93,441.92	84,966.20	8,475.72	2,166,589.00	2,137,013.32	30
97	8/20/2017	2,166,589.00	93,441.92	85,014.19	8,427.73	2,081,574.81	2,145,441.05	31
98	9/20/2017	2,081,574.81	93,441.92	85,344.88	8,097.04	1,996,229.93	2,153,538.09	31
99	10/20/2017	1,996,229.93	93,441.92	85,927.34	7,514.58	1,910,302.59	2,161,052.67	30
100	11/20/2017	1,910,302.59	93,441.92	86,011.10	7,430.82	1,824,291.48	2,168,483.48	31

846,532.10
274,770.94
886,127.54
235,175.50
927,574.97
193,728.07
970,497.90
150,805.14
1,016,354.84

No.	Payment Date	Beginning Balance	Scheduled Payment	Principal	Interest	Ending Balance	Cumulative Interest	Days
101	12/20/2017	1,824,291.48	93,441.92	86,574.59	6,867.33	1,737,716.90	2,175,350.82	30
102	1/20/2018	1,737,716.90	93,441.92	86,682.44	6,759.48	1,651,034.46	2,182,110.30	31
103	2/20/2018	1,651,034.46	93,441.92	87,019.62	6,422.30	1,564,014.84	2,188,532.60	31
104	3/20/2018	1,564,014.84	93,441.92	87,946.87	5,495.05	1,476,067.96	2,194,027.64	28
105	4/20/2018	1,476,067.96	93,441.92	87,700.22	5,741.70	1,388,367.75	2,199,769.35	31
106	5/20/2018	1,388,367.75	93,441.92	88,215.57	5,226.35	1,300,152.17	2,204,995.69	30
107	6/20/2018	1,300,152.17	93,441.92	88,384.51	5,057.41	1,211,767.67	2,210,053.11	31
108	7/20/2018	1,211,767.67	93,441.92	88,880.36	4,561.56	1,122,887.31	2,214,614.67	30
109	8/20/2018	1,122,887.31	93,441.92	89,074.04	4,367.88	1,033,813.26	2,218,982.54	31
110	9/20/2018	1,033,813.26	93,441.92	89,420.53	4,021.39	944,392.74	2,223,003.94	31
111	10/20/2018	944,392.74	93,441.92	89,886.86	3,555.06	854,505.87	2,226,558.99	30
112	11/20/2018	854,505.87	93,441.92	90,118.01	3,323.91	764,387.86	2,229,882.90	31
113	12/20/2018	764,387.86	93,441.92	90,564.47	2,877.45	673,823.39	2,232,760.35	30
114	1/20/2019	673,823.39	93,441.92	90,820.84	2,621.08	583,002.55	2,235,381.43	31
115	2/20/2019	583,002.55	93,441.92	91,174.12	2,267.80	491,828.43	2,237,649.23	31
116	3/20/2019	491,828.43	93,441.92	91,713.92	1,728.00	400,114.52	2,239,377.24	28
117	4/20/2019	400,114.52	93,441.92	91,885.53	1,556.39	308,228.99	2,240,933.63	31
118	5/20/2019	308,228.99	93,441.92	92,281.63	1,160.29	215,947.36	2,242,093.92	30
119	6/20/2019	215,947.36	93,441.92	92,601.91	840.01	123,345.44	2,242,933.92	31
120	7/20/2019	123,345.44	93,441.92	92,977.60	464.32	30,367.84	2,243,398.24	30

1,063,893.50

643,455.55

Appendix J – Quarterly Prepaids

Quarterly Prepaid Expenses

Invoice Date	Amount	Vendor Name	Description	Cheque Date	Start Date	End Date	Service Period	Service Lead	Payment Lead	Total Lead	Weight Factor %	Weighted Lead (Days)	Weighted Service Lead	Weighted Payment Lead
6/10/2014	989.25	Pitney Bowes	Jul - Sep feeder tower	6/13/14	7/1/2014	9/30/2014	92	46	-109	-63	0.22%	(0.14)	0.10	(0.24)
9/22/2014	989.25	Pitney Bowes	DI950 feeder:Oct-Dec rental	9/26/14	10/1/2014	12/31/2014	92	46	-96	-50	0.22%	(0.11)	0.10	(0.21)
1/7/2015	1,011.60	Pitney Bowes	Jan-Mar 2015 Feeder tower	1/9/15	1/1/2015	3/31/2015	90	45	-81	-36	0.22%	(0.08)	0.10	(0.18)
10/28/2014	10,740.00	Gemco Business Forms Inc.	Receivings Transaction Entry	11/14/14	10/1/2014	3/31/2015	182	91	-137	-46	2.34%	(1.08)	2.13	(3.21)
2/11/2015	12,180.00	Gemco Business Forms Inc.	Forms	2/20/15	4/1/2015	6/30/2015	91	45.5	-130	-84.5	2.66%	(2.25)	1.21	(3.46)
3/31/2015	12,180.00	Gemco Business Forms Inc.	Forms	4/22/15	4/1/2015	6/30/2015	91	45.5	-69	-23.5	2.66%	(0.62)	1.21	(1.83)
	38,090.10													
6/1/2014	14.00	Prepaid	Pelham Prop Tax	6/20/2014	7/1/2014	12/31/2014	184	92	-194	-102	0.00%	(0.00)	0.00	(0.01)
6/1/2014	254.00	Prepaid	Pelham Prop Tax	6/20/2014	7/1/2014	12/31/2014	184	92	-194	-102	0.06%	(0.06)	0.05	(0.11)
6/1/2014	45.00	Prepaid	Pelham Prop Tax	6/20/2014	7/1/2014	12/31/2014	184	92	-194	-102	0.01%	(0.01)	0.01	(0.02)
6/18/2014	15.06	TOWN OF PELHAM	1st&2nd install-Pelham St	6/20/2014	1/1/2014	6/30/2014	181	90.5	-10	80.5	0.00%	0.00	0.00	(0.00)
6/18/2014	255.60	TOWN OF PELHAM	1st&2nd install-Station St WS	6/20/2014	1/1/2014	6/30/2014	181	90.5	-10	80.5	0.06%	0.04	0.05	(0.01)
6/18/2014	46.63	TOWN OF PELHAM	1st&2nd install-1582 Pelham St	6/20/2014	1/1/2014	6/30/2014	181	90.5	-10	80.5	0.01%	0.01	0.01	(0.00)
8/20/2014	69,553.81	City of Niagara Falls	2014Final PIL	8/22/2014	7/1/2014	12/31/2014	184	92	-131	-39	15.18%	(5.92)	13.96	(19.88)
8/22/2014	2,663.96	City of Niagara Falls	3rd Install Montgomery St	8/22/2014	7/1/2014	9/30/2014	92	46	-39	7	0.58%	0.04	0.27	(0.23)
8/1/2014	153.00	TOWN OF LINCOLN	Lincoln Prop Tax Fly, Green, M	8/22/2014	9/1/2014	12/31/2014	122	61	-131	-70	0.03%	(0.02)	0.02	(0.04)
8/1/2014	94.00	TOWN OF LINCOLN	Lincoln Prop Tax Fly, Green, M	8/22/2014	9/1/2014	12/31/2014	122	61	-131	-70	0.02%	(0.01)	0.01	(0.03)
8/1/2014	268.00	TOWN OF LINCOLN	Lincoln Prop Tax Fly, Green, M	8/22/2014	9/1/2014	12/31/2014	122	61	-131	-70	0.06%	(0.04)	0.04	(0.08)
8/20/2014	154.37	TOWN OF LINCOLN	1st&2ndInstall-4299 Fly Rd	8/22/2014	7/1/2014	9/30/2014	92	46	-39	7	0.03%	0.00	0.02	(0.01)
8/20/2014	94.81	TOWN OF LINCOLN	1st&2ndInstall-3897GreenlaneRd	8/22/2014	7/1/2014	9/30/2014	92	46	-39	7	0.02%	0.00	0.01	(0.01)
8/20/2014	268.67	TOWN OF LINCOLN	1st&2ndInstall-Red Maple	8/22/2014	7/1/2014	9/30/2014	92	46	-39	7	0.06%	0.00	0.03	(0.02)
10/9/2014	10,177.40	Ontario Electricity Financial Co	2014 Return	10/10/2014	7/1/2014	12/31/2014	184	92	-82	10	2.22%	0.22	2.04	(1.82)
10/15/2014	2,662.00	City of Niagara Falls	4th Install Montgomery St	10/17/2014	9/1/2014	12/31/2014	122	61	-75	-14	0.58%	(0.08)	0.35	(0.44)
2/4/2015	76,518.68	City of Niagara Falls	2015 Interim PILS	2/6/2015	1/1/2015	6/30/2015	181	90.5	-144	-53.5	16.70%	(8.93)	15.11	(24.04)
1/1/2015	150.00	Prepaid	Lincoln Prop Tx Fly Maple Gre	2/13/2015	4/1/2015	6/30/2015	91	45.5	-137	-91.5	0.03%	(0.03)	0.01	(0.04)
1/1/2015	253.00	Prepaid	Lincoln Prop Tx Fly Maple Gre	2/13/2015	4/1/2015	6/30/2015	91	45.5	-137	-91.5	0.06%	(0.05)	0.03	(0.08)
1/1/2015	92.00	Prepaid	Lincoln Prop Tx Fly Maple Gre	2/13/2015	4/1/2015	6/30/2015	91	45.5	-137	-91.5	0.02%	(0.02)	0.01	(0.03)
1/31/2015	151.19	TOWN OF LINCOLN	1st&2nd Install-4299 Fly Rd	2/13/2015	1/1/2015	3/31/2015	90	45	-46	-1	0.03%	(0.00)	0.01	(0.02)
1/31/2015	254.39	TOWN OF LINCOLN	1st&2nd Install-Red Maple Ave	2/13/2015	1/1/2015	3/31/2015	90	45	-46	-1	0.06%	(0.00)	0.02	(0.03)
1/31/2015	93.68	TOWN OF LINCOLN	1st&2nd Install-3897 Greenlane	2/13/2015	1/1/2015	3/31/2015	90	45	-46	-1	0.02%	(0.00)	0.01	(0.01)
2/18/2015	2,159.07	City of Niagara Falls	1st Install Montgomery St	2/20/2015	1/1/2015	6/30/2015	181	90.5	-130	-39.5	0.47%	(0.19)	0.43	(0.61)
3/24/2015	8,268.35	Ontario Electricity Financial Co	2015 Interim PILS	3/26/2015	1/1/2015	6/30/2015	181	90.5	-96	-5.5	1.80%	(0.10)	1.63	(1.73)
4/8/2015	2,158.00	City of Niagara Falls	2nd Install Montgomery St	4/9/2015	7/1/2014	12/31/2014	184	92	99	191	0.47%	0.90	0.43	0.47
1/1/2015	212.21	Prepaid	West Lincoln Prop Tx Reg Rd	2/13/2015	1/1/2015	6/30/2015	181	90.5	-137	-46.5	0.05%	(0.02)	0.04	(0.06)
7/22/2014	210.53	Township of West Lincoln	3rd tax install- RR#20	8/1/2014	7/1/2014	9/30/2014	92	46	-60	-14	0.05%	(0.01)	0.02	(0.03)
7/22/2014	346.56	Township of West Lincoln	3rd tax install- RR#12	8/1/2014	7/1/2014	9/30/2014	92	46	-60	-14	0.08%	(0.01)	0.03	(0.05)
7/22/2014	19,088.23	Township of West Lincoln	3rd tax install- Clifford St	8/1/2014	7/1/2014	9/30/2014	92	46	-60	-14	4.17%	(0.58)	1.92	(2.50)
10/1/2014	210.57	Township of West Lincoln	4th tax install-RR#20	10/3/2014	9/1/2014	12/31/2014	122	61	-89	-28	0.05%	(0.01)	0.03	(0.04)
10/1/2014	19,088.28	Township of West Lincoln	4th tax install-Clifford St	10/3/2014	9/1/2014	12/31/2014	122	61	-89	-28	4.17%	(1.17)	2.54	(3.71)
10/1/2014	333.57	Township of West Lincoln	4th tax install-RR#12	10/3/2014	9/1/2014	12/31/2014	122	61	-89	-28	0.07%	(0.02)	0.04	(0.06)
11/19/2014	428.94	Township of West Lincoln	2014Clifford st tax supplement	11/21/2014	1/1/2014	12/31/2014	365	182.5	-40	142.5	0.09%	0.13	0.17	(0.04)
1/31/2015	214.81	Township of West Lincoln	1st&2nd Install-RR#20	2/13/2015	1/1/2015	6/30/2015	181	90.5	-137	-46.5	0.05%	(0.02)	0.04	(0.06)
2/11/2015	19,590.26	Township of West Lincoln	1st Install-2676 Clifford St	2/13/2015	1/1/2015	3/31/2015	90	45	-46	-1	4.27%	(0.04)	1.92	(1.97)
4/8/2015	19,590.27	Township of West Lincoln	2nd Install-2676 Clifford St	4/9/2015	4/1/2015	6/30/2015	91	45.5	-82	-36.5	4.27%	(1.56)	1.95	(3.51)
	256,132.90													
4/16/2015	41,298.00	Ontario Energy Board	Apr 1 to Jun 30 Assessment	4/17/2015	4/1/2015	6/30/2015	91	45.5	-74	-28.5	9.01%	(2.57)	4.10	(6.67)
1/7/2015	40,580.00	Ontario Energy Board	Jan -Mar assessment	1/16/15	1/1/2015	3/31/2015	90	45	-74	-29	8.86%	(2.57)	3.98	(6.55)
7/15/2014	41,577.00	Ontario Energy Board	Jul 1- Sep 30 assessment	7/25/14	7/1/2014	9/30/2014	92	46	-67	-21	9.07%	(1.91)	4.17	(6.08)
10/15/2014	40,580.00	Ontario Energy Board	Oct1-Dec31 Assessments	10/17/14	10/1/2014	12/31/2014	92	46	-75	-29	8.86%	(2.57)	4.07	(6.64)
	164,035.00													
	458,258.00										100.00%	(31.44)	64.47	(95.90)

Appendix K – Elenchus CVs

ANDREW FRANK

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CONSULTANT

Andrew Frank has over 10 years of experience across the energy, financial services, and high tech industries. Andrew is focused on Cost Allocation, Rate Design and modeling, and has been engaged for Economic Evaluation of new energy and infrastructure projects. He performed the model updates required for the OEB's Cost Allocation model version 2.0, released August 2011, and has contributed to the OEB's rate design project, performing analysis on the impact of various proposed rate structures. In addition to his consulting responsibilities, Andrew is responsible for the continued development and ongoing support of new and existing Elenchus applications, including RateMaker and other economic models.

He is experienced in software development, data warehousing / data mining, and decision analysis. Andrew has considerable experience in organizational change and managing stakeholder issues. Andrew holds a LL.M. in Energy and Infrastructure Law (Osgoode Hall), an MBA with a concentration in accounting (Wilfrid Laurier University), and a Bachelor of Mathematics in Computer Science (University of Waterloo).

PROFESSIONAL OVERVIEW

Elenchus **October 2008 - Present**
Consultant

- Consulting in the areas of cost allocation, rate design, load forecasting, cost of service modeling
- Updated the OEB's Cost Allocation Model to version 2.0.
- Contributed to the OEB's rate design project by analyzing impacts of various proposed rate structures
- Acted as advisor to board staff in OEB consultations in Cost Allocation and Rate Design.
- Perform Economic Evaluations for energy and infrastructure projects
- Develop new Elenchus applications, and support existing applications including RateMaker
- Perform internally focused software development

Manulife Financial **February 2003 - October 2008**
Systems Designer

- Supported Flexible Benefits Online Enrollment
  - Performed customizations of the re-enrollment site to satisfy customer's requirements
  - Coordinated the build and deployment to production environment with vendor
- Supported growth of a world class financial services leader in the Group Benefits area
- Enhanced Clients II, an Z/OS mainframe claims processing application
  - Updates to satisfy needs of corporate clients, new legislation requirements, and new treatments
  - Reduced costs by decreasing the frequency of on-call incidents and improving code efficiency
- Created a C# ASP.NET interface between a DB2 / Z/OS data warehouse, and a fraud detection and pricing tool which uses SQL Server
- Added support for new 7-digit contracts to SQL server stored procedures and a Delphi Application

IBM Canada Ltd. **May – Aug 2001, Sept – Dec 2000**
DB2 UDB Optimizer Performance Tester

- Maintained and extended SQLVALID, a performance measurement tool.
  - Introduced centralized database logging of results utilizing the DB2 Call Level Interface (CLI)
- Maintained and extended a Perl database generation tool
- Used SQLVALID to perform tests on AIX and NT Server

Portfolio Analytics, Toronto (now Morningstar Canada) **May – Aug 1999, Jan – April 1998, Summer 1997**

Programmer/ Analyst

- Redesigned and wrote the client management system with a team of three software developers
  - Designed a new relational table structure for more flexible and efficient reporting.
  - Administered the SQL Server, selecting appropriate indexes, writing and scheduling maintenance scripts, and implementing appropriate security rules
  - Minimized network traffic and CPU usage and increased flexibility using stored procedures
  - Interfaced with users from every department covering all aspects of the business to assess their needs, and train users on the system

ACADEMIC ACHIEVEMENTS

June 2014	Master of Laws, Energy and Infrastructure Law, Osgoode Hall Law School, York University • Emphasis on Energy Regulation
June 2007	Master of Business Administration, Wilfrid Laurier University • Concentration in Accounting – Qualify for advanced standing in the CMA Program • Part-Time program
2002	Bachelor of Mathematics in Honours Computer Science / Information Systems – Co-operative Program, University of Waterloo • Information Systems option earned including 9 Economics courses • Received outstanding evaluations from every employer

MICHAEL J. ROGER

elenchus

34 King Street East, Suite 600 | Toronto, ON M5C 2X8 | 905 731 9322 | mroger@elenchus.ca

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ASSOCIATE, RATES AND REGULATION

Michael has over 35 years of experience in the electricity industry dealing in areas of finance, cost allocation, rate design and regulatory environment. Michael has been an expert witness at numerous Ontario Energy Board proceedings and has participated in task forces dealing with his areas of expertise. Michael is a leader and team player that gets things done and gets along well with colleagues.

PROFESSIONAL OVERVIEW

Elenchus **2010 - Present**
Associate Consultant, Rates & Regulation

- Provide guidance on the Regulatory environment in Ontario for distributors, with particular emphasis in electricity rates in Ontario and the regulatory review and approval process for cost allocation, rate design and special studies.
- Some of the clients that Michael provides advice include: Hydro Quebec Energy Marketing Inc., GTAA, Ontario Energy Board, City of Hamilton, Hydro One Transmission, Powerstream, Hydro Ottawa, Veridian and APPrO.

Hydro One Networks Inc. **2002 - 2010**
Manager, Pricing, Regulatory Affairs, Corporate and Regulatory Affairs

- In charge of Distribution and Transmission pricing for directly connected customers to Hydro One's Distribution system, embedded distributors and customers connected to Hydro One's Transmission system.
- Determine prices charged to customers that conform to guidelines and principles established by the Ontario Energy Board, (OEB).
- Provide expert testimony at OEB Hearings on behalf of Hydro One in the areas of Cost Allocation and Rate Design.
- Keep up to date on Cost Allocation and Rate Design issues in the industry.
- Ensure deliverables are of high quality, defensible and meet all deadlines.

- Keep staff focused and motivated and work as a team member of the Regulatory Affairs function. Provide support to other units as necessary.

Ontario Power Generation Inc. **1999 - 2002**
Manager, Management Reporting and Decision Support, Corporate Finance

- Produce weekly, monthly, quarterly and annual internal financial reporting products.
- Input to and coordination of senior management reporting and performance assessment activities.
- Expert line of business knowledge in support of financial and business planning processes.
- Coordination, execution of review, and assessment of business plans, business cases and proposals of an operational nature.
- Provide support to other units as necessary.
- Work as a team member of the Corporate Finance function.

Ontario Hydro **1998 - 1999**
Acting Director, Financial Planning and Reporting, Corporate Finance

- Responsible for the day to day operation of the division supporting the requirements of Ontario Hydro's Board of Directors, Chairman, President and CEO, and the Chief Financial Officer, to enable them to perform their due diligence role in running the company.
- Interact with business units to exchange financial information.

Financial Advisor, Financial Planning and Reporting, Corporate Finance **1997**

- Responsible for co-ordinating Retail, Transmission, and Central Market Operation divisions' support of Corporate Finance function of Ontario Hydro to ensure financial information consistency between business units and Corporate Office, review business units compliance with corporate strategy.
- Provide advice to Chief Financial Officer and Vice President of Finance on business unit issues subject to review by Corporate Officers.
- Participate or lead task team dealing with issues being evaluated in the company.
- Supervise professional staff supporting the function.
- Co-ordinate efforts with advisors for GENCO and Corporate Function divisions to ensure consistent treatment throughout the company.

Section Head, Pricing Implementation, Pricing **1986 - 1997**

- Responsible for pricing experiments, evaluation of marginal costs based prices, cost-of-service studies for municipal utilities, analysis and comparison of prices in the electric industry, rate structure reform evaluation, analysis of cost of servicing individual customers and support the cost allocation process used to determine prices to end users.
- Responsible for the derivation of wholesale prices charged to Municipal Electric Utilities and retail prices for Direct Industrial customers, preparation of Board Memos presented to Ontario

Hydro's Board of Directors and support the department's involvement at the Ontario Energy Board Hearings by providing expert witness testimony.

Section Head (acting), Power Costing, Financial Planning & Reporting, Corporate Finance **1994 - 1995**

- Responsible for the allocation of Ontario Hydro's costs among its customer groups and ensure that costs are tracked properly and are used to bill customers.
- Maintain the computer models used for cost allocation and update the models to reflect the structural changes at Ontario Hydro.
- Participate at the Ontario Energy Board Hearings providing support and expert testimony on the proposed cost allocation and rates.
- Provide cost allocation expertise to other functions in the company.

Additional Duties **1991**

- Manager (acting) Rate Structures Department.
- Review of utilities' rates and finances for regulatory approval.
- Consultant: Sent by Ontario Hydro International to Estonia to provide consulting services on cost allocation and rate design issues to the country's electric company.

Analyst, Rates **1983 - 1986**

- In charge of evaluating different marketing strategies to provide alternatives to customers for the efficient use of electricity.
- Co-ordinate and supervise efforts of a work group set up to develop a cost of service study methodology recommended for implementation by Municipal Electric Utilities and Ontario Hydro's Rural Retail System.
- Provide support data to Ontario Hydro's annual Rate Submission to the Ontario Energy Board.
- Participate in various studies analysing cost allocation areas and financial aspects of the company.

Forecast Analyst, Financial Forecasts **1980 – 1983**

- Evaluating cost data related to electricity production by nuclear plants and preparing short term forecasts of costs used by the company. Maintain and improve computer models used to analyse the data.
- Review Ontario Hydro's forecast of customer revenues, report actual monthly, quarterly and yearly results and explain variances from budget.
- Support the development of new computerized models to assist in the short-term forecast of revenues.

Project Development Analyst, Financial Forecasts **1979 - 1980**

- In charge of developing computerized financial models used by forecasting analysts planning Ontario Hydro's short term revenue and cost forecasts and also in the preparation of Statement of Operations and Balance Sheet for the Corporation.

Assistant Engineer – Reliability Statics, Hydroelectric Generations Services **1978 – 1979**

- In charge of analysing statistical data related to hydroelectric generating stations and producing periodic report on plants' performance.

ACADEMIC ACHIEVEMENTS

1977	Master of Business Administration, University of Toronto. Specialized in Management Science, Data Processing and Finance. Teaching Assistant in Statistics.
1975	Bachelor of Science in Industrial and Management Engineering, Technician, Israel Institute of Technology, Haifa, Israel.

Appendix L – IndEco Sample CDM Calculations

Sample calculations of the impact of CDM on load for the Residential rate class for 2012 for Niagara Peninsula Energy Inc.

	A	B	C	D	E	F	G=(A+B)*C+(D+E)*F
	Persistence of 2011 results	Persistence of 2011 adjustments	Allocation by rate class for 2011 results and adjustments	CDM impact on 2012 load	2012 adjustments	Allocation by rate class for 2012 results and adjustments	Impact of CDM on load by rate class for 2012
	Incremental Energy Savings (kWh)		Residential (%)	Incremental Energy Savings (kWh)		Residential (%)	Residential (kWh)
Consumer Program							
Appliance Retirement	214,685		100%	135,814		100%	350,499
Appliance Exchange	4,714		100%	14,737		100%	19,450
HVAC Incentives	504,642	-85,312	90%	253,365	8,601	90%	613,166
Conservation Instant Coupon Booklet	272,325	2,741	100%	13,904		100%	288,970
Bi-Annual Retailer Event	292,245	21,713	100%	266,332		100%	580,289
Retailer Co-op			100%			100%	
Residential Demand Response (switch/pstat)			100%			100%	
Residential Demand Response (IHD)			100%			100%	
Residential New Construction			100%			100%	
Business Program							
Retrofit	927,120	30,127		3,486,336	423,970		
Direct Install Lighting	903,623	91,276		712,848			
Building Commissioning							
New Construction					12,172		
Energy Audit		26,398		201,410	32,863		
Small Commercial Demand Response (switch/pstat)							
Small Commercial Demand Response (IHD)							
Demand Response 3				1,548			
Industrial Program							
Process & System Upgrades							
Monitoring & Targeting							
Energy Manager							
Retrofit	13,815						
Demand Response 3				1,578			
Home Assistance Program							
Home Assistance Program	9,137		100%	54,743	53,613	100%	117,493
Pre-2011 Programs completed in 2011							
Electricity Retrofit Incentive Program	1,480,972						
High Performance New Construction	395,844	-255,067		643,518			
Other							
Program Enabled Savings		2,310,596			2,072,243		
Time-of-Use Savings							
Totals	**5,019,121**	**2,142,472**		**5,786,134**	**2,603,462**		**1,969,867**

Notes: CDM results, adjustments, and persistence of results and adjustments is as reported by the IESO. Percentage allocation by rate class for results and adjustments was provided by Niagara Peninsula Energy Inc. CDM staff, based on program participation data.
In this table:
Column A is from the IESO and is shown in Table A-1 of the LRAMVA report, 5th column;
Column B is from the IESO and is shown in Table A-4 of the LRAMVA report, 5th column;
Column C is from NPEI CDM staff based on program participation data and is shown in Table B-1 of the LRAMVA report, 2nd column;
Column D is from the IESO and is shown in Table A-2 of the LRAMVA report, 3rd column;
Column E is from the IESO and is shown in Table A-5 of the LRAMVA report, 3rd column;
Column F is from NPEI CDM staff based on program participation data and is shown in Table B-2 of the LRAMVA report, 2nd column;
Column G is as shown in Table B-7 of the LRAMVA report, 2nd column; and
The total of column G is the 2012 current year load losses value for the Residential rate class in row 6 of Table C-2 of the LRAMVA report.

Appendix M – Updated Models

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

This Workbook Model is protected by copyright and is being made available to you solely for the purpose of filing your application. You may use and copy this model for that purpose, and provide a copy of this model to any person that is advising or assisting you in that regard. Except as indicated above, any copying, reproduction, publication, sale, adaptation, translation, modification, reverse engineering or other use or dissemination of this model without the express written consent of the Ontario Energy Board is prohibited. If you provide a copy of this model to a person that is advising or assisting you in preparing the application or reviewing your draft rate order, you must ensure that the person understands and agrees to the restrictions noted above.

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)	Adjustments	Settlement Agreement	(6)	Adjustments	Per Board Decision	
1	**Rate Base**								
	Gross Fixed Assets (average)	$247,689,793		($1,445,365)	$ 246,244,429			$246,244,429	
	Accumulated Depreciation (average)	($123,945,922)	(5)	$834,982	($123,110,940)			($123,110,940)	
	Allowance for Working Capital:								
	Controllable Expenses	$17,041,580		($616,585)	$ 16,424,995			$16,424,995	
	Cost of Power	$136,943,243		$7,206,425.71	$ 144,149,669			$144,149,669	
	Working Capital Rate (%)	13.00%	(9)		13.00%	(9)		12.61%	(9)
2	**Utility Income**								
	Operating Revenues:								
	Distribution Revenue at Current Rates	$28,371,080		$294,112	$28,665,192		$0	$28,665,192	
	Distribution Revenue at Proposed Rates	$29,374,853		($709,662)	$28,665,191		$0	$28,665,191	
	Other Revenue:								
	Specific Service Charges	$803,285		($0)	$803,285		$0	$803,285	
	Late Payment Charges	$361,000		$0	$361,000		$0	$361,000	
	Other Distribution Revenue	$251,187		$6,047	$257,234		$0	$257,234	
	Other Income and Deductions	$181,003		$0	$181,003		$0	$181,003	
	Total Revenue Offsets	$1,596,475	(7)	$6,047	$1,602,522		$0	$1,602,522	
	Operating Expenses:								
	OM+A Expenses	$16,754,348		($616,585)	$ 16,137,763		$ -	$16,137,763	
	Depreciation/Amortization	$4,936,879		$97,195	$ 5,034,074			$5,034,074	
	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)		($4,598,147)			($4,598,147)	
	Utility Income Taxes and Rates:								
	Income taxes (not grossed up)	$34,407			$120,121			$113,947	
	Income taxes (grossed up)	$43,189			$163,430			$155,030	
	Federal tax (%)	15.00%			15.00%			15.00%	
	Provincial tax (%)	5.33%			11.50%			11.50%	
	Income Tax Credits	($81,003)			($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%			3.92%			3.92%	
	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	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(3)	$247,689,793	($1,445,365)	$246,244,429	$ -	$246,244,429
2	Accumulated Depreciation (average)	(3)	($123,945,922)	$834,982	($123,110,940)	$ -	($123,110,940)
3	Net Fixed Assets (average)	(3)	$123,743,871	($610,383)	$123,133,488	$ -	$123,133,488
4	Allowance for Working Capital	(1)	$20,018,027	$856,679	$20,874,706	($626,241)	$20,248,465
5	**Total Rate Base**		$143,761,898	$246,296	$144,008,195	($626,241)	$143,381,953

(1) Allowance for Working Capital - Derivation

Line No.	Particulars		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
6	Controllable Expenses		$17,041,580	($616,585)	$16,424,995	$ -	$16,424,995
7	Cost of Power		$136,943,243	$7,206,426	$144,149,669	$ -	$144,149,669
8	Working Capital Base		$153,984,823	$6,589,841	$160,574,664	$ -	$160,574,664
9	Working Capital Rate %	(2)	13.00%	0.00%	13.00%	-0.39%	12.61%
10	Working Capital Allowance		$20,018,027	$856,679	$20,874,706	($626,241)	$20,248,465

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	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$29,374,853	($709,662)	$28,665,191	$ -	$28,665,191
2	Other Revenue	(1)	$1,596,475	$6,047	$1,602,522	$ -	$1,602,522
3	Total Operating Revenues		$30,971,328	($703,615)	$30,267,713	$ -	$30,267,713
	Operating Expenses:						
4	OM+A Expenses		$16,754,348	($616,585)	$16,137,763	$ -	$16,137,763
5	Depreciation/Amortization		$4,936,879	$97,195	$5,034,074	$ -	$5,034,074
6	Property taxes		$287,232	$ -	$287,232	$ -	$287,232
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -		$ -	
9	Subtotal (lines 4 to 8)		$21,978,459	($519,390)	$21,459,069	$ -	$21,459,069
10	Deemed Interest Expense		$3,567,234	($279,124)	$3,288,110	($14,299)	$3,273,811
11	Total Expenses (lines 9 to 10)		$25,545,693	($798,514)	$24,747,179	($14,299)	$24,732,880
12	**Utility income before income taxes**		$5,425,635	$94,899	$5,520,534	$14,299	$5,534,832
13	Income taxes (grossed-up)		$43,189	$120,241	$163,430	($8,400)	$155,030
14	**Utility net income**		$5,382,446	($25,342)	$5,357,104	$22,698	$5,379,802

Notes

Other Revenues / Revenue Offsets

Note	Particulars	Initial Application	Adjustments	Settlement Agreement	Adjustments	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	Settlement Agreement	Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$5,382,445	$5,357,105	$5,333,809
2	Adjustments required to arrive at taxable utility income	($4,814,861)	($4,598,147)	($4,598,147)
3	Taxable income	$567,584	$758,958	$735,662
	Calculation of Utility income Taxes			
4	Income taxes	$34,407	$120,121	$113,947
6	Total taxes	$34,407	$120,121	$113,947
7	Gross-up of Income Taxes	$8,782	$43,309	$41,083
8	Grossed-up Income Taxes	$43,189	$163,430	$155,030
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$43,189	$163,430	$155,030
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%	$8,949,680
		Settlement Agreement			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$80,644,589	3.92%	$3,163,687
2	Short-term Debt	4.00%	$5,760,328	2.16%	$124,423
3	**Total Debt**	60.00%	$86,404,917	3.81%	$3,288,110
	Equity				
4	Common Equity	40.00%	$57,603,278	9.30%	$5,357,105
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$57,603,278	9.30%	$5,357,105
7	**Total**	100.00%	$144,008,195	6.00%	$8,645,215
		Per Board Decision			
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$80,293,894	3.92%	$3,149,929
9	Short-term Debt	4.00%	$5,735,278	2.16%	$123,882
10	**Total Debt**	60.00%	$86,029,172	3.81%	$3,273,811
	Equity				
11	Common Equity	40.00%	$57,352,781	9.30%	$5,333,809
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$57,352,781	9.30%	$5,333,809
14	**Total**	100.00%	$143,381,953	6.00%	$8,607,620

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	Settlement Agreement: At Current Approved Rates	Settlement Agreement: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$1,003,772		($0)		($45,994)
2	Distribution Revenue	$28,371,080	$28,371,081	$28,665,192	$28,665,191	$28,665,192	$28,711,185
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	$30,267,713	$30,267,714	$30,267,713
5	Operating Expenses	$21,978,459	$21,978,459	$21,459,069	$21,459,069	$21,459,069	$21,459,069
6	Deemed Interest Expense	$3,567,234	$3,567,234	$3,288,110	$3,288,110	$3,273,811	$3,273,811
8	**Total Cost and Expenses**	$25,545,693	$25,545,693	$24,747,179	$24,747,179	$24,732,880	$24,732,880
9	**Utility Income Before Income Taxes**	$4,421,862	$5,425,635	$5,520,535	$5,520,534	$5,534,834	$5,534,832
10	Tax Adjustments to Accounting Income per 2013 PILs model	($4,814,861)	($4,814,861)	($4,598,147)	($4,598,147)	($4,598,147)	($4,598,147)
11	**Taxable Income**	($392,999)	$610,774	$922,388	$922,387	$936,687	$936,686
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	$244,433	$244,432	$248,222	$248,222
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	$5,357,105	$5,357,104	$5,367,615	$5,379,802
16	**Utility Rate Base**	$143,761,898	$143,761,898	$144,008,195	$144,008,195	$143,381,953	$143,381,953
17	Deemed Equity Portion of Rate Base	$57,504,759	$57,504,759	$57,603,278	$57,603,278	$57,352,781	$57,352,781
18	Income/(Equity Portion of Rate Base)	7.97%	9.36%	9.30%	9.30%	9.36%	9.38%
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%	0.00%	0.00%	0.06%	0.08%
21	Indicated Rate of Return	5.67%	6.23%	6.00%	6.00%	6.03%	6.04%
22	Requested Rate of Return on Rate Base	6.23%	6.23%	6.00%	6.00%	6.00%	6.00%
23	Deficiency/Sufficiency in Rate of Return	-0.56%	0.00%	0.00%	0.00%	0.02%	0.03%
24	Target Return on Equity	$5,382,445	$5,382,445	$5,357,105	$5,357,105	$5,333,809	$5,333,809
25	Revenue Deficiency/(Sufficiency)	$799,670	$0	($0)	($1)	($33,806)	$45,993
26	**Gross Revenue Deficiency/(Sufficiency)**	$1,003,772 **(1)**		($0) **(1)**		($45,994) **(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		Settlement Agreement		Per Board Decision	
1	OM&A Expenses	$16,754,348		$16,137,763		$16,137,763	
2	Amortization/Depreciation	$4,936,879		$5,034,074		$5,034,074	
3	Property Taxes	$287,232		$287,232		$287,232	
5	Income Taxes (Grossed up)	$43,189		$163,430		$155,030	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$3,567,234		$3,288,110		$3,273,811	
	Return on Deemed Equity	$5,382,445		$5,357,105		$5,333,809	
8	**Service Revenue Requirement (before Revenues)**	$30,971,328		$30,267,714		$30,221,719	
9	Revenue Offsets	$1,596,475		$1,602,522		$1,602,522	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$29,374,853		$28,665,192		$28,619,198	
11	Distribution revenue	$29,374,853		$28,665,191		$28,665,191	
12	Other revenue	$1,596,475		$1,602,522		$1,602,522	
13	**Total revenue**	$30,971,328		$30,267,713		$30,267,713	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$0	(1)	($1)	(1)	$45,993	(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														

Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

Version 3.0

Utility Name	Niagara Peninsula Energy Inc.
Assigned EB Number	EB-2014-0096
Name and Title	Suzanne Wilson, VP Finance
Phone Number	905-353-6004
Email Address	Suzanne.wilson@npei.ca
Date	9/23/2014
Last COS Re-based Year	**2011**

Note: Drop-down lists are shaded blue; Input cells are shaded green.

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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

Income Tax/PILs Workform for 2015 Filers

Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

Rate Base			**$**	**143,381,949**	
Return on Ratebase					
Deemed ShortTerm Debt %	4.00%	T	$	5,735,278	*W = S * T*
Deemed Long Term Debt %	56.00%	U	$	80,293,891	*X = S * U*
Deemed Equity %	40.00%	V	$	57,352,780	*Y = S * V*
Short Term Interest Rate	2.16%	Z	$	123,882	*AC = W * Z*
Long Term Interest	3.92%	AA	$	3,149,929	*AD = X * AA*
Return on Equity (Regulatory Income)	9.30%	AB	**$**	**5,333,809**	*AE = Y * AB*
Return on Rate Base			**$**	**8,607,620**	*AF = AC + AD + AE*

Questions that must be answered

	Historical	**Bridge**	**Test Year**
1. Does the applicant have any Investment Tax Credits (ITC)?	Yes	Yes	Yes
2. Does the applicant have any SRED Expenditures?	No	No	No
3. Does the applicant have any Capital Gains or Losses for tax purposes?	No	No	No
4. Does the applicant have any Capital Leases?	No	No	No
5. Does the applicant have any Loss Carry-Forwards (non-capital or net capital)?	No	No	No
6. Since 1999, has the applicant acquired another regulated applicant's assets?	Yes	Yes	Yes
7. Did the applicant pay dividends? *If Yes, please describe what was the tax treatment in the manager's summary.*	Yes	Yes	Yes
8. Did the applicant elect to capitalize interest incurred on CWIP for tax purposes?	No	No	No

Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

Tax Rates **Federal & Provincial** **As of June 20, 2012**	**Effective** **################**	**Effective** **################**	**Effective** **################**	**Effective** **################**	**Effective** **################**
Federal income tax					
General corporate rate	38.00%	38.00%	38.00%	38.00%	38.00%
Federal tax abatement	-10.00%	-10.00%	-10.00%	-10.00%	-10.00%
Adjusted federal rate	28.00%	28.00%	28.00%	28.00%	28.00%
Rate reduction	-11.50%	-13.00%	-13.00%	-13.00%	-13.00%
	16.50%	15.00%	15.00%	15.00%	15.00%
Ontario income tax	11.75%	11.50%	11.50%	11.50%	11.50%
Combined federal and Ontario	28.25%	26.50%	26.50%	26.50%	26.50%
Federal & Ontario Small Business					
Federal small business threshold	500,000	500,000	500,000	500,000	500,000
Ontario Small Business Threshold	500,000	500,000	500,000	500,000	0
Federal small business rate	11.00%	11.00%	11.00%	11.00%	11.00%
Ontario small business rate	4.50%	4.50%	4.50%	4.50%	0.00%

Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

Schedule 8 - Historical Year

Class	Class Description	UCC End of Year Historical per tax returns	Less: Non-Distribution Portion	UCC Regulated Historical Year
1	Distribution System - post 1987	56,259,372		56,259,372
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	0		0
2	Distribution System - pre 1988	3,633,291		3,633,291
8	General Office/Stores Equip	1,666,790		1,666,790
10	Computer Hardware/ Vehicles	2,705,841		2,705,841
10.1	Certain Automobiles			0
12	Computer Software	57,371		57,371
13_1	Lease # 1			0
13_2	Lease #2			0
13_3	Lease # 3			0
13_4	Lease # 4			0
14	Franchise			0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	282,408		282,408
42	Fibre Optic Cable			0
43.1	Certain Energy-Efficient Electrical Generating Equipment			0
43.2	Certain Clean Energy Generation Equipment			0
45	Computers & Systems Software acq'd post Mar 22/04	2,832		2,832
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)			0
47	Distribution System - post February 2005	48,060,734		48,060,734
50	Data Network Infrastructure Equipment - post Mar 2007	364,650		364,650
52	Computer Hardware and system software			0
95	CWIP			0
3	Buildings acquired before 1988	1,275,277		1,275,277
1b	Buildings > 18-03-07	4,969,771		4,969,771
1b	Buildings > 18-03-07	2,425,531		2,425,531
				0
				0
				0
				0
				0
				0
				0
	SUB-TOTAL - UCC	121,703,868	0	121,703,868

Ontario Energy Board

Income Tax/PILs Workform for 2015 Filer

Schedule 10 CEC - Historical Year

Cumulative Eligible Capital				**1,050,008**
Additions				
Cost of Eligible Capital Property Acquired during Test Year				
Other Adjustments	0			
Subtotal	0	**x 3/4 =**	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	**x 1/2 =**	0	
			0	**0**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				**1,050,008**
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year				
Other Adjustments	0			
Subtotal	0	**x 3/4 =**		**0**
Cumulative Eligible Capital Balance				**1,050,008**
Current Year Deduction		**1,050,008**	**x 7% =**	**73,501**
Cumulative Eligible Capital - Closing Balance				**976,507**

Ontario Energy Board

Income Tax/PILs Workform for 2

Schedule 13 Tax Reserves - Historical

Continuity of Reserves

Description	Historical Balance as per tax returns	Non-Distribution Eliminations	Utility Only
Capital Gains Reserves ss.40(1)			0
Tax Reserves Not Deducted for accounting purposes			
Reserve for doubtful accounts ss. 20(1)(l)			0
Reserve for goods and services not delivered ss. 20(1)(m)			0
Reserve for unpaid amounts ss. 20(1)(n)			0
Debt & Share Issue Expenses ss. 20(1)(e)			0
Other tax reserves			0
			0
			0
			0
			0
			0
Total	0	0	0
Financial Statement Reserves (not deductible for Tax Purposes)			
General Reserve for Inventory Obsolescence (non-specific)			0
General reserve for bad debts			0
Accrued Employee Future Benefits:			0
- Medical and Life Insurance			0
-Short & Long-term Disability			0
-Accmulated Sick Leave			0
- Termination Cost			0
- Other Post-Employment Benefits			0
Provision for Environmental Costs			0
Restructuring Costs			0
Accrued Contingent Litigation Costs			0
Accrued Self-Insurance Costs			0
Other Contingent Liabilities			0
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)			0
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)			0
Other			0
			0
			0
Total	0	0	0

Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

Schedule 7-1 Loss Carry Forward - Historical

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance
Actual Historical			0

Net Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance
Actual Historical			0

Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

Adjusted Taxable Income - Historical Year

	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	Historic Wires Only
Income before PILs/Taxes	**A**	3,187,387		3,187,387
Additions:				
Interest and penalties on taxes	103			0
Amortization of tangible assets	104	5,321,041		5,321,041
Amortization of intangible assets	106			0
Recapture of capital cost allowance from Schedule 8	107			0
Gain on sale of eligible capital property from Schedule 10	108			0
Income or loss for tax purposes- joint ventures or partnerships	109			0
Loss in equity of subsidiaries and affiliates	110			0
Loss on disposal of assets	111			0
Charitable donations	112			0
Taxable Capital Gains	113			0
Political Donations	114			0
Deferred and prepaid expenses	116			0
Scientific research expenditures deducted on financial statements	118			0
Capitalized interest	119			0
Non-deductible club dues and fees	120			0
Non-deductible meals and entertainment expense	121			0
Non-deductible automobile expenses	122			0
Non-deductible life insurance premiums	123			0
Non-deductible company pension plans	124			0
Tax reserves deducted in prior year	125			0
Reserves from financial statements- balance at end of year	126			0
Soft costs on construction and renovation of buildings	127			0
Book loss on joint ventures or partnerships	205			0
Capital items expensed	206			0
Debt issue expense	208			0
Development expenses claimed in current year	212			0
Financing fees deducted in books	216			0
Gain on settlement of debt	220			0
Non-deductible advertising	226			0
Non-deductible interest	227			0
Non-deductible legal and accounting fees	228			0
Recapture of SR&ED expenditures	231			0
Share issue expense	235			0
Write down of capital property	236			0
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237			0
Other Additions				
Interest Expensed on Capital Leases	290			0
Realized Income from Deferred Credit Accounts	291			0
Pensions	292			0
Non-deductible penalties	293			0
Previous years apprenticeship tax credit claimed	294	106,351		106,351
	295			0
ARO Accretion expense				0
Capital Contributions Received (ITA 12(1)(x))				0
Lease Inducements Received (ITA 12(1)(x))				0
Deferred Revenue (ITA 12(1)(a))				0
Prior Year Investment Tax Credits received				0
Change in Employee Future Benefits		107,944		107,944

Change in Regulatory variance accounts		879,966		879,966
Inducement - ITA 12(1)(x)-ITC from apprenticeship job creation expenditures		12,572		12,572
				0
				0
				0
				0
				0
				0
				0
Total Additions		**6,427,874**	**0**	**6,427,874**
Deductions:				
Gain on disposal of assets per financial statements	401			0
Dividends not taxable under section 83	402			0
Capital cost allowance from Schedule 8	403	8,552,056		8,552,056
Terminal loss from Schedule 8	404			0
Cumulative eligible capital deduction from Schedule 10	405	73,501		73,501
Allowable business investment loss	406			0
Deferred and prepaid expenses	409			0
Scientific research expenses claimed in year	411			0
Tax reserves claimed in current year	413			0
Reserves from financial statements - balance at beginning of year	414			0
Contributions to deferred income plans	416			0
Book income of joint venture or partnership	305			0
Equity in income from subsidiary or affiliates	306			0
Other deductions: (Please explain in detail the nature of the item)				
Interest capitalized for accounting deducted for tax	390			0
Capital Lease Payments	391			0
Non-taxable imputed interest income on deferral and variance accounts	392			0
	393			0
	394			0
ARO Payments - Deductible for Tax when Paid				0
ITA 13(7.4) Election - Capital Contributions Received				0
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds				0
Deferred Revenue - ITA 20(1)(m) reserve				0
Principal portion of lease payments				0
Lease Inducement Book Amortization credit to income				0
Financing fees for tax ITA 20(1)(e) and (e.1)				0
Apprenticeship credits included in FS income		118,062		118,062
				0
				0
				0
				0
				0
				0
Total Deductions		**8,743,619**	**0**	**8,743,619**
Net Income for Tax Purposes		**871,642**	**0**	**871,642**
Charitable donations from Schedule 2	311			0
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320			0
Non-capital losses of preceding taxation years from Schedule 4	331			0
Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)*	332			0
Limited partnership losses of preceding taxation years from Schedule 4	335			0
TAXABLE INCOME		**871,642**	**0**	**871,642**

Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

PILs Tax Provision - Historical Year

Note: Input the actual information from the tax returns for the historical year.

						Wires Only	
Regulatory Taxable Income						$ 871,642	**A**
Ontario Income Taxes							
Income tax payable	**Ontario Income Tax**	11.50%	**B**	$ 100,239	**C = A * B**		
Small business credit	Ontario Small Business Threshold	$ 500,000	**D**				
	Rate reduction (negative)	-7.00%	**E**	-$ 35,000	**F = D * E**		
Ontario Income tax						$ 65,239	**J = C + F**
Combined Tax Rate and PILs	Effective Ontario Tax Rate			7.48%	**K = J / A**		
	Federal tax rate (Maximum 15%)			15.00%	**L**		
	Combined tax rate					22.48%	**M = K + L**
Total Income Taxes						**$ 195,985**	**N = A * M**
Investment Tax Credits						$ 8,909	**O**
Miscellaneous Tax Credits						$ 109,153	**P**
Total Tax Credits						**$ 118,062**	**Q = O + P**
Corporate PILs/Income Tax Provision for Historical Year						**$ 77,923**	**R = N - Q**

Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

Schedule 8 CCA - Bridge Year

Class	Class Description	UCC Regulated Historical Year	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Bridge Year CCA	UCC End of Bridge Year
1	Distribution System - post 1987	$ 56,259,372			$ 56,259,372	$ -	$ 56,259,372	4%	$ 2,250,375	$ 54,008,997
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	$ -			$ -	$ -	$ -	6%	$ -	$ -
2	Distribution System - pre 1988	$ 3,633,291			$ 3,633,291	$ -	$ 3,633,291	6%	$ 217,997	$ 3,415,294
8	General Office/Stores Equip	$ 1,666,790	$ 526,500		$ 2,193,290	$ 263,250	$ 1,930,040	20%	$ 386,008	$ 1,807,282
10	Computer Hardware/ Vehicles	$ 2,705,841	$ 672,000	$ -	$ 3,377,841	$ 336,000	$ 3,041,841	30%	$ 912,552	$ 2,465,289
10.1	Certain Automobiles				$ -	$ -	$ -	30%	$ -	$ -
12	Computer Software	$ 57,371	$ 652,966		$ 710,337	$ 326,483	$ 383,854	100%	$ 383,854	$ 326,483
13 1	Lease # 1				$ -	$ -	$ -		$ -	$ -
13 2	Lease #2				$ -	$ -	$ -		$ -	$ -
13 3	Lease # 3				$ -	$ -	$ -		$ -	$ -
13 4	Lease # 4				$ -	$ -	$ -		$ -	$ -
14	Franchise				$ -	$ -	$ -		$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	$ 282,408			$ 282,408	$ -	$ 282,408	8%	$ 22,593	$ 259,815
42	Fibre Optic Cable				$ -	$ -	$ -	12%	$ -	$ -
43.1	Certain Energy-Efficient Electrical Generating Equipment				$ -	$ -	$ -	30%	$ -	$ -
43.2	Certain Clean Energy Generation Equipment				$ -	$ -	$ -	50%	$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04	$ 2,832			$ 2,832	$ -	$ 2,832	45%	$ 1,274	$ 1,558
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)				$ -	$ -	$ -	30%	$ -	$ -
47	Distribution System - post February 2005	$ 48,060,734	$ 10,678,726	$ -	$ 58,739,460	$ 5,339,363	$ 53,400,097	8%	$ 4,272,008	$ 54,467,452
50	Data Network Infrastructure Equipment - post Mar 2007	$ 364,650	$ 302,295		$ 666,945	$ 151,148	$ 515,798	55%	$ 283,689	$ 383,256
52	Computer Hardware and system software				$ -	$ -	$ -	100%	$ -	$ -
95	CWIP				$ -	$ -	$ -		$ -	$ -
3	Buildings acquired before 1988	$ 1,275,277			$ 1,275,277	$ -	$ 1,275,277	5%	$ 63,764	$ 1,211,513
1b	Buildings > 18-03-07	$ 4,969,771	$ 1,457,845		$ 6,427,616	$ 728,923	$ 5,698,694	6%	$ 341,922	$ 6,085,694
1b	Buildings > 18-03-07	$ 2,425,531			$ 2,425,531	$ -	$ 2,425,531	6%	$ 145,532	$ 2,279,999
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
	TOTAL	$ 121,703,868	$ 14,290,332	$ -	$ 135,994,200	$ 7,145,166	$ 128,849,034		$ 9,281,567	$ 126,712,633

Ontario Energy Board

Income Tax/PILs Workform for 2015 Filer

Schedule 10 CEC - Bridge Year

Cumulative Eligible Capital				**976,507**
Additions				
Cost of Eligible Capital Property Acquired during Test Year				
Other Adjustments	0			
Subtotal	0	**x 3/4 =**	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	**x 1/2 =**	0	
			0	**0**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				**976,507**
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year				
Other Adjustments	0			
Subtotal	0	**x 3/4 =**		**0**
Cumulative Eligible Capital Balance				**976,507**
Current Year Deduction		**976,507**	**x 7% =**	**68,356**
Cumulative Eligible Capital - Closing Balance				**908,152**

Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

Schedule 13 Tax Reserves - Bridge Year

Continuity of Reserves

Description	Historical Utility Only	Eliminate Amounts Not Relevant for Bridge Year	Adjusted Utility Balance	Bridge Year Adjustments: Additions	Bridge Year Adjustments: Disposals	Balance for Bridge Year	Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)	0		0			0	0	
Tax Reserves Not Deducted for accounting purposes								
Reserve for doubtful accounts ss. 20(1)(l)	0		0			0	0	
Reserve for goods and services not delivered ss. 20(1)(m)	0		0			0	0	
Reserve for unpaid amounts ss. 20(1)(n)	0		0			0	0	
Debt & Share Issue Expenses ss. 20(1)(e)	0		0			0	0	
Other tax reserves	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Financial Statement Reserves (not deductible for Tax Purposes)								
General Reserve for Inventory Obsolescence (non-specific)	0		0			0	0	
General reserve for bad debts	0		0			0	0	
Accrued Employee Future Benefits:	0		0			0	0	
- Medical and Life Insurance	0		0			0	0	
-Short & Long-term Disability	0		0			0	0	
-Accmulated Sick Leave	0		0			0	0	
- Termination Cost	0		0			0	0	
- Other Post-Employment Benefits	0		0			0	0	
Provision for Environmental Costs	0		0			0	0	
Restructuring Costs	0		0			0	0	
Accrued Contingent Litigation Costs	0		0			0	0	
Accrued Self-Insurance Costs	0		0			0	0	
Other Contingent Liabilities	0		0			0	0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	0		0			0	0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	0		0			0	0	
Other	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Ontario Energy Board

Income Tax/PILs Workform for 2015 Filer

Corporation Loss Continuity and Application

Schedule 7-1 Loss Carry Forward - Bridge Year

Non-Capital Loss Carry Forward Deduction	**Total**
Actual Historical	0
Application of Loss Carry Forward to reduce taxable income in Bridge Year	
Other Adjustments Add (+) Deduct (-)	0
Balance available for use in Test Year	0
Amount to be used in Bridge Year	0
Balance available for use post Bridge Year	0

Net Capital Loss Carry Forward Deduction	**Total**
Actual Historical	0
Application of Loss Carry Forward to reduce taxable income in Bridge Year	
Other Adjustments Add (+) Deduct (-)	
Balance available for use in Test Year	0
Amount to be used in Bridge Year	
Balance available for use post Bridge Year	0

Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

Adjusted Taxable Income - Bridge Year

	T2S1 line #	Total for Regulated Utility
Income before PILs/Taxes	**A**	3,884,895

Additions:		
Interest and penalties on taxes	103	
Amortization of tangible assets	104	
Amortization of intangible assets	106	5,584,950
Recapture of capital cost allowance from Schedule 8	107	
Gain on sale of eligible capital property from Schedule 10	108	
Income or loss for tax purposes- joint ventures or partnerships	109	
Loss in equity of subsidiaries and affiliates	110	
Loss on disposal of assets	111	
Charitable donations	112	
Taxable Capital Gains	113	
Political Donations	114	
Deferred and prepaid expenses	116	
Scientific research expenditures deducted on financial statements	118	
Capitalized interest	119	
Non-deductible club dues and fees	120	
Non-deductible meals and entertainment expense	121	
Non-deductible automobile expenses	122	
Non-deductible life insurance premiums	123	
Non-deductible company pension plans	124	
Tax reserves deducted in prior year	125	0
Reserves from financial statements- balance at end of year	126	0
Soft costs on construction and renovation of buildings	127	
Book loss on joint ventures or partnerships	205	
Capital items expensed	206	
Debt issue expense	208	
Development expenses claimed in current year	212	
Financing fees deducted in books	216	
Gain on settlement of debt	220	
Non-deductible advertising	226	
Non-deductible interest	227	
Non-deductible legal and accounting fees	228	
Recapture of SR&ED expenditures	231	
Share issue expense	235	
Write down of capital property	236	
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	

Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

Adjusted Taxable Income - Bridge Year

Other Additions		
Interest Expensed on Capital Leases	290	
Realized Income from Deferred Credit Accounts	291	
Pensions	292	
Non-deductible penalties	293	
	294	
	295	
ARO Accretion expense		
Capital Contributions Received (ITA 12(1)(x))		
Lease Inducements Received (ITA 12(1)(x))		
Deferred Revenue (ITA 12(1)(a))		
Prior Year Investment Tax Credits received		8,909
Change in Employee Benefits		20,994
Previous years Ontario apprenticeship tax credits claimed		109,153
Change in regulatory variance accounts		0
Total Additions		**5,724,006**
Deductions:		
Gain on disposal of assets per financial statements	401	
Dividends not taxable under section 83	402	
Capital cost allowance from Schedule 8	403	9,281,567
Terminal loss from Schedule 8	404	
Cumulative eligible capital deduction from Schedule 10	405	68,356
Allowable business investment loss	406	
Deferred and prepaid expenses	409	
Scientific research expenses claimed in year	411	
Tax reserves claimed in current year	413	0
Reserves from financial statements - balance at beginning of year	414	0
Contributions to deferred income plans	416	
Book income of joint venture or partnership	305	
Equity in income from subsidiary or affiliates	306	
Other deductions: (Please explain in detail the nature of the item)		

Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

Adjusted Taxable Income - Bridge Year

Interest capitalized for accounting deducted for tax	390	
Capital Lease Payments	391	
Non-taxable imputed interest income on deferral and variance accounts	392	
	393	
	394	
ARO Payments - Deductible for Tax when Paid		
ITA 13(7.4) Election - Capital Contributions Received		
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds		
Deferred Revenue - ITA 20(1)(m) reserve		
Principal portion of lease payments		
Lease Inducement Book Amortization credit to income		
Financing fees for tax ITA 20(1)(e) and (e.1)		
Apprenticeship credits included in FS income		111,027
Total Deductions		**9,460,950**
Net Income for Tax Purposes		**147,952**
Charitable donations from Schedule 2	311	
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320	
Non-capital losses of preceding taxation years from Schedule 4	331	0
Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)*	332	
Limited partnership losses of preceding taxation years from Schedule 4	335	
TAXABLE INCOME		**147,952**

Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

PILS Tax Provision - Bridge Year

						Wires Only	
Regulatory Taxable Income						$ 147,952	**A**
Ontario Income Taxes							
Income tax payable	**Ontario Income Tax**	4.50%	**B**	$ 6,658	**C = A * B**		
Small business credit	Ontario Small Business Threshold	$ -	**D**				
	Rate reduction	-7.00%	**E**	$ -	**F = D * E**		
Ontario Income tax						$ 6,658	**J = C + F**
Combined Tax Rate and PILs	Effective Ontario Tax Rate			4.50%	**K = J / A**		
	Federal tax rate (Maximum 15%)			11.00%	**L**		
	Combined tax rate					15.50%	**M = K + L**
Total Income Taxes						**$ 22,932**	**N = A * M**
Investment Tax Credits						$ 7,329	**O**
Miscellaneous Tax Credits						$ 103,699	**P**
Total Tax Credits						**$ 111,028**	**Q = O + P**
Corporate PILs/Income Tax Provision for Bridge Year						**$ -**	**R = N - Q**

Note:

1. This is for the derivation of Bridge year PILs income tax expense and should not be used for Test year revenue requirement calculations.

Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

Schedule 8 CCA - Test Year

Class	Class Description	UCC Test Year Opening Balance	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Test Year CCA	UCC End of Test Year
1	Distribution System - post 1987	$ 54,008,997			$ 54,008,997	$ -	$ 54,008,997	4%	$ 2,160,360	$ 51,848,637
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	$ -			$ -	$ -	$ -	6%	$ -	$ -
2	Distribution System - pre 1988	$ 3,415,294			$ 3,415,294	$ -	$ 3,415,294	6%	$ 204,918	$ 3,210,376
8	General Office/Stores Equip	$ 1,807,282	310,627		$ 2,117,909	$ 155,313	$ 1,962,595	20%	$ 392,519	$ 1,725,389
10	Computer Hardware/ Vehicles	$ 2,465,289	698,878	0	$ 3,164,167	$ 349,439	$ 2,814,728	30%	$ 844,418	$ 2,319,748
10.1	Certain Automobiles	$ -			$ -	$ -	$ -	30%	$ -	$ -
12	Computer Software	$ 326,483	368,740		$ 695,223	$ 184,370	$ 510,853	100%	$ 510,853	$ 184,370
13 1	Lease # 1	$ -			$ -	$ -	$ -		$ -	$ -
13 2	Lease #2	$ -			$ -	$ -	$ -		$ -	$ -
13 3	Lease # 3	$ -			$ -	$ -	$ -		$ -	$ -
13 4	Lease # 4	$ -			$ -	$ -	$ -		$ -	$ -
14	Franchise	$ -			$ -	$ -	$ -		$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bl	$ 259,815			$ 259,815	$ -	$ 259,815	8%	$ 20,785	$ 239,030
42	Fibre Optic Cable	$ -			$ -	$ -	$ -	12%	$ -	$ -
43.1	Certain Energy-Efficient Electrical Generating Equipment	$ -			$ -	$ -	$ -	30%	$ -	$ -
43.2	Certain Clean Energy Generation Equipment	$ -			$ -	$ -	$ -	50%	$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04	$ 1,558			$ 1,558	$ -	$ 1,558	45%	$ 701	$ 857
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ -			$ -	$ -	$ -	30%	$ -	$ -
47	Distribution System - post February 2005	$ 54,467,452	9,166,447		$ 63,633,900	$ 4,583,224	$ 59,050,676	8%	$ 4,724,054	$ 58,909,845
50	Data Network Infrastructure Equipment - post Mar 2007	$ 383,256	240,248		$ 623,504	$ 120,124	$ 503,380	55%	$ 276,859	$ 346,645
52	Computer Hardware and system software	$ -			$ -	$ -	$ -	100%	$ -	$ -
95	CWIP	$ -			$ -	$ -	$ -	0%	$ -	$ -
3	Buildings acquired before 1988	$ 1,211,513			$ 1,211,513	$ -	$ 1,211,513	5%	$ 60,576	$ 1,150,937
1b	Buildings > 18-03-07	$ 6,085,694			$ 6,085,694	$ -	$ 6,085,694	6%	$ 365,142	$ 5,720,553
1b	Buildings > 18-03-07	$ 2,279,999	86,640		$ 2,366,639	$ 43,320	$ 2,323,319	6%	$ 139,399	$ 2,227,240
		$ -			$ -	$ -	$ -	0%	$ -	$ -
		$ -			$ -	$ -	$ -	0%	$ -	$ -
		$ -			$ -	$ -	$ -	0%	$ -	$ -
		$ -			$ -	$ -	$ -	0%	$ -	$ -
		$ -			$ -	$ -	$ -	0%	$ -	$ -
		$ -			$ -	$ -	$ -	0%	$ -	$ -
		$ -			$ -	$ -	$ -	0%	$ -	$ -
	TOTAL	$ 126,712,633	$ 10,871,580	$ -	$ 137,584,213	$ 5,435,790	$ 132,148,423		$ 9,700,584	$ 127,883,629

Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

Schedule 10 CEC - Test Year

Cumulative Eligible Capital				**908,152**
Additions				
Cost of Eligible Capital Property Acquired during Test Year	0			
Other Adjustments	0			
Subtotal	0	**x 3/4 =**	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	**x 1/2 =**	0	
			0	**0**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				**908,152**
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year	0			
Other Adjustments	0			
Subtotal	0	**x 3/4 =**		**0**
Cumulative Eligible Capital Balance				**908,152**
Current Year Deduction (Carry Forward to Tab "Test Year Taxable Income")		**908,152**	**x 7% =**	**63,571**
Cumulative Eligible Capital - Closing Balance				**844,581**

Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

Schedule 13 Tax Reserves - Test Year

Continuity of Reserves

Description	Bridge Year	Eliminate Amounts Not Relevant for Bridge Year	Adjusted Utility Balance	Test Year Adjustments: Additions	Test Year Adjustments: Disposals	Balance for Test Year	Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)	0		0			0	0	
Tax Reserves Not Deducted for accounting purposes								
Reserve for doubtful accounts ss. 20(1)(l)	0		0			0	0	
Reserve for goods and services not delivered ss. 20(1)(m)	0		0			0	0	
Reserve for unpaid amounts ss. 20(1)(n)	0		0			0	0	
Debt & Share Issue Expenses ss. 20(1)(e)	0		0			0	0	
Other tax reserves	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Financial Statement Reserves (not deductible for Tax Purposes)								
General Reserve for Inventory Obsolescence (non-specific)	0		0			0	0	
General reserve for bad debts	0		0			0	0	
Accrued Employee Future Benefits:	0		0			0	0	
- Medical and Life Insurance	0		0			0	0	
-Short & Long-term Disability	0		0			0	0	
-Accmulated Sick Leave	0		0			0	0	
- Termination Cost	0		0			0	0	
- Other Post-Employment Benefits	0		0			0	0	
Provision for Environmental Costs	0		0			0	0	
Restructuring Costs	0		0			0	0	
Accrued Contingent Litigation Costs	0		0			0	0	
Accrued Self-Insurance Costs	0		0			0	0	
Other Contingent Liabilities	0		0			0	0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	0		0			0	0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	0		0			0	0	
Other	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

Schedule 7-1 Loss Carry Forward - Test Year

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	**Total**	**Non-Distribution Portion**	**Utility Balance**
Actual/Estimated Bridge Year	0		0
			0
Other Adjustments Add (+) Deduct (-)	0		0
Balance available for use in Test Year	0	0	0
Amount to be used in Test Year	0		0
Balance available for use post Test Year	0	0	0

Net Capital Loss Carry Forward Deduction	**Total**	**Non-Distribution Portion**	**Utility Balance**
Actual/Estimated Bridge Year	0		0
			0
Other Adjustments Add (+) Deduct (-)			0
Balance available for use in Test Year	0	0	0
Amount to be used in Test Year			0
Balance available for use post Test Year	0	0	0

Ontario Energy Board

Income Tax/PILs Workform for 2015 Fi

Taxable Income - Test Year

	T2 S1 line #	Test Year Taxable Income
Net Income Before Taxes		5,333,809
Additions:		
Interest and penalties on taxes	103	
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104	
Amortization of intangible assets *2-4 ADJUSTED ACCOUNTING DATA P490*	106	5,034,074
Recapture of capital cost allowance from Schedule 8	107	
Gain on sale of eligible capital property from Schedule 10	108	
Income or loss for tax purposes- joint ventures or partnerships	109	
Loss in equity of subsidiaries and affiliates	110	
Loss on disposal of assets	111	
Charitable donations	112	
Taxable Capital Gains	113	
Political Donations	114	
Deferred and prepaid expenses	116	
Scientific research expenditures deducted on financial statements	118	
Capitalized interest	119	
Non-deductible club dues and fees	120	
Non-deductible meals and entertainment expense	121	
Non-deductible automobile expenses	122	
Non-deductible life insurance premiums	123	
Non-deductible company pension plans	124	
Tax reserves beginning of year	125	0
Reserves from financial statements- balance at end of year	126	0
Soft costs on construction and renovation of buildings	127	
Book loss on joint ventures or partnerships	205	
Capital items expensed	206	
Debt issue expense	208	
Development expenses claimed in current year	212	
Financing fees deducted in books	216	
Gain on settlement of debt	220	
Non-deductible advertising	226	
Non-deductible interest	227	
Non-deductible legal and accounting fees	228	
Recapture of SR&ED expenditures	231	
Share issue expense	235	
Write down of capital property	236	

Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	
Other Additions: (please explain in detail the nature of the item)		
Interest Expensed on Capital Leases	290	
Realized Income from Deferred Credit Accounts	291	
Pensions	292	
Non-deductible penalties	293	
	294	
	295	
	296	
	297	
ARO Accretion expense		
Capital Contributions Received (ITA 12(1)(x))		
Lease Inducements Received (ITA 12(1)(x))		
Deferred Revenue (ITA 12(1)(a))		
Prior Year Investment Tax Credits received		7,329
Change in Regulatory variance accounts		0
Change in Employee future benefits		101,909
Previous years Ontario apprenticeship tax credit claimed		103,699
Total Additions		**5,247,011**
Deductions:		
Gain on disposal of assets per financial statements	401	
Dividends not taxable under section 83	402	
Capital cost allowance from Schedule 8	403	9,700,584
Terminal loss from Schedule 8	404	
Cumulative eligible capital deduction from Schedule 10 CEC	405	63,571
Allowable business investment loss	406	
Deferred and prepaid expenses	409	
Scientific research expenses claimed in year	411	
Tax reserves end of year	413	0
Reserves from financial statements - balance at beginning of year	414	0
Contributions to deferred income plans	416	
Book income of joint venture or partnership	305	
Equity in income from subsidiary or affiliates	306	
Other deductions: (Please explain in detail the nature of the item)		
Interest capitalized for accounting deducted for tax	390	
Capital Lease Payments	391	

Non-taxable imputed interest income on deferral and variance accounts	392	
	393	
	394	
	395	
	396	
	397	
ARO Payments - Deductible for Tax when Paid		
ITA 13(7.4) Election - Capital Contributions Received		
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds		
Deferred Revenue - ITA 20(1)(m) reserve		
Principal portion of lease payments		
Lease Inducement Book Amortization credit to income		
Financing fees for tax ITA 20(1)(e) and (e.1)		
Apprenticeship credits included in FS income		81,003
Total Deductions		**9,845,158**
NET INCOME FOR TAX PURPOSES		**735,662**
Charitable donations	311	
Taxable dividends received under section 112 or 113	320	
Non-capital losses of preceding taxation years from Schedule 7-1	331	0
Net-capital losses of preceding taxation years (Please show calculation)	332	
Limited partnership losses of preceding taxation years from Schedule 4	335	
REGULATORY TAXABLE INCOME		**735,662**

Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

PILs Tax Provision - Test Year

							Wires Only	
Regulatory Taxable Income							$ 735,662	**A**
Ontario Income Taxes								
Income tax payable	**Ontario Income Tax**	11.50%	**B**	$	84,601	**C = A * B**		
Small business credit	Ontario Small Business Threshold	$ -	**D**					
	Rate reduction	-11.50%	**E**	$	-	**F = D * E**		
Ontario Income tax							$ 84,601	**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							**$ 194,950**	**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							**$ 113,947**	**R = N - Q**
Corporate PILs/Income Tax Provision Gross Up [1]					73.50%	**S = 1 - M**	**$ 41,083**	**T = R / S - R**
Income Tax (grossed-up)							**$ 155,030**	**U = R + T**

Note:

1. This is for the derivation of revenue requirement and should not be used for sufficiency/deficiency calculations.

Ontario Energy Board

2015 Cost Allocation Model

EB-2014-0096

Sheet I5.1 Miscellaneous Data Worksheet - Public

Structure KM (kMs of Roads in Service Area that have distribution line)	**1977**
Deemed Equity Component of Rate Base (ref: RRWF 7. cell F24)	**40%**
Working Capital Allowance to be included in Rate Base (%)	**12.61%**
Portion of pole leasing revenue from Secondary - Remainder assumed to be Primary (%)	**0%**

Ontario Energy Board

2015 Cost Allocation Model

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Sheet O1 Revenue to Cost Summary Worksheet - Public

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

			1	2	3	7	8	9
		Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
Rate Base Assets								
crev	Distribution Revenue at Existing Rates	$28,665,190	$15,624,862	$3,659,015	$8,920,209	$273,854	$58,114	$129,135
mi	Miscellaneous Revenue (mi)	$1,602,522	$1,262,498	$188,449	$138,127	$6,039	$5,257	$2,153
		Miscellaneous Revenue Input equals Output						
	Total Revenue at Existing Rates	$30,267,712	$16,887,360	$3,847,464	$9,058,336	$279,893	$63,371	$131,288
	Factor required to recover deficiency (1 + D)	0.9984						
	Distribution Revenue at Status Quo Rates	$28,619,197	$15,599,792	$3,653,144	$8,905,897	$273,415	$58,021	$128,928
	Miscellaneous Revenue (mi)	$1,602,522	$1,262,498	$188,449	$138,127	$6,039	$5,257	$2,153
	Total Revenue at Status Quo Rates	$30,221,719	$16,862,290	$3,841,593	$9,044,024	$279,454	$63,278	$131,081
	Expenses							
di	Distribution Costs (di)	$6,076,213	$4,018,843	$618,590	$1,299,617	$90,672	$17,907	$30,584
cu	Customer Related Costs (cu)	$5,792,820	$4,649,821	$675,876	$441,373	$3,294	$20,563	$1,892
ad	General and Administration (ad)	$4,555,962	$3,281,707	$492,679	$713,895	$39,584	$14,471	$13,625
dep	Depreciation and Amortization (dep)	$5,034,074	$3,275,023	$523,330	$1,137,742	$63,935	$12,376	$21,669
INPUT	PILs (INPUT)	$155,030	$100,582	$15,715	$35,405	$2,171	$421	$736
INT	Interest	$3,273,811	$2,124,016	$331,862	$747,650	$45,850	$8,900	$15,534
	Total Expenses	$24,887,910	$17,449,992	$2,658,052	$4,375,681	$245,506	$74,639	$84,039
	Direct Allocation	$0	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$5,333,809	$3,460,521	$540,682	$1,218,097	$74,700	$14,500	$25,308
	Revenue Requirement (includes NI)	$30,221,719	$20,910,514	$3,198,734	$5,593,778	$320,207	$89,139	$109,348
		Revenue Requirement Input equals Output						
	Rate Base Calculation							
	Net Assets							
dp	Distribution Plant - Gross	$229,999,767	$151,033,396	$23,262,519	$50,507,950	$3,384,945	$663,701	$1,147,255
gp	General Plant - Gross	$39,645,270	$25,884,419	$4,049,658	$8,857,703	$556,478	$108,498	$188,514
accum dep	Accumulated Depreciation	($123,110,941)	($81,042,583)	($12,303,241)	($26,874,620)	($1,882,186)	($370,108)	($638,203)
co	Capital Contribution	($23,400,607)	($15,897,099)	($2,509,930)	($4,479,479)	($334,057)	($66,954)	($113,088)
	Total Net Plant	$123,133,489	$79,978,133	$12,499,006	$28,011,553	$1,725,180	$335,138	$584,478
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$144,149,669	$48,575,506	$14,442,505	$79,944,100	$892,292	$30,959	$264,306
	OM&A Expenses	$16,424,995	$11,950,372	$1,787,145	$2,454,885	$133,550	$52,942	$46,101
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0
	Subtotal	$160,574,663	$60,525,878	$16,229,650	$82,398,985	$1,025,843	$83,901	$310,407
	Working Capital	$20,248,465	$7,632,313	$2,046,559	$10,390,512	$129,359	$10,580	$39,142
	Total Rate Base	$143,381,954	$87,610,446	$14,545,565	$38,402,065	$1,854,539	$345,718	$623,621
		Rate Base Input equals Output						
	Equity Component of Rate Base	$57,352,781	$35,044,179	$5,818,226	$15,360,826	$741,816	$138,287	$249,448
	Net Income on Allocated Assets	$5,333,809	($587,702)	$1,183,541	$4,668,343	$33,947	($11,361)	$47,041
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0
	Net Income	$5,333,809	($587,702)	$1,183,541	$4,668,343	$33,947	($11,361)	$47,041
	RATIOS ANALYSIS							
	REVENUE TO EXPENSES STATUS QUO%	100.00%	80.64%	120.10%	161.68%	87.27%	70.99%	119.88%
	EXISTING REVENUE MINUS ALLOCATED COSTS	$45,993	($4,023,154)	$648,730	$3,464,558	($40,314)	($25,768)	$21,940
		Deficiency Input equals Output						
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	($0)	($4,048,223)	$642,859	$3,450,246	($40,753)	($25,861)	$21,733
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.30%	-1.68%	20.34%	30.39%	4.58%	-8.22%	18.86%

Ontario Energy Board

2015 Cost Allocation Model

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Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - Public

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
Customer Unit Cost per month - Avoided Cost	$6.67	$10.50	$49.55	$0.16	$4.16	$0.28
Customer Unit Cost per month - Directly Related	$9.18	$14.55	$68.25	$0.24	$5.75	$0.41
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$27.85	$36.06	$102.20	$15.98	$23.46	$16.20
Existing Approved Fixed Charge	$16.06	$37.79	$179.58	$1.15	$12.87	$19.53

Information to be Used to Allocate PILs, ROD, ROE and A&G	Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
General Plant - Gross Assets	$39,645,270	$25,884,419	$4,049,658	$8,857,703	$556,478	$108,498	$188,514
General Plant - Accumulated Depreciation	($17,662,464)	($11,531,833)	($1,804,173)	($3,946,217)	($247,918)	($48,337)	($83,985)
General Plant - Net Fixed Assets	$21,982,806	$14,352,586	$2,245,485	$4,911,485	$308,560	$60,161	$104,529
General Plant - Depreciation	$1,373,937	$897,044	$140,344	$306,970	$19,285	$3,760	$6,533
Total Net Fixed Assets Excluding General Plant	$101,150,683	$65,625,547	$10,253,522	$23,100,068	$1,416,620	$274,977	$479,950
Total Administration and General Expense	$4,555,962	$3,281,707	$492,679	$713,895	$39,584	$14,471	$13,625
Total O&M	$11,869,033	$8,668,665	$1,294,466	$1,740,990	$93,966	$38,471	$32,476

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

USoA Account #	Accounts	Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	
	Distribution Plant								
1860	Meters	$9,570,017	$6,334,218	$1,022,821	$2,212,978	$0	$0	$0	CWMC

	Accumulated Amortization								
	Accum. Amortization of Electric Utility Plant - Meters only	($3,198,575)	($2,117,078)	($341,856)	($739,641)	$0	$0	$0	
	Meter Net Fixed Assets	**$6,371,442**	**$4,217,140**	**$680,965**	**$1,473,337**	**$0**	**$0**	**$0**	
	Misc Revenue								
4082	Retail Services Revenues	($44,424)	($32,322)	($4,834)	($6,640)	($361)	($143)	($125)	CWNB
4084	Service Transaction Requests (STR) Revenues	($1,047)	($762)	($114)	($156)	($9)	($3)	($3)	CWNB
4090	Electric Services Incidental to Energy Sales	($21,060)	($15,323)	($2,291)	($3,148)	($171)	($68)	($59)	CWNB
4220	Other Electric Revenues	$0	$0	$0	$0	$0	$0	$0	NFA
4225	Late Payment Charges	($361,000)	($243,754)	($49,911)	($67,335)	$0	$0	$0	LPHA
	Sub-total	*($427,531)*	*($292,160)*	*($57,150)*	*($77,279)*	*($541)*	*($214)*	*($187)*	
	Operation								
5065	Meter Expense	$439,640	$290,990	$46,988	$101,663	$0	$0	$0	CWMC
5070	Customer Premises - Operation Labour	$99,134	$85,870	$8,001	$1,573	$2,370	$552	$769	CCA
5075	Customer Premises - Materials and Expenses	$0	$0	$0	$0	$0	$0	$0	CCA
	Sub-total	*$538,775*	*$376,860*	*$54,989*	*$103,235*	*$2,370*	*$552*	*$769*	
	Maintenance								
5175	Maintenance of Meters	$5,163	$3,417	$552	$1,194	$0	$0	$0	1860
	Billing and Collection								
5310	Meter Reading Expense	$390,850	$179,445	$51,469	$159,936	$0	$0	$0	CWMR
5315	Customer Billing	$2,958,889	$2,503,145	$349,846	$91,688	$596	$12,892	$723	CWNB
5320	Collecting	$431,182	$364,769	$50,981	$13,361	$87	$1,879	$105	CWNB
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	CWNB
5330	Collection Charges	$0	$0	$0	$0	$0	$0	$0	CWNB
	Sub-total	$3,780,920	$3,047,359	$452,295	$264,985	$682	$14,770	$829	
	Total Operation, Maintenance and Billing	$4,324,858	$3,427,636	$507,836	$369,414	$3,052	$15,322	$1,598	
	Amortization Expense - Meters	$498,133	$329,705	$53,239	$115,189	$0	$0	$0	
	Allocated PILs	$8,022	$5,304	$856	$1,862	$0	$0	$0	
	Allocated Debt Return	$169,401	$111,997	$18,080	$39,324	$0	$0	$0	
	Allocated Equity Return	$275,995	$182,469	$29,457	$64,069	$0	$0	$0	
	Total	**$4,848,878**	**$3,764,950**	**$552,319**	**$512,579**	**$2,511**	**$15,108**	**$1,411**	

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

			1	2	3	7	8	9	
USoA Account #	**Accounts**	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	
	Distribution Plant								
1860	Meters	$9,570,017	$6,334,218	$1,022,821	$2,212,978	$0	$0	$0	CWMC
	Accumulated Amortization								
	Accum. Amortization of Electric Utility Plant - Meters only	($3,198,575)	($2,117,078)	($341,856)	($739,641)	$0	$0	$0	
	Meter Net Fixed Assets	$6,371,442	$4,217,140	$680,965	$1,473,337	$0	$0	$0	
	Allocated General Plant Net Fixed Assets	$1,384,693	$922,307	$149,129	$313,258	$0	$0	$0	
	Meter Net Fixed Assets Including General Plant	$7,756,135	$5,139,447	$830,094	$1,786,595	$0	$0	$0	
	Misc Revenue								
4082	Retail Services Revenues	($44,424)	($32,322)	($4,834)	($6,640)	($361)	($143)	($125)	CWNB
4084	Service Transaction Requests (STR) Revenues	($1,047)	($762)	($114)	($156)	($9)	($3)	($3)	CWNB

4090	Electric Services Incidental to Energy Sales	($21,060)	($15,323)	($2,291)	($3,148)	($171)	($68)	($59)	CWNB
4220	Other Electric Revenues	$0	$0	$0	$0	$0	$0	$0	NFA
4225	Late Payment Charges	($361,000)	($243,754)	($49,911)	($67,335)	$0	$0	$0	LPHA
	Sub-total	*($427,531)*	*($292,160)*	*($57,150)*	*($77,279)*	*($541)*	*($214)*	*($187)*	
	Operation								
5065	Meter Expense	$439,640	$290,990	$46,988	$101,663	$0	$0	$0	CWMC
5070	Customer Premises - Operation Labour	$99,134	$85,870	$8,001	$1,573	$2,370	$552	$769	CCA
5075	Customer Premises - Materials and Expenses	$0	$0	$0	$0	$0	$0	$0	CCA
	Sub-total	*$538,775*	*$376,860*	*$54,989*	*$103,235*	*$2,370*	*$552*	*$769*	
	Maintenance								
5175	Maintenance of Meters	$5,163	$3,417	$552	$1,194	$0	$0	$0	1860
	Billing and Collection								
5310	Meter Reading Expense	$390,850	$179,445	$51,469	$159,936	$0	$0	$0	CWMR
5315	Customer Billing	$2,958,889	$2,503,145	$349,846	$91,688	$596	$12,892	$723	CWNB
5320	Collecting	$431,182	$364,769	$50,981	$13,361	$87	$1,879	$105	CWNB
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	CWNB
5330	Collection Charges	$0	$0	$0	$0	$0	$0	$0	CWNB
	Sub-total	*$3,780,920*	*$3,047,359*	*$452,295*	*$264,985*	*$682*	*$14,770*	*$829*	
	Total Operation, Maintenance and Billing	$4,324,858	$3,427,636	$507,836	$369,414	$3,052	$15,322	$1,598	
	Amortization Expense - Meters	$498,133	$329,705	$53,239	$115,189	$0	$0	$0	
	Amortization Expense - General Plant assigned to Meters	*$86,544*	*$57,645*	*$9,321*	*$19,579*	*$0*	*$0*	*$0*	
	Admin and General	$1,650,087	$1,297,604	$193,284	$151,479	$1,286	$5,764	$670	
	Allocated PILs	$9,765	$6,463	$1,044	$2,258	$0	$0	$0	
	Allocated Debt Return	$206,216	$136,491	$22,040	$47,686	$0	$0	$0	
	Allocated Equity Return	$335,975	$222,375	$35,908	$77,691	$0	$0	$0	
	Total	**$6,684,047**	**$5,185,759**	**$765,522**	**$706,016**	**$3,797**	**$20,872**	**$2,081**	

Scenario 3

Minimum System Customer Costs Adjusted for PLCC - High Limit Fixed Customer Charge

			1	2	3	7	8	9	
USoA Account #	**Accounts**	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	
	Distribution Plant								
1565	Conservation and Demand Management Expenditures and Recoveries	$0	$0	$0	$0	$0	$0	$0	CDMPP
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	#N/A
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	BCP
1830-4	Poles, Towers and Fixtures - Primary	$21,734,602	$18,826,269	$1,754,137	$344,986	$519,563	$121,041	$168,608	PNCP
1830-5	Poles, Towers and Fixtures - Secondary	$6,169,625	$5,348,686	$498,364	$92,672	$147,612	$34,389	$47,903	SNCP
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	#N/A
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	BCP
1835-4	Overhead Conductors and Devices - Primary	$15,650,179	$13,556,010	$1,263,081	$248,410	$374,115	$87,156	$121,407	PNCP
1835-5	Overhead Conductors and Devices - Secondary	$2,759,630	$2,392,430	$222,915	$41,452	$66,026	$15,382	$21,427	SNCP
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	#N/A
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	BCP
1840-4	Underground Conduit - Primary	$3,382,061	$2,929,504	$272,956	$53,682	$80,848	$18,835	$26,237	PNCP
1840-5	Underground Conduit - Secondary	$3,492,047	$3,027,390	$282,077	$52,453	$83,549	$19,464	$27,113	SNCP
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	#N/A

1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	BCP
1845-4	Underground Conductors and Devices - Primary	$32,625,614	$28,259,941	$2,633,119	$517,855	$779,911	$181,693	$253,095	PNCP
1845-5	Underground Conductors and Devices - Secondary	$9,406,870	$8,155,179	$759,859	$141,298	$225,065	$52,433	$73,038	SNCP
1850	Line Transformers	$23,629,051	$20,508,358	$1,907,380	$331,801	$565,985	$131,855	$183,672	LTNCP
1855	Services	$6,613,181	$4,761,547	$1,109,142	$742,492	$0	$0	$0	CWCS
1860	Meters	$9,570,017	$6,334,218	$1,022,821	$2,212,978	$0	$0	$0	CWMC
									0
	Sub-total	*$135,032,879*	*$114,099,532*	*$11,725,849*	*$4,780,078*	*$2,842,672*	*$662,248*	*$922,499*	
	Accumulated Amortization								
	Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	($76,568,262)	($65,164,809)	($6,585,356)	($2,222,257)	($1,666,687)	($388,282)	($540,871)	
	Customer Related Net Fixed Assets	$58,464,617	$48,934,723	$5,140,494	$2,557,821	$1,175,985	$273,965	$381,629	
	Allocated General Plant Net Fixed Assets	$12,771,021	$10,702,232	$1,125,750	$543,838	$256,147	$59,940	$83,115	
	Customer Related NFA Including General Plant	$71,235,638	$59,636,955	$6,266,244	$3,101,659	$1,432,132	$333,905	$464,744	
	Misc Revenue								
4082	Retail Services Revenues	($44,424)	($32,322)	($4,834)	($6,640)	($361)	($143)	($125)	CWNB
4084	Service Transaction Requests (STR) Revenues	($1,047)	($762)	($114)	($156)	($9)	($3)	($3)	CWNB
4090	Electric Services Incidental to Energy Sales	($21,060)	($15,323)	($2,291)	($3,148)	($171)	($68)	($59)	CWNB
4220	Other Electric Revenues	$0	$0	$0	$0	$0	$0	$0	NFA
4225	Late Payment Charges	($361,000)	($243,754)	($49,911)	($67,335)	$0	$0	$0	LPHA
4235	Miscellaneous Service Revenues	($803,285)	($679,559)	($94,977)	($24,892)	($162)	($3,500)	($196)	CWNB
	Sub-total	*($1,230,816)*	*($971,719)*	*($152,127)*	*($102,170)*	*($703)*	*($3,714)*	*($383)*	
	Operating and Maintenance								
5005	Operation Supervision and Engineering	$470,808	$404,397	$40,164	$9,633	$10,667	$2,485	$3,462	1815-1855
5010	Load Dispatching	$27,600	$23,707	$2,355	$565	$625	$146	$203	1815-1855
5020	Overhead Distribution Lines and Feeders - Operation Labour	$136,999	$118,687	$11,059	$2,152	$3,275	$763	$1,063	1830 & 1835
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$9,560	$8,282	$772	$150	$229	$53	$74	1830 & 1835
5035	Overhead Distribution Transformers- Operation	$0	$0	$0	$0	$0	$0	$0	1850
5040	Underground Distribution Lines and Feeders - Operation Labour	$54,087	$46,860	$4,366	$846	$1,293	$301	$420	1840 & 1845
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$158,895	$137,665	$12,827	$2,486	$3,799	$885	$1,233	1840 & 1845
5055	Underground Distribution Transformers - Operation	$191	$166	$15	$3	$5	$1	$1	1850
5065	Meter Expense	$439,640	$290,990	$46,988	$101,663	$0	$0	$0	CWMC
5070	Customer Premises - Operation Labour	$99,134	$85,870	$8,001	$1,573	$2,370	$552	$769	CCA
5075	Customer Premises - Materials and Expenses	$0	$0	$0	$0	$0	$0	$0	CCA
5085	Miscellaneous Distribution Expense	$1,173,610	$1,008,062	$100,119	$24,013	$26,591	$6,195	$8,629	1815-1855
5090	Underground Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	1840 & 1845
5095	Overhead Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	1830 & 1835
5096	Other Rent	$0	$0	$0	$0	$0	$0	$0	O&M
5105	Maintenance Supervision and Engineering	$327,860	$281,613	$27,969	$6,708	$7,428	$1,731	$2,411	1815-1855
5120	Maintenance of Poles, Towers and Fixtures	$122,444	$106,080	$9,884	$1,920	$2,928	$682	$950	1830
5125	Maintenance of Overhead Conductors and Devices	$423,503	$366,881	$34,184	$6,668	$10,125	$2,359	$3,286	1835
5130	Maintenance of Overhead Services	$166,973	$120,222	$28,004	$18,747	$0	$0	$0	1855
5135	Overhead Distribution Lines and Feeders - Right of Way	$158,540	$137,348	$12,797	$2,490	$3,791	$883	$1,230	1830 & 1835
5145	Maintenance of Underground Conduit	$18,906	$16,383	$1,527	$292	$452	$105	$147	1840
5150	Maintenance of Underground Conductors and Devices	$130,567	$113,118	$10,540	$2,048	$3,122	$727	$1,013	1845
5155	Maintenance of Underground Services	$90,440	$65,118	$15,168	$10,154	$0	$0	$0	1855
5160	Maintenance of Line Transformers	$94,048	$81,627	$7,592	$1,321	$2,253	$525	$731	1850
5175	Maintenance of Meters	$5,163	$3,417	$552	$1,194	$0	$0	$0	1860

	Sub-total	*$4,108,970*	*$3,416,494*	*$374,882*	*$194,627*	*$78,953*	*$18,393*	*$25,622*	
	Billing and Collection								
5305	Supervision	$956,144	$808,873	$113,050	$29,628	$192	$4,166	$234	CWNB
5310	Meter Reading Expense	$390,850	$179,445	$51,469	$159,936	$0	$0	$0	CWMR
5315	Customer Billing	$2,958,889	$2,503,145	$349,846	$91,688	$596	$12,892	$723	CWNB
5320	Collecting	$431,182	$364,769	$50,981	$13,361	$87	$1,879	$105	CWNB
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	CWNB
5330	Collection Charges	$0	$0	$0	$0	$0	$0	$0	CWNB
5335	Bad Debt Expense	$265,000	$204,510	$25,807	$34,682	$0	$0	$0	BDHA
5340	Miscellaneous Customer Accounts Expenses	$246,819	$208,802	$29,183	$7,648	$50	$1,075	$60	CWNB
	Sub-total	*$5,248,882*	*$4,269,544*	*$620,336*	*$336,944*	*$925*	*$20,011*	*$1,123*	
	Sub Total Operating, Maintenance and Biling	*$9,357,853*	*$7,686,038*	*$995,217*	*$531,570*	*$79,878*	*$38,405*	*$26,744*	
	Amortization Expense - Customer Related	$2,272,274	$1,833,045	$216,854	$165,016	$36,828	$8,580	$11,951	
	Amortization Expense - General Plant assigned to Meters	$798,196	$668,895	$70,360	$33,990	$16,009	$3,746	$5,195	
	Admin and General	$3,565,784	$2,909,713	$378,784	$217,971	$33,649	$14,447	$11,221	
	Allocated PILs	$89,607	$75,001	$7,879	$3,920	$1,802	$420	$585	
	Allocated Debt Return	$1,892,248	$1,583,806	$166,376	$82,786	$38,062	$8,867	$12,352	
	Allocated Equity Return	$3,082,916	$2,580,392	$271,065	$134,877	$62,011	$14,447	$20,124	
	PLCC Adjustment for Line Transformer	$130,149	$113,586	$10,566	$1,837	$3,141	$0	$1,019	
	PLCC Adjustment for Primary Costs	$432,799	$376,883	$35,130	$6,928	$10,463	$0	$3,395	
	PLCC Adjustment for Secondary Costs	$162,827	$143,602	$11,028	$1,997	$4,785	$0	$1,416	
	Total	$19,102,286	**$15,731,101**	**$1,897,684**	**$1,057,198**	**$249,148**	**$85,197**	**$81,959**	

Below: Grouping to
avoid disclosure

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

Accounts	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
Distribution Plant							
CWMC	$ 9,570,017	$ 6,334,218	$ 1,022,821	$ 2,212,978	$ -	$ -	$ -
Accumulated Amortization							
Accum. Amortization of Electric Utility Plant - Meters only	$ (3,198,575)	$ (2,117,078)	$ (341,856)	$ (739,641)	$ -	$ -	$ -
Meter Net Fixed Assets	$ 6,371,442	$ 4,217,140	$ 680,965	$ 1,473,337	$ -	$ -	$ -
Misc Revenue							
CWNB	$ (66,531)	$ (48,406)	$ (7,239)	$ (9,944)	$ (541)	$ (214)	$ (187)
NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ (361,000)	$ (243,754)	$ (49,911)	$ (67,335)	$ -	$ -	$ -
Sub-total	$ (427,531)	$ (292,160)	$ (57,150)	$ (77,279)	$ (541)	$ (214)	$ (187)
Operation							
CWMC	$ 439,640	$ 290,990	$ 46,988	$ 101,663	$ -	$ -	$ -
CCA	$ 99,134	$ 85,870	$ 8,001	$ 1,573	$ 2,370	$ 552	$ 769
Sub-total	$ 538,775	$ 376,860	$ 54,989	$ 103,235	$ 2,370	$ 552	$ 769
Maintenance							

1860	$ 5,163	$ 3,417	$ 552	$ 1,194	$ -	$ -	$ -
Billing and Collection							
CWMR	$ 390,850	$ 179,445	$ 51,469	$ 159,936	$ -	$ -	$ -
CWNB	$ 3,390,071	$ 2,867,914	$ 400,827	$ 105,049	$ 682	$ 14,770	$ 829
Sub-total	$ 3,780,920	$ 3,047,359	$ 452,295	$ 264,985	$ 682	$ 14,770	$ 829
Total Operation, Maintenance and Billing	$ 4,324,858	$ 3,427,636	$ 507,836	$ 369,414	$ 3,052	$ 15,322	$ 1,598
Amortization Expense - Meters	$ 498,133	$ 329,705	$ 53,239	$ 115,189	$ -	$ -	$ -
Allocated PILs	$ 8,022	$ 5,304	$ 856	$ 1,862	$ -	$ -	$ -
Allocated Debt Return	$ 169,401	$ 111,997	$ 18,080	$ 39,324	$ -	$ -	$ -
Allocated Equity Return	$ 275,995	$ 182,469	$ 29,457	$ 64,069	$ -	$ -	$ -
Total	**$ 4,848,878**	**$ 3,764,950**	**$ 552,319**	**$ 512,579**	**$ 2,511**	**$ 15,108**	**$ 1,411**

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

Accounts	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
Distribution Plant							
CWMC	$ 9,570,017	$ 6,334,218	$ 1,022,821	$ 2,212,978	$ -	$ -	$ -
Accumulated Amortization							
Accum. Amortization of Electric Utility Plant - Meters only	$ (3,198,575)	$ (2,117,078)	$ (341,856)	$ (739,641)	$ -	$ -	$ -
Meter Net Fixed Assets	$ 6,371,442	$ 4,217,140	$ 680,965	$ 1,473,337	$ -	$ -	$ -
Allocated General Plant Net Fixed Assets	$ 1,384,693	$ 922,307	$ 149,129	$ 313,258	$ -	$ -	$ -
Meter Net Fixed Assets Including General Plant	$ 7,756,135	$ 5,139,447	$ 830,094	$ 1,786,595	$ -	$ -	$ -
Misc Revenue							
CWNB	$ (66,531)	$ (48,406)	$ (7,239)	$ (9,944)	$ (541)	$ (214)	$ (187)
NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ (361,000)	$ (243,754)	$ (49,911)	$ (67,335)	$ -	$ -	$ -
Sub-total	*$ (427,531)*	*$ (292,160)*	*$ (57,150)*	*$ (77,279)*	*$ (541)*	*$ (214)*	*$ (187)*
Operation							
CWMC	$ 439,640	$ 290,990	$ 46,988	$ 101,663	$ -	$ -	$ -
CCA	$ 99,134	$ 85,870	$ 8,001	$ 1,573	$ 2,370	$ 552	$ 769
Sub-total	*$ 538,775*	*$ 376,860*	*$ 54,989*	*$ 103,235*	*$ 2,370*	*$ 552*	*$ 769*
Maintenance							
1860	$ 5,163	$ 3,417	$ 552	$ 1,194	$ -	$ -	$ -
Billing and Collection							
CWMR	$ 390,850	$ 179,445	$ 51,469	$ 159,936	$ -	$ -	$ -
CWNB	$ 3,390,071	$ 2,867,914	$ 400,827	$ 105,049	$ 682	$ 14,770	$ 829
Sub-total	*$ 3,780,920*	*$ 3,047,359*	*$ 452,295*	*$ 264,985*	*$ 682*	*$ 14,770*	*$ 829*
Total Operation, Maintenance and Billing	$ 4,324,858	$ 3,427,636	$ 507,836	$ 369,414	$ 3,052	$ 15,322	$ 1,598
Amortization Expense - Meters	$ 498,133	$ 329,705	$ 53,239	$ 115,189	$ -	$ -	$ -
Amortization Expense - General Plant assigned to Meters	$ 86,544	$ 57,645	$ 9,321	$ 19,579	$ -	$ -	$ -
Admin and General	$ 1,650,087	$ 1,297,604	$ 193,284	$ 151,479	$ 1,286	$ 5,764	$ 670
Allocated PILs	$ 9,765	$ 6,463	$ 1,044	$ 2,258	$ -	$ -	$ -
Allocated Debt Return	$ 206,216	$ 136,491	$ 22,040	$ 47,686	$ -	$ -	$ -
Allocated Equity Return	$ 335,975	$ 222,375	$ 35,908	$ 77,691	$ -	$ -	$ -

Total	**$ 6,684,047**	**$ 5,185,759**	**$ 765,522**	**$ 706,016**	**$ 3,797**	**$ 20,872**	**$ 2,081**

Scenario 3

Minimum System Customer Costs Adjusted for PLCC - High Limit Fixed Customer Charge

USoA Account #	Accounts	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
	Distribution Plant							
	CDMPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Poles, Towers and Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	PNCP	$ 73,392,457	$ 63,571,723	$ 5,923,293	$ 1,164,933	$ 1,754,436	$ 408,725	$ 569,347
	SNCP	$ 21,828,172	$ 18,923,686	$ 1,763,214	$ 327,874	$ 522,251	$ 121,667	$ 169,480
	Overhead Conductors and Devices	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	LTNCP	$ 23,629,051	$ 20,508,358	$ 1,907,380	$ 331,801	$ 565,985	$ 131,855	$ 183,672
	CWCS	$ 6,613,181	$ 4,761,547	$ 1,109,142	$ 742,492	$ -	$ -	$ -
	CWMC	$ 9,570,017	$ 6,334,218	$ 1,022,821	$ 2,212,978	$ -	$ -	$ -
	Sub-total	*$ 135,032,879*	*$ 114,099,532*	*$ 11,725,849*	*$ 4,780,078*	*$ 2,842,672*	*$ 662,248*	*$ 922,499*
	Accumulated Amortization							
	Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	$ (76,568,262)	$ (65,164,809)	$ (6,585,356)	$ (2,222,257)	$ (1,666,687)	$ (388,282)	$ (540,871)
	Customer Related Net Fixed Assets	$ 58,464,617	$ 48,934,723	$ 5,140,494	$ 2,557,821	$ 1,175,985	$ 273,965	$ 381,629
	Allocated General Plant Net Fixed Assets	$ 12,771,021	$ 10,702,232	$ 1,125,750	$ 543,838	$ 256,147	$ 59,940	$ 83,115
	Customer Related NFA Including General Plant	$ 71,235,638	$ 59,636,955	$ 6,266,244	$ 3,101,659	$ 1,432,132	$ 333,905	$ 464,744
	Misc Revenue							
	CWNB	$ (869,816)	$ (727,965)	$ (102,216)	$ (34,835)	$ (703)	$ (3,714)	$ (383)
	NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	LPHA	$ (361,000)	$ (243,754)	$ (49,911)	$ (67,335)	$ -	$ -	$ -
	Sub-total	*$ (1,230,816)*	*$ (971,719)*	*$ (152,127)*	*$ (102,170)*	*$ (703)*	*$ (3,714)*	*$ (383)*
	Operating and Maintenance							
	1815-1855	$ 1,999,878	$ 1,717,779	$ 170,606	$ 40,920	$ 45,312	$ 10,556	$ 14,705
	1830 & 1835	$ 305,099	$ 264,317	$ 24,628	$ 4,793	$ 7,295	$ 1,699	$ 2,367
	1850	$ 94,240	$ 81,793	$ 7,607	$ 1,323	$ 2,257	$ 526	$ 733
	1840 & 1845	$ 212,982	$ 184,525	$ 17,193	$ 3,333	$ 5,092	$ 1,186	$ 1,653
	CWMC	$ 439,640	$ 290,990	$ 46,988	$ 101,663	$ -	$ -	$ -
	CCA	$ 99,134	$ 85,870	$ 8,001	$ 1,573	$ 2,370	$ 552	$ 769
	O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1830	$ 122,444	$ 106,080	$ 9,884	$ 1,920	$ 2,928	$ 682	$ 950
	1835	$ 423,503	$ 366,881	$ 34,184	$ 6,668	$ 10,125	$ 2,359	$ 3,286
	1855	$ 257,414	$ 185,340	$ 43,173	$ 28,901	$ -	$ -	$ -
	1840	$ 18,906	$ 16,383	$ 1,527	$ 292	$ 452	$ 105	$ 147
	1845	$ 130,567	$ 113,118	$ 10,540	$ 2,048	$ 3,122	$ 727	$ 1,013
	1860	$ 5,163	$ 3,417	$ 552	$ 1,194	$ -	$ -	$ -
	Sub-total	*$ 4,108,970*	*$ 3,416,494*	*$ 374,882*	*$ 194,627*	*$ 78,953*	*$ 18,393*	*$ 25,622*
	Billing and Collection							
	CWNB	$ 4,593,033	$ 3,885,589	$ 543,059	$ 142,325	$ 925	$ 20,011	$ 1,123
	CWMR	$ 390,850	$ 179,445	$ 51,469	$ 159,936	$ -	$ -	$ -
	BDHA	$ 265,000	$ 204,510	$ 25,807	$ 34,682	$ -	$ -	$ -
	Sub-total	*$ 5,248,882*	*$ 4,269,544*	*$ 620,336*	*$ 336,944*	*$ 925*	*$ 20,011*	*$ 1,123*
	Sub Total Operating, Maintenance and Biling	*$ 9,357,853*	*$ 7,686,038*	*$ 995,217*	*$ 531,570*	*$ 79,878*	*$ 38,405*	*$ 26,744*
	Amortization Expense - Customer Related	$ 2,272,274	$ 1,833,045	$ 216,854	$ 165,016	$ 36,828	$ 8,580	$ 11,951
	Amortization Expense - General Plant assigned to Meters	$ 798,196	$ 668,895	$ 70,360	$ 33,990	$ 16,009	$ 3,746	$ 5,195

Admin and General	$	3,565,784	$	2,909,713	$	378,784	$	217,971	$	33,649	$	14,447	$	11,221
Allocated PILs	$	89,607	$	75,001	$	7,879	$	3,920	$	1,802	$	420	$	585
Allocated Debt Return	$	1,892,248	$	1,583,806	$	166,376	$	82,786	$	38,062	$	8,867	$	12,352
Allocated Equity Return	$	3,082,916	$	2,580,392	$	271,065	$	134,877	$	62,011	$	14,447	$	20,124
PLCC Adjustment for Line Transformer	$	130,149	$	113,586	$	10,566	$	1,837	$	3,141	$	-	$	1,019
PLCC Adjustment for Primary Costs	$	432,799	$	376,883	$	35,130	$	6,928	$	10,463	$	-	$	3,395
PLCC Adjustment for Secondary Costs	$	162,827	$	143,602	$	11,028	$	1,997	$	4,785	$	-	$	1,416
Total	**$**	**19,102,286**	**$**	**15,731,101**	**$**	**1,897,684**	**$**	**1,057,198**	**$**	**249,148**	**$**	**85,197**	**$**	**81,959**

Niagara Peninsula Energy

Cost Allocation Based Calculations

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	Check Revenue Cost Ratios from 2015 Cost Allocation Model	Revenue to Cost Ratio after Settlement	Service Revenue after Settlement	Miscellaneous Revenue	Base Revenue after Settlement
Residential	20,910,514	15,599,792	1,262,498	16,862,290	80.64%	80.64%	91.65%	19,164,486	1,262,498	17,901,988
GS < 50 kW	3,198,734	3,653,144	188,449	3,841,593	120.10%	120.10%	120.00%	3,838,481	188,449	3,650,032
GS >50	5,593,778	8,905,897	138,127	9,044,024	161.68%	161.68%	120.00%	6,712,370	138,127	6,574,244
Sentinel Lights	89,139	58,021	5,257	63,278	70.99%	70.99%	91.65%	81,696	5,257	76,439
Street Lighting	320,207	273,415	6,039	279,454	87.27%	87.27%	91.65%	293,469	6,039	287,430
USL	109,348	128,928	2,153	131,081	119.88%	119.88%	120.00%	131,217	2,153	129,065
TOTAL	**30,221,719**	**28,619,197**	**1,602,522**	**30,221,719**	100.0%	**100.0%**		**30,221,719**	**1,602,522**	**28,619,197**

Exhibit	
Tab	
Schedule	
Attachment	

Niagara Penisula Energy Inc. (ED-2007-0749)

2015 EDR Application (EB-2014-0096) version: Initial

August 31, 2014

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F2 Cost Allocation

Enter selected amounts from sheets 'O1' and 'O2' of Cost Allocation model

Customer Class Name	REVENUE ALLOCATION (sheet O1) Service Revenue Requirement	%	Miscellaneous Revenue (mi)	%	Base Revenue Requirement *	%	Proposed Revenue to Expenses %	Per Cost Allocation Model Revenue to Expenses %
Residential	20,910,514	69.19%	1,262,498	78.78%	19,648,016	68.65%	91.65%	80.64%
General Service < 50 kW	3,198,734	10.58%	188,449	11.76%	3,010,285	10.52%	120.00%	120.10%
General Service > 50	5,593,778	18.51%	138,127	8.62%	5,455,652	19.06%	120.00%	161.68%
Unmetered Scattered Load	109,348	0.36%	2,153	0.13%	107,195	0.37%	120.00%	119.88%
Sentinel Lighting	89,139	0.29%	5,257	0.33%	83,882	0.29%	91.65%	70.99%
Street Lighting	320,207	1.06%	6,039	0.38%	314,168	1.10%	91.65%	87.27%
TOTAL (from Column C of sheet O1)	**30,221,719**	**100.00%**	**1,602,522**	**100.00%**	**28,619,197**	**100.00%**		
	OK	OK	OK	OK	OK	OK		

** Service Revenue Requirement less Miscellaneous Revenue*

Customer Class Name	CUSTOMER UNIT COST PER MONTH (sheet O2) Avoided Costs (Minimum Charge)	Directly Related	Minimum System with PLCC * adjustment	Existing Fixed Rate	Maximum Charge **
Residential	$6.67	$9.18	$27.85	$16.06	$27.85
General Service < 50 kW	$10.50	$14.55	$36.06	$37.79	$37.79
General Service > 50	$49.55	$68.25	$102.20	$179.58	$179.58
Unmetered Scattered Load	$0.28	$0.41	$16.20	$19.53	$19.53
Sentinel Lighting	$4.16	$5.75	$23.46	$12.87	$23.46
Street Lighting	$0.16	$0.24	$15.98	$1.15	$15.98

** PLCC = 'Peak Load Carrying Capability'*

*** Greater of 'Directly Related', 'Minimum System with PLCC adjustment', and Existing Fixed Rate*

Exhibit	
Tab	
Schedule	
Attachment	

Niagara Penisula Energy Inc. (ED-2007-0749)

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August 31, 2014

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F3 Revenue Requirement Allocation

Enter allocation of Base Revenue Requirement and RC ratio ranges by customer class

Customer Class Name	Base Revenue Requirement %			Base Revenue Requirement $ [3]		
	Cost Allocation [1]	Existing Rates [2]	Rate Application	Cost Allocation	Existing Rates	Rate Application
Residential	68.65%	54.51%	62.55%	19,648,016	15,599,791	17,901,988
General Service < 50 kW	10.52%	12.76%	12.75%	3,010,285	3,653,144	3,650,032
General Service > 50	19.06%	31.12%	22.97%	5,455,652	8,905,897	6,574,244
Unmetered Scattered Load	0.37%	0.45%	0.45%	107,195	128,928	129,065
Sentinel Lighting	0.29%	0.20%	0.27%	83,882	58,021	76,439
Street Lighting	1.10%	0.96%	1.00%	314,168	273,415	287,430
TOTAL	**100.00%**	**100.00%**	**100.00%**	**28,619,197**	**28,619,197**	**28,619,197**
			OK			**OK**

[1] from sheet F2
[2] from sheet C3
[3] Base Revenue Requirement (from sheet F1), multiplied by Base Revenue Requirement %

Customer Class Name	Revenue Offsets [4]		Base Revenue Requirement $			Service Revenue Requirement $ [5]		
	%	$	Cost Allocation	Existing Rates	Rate Application	Cost Allocation	Existing Rates	Rate Application
Residential	78.78%	1,262,498	19,648,016	15,599,791	17,901,988	20,910,514	16,862,289	19,164,486
General Service < 50 kW	11.76%	188,449	3,010,285	3,653,144	3,650,032	3,198,734	3,841,592	3,838,480
General Service > 50	8.62%	138,127	5,455,652	8,905,897	6,574,244	5,593,778	9,044,024	6,712,370
Unmetered Scattered Load	0.13%	2,153	107,195	128,928	129,065	109,348	131,081	131,217
Sentinel Lighting	0.33%	5,257	83,882	58,021	76,439	89,139	63,278	81,696
Street Lighting	0.38%	6,039	314,168	273,415	287,430	320,207	279,455	293,469
TOTAL	**100.00%**	**1,602,522**	**28,619,197**	**28,619,197**	**28,619,197**	**30,221,719**	**30,221,719**	**30,221,719**

[4] %s from sheet F2; total $ from sheet F1
[5] Revenue Offsets plus Base Revenue Requirement

Customer Class Name	Service Revenue Requirement			Cost Allocation	Variance	Target Range	
	Rate Application	Cost Allocation	Revenue to Cost Ratio [6]	Revenue to Cost Ratio [7]		Floor	Ceiling
Residential	19,164,486	20,910,514	91.65%	80.64%	11.01%	85.00	115.00
General Service < 50 kW	3,838,480	3,198,734	120.00%	120.10%	-0.10%	80.00	120.00
General Service > 50	6,712,370	5,593,778	120.00%	161.68%	-41.68%	80.00	120.00
Unmetered Scattered Load	131,217	109,348	120.00%	119.88%	0.12%	80.00	120.00
Sentinel Lighting	81,696	89,139	91.65%	70.99%	20.66%	80.00	120.00
Street Lighting	293,469	320,207	91.65%	87.27%	4.38%	70.00	120.00
TOTAL	**30,221,719**	**30,221,719**	100.00%		**1.00**		

[6] Rate Application value divided by Cost Allocation value
[7] from sheet F2

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F4 Fixed/Variable Rate Design

Enter the proposed fixed monthly rate for each customer class

	Existing Rates (a)			Cost Allocation - Minimum Fixed Rate (b)			Cost Allocation - Maximun Fixed Rate (b)		
Customer Class Name	**Rate**	**Fixed %**	**Variable %**	**Rate**	**Fixed %**	**Variable %**	**Rate**	**Fixed %**	**Variable %**
Residential	$16.06	58.05%	41.95%	$6.67	21.03%	78.97%	$27.85	87.87%	12.13%
General Service < 50 kW	$37.79	54.35%	45.65%	$10.50	15.13%	84.87%	$37.79	54.48%	45.52%
General Service > 50	$179.58	20.82%	79.18%	$49.55	7.80%	92.20%	$179.58	28.26%	71.74%
Unmetered Scattered Load	$19.53	76.50%	23.50%	$0.28	1.09%	98.91%	$19.53	76.54%	23.46%
Sentinel Lighting	$12.87	80.52%	19.48%	$4.16	19.79%	80.21%	$23.46	111.60%	-11.60%
Street Lighting	$1.15	65.46%	34.54%	$0.16	8.74%	91.26%	$15.98	866.81%	-766.81%

(a) per sheet C3

(b) Rates per sheet F2; %s based on # customers/connections (sheet C2) and Base Revenue Requirement allocated to class (sheet F3)

	Existing Fixed/Variable Split (c)			Rate Application			Base Revenue Requirement $		
Customer Class Name	**Rate**	**Fixed %**	**Variable %**	**Fixed Rate**	**Fixed %**	**Variable %**	**Total (d)**	**Fixed (e)**	**Variable (f)**
Residential	$18.40	58.05%	41.95%	$18.40	58.05%	41.95%	17,901,988	10,392,603	7,509,385
General Service < 50 kW	$37.70	54.35%	45.65%	$37.70	54.35%	45.65%	3,650,032	1,983,820	1,666,212
General Service > 50	$132.35	20.82%	79.18%	$102.20	16.08%	83.92%	6,574,244	1,057,198	5,517,045
Unmetered Scattered Load	$19.52	76.50%	23.50%	$19.52	76.50%	23.50%	129,065	98,735	30,330
Sentinel Lighting	$16.93	80.52%	19.48%	$16.93	80.52%	19.48%	76,439	61,550	14,889
Street Lighting	$1.21	65.46%	34.54%	$1.21	65.46%	34.54%	287,430	188,138	99,292
							28,619,197	13,782,046	14,837,151

(c) %s per Existing Rates, Rate based on Fixed % of Total Base Revenue allocated to class (4) and # c

(d) per sheet F3

(e) Based on Rate Application Fixed Rate and # customers/connections (sheet C2)

(f) Total amount (d) less Fixed amount (e)

	Transf. Allowance ($/kW):		($0.60)	Gross $	Resulting Variable		Existing	Base Revenue $	
Customer Class Name	**kW**	**Rate**	**Total $ (g)**	**Variable (h)**	**Rate (i)**	**per**	**Var. Rate (j)**	**Fixed (k)**	**Gross (l)**
Residential				7,509,385	$0.0184	kWh	$0.0161	10,392,603	17,901,988
General Service < 50 kW				1,666,212	$0.0138	kWh	$0.0138	1,983,820	3,650,032
General Service > 50	748,780	$0.60	429,224	5,946,269	$3.3563	kW	$4.2400	1,057,198	7,003,468
Unmetered Scattered Load				30,330	$0.0137	kWh	$0.0137	98,735	129,065
Sentinel Lighting				14,889	$21.1177	kW	$16.0553	61,550	76,439
Street Lighting				99,292	$4.6871	kW	$4.4657	188,138	287,430

(g) kW volume multiplied by Rate

(h) Variable Base Revenue Requirement (f), plus total Transformer Allowances (g)

(i) Gross Variable amount $ (h), divided by test year volume (sheet C2)

(k) per (e) above

(l) Gross Variable amount (h), plus Fixed Base Revenue (k)

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F5 Fixed/Variable Revenue

Fixed / Variable Revenue for each customer class

FIXED / VARIABLE REVENUE SPLITS

(Excluding Low Voltage rate adder and Transformer Allowance recoveries)

2015 Projected Revenue at Existing Rates	**Net Distribution Revenue** *(A)*	**Fixed Charge Revenue** *(B)*	**Fixed %** *(C)*	**Variable %** *(D)*	**Total %** *(E)*
Residential	15,624,862	9,070,668	58.05%	41.95%	54.51%
General Service < 50 kW	3,659,015	1,988,703	54.35%	45.65%	12.76%
General Service > 50	8,920,210	1,857,576	20.82%	79.18%	31.12%
Unmetered Scattered Load	129,135	98,789	76.50%	23.50%	0.45%
Sentinel Lighting	58,115	46,795	80.52%	19.48%	0.20%
Street Lighting	273,855	179,253	65.46%	34.54%	0.96%
TOTAL	**28,665,192**	**13,241,783**	**46.19%**	**53.81%**	**100.00%**

(A) per sheet "Net Distribution Revenue"
(B) per sheet C4
(C) = (B) / (A)
(D) = 1 - (C)
(E) Class Revenue from column (A) divided by Total from column (A)

2015 Projected Revenue at Proposed Rates	**Net Distribution Revenue** *(E)*	**Fixed Charge Revenue** *(F)*	**Fixed %** *(G)*	**Variable %** *(H)*	**Total %** *(I)*	**Variable Charge** *Revenue*
Residential	17,901,988	10,392,603	58.05%	41.95%	62.55%	7,509,385
General Service < 50 kW	3,650,032	1,983,820	54.35%	45.65%	12.75%	1,666,212
General Service > 50	6,574,244	1,057,198	16.08%	83.92%	22.97%	5,517,045
Unmetered Scattered Load	129,065	98,735	76.50%	23.50%	0.45%	30,330
Sentinel Lighting	76,439	61,550	80.52%	19.48%	0.27%	14,889
Street Lighting	287,430	188,138	65.46%	34.54%	1.00%	99,292
TOTAL	**28,619,197**	**13,782,046**	**48.16%**	**51.84%**	**100.00%**	14,837,151

(E) Sheet F4; "Total Base Revenue Requirement"
(F) Sheet F6; "Fixed Charge Revenue"
(G) = (F) / (E)
(H) = 1 - (G)
(I) Class Revenue from column (E) divided by Total from column (E)

Appendix N – Bill Impacts

If applicable, please enter any adjustments related to the revenue to cost ratio model into columns C and E. The Price Escalator and Stretch

Price Escalator	**1.60%**	**Productivity Factor**	**0.00%**	**# of Residential Customers**	47,067
Choose Stretch Factor Group	III	**Price Cap Index**	**1.30%**	**Billed kWh**	407,092,792
Associated Stretch Factor Value	**0.30%**			**Rate Design Transition Years Left**	4

Rate Class	**Current tariff - Interim rates**	**Current Volumetric Charge- Interim rates**	**Updated for WCA interrogatories**	**MFC Adjustment from R/C Model**	**Updated for WCA interrogatories**	**DVR Adjustment from R/C Model**	**Price Cap Index to be Applied to MFC and DVR**	**Proposed MFC**	**Proposed Volumetric Charge**
RESIDENTIAL SERVICE CLASSIFICATION	18.43	0.0185	18.40		0.0184		1.30%	22.00	0.0140
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	37.76	0.0138	37.70		0.0138		1.30%	38.19	0.0139
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION	102.31	3.3629	102.20		3.3563		1.30%	103.53	3.3999
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	19.53	0.0137	19.52		0.0137		1.30%	19.77	0.0139
SENTINEL LIGHTING SERVICE CLASSIFICATION	16.95	21.1488	16.93		21.1177		1.30%	17.15	21.3923
STREET LIGHTING SERVICE CLASSIFICATION	121	4.6966	1.21		4.6871		1.30%	1.22	4.7480
microFIT SERVICE CLASSIFICATION	5.4		5.40					5.40	

Rate Design Transition

				Revenue from Rates	**Current F/V Split**	**Decoupling MFC Split**	**Incremental Fixed Charge ($/month/year)**	**New F/V Split**	**Adjusted Rates[1]**
Current Residential Fixed Rate (inclusive of R/C adj.)	18.43		18.40	10,392,699	58.1%	10.5%	3.32	68.5%	21.72
Current Residential Variable Rate (inclusive of R/C adj.)	0.0185		0.0184	7,509,385	41.9%			31.5%	0.0138
				17,902,084					

[1] These are the residential rates to which the Price Cap Index will be applied to.

Monthly Bill Impacts RPP

Customer Class	Volume		2015 Interim Distribution Charges	Proposed 2016 Distribution Charges	Total Distribution Charges only excluding Pass through		2015 Total Bill	Proposed 2016 Total Bill	Total Bill	
	kWh	kW	$	$	$ Change	% Change	$	$	$ Change	% Change
Residential	800		34.16	34.12	$ (0.04)	-0.13%	141.99	152.03	$ 10.04	7.07%
Residential 10th percentile	285.5		24.64	26.92	$ 2.28	9.26%	64.02	71.68	$ 7.66	11.96%
GS<50 kw	2000		68.09	68.81	$ 0.72	1.05%	331.38	373.99	$ 42.61	12.86%
GS>50 kW	65000	180	707.63	715.52	$ 7.89	1.11%	10,264.97	10,414.97	$ 150.00	1.46%
USL	250		22.96	23.24	$ 0.29	1.24%	62.42	63.12	$ 0.69	1.11%
Sentinel	44	0.12	19.49	19.72	$ 0.23	1.17%	28.99	28.90	$ (0.09)	-0.32%
Streetlighting	50	0.13	1.82	1.84	$ 0.02	1.06%	9.44	9.53	$ 0.10	1.02%

File Number: EB-2015-0090

Bill Impacts

Customer Class: **Residential RPP**
TOU / non-TOU: TOU
Current Loss Factor **1.0479**

Consumption **800** **kWh**

	Charge Unit	Current Board-Approved Interim Rate ($)	Current Board-Approved Interim Volume	Current Board-Approved Interim Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 18.4300	1	$ 18.43	22.00	1	$ 22.00	$ 3.57	19.38%
Distribution Volumetric Rate	kWh	$ 0.0185	800	$ 14.80	$ 0.0140	800	$ 11.18	-$ 3.62	-24.44%
Fixed rate riders	Monthly	$ 0.9300	1	$ 0.93	$ 0.9300	1	$ 0.93	$ -	
Volumetric rate riders	kWh		800	$ -		800	$ -	$ -	
Sub-Total A (excluding pass through)				$ 34.16			$ 34.12	**-$ 0.04**	**-0.13%**
Line Losses on Cost of Power	kWh	$ 0.1021	38	$ 3.91	$ 0.1021	38	$ 3.91	$ -	
Total Deferral/Variance Account Rate Riders	kWh	-$ 0.0035	800	-$ 2.80	-$ 0.0030	800	-$ 2.40	$ 0.40	-14.29%
Lost Revenue Adjustment Mechanism (LRAM)	kWh	$ -	800	$ -	$ 0.0001	800	$ 0.08	$ 0.08	
Low Voltage Service Charge	kWh	$ 0.0005	800	$ 0.40	$ 0.0005	800	$ 0.40	$ -	
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 36.46**			**$ 36.90**	**$ 0.44**	**1.20%**
RTSR - Network	kWh	$ 0.0076	838	$ 6.37	$ 0.0074	838	$ 6.20	-$ 0.17	-2.63%
RTSR - Line and Transformation Connection	kWh	$ 0.0053	838	$ 4.44	$ 0.0053	838	$ 4.44	$ 0.00	0.00%
Sub-Total C - Delivery (including Sub-Total B)				**$ 47.28**			**$ 47.55**	**$ 0.27**	**0.57%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0044	838	$ 3.69	$ 0.0036	838	$ 3.02	-$ 0.67	-18.18%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	838	$ 1.09	$ 0.0013	838	$ 1.09	$ 0.00	0.00%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	800	$ 5.60	$ -		$ -	-$ 5.60	-100.00%
Ontario Electricity Support Program (OESP)		$ -	838	$ -	$ 0.0011	838	$ 0.92	$ 0.92	100.00%
TOU - Off Peak	kWh	$ 0.0800	512	$ 40.96	$ 0.0800	512	$ 40.96	$ -	
TOU - Mid Peak	kWh	$ 0.1220	144	$ 17.57	$ 0.1220	144	$ 17.57	$ -	
TOU - On Peak	kWh	$ 0.1610	144	$ 23.18	$ 0.1610	144	$ 23.18	$ -	
Total Bill on TOU (before Taxes)				**$ 139.62**			**$ 134.54**	**-$ 5.08**	**-3.64%**
HST		13%		$ 18.15	13%		$ 17.49	-$ 0.66	-3.64%
Total Bill (including HST)				$ 157.77			$ 152.03	-$ 5.74	-3.64%
Ontario Clean Energy Benefit 1				-$ 15.78			$ -	$ 15.78	-100.00%
Total Bill on TOU (including OCEB)				**$ 141.99**			**$ 152.03**	**$ 10.04**	**7.07%**

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:

Bill Impacts

Customer Class: **Residential- 10th Percentile usage**
RPP
TOU / non-TOU: TOU
Current Loss Factor **1.0479**

Consumption **285.5** **kWh**

	Charge Unit	Current Board-Approved Interim Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 18.4300	1	$ 18.43	22.00	1	$ 22.00	$ 3.57	19.38%
Distribution Volumetric Rate	kWh	$ 0.0185	285.5	$ 5.28	$ 0.0140	285.5	$ 3.99	-$ 1.29	-24.44%
Fixed rate riders	Monthly	$ 0.9300	1	$ 0.93	$ 0.9300	1	$ 0.93	$ -	
Volumetric rate riders	kWh		285.5	$ -		285.5	$ -	$ -	
Sub-Total A (excluding pass through)				$ 24.64			$ 26.92	**$ 2.28**	**9.26%**
Line Losses on Cost of Power	kWh	$ 0.1021	14	$ 1.40	$ 0.1021	14	$ 1.40	$ -	
Total Deferral/Variance Account Rate Riders	kWh	-$ 0.0035	285.5	-$ 1.00	-$ 0.0030	285.5	-$ 0.86	$ 0.14	-14.29%
Lost Revenue Adjustment Mechanism (LRAM)	kWh	$ -	285.5	$ -	$ 0.0001	285.5	$ 0.03	$ 0.03	
Low Voltage Service Charge	kWh	$ 0.0005	285.5	$ 0.14	$ 0.0005	285.5	$ 0.14	$ -	
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 25.97**			**$ 28.42**	**$ 2.45**	**9.45%**
RTSR - Network	kWh	$ 0.0076	299	$ 2.27	$ 0.0074	299	$ 2.21	-$ 0.06	-2.63%
RTSR - Line and Transformation Connection	kWh	$ 0.0053	299	$ 1.59	$ 0.0053	299	$ 1.59	$ -	
Sub-Total C - Delivery (including Sub-Total B)				**$ 29.83**			**$ 32.22**	**$ 2.39**	**8.02%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0044	299	$ 1.32	$ 0.0036	299	$ 1.08	-$ 0.24	-18.18%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	299	$ 0.39	$ 0.0013	299	$ 0.39	$ -	
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	286	$ 2.00	$ -		$ -	-$ 2.00	-100.00%
Ontario Electricity Support Program (OESP)					$ 0.0011	299	$ 0.33	$ 0.33	100.00%
TOU - Off Peak	kWh	$ 0.0800	183	$ 14.62	$ 0.0800	183	$ 14.62	$ -	
TOU - Mid Peak	kWh	$ 0.1220	51	$ 6.27	$ 0.1220	51	$ 6.27	$ -	
TOU - On Peak	kWh	$ 0.1610	51	$ 8.27	$ 0.1610	51	$ 8.27	$ -	
Total Bill on TOU (before Taxes)				**$ 62.95**			**$ 63.43**	**$ 0.48**	**0.77%**
HST		13%		$ 8.18	13%		$ 8.25	$ 0.06	0.77%
Total Bill (including HST)				$ 71.13			$ 71.68	$ 0.55	0.77%
Ontario Clean Energy Benefit 1				-$ 7.11			$ -	$ 7.11	-100.00%
Total Bill on TOU (including OCEB)				**$ 64.02**			**$ 71.68**	**$ 7.66**	**11.96%**

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.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Bill Impacts

Customer Class: **General Service < 50 kW RPP**

TOU / non-TOU: TOU

Current Loss Factor **1.0479**

Consumption **2,000** **kWh**

	Charge Unit	Current Board-Approved Interim Rate ($)	Current Board-Approved Interim Volume	Current Board-Approved Interim Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 37.7600	1	$ 37.76	38.19	1	$ 38.19	$ 0.43	1.13%
Distribution Volumetric Rate	kWh	$ 0.0138	2,000	$ 27.60	$ 0.0139	2,000	$ 27.89	$ 0.29	1.05%
Fixed rate riders	Monthly	$ 2.7300	1	$ 2.73	$ 2.7300	1	$ 2.73	$ -	
Volumetric rate riders	kWh	$ -	2,000	$ -		2,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 68.09			$ 68.81	**$ 0.72**	**1.05%**
Line Losses on Cost of Power	kWh	$ 0.1021	96	$ 9.79	$ 0.1021	96	$ 9.79	$ -	
Total Deferral/Variance Account Rate Riders	kWh	-$ 0.0040	2,000	-$ 8.00	-$ 0.0030	2,000	-$ 6.00	$ 2.00	-25.00%
Lost Revenue Adjustment Mechanism (LRAM)	kWh	$ -	2000	$ -	$ 0.0011	2,000	$ 2.20	$ 2.20	
Low Voltage Service Charge	kWh	$ 0.0004	2,000	$ 0.80	$ 0.0004	2,000	$ 0.80	$ -	
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 71.47**			**$ 76.39**	**$ 4.92**	**6.88%**
RTSR - Network	kWh	$ 0.0068	2096	$ 14.25	$ 0.0066	2096	$ 13.83	-$ 0.42	-2.94%
RTSR - Line and Transformation Connection	kWh	$ 0.0046	2096	$ 9.64	$ 0.0046	2096	$ 9.64	$ -	
Sub-Total C - Delivery (including Sub-Total B)				**$ 95.36**			**$ 99.86**	**$ 4.50**	**4.72%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0044	2096	$ 9.22	$ 0.0036	2096	$ 7.55	-$ 1.68	-18.18%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	2096	$ 2.72	$ 0.0013	2096	$ 2.72	$ -	
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	$ -	
Ontario Electricity Support Program (OESP)					$ 0.0011	2096	$ 2.31	$ 2.31	100.00%
TOU - Off Peak	kWh	$ 0.0800	1280	$ 102.40	$ 0.0800	1280	$ 102.40	$ -	
TOU - Mid Peak	kWh	$ 0.1220	360	$ 43.92	$ 0.1220	360	$ 43.92	$ -	
TOU - On Peak	kWh	$ 0.1610	360	$ 57.96	$ 0.1610	360	$ 57.96	$ -	
Total Bill on TOU (before Taxes)				**$ 325.84**			**$ 330.97**	**$ 5.13**	**1.57%**
HST		13%		$ 42.36	13%		$ 43.03	$ 0.67	1.57%
Total Bill (including HST)				$ 368.20			$ 373.99	$ 5.79	1.57%
Ontario Clean Energy Benefit 1				-$ 36.82			$ -	$ 36.82	-100.00%
Total Bill on TOU (including OCEB)				**$ 331.38**			**$ 373.99**	**$ 42.61**	**12.86%**

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.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Bill Impacts

Customer Class: **General Service > 50 RPP**
TOU / non-TOU: TOU
Current Loss Factor **1.0479**
Consumption 65,000 **kWh**
Demand 180 **kW**

		Current Board-Approved Interim			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 102.3100	1	$ 102.31	103.53	1	$ 103.53	$ 1.22	1.20%
Distribution Volumetric Rate	kW	$ 3.3629	180	$ 605.32	$ 3.3999	180	$ 611.99	$ 6.67	1.10%
Fixed rate riders	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric rate riders	kW	$ -	180	$ -		180	$ -	$ -	
Sub-Total A (excluding pass through)				$ 707.63			$ 715.52	**$ 7.89**	**1.11%**
Line Losses on Cost of Power	kWh	$ 0.1021	-	$ -	$ 0.1021	9	$ 0.89	$ 0.89	
Total Deferral/Variance Account Rate Riders	kW	-$ 1.6208	180	-$ 291.74	-$ 1.1427	180	-$ 205.69	$ 86.06	-29.50%
Lost Revenue Adjustment Mechanism (LRAM)	kW	$ -	180	$ -	$ 0.1797	180	$ 32.35	$ 32.35	
Low Voltage Service Charge	kW	$ 0.1612	180	$ 29.02	$ 0.1612	180	$ 29.02	$ -	
Smart Meter Entity Charge	Monthly	$ -		$ -	$ -	1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 444.90**			**$ 572.08**	**$ 127.18**	**28.59%**
RTSR - Network	kW	$ 2.8172	180	$ 507.10	$ 2.7281	180	$ 491.06	-$ 16.04	-3.16%
RTSR - Line and Transformation Connection	kW	$ 1.8413	180	$ 331.43	$ 1.8478	180	$ 332.60	$ 1.17	0.35%
Sub-Total C - Delivery (including Sub-Total B)				**$ 1,283.43**			**$ 1,395.75**	**$ 112.31**	**8.75%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0044	68,114	$ 299.70	$ 0.0036	68,114	$ 245.21	-$ 54.49	-18.18%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	68,114	$ 88.55	$ 0.0013	68,114	$ 88.55	$ -	
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	65,000	$ 455.00	$ 0.0070	65,000	$ 455.00	$ -	
Ontario Electricity Support Program (OESP)					$ 0.0011	68,114	$ 74.92	$ 74.92	100.00%
TOU - Off Peak	kWh	$ 0.0800	43593	$ 3,487.41	$ 0.0800	43593	$ 3,487.41	$ -	
TOU - Mid Peak	kWh	$ 0.1220	12260	$ 1,495.77	$ 0.1220	12260	$ 1,495.77	$ -	
TOU - On Peak	kWh	$ 0.1610	12260	$ 1,973.93	$ 0.1610	12260	$ 1,973.93	$ -	
Total Bill on TOU (before Taxes)				**$ 9,084.04**			**$ 9,216.79**	**$ 132.75**	**1.46%**
HST		13%		$ 1,180.93	13%		$ 1,198.18	$ 17.26	1.46%
Total Bill (including HST)				$ 10,264.97			$ 10,414.97	$ 150.00	1.46%
Ontario Clean Energy Benefit 1				$ -			$ -	$ -	
Total Bill on TOU (including OCEB)				**$ 10,264.97**			**$ 10,414.97**	**$ 150.00**	**1.46%**

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.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Bill Impacts

Customer Class: **Unmetered Scattered Load**
RPP
TOU / non-TOU: TOU
Current Loss Factor **1.0479**
Consumption 250 **kWh**
Demand

	Charge Unit	Current Board-Approved Interim Rate ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Monthly Service Charge	Monthly	$ 19.5300	1	$ 19.53	19.7731	1	$ 19.77	$ 0.24	1.24%
Distribution Volumetric Rate	kWh	$ 0.0137	250	$ 3.43	$ 0.0139	250	$ 3.47	$ 0.04	1.24%
Fixed rate riders	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric rate riders	kWh	$ -	250	$ -		250	$ -	$ -	
Sub-Total A (excluding pass through)				$ 22.96			$ 23.24	**$ 0.29**	**1.24%**
Line Losses on Cost of Power	kWh	$ 0.1021	12	$ 1.22	$ 0.1021	12	$ 1.22	$ -	
Total Deferral/Variance Account Rate Riders	kWh	-$ 0.0042	250	-$ 1.05	-$ 0.0030	250	-$ 0.75	$ 0.30	-28.57%
Lost Revenue Adjustment Mechanism (LRAM)	kWh	$ -	250	$ -	$ -	250	$ -	$ -	
Low Voltage Service Charge	kWh	$ 0.0004	250	$ 0.10	$ 0.0004	250	$ 0.10	$ -	
Smart Meter Entity Charge	Monthly	$ -		$ -	$ -		$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 23.23**			**$ 23.81**	**$ 0.59**	**2.52%**
RTSR - Network	kWh	$ 0.0068	262	$ 1.78	$ 0.0066	262	$ 1.73	-$ 0.05	-2.94%
RTSR - Line and	kWh	$ 0.0046	262	$ 1.21	$ 0.0046	262	$ 1.21	$ -	
Sub-Total C - Delivery				**$ 26.21**			**$ 26.75**	**$ 0.53**	**2.03%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0044	262	$ 1.15	$ 0.0036	262	$ 0.94	-$ 0.21	-18.18%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	262	$ 0.34	$ 0.0013	262	$ 0.34	$ -	
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	$ -	
Ontario Electricity Support Program (OESP)					$ 0.0011	262	$ 0.29	$ 0.29	100.00%
TOU - Off Peak	kWh	$ 0.0800	160	$ 12.80	$ 0.0800	160	$ 12.80	$ -	
TOU - Mid Peak	kWh	$ 0.1220	45	$ 5.49	$ 0.1220	45	$ 5.49	$ -	
TOU - On Peak	kWh	$ 0.1610	45	$ 7.25	$ 0.1610	45	$ 7.25	$ -	
Total Bill on TOU (before Taxes)				**$ 55.24**			**$ 55.85**	**$ 0.61**	**1.11%**
HST		13%		$ 7.18	13%		$ 7.26	$ 0.08	1.11%
Total Bill (including HST)				$ 62.42			$ 63.12	$ 0.69	1.11%
Ontario Clean Energy Benefit 1				$ -			$ -	$ -	
Total Bill on TOU (including OCEB)				**$ 62.42**			**$ 63.12**	**$ 0.69**	**1.11%**

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.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Bill Impacts

Customer Class: **Sentinel Lighting**
RPP
TOU / non-TOU: TOU
Current Loss Factor **1.0479**
Consumption **44** **kWh**
Demand **0.12** **kW**

		Current Board-Approved Interim								Proposed						Impact		
	Charge Unit		Rate ($)	Volume		Charge ($)			Rate ($)	Volume		Charge ($)			$ Change		% Change
Monthly Service Charge	Monthly	$	16.9500	1	$	16.95			17.1481	1	$	17.15		$	0.20		1.17%
Distribution Volumetric Rate	kW	$	21.1488	0.12	$	2.54		$	21.3923	0.12	$	2.57		$	0.03		1.15%
Fixed rate riders	Monthly	$	-	1	$	-		$	-	1	$	-		$	-		
Volumetric rate riders	kW	$	-	0.12	$	-				0.12	$	-		$	-		
Sub-Total A (excluding pass through)					$	19.49					$	19.72		**$**	**0.23**		**1.17%**
Line Losses on Cost of Power	kWh	$	0.1021	2	$	0.22		$	0.1021	2	$	0.22		$	-		
Total Deferral/Variance Account Rate Riders	kW	$	1.5144	0.12	$	0.18		-$	1.1122	0.12	-$	0.13		-$	0.32		-173.44%
Lost Revenue Adjustment Mechanism (LRAM)	kW	$	-	0.12	$	-		$	-	0.12	$	-		$	-		
Low Voltage Service Charge	kW	$	0.1347	0.12	$	0.02		$	0.1347	0.12	$	0.02		$	-		
Smart Meter Entity Charge	Monthly	$	-		$	-		$	-		$	-		$	-		
Sub-Total B - Distribution (includes Sub-Total A)					**$**	**19.90**					**$**	**19.81**		**-$**	**0.09**		**-0.44%**
RTSR - Network	kW	$	2.0858	0.12	$	0.25		$	2.0198	0.12	$	0.24		-$	0.01		-3.16%
RTSR - Line and Transformation Connection	kW	$	1.5386	0.12	$	0.18		$	1.5440	0.12	$	0.19		$	0.00		0.35%
Sub-Total C - Delivery (including Sub-Total B)					**$**	**20.34**					**$**	**20.24**		**-$**	**0.10**		**-0.47%**
Wholesale Market Service	kWh	$	0.0044	46	$	0.20		$	0.0036	46	$	0.17		-$	0.04		-18.18%
Rural and Remote Rate	kWh	$	0.0013	46	$	0.06		$	0.0013	46	$	0.06		$	-		
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		$	-		
Ontario Electricity Support Program (OESP)								$	0.0011	46	$	0.05		$	0.05		100.00%
TOU - Off Peak	kWh	$	0.0800	28	$	2.25		$	0.0800	28	$	2.25		$	-		
TOU - Mid Peak	kWh	$	0.1220	8	$	0.97		$	0.1220	8	$	0.97		$	-		
TOU - On Peak	kWh	$	0.1610	8	$	1.28		$	0.1610	8	$	1.28		$	-		
Total Bill on TOU (before Taxes)					**$**	**25.66**					**$**	**25.58**		**-$**	**0.08**		**-0.32%**
HST			13%		$	3.34			13%		$	3.32		-$	0.01		-0.32%
Total Bill (including HST)					$	28.99					$	28.90		-$	0.09		-0.32%
Ontario Clean Energy Benefit 1					$	-					$	-		$	-		
Total Bill on TOU (including OCEB)					**$**	**28.99**					**$**	**28.90**		**-$**	**0.09**		**-0.32%**

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.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Bill Impacts

Customer Class: **Street Lighting RPP**

TOU / non-TOU: TOU

Current Loss Factor **1.0479**

Consumption 50 kWh

Demand 0.13 kW

		Current Board-Approved Interim			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 1.2100	1	$ 1.21	1.2227	1	$ 1.22	$ 0.01	1.05%
Distribution Volumetric Rate	kW	$ 4.6966	0.13	$ 0.61	$ 4.7480	0.13	$ 0.62	$ 0.01	1.09%
Fixed rate riders	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric rate riders	kW	$ -	0.13	$ -		0.13	$ -	$ -	
Sub-Total A (excluding pass through)				$ 1.82			$ 1.84	**$ 0.02**	**1.06%**
Line Losses on Cost of Power	kWh	$ 0.1021	2	$ 0.24	$ 0.1021	2	$ 0.24	$ -	
Total Deferral/Variance Account Rate Riders	kW	-$ 1.5056	0.13	-$ 0.20	-$ 1.0585	0.13	-$ 0.14	$ 0.06	-29.70%
Lost Revenue Adjustment Mechanism (LRAM)	kW	$ -	0.13	$ -	$ -	0.13	$ -	$ -	
Low Voltage Service Charge	kW	$ 0.1239	0.13	$ 0.02	$ 0.1239	0.13	$ 0.02	$ -	
Smart Meter Entity Charge	Monthly	$ -		$ -	$ -		$ -	$ -	
Sub-Total B - Distribution				**$ 1.89**			**$ 1.96**	**$ 0.08**	**4.11%**
RTSR - Network	kW	$ 2.1297	0.13	$ 0.28	$ 2.0624	0	$ 0.27	-$ 0.01	-3.16%
RTSR - Line and Transformation Connection	kW	$ 1.4147	0.13	$ 0.18	$ 1.4197	0	$ 0.18	$ 0.00	0.35%
Sub-Total C - Delivery (including Sub-Total B)				**$ 2.35**			**$ 2.42**	**$ 0.07**	**2.96%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0044	52	$ 0.23	$ 0.0036	52	$ 0.19	-$ 0.04	-18.18%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	52	$ 0.07	$ 0.0013	52	$ 0.07	$ -	
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	$ -	
Ontario Electricity Support Program (OESP)					$ 0.0011	52	$ 0.06	$ 0.06	100.00%
TOU - Off Peak	kWh	$ 0.0800	32	$ 2.56	$ 0.0800	32	$ 2.56	$ -	
TOU - Mid Peak	kWh	$ 0.1220	9	$ 1.10	$ 0.1220	9	$ 1.10	$ -	
TOU - On Peak	kWh	$ 0.1610	9	$ 1.45	$ 0.1610	9	$ 1.45	$ -	
Total Bill on TOU (before Taxes)				**$ 8.35**			**$ 8.44**	**$ 0.09**	**1.02%**
HST		13%		$ 1.09	13%		$ 1.10	$ 0.01	1.02%
Total Bill (including HST)				$ 9.44			$ 9.53	$ 0.10	1.02%
Ontario Clean Energy Benefit 1				$ -			$ -	$ -	
Total Bill on TOU (including OCEB)				**$ 9.44**			**$ 9.53**	**$ 0.10**	**1.02%**

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.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Customer Class: **Residential Non-RPP**
TOU / non-TOU: non-TOU
Current Loss Factor **1.0479**

Consumption 800 **kWh**

		Current Board-Approved Interim			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 18.4300	1	$ 18.43	22.00	1	$ 22.00	$ 3.57	19.38%
Distribution Volumetric Rate	kWh	$ 0.0185	800	$ 14.80	$ 0.0140	800	$ 11.18	-$ 3.62	-24.44%
Fixed rate riders	Monthly	$ 0.9300	1	$ 0.93	$ 0.9300	1	$ 0.93	$ -	
Volumetric rate riders	kWh		800	$ -		800	$ -	$ -	
Sub-Total A (excluding pass through)				$ 34.16			$ 34.12	**-$ 0.04**	**-0.13%**
Line Losses on Cost of Power	kWh	$ 0.0954	38	$ 3.66	$ 0.0954	38	$ 3.66	$ -	
Total Deferral/Variance Account Rate Riders	kWh	$ 0.0015	800	$ 1.20	-$ 0.0030	800	-$ 2.40	-$ 3.60	-300.00%
Lost Revenue Adjustment Mechanism (LRAM)	kWh	$ -	800	$ -	$ 0.0001	800	$ 0.08	$ 0.08	
Low Voltage Service Charge	kWh	$ 0.0005	800	$ 0.40	$ 0.0005	800	$ 0.40	$ -	
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 40.21**			**$ 36.64**	**-$ 3.56**	**-8.86%**
RTSR - Network	kWh	$ 0.0076	838	$ 6.37	$ 0.0074	838	$ 6.20	-$ 0.17	-2.63%
RTSR - Line and Transformation Connection	kWh	$ 0.0053	838	$ 4.44	$ 0.0053	838	$ 4.44	$ 0.00	0.00%
Sub-Total C - Delivery (including Sub-Total B)				**$ 51.02**			**$ 47.29**	**-$ 3.73**	**-7.31%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0044	838	$ 3.69	$ 0.0036	838	$ 3.02	-$ 0.67	-18.18%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	838	$ 1.09	$ 0.0013	838	$ 1.09	$ 0.00	0.00%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	800	$ 5.60	$ -		$ -	-$ 5.60	-100.00%
Ontario Electricity Support Program (OESP)					$ 0.0011	838	$ 0.92	$ 0.92	100.00%
Non-RPP Retailer Average Price	kWh	$ 0.0954	800	$ 76.32	$ 0.0954	800	$ 76.32	$ -	
Total Bill on TOU (before Taxes)				**$ 137.97**			**$ 128.89**	**-$ 9.08**	**-6.58%**
HST		13%		$ 17.94	13%		$ 16.76	-$ 1.18	-6.58%
Total Bill (including HST)				$ 155.90			$ 145.64	-$ 10.26	-6.58%
Ontario Clean Energy Benefit 1				-$ 15.59			$ -	$ 15.59	-100.00%
Total Bill on TOU (including OCEB)				**$ 140.31**			**$ 145.64**	**$ 5.33**	**3.80%**

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:

Bill Impacts

Customer Class: **Residential- 10th Percentile usage**
Non-RPP
TOU / non-TOU: non-TOU
Current Loss Factor **1.0479**

Consumption **285.5** **kWh**

	Charge Unit	Current Board-Approved Interim Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 18.4300	1	$ 18.43	22.00	1	$ 22.00	$ 3.57	19.38%
Distribution Volumetric Rate	kWh	$ 0.0185	285.5	$ 5.28	$ 0.0140	285.5	$ 3.99	-$ 1.29	-24.44%
Fixed rate riders	Monthly	$ 0.9300	1	$ 0.93	$ 0.9300	1	$ 0.93	$ -	
Volumetric rate riders	kWh		285.5	$ -		285.5	$ -	$ -	
Sub-Total A (excluding pass through)				$ 24.64			$ 26.92	**$ 2.28**	**9.26%**
Line Losses on Cost of Power	kWh	$ 0.0954	14	$ 1.30	$ 0.0954	14	$ 1.30	$ -	
Total Deferral/Variance Account Rate Riders	kWh	$ 0.0015	285.5	$ 0.43	-$ 0.0030	285.5	-$ 0.86	-$ 1.28	-300.00%
Lost Revenue Adjustment Mechanism (LRAM)	kWh	$ -	285.5	$ -	$ 0.0001	285.5	$ 0.03	$ 0.03	
Low Voltage Service Charge	kWh	$ 0.0005	285.5	$ 0.14	$ 0.0005	285.5	$ 0.14	$ -	
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 27.31**			**$ 28.33**	**$ 1.03**	**3.76%**
RTSR - Network	kWh	$ 0.0076	299	$ 2.27	$ 0.0074	299	$ 2.21	-$ 0.06	-2.63%
RTSR - Line and Transformation Connection	kWh	$ 0.0053	299	$ 1.59	$ 0.0053	299	$ 1.59	$ -	
Sub-Total C - Delivery (including Sub-Total B)				**$ 31.17**			**$ 32.13**	**$ 0.97**	**3.10%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0044	299	$ 1.32	$ 0.0036	299	$ 1.08	-$ 0.24	-18.18%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	299	$ 0.39	$ 0.0013	299	$ 0.39	$ -	
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	285.5	$ 2.00	$ -		$ -	-$ 2.00	-100.00%
Ontario Electricity Support Program (OESP)					$ 0.0011	299	$ 0.33	$ 0.33	100.00%
Non-RPP Retailer Average Price	kWh	$ 0.0954	285.5	$ 27.24	$ 0.0954	285.5	$ 27.24	$ -	
Total Bill on TOU (before Taxes)				**$ 62.36**			**$ 61.41**	**-$ 0.94**	**-1.51%**
HST		13%		$ 8.11	13%		$ 7.98	-$ 0.12	-1.51%
Total Bill (including HST)				$ 70.46			$ 69.40	-$ 1.07	-1.51%
Ontario Clean Energy Benefit 1				-$ 7.05			$ -	$ 7.05	-100.00%
Total Bill on TOU (including OCEB)				**$ 63.41**			**$ 69.40**	**$ 5.98**	**9.44%**

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.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Bill Impacts

Customer Class: **General Service < 50 kW non-RPP**
TOU / non-TOU: non-TOU
Current Loss Factor **1.0479**
Consumption **2,000** **kWh**

	Charge Unit	Current Board-Approved Interim Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 37.7600	1	$ 37.76	38.19	1	$ 38.19	$ 0.43	1.13%
Distribution Volumetric Rate	kWh	$ 0.0138	2,000	$ 27.60	$ 0.0139	2,000	$ 27.89	$ 0.29	1.05%
Fixed rate riders	Monthly	$ 2.7300	1	$ 2.73	$ 2.7300	1	$ 2.73	$ -	
Volumetric rate riders	kWh	$ -	2,000	$ -		2,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 68.09			$ 68.81	**$ 0.72**	**1.05%**
Line Losses on Cost of Power	kWh	$ 0.0954	96	$ 9.15	$ 0.0954	96	$ 9.15	$ -	
Total Deferral/Variance Account Rate Riders	kWh	$ 0.0010	2,000	$ 2.00	-$ 0.0030	2,000	-$ 6.00	-$ 8.00	-400.00%
Lost Revenue Adjustment Mechanism (LRAM)	kWh	$ -	2000	$ -	$ 0.0011	2,000	$ 2.20	$ 2.20	
Low Voltage Service Charge	kWh	$ 0.0004	2,000	$ 0.80	$ 0.0004	2,000	$ 0.80	$ -	
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 80.83**			**$ 75.74**	**-$ 5.08**	**-6.29%**
RTSR - Network	kWh	$ 0.0068	2096	$ 14.25	$ 0.0066	2096	$ 13.83	-$ 0.42	-2.94%
RTSR - Line and Transformation Connection	kWh	$ 0.0046	2096	$ 9.64	$ 0.0046	2096	$ 9.64	$ -	
Sub-Total C - Delivery (including Sub-Total B)				**$ 104.72**			**$ 99.22**	**-$ 5.50**	**-5.25%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0044	2096	$ 9.22	$ 0.0036	2096	$ 7.55	-$ 1.68	-18.18%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	2096	$ 2.72	$ 0.0013	2096	$ 2.72	$ -	
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	$ -	
Ontario Electricity Support Program (OESP)					$ 0.0011	2096	$ 2.31	$ 2.31	100.00%
Non-RPP Retailer Average Price	kWh	$ 0.0954	2000	$ 190.80	$ 0.0954	2000	$ 190.80	$ -	
Total Bill on TOU (before Taxes)				**$ 321.72**			**$ 316.84**	**-$ 4.87**	**-1.51%**
HST		13%		$ 41.82	13%		$ 41.19	-$ 0.63	-1.51%
Total Bill (including HST)				$ 363.54			$ 358.03	-$ 5.51	-1.51%
Ontario Clean Energy Benefit 1				-$ 36.35			$ -	$ 36.35	-100.00%
Total Bill on TOU (including OCEB)				**$ 327.19**			**$ 358.03**	**$ 30.84**	**9.43%**

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.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Bill Impacts

Customer Class: **General Service > 50 non-RPP**
TOU / non-TOU: non--TOU
Current Loss Factor **1.0479**
Consumption **65,000** **kWh**
Demand **180** **kW**

	Charge Unit	Current Board-Approved Interim Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 102.3100	1	$ 102.31	103.53	1	$ 103.53	$ 1.22	1.20%
Distribution Volumetric Rate	kW	$ 3.3629	180	$ 605.32	$ 3.3999	180	$ 611.99	$ 6.67	1.10%
Fixed rate riders	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric rate riders	kW	$ -	180	$ -		180	$ -	$ -	
Sub-Total A (excluding pass through)				$ 707.63			$ 715.52	**$ 7.89**	**1.11%**
Line Losses on Cost of Power	kWh	$ -	-	$ -	$ -	9	$ -	$ -	
Total Deferral/Variance Account Rate Riders	kW	-$ 0.6505	180	-$ 117.09	-$ 1.1427	180	-$ 205.69	-$ 88.60	75.66%
Lost Revenue Adjustment Mechanism (LRAM)	kW	$ -	180	$ -	$ 0.1797	180	$ 32.35	$ 32.35	
Low Voltage Service Charge	kW	$ 0.1612	180	$ 29.02	$ 0.1612	180	$ 29.02	$ -	
Smart Meter Entity Charge	Monthly	$ -		$ -	$ -	1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 619.56**			**$ 571.20**	**-$ 48.36**	**-7.81%**
RTSR - Network	kW	$ 2.8172	180	$ 507.10	$ 2.7281	180	$ 491.06	-$ 16.04	-3.16%
RTSR - Line and Transformation Connection	kW	$ 1.8413	180	$ 331.43	$ 1.8478	180	$ 332.60	$ 1.17	0.35%
Sub-Total C - Delivery (including Sub-Total B)				**$ 1,458.09**			**$ 1,394.86**	**-$ 63.23**	**-4.34%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0044	68,114	$ 299.70	$ 0.0036	68114	$ 245.21	-$ 54.49	-18.18%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	68,114	$ 88.55	$ 0.0013	68114	$ 88.55	$ -	
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	65,000	$ 455.00	$ 0.0070	65,000	$ 455.00	$ -	
Ontario Electricity Support Program (OESP)					$ 0.0011	68114	$ 74.92	$ 74.92	100.00%
Non-Retailer Avg. Prive	kWh	$ 0.0954	68114	$ 6,498.03	$ 0.0954	68114	$ 6,498.03	$ -	
Total Bill on TOU (before Taxes)				**$ 8,799.61**			**$ 8,756.82**	**-$ 42.80**	**-0.49%**
HST		13%		$ 1,143.95	13%		$ 1,138.39	-$ 5.56	-0.49%
Total Bill (including HST)				$ 9,943.56			$ 9,895.20	-$ 48.36	-0.49%
Ontario Clean Energy Benefit 1				$ -			$ -	$ -	
Total Bill on TOU (including OCEB)				**$ 9,943.56**			**$ 9,895.20**	**-$ 48.36**	**-0.49%**

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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Bill Impacts

Customer Class: **Unmetered Scattered Load**
non-RPP
TOU / non-TOU: non-TOU
Current Loss Factor **1.0479**
Consumption **250** **kWh**
Demand

		Current Board-Approved Interim			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 19.5300	1	$ 19.53	19.7731	1	$ 19.77	$ 0.24	1.24%
Distribution Volumetric Rate	kWh	$ 0.0137	250	$ 3.43	$ 0.0139	250	$ 3.47	$ 0.04	1.24%
Fixed rate riders	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric rate riders	kWh	$ -	250	$ -		250	$ -	$ -	
Sub-Total A (excluding pass through)				$ 22.96			$ 23.24	**$ 0.29**	**1.24%**
Line Losses on Cost of Power	kWh	$ 0.0954	12	$ 1.14	$ 0.0954	12	$ 1.14	$ -	
Total Deferral/Variance Account Rate Riders	kWh	-$ 0.0042	250	-$ 1.05	-$ 0.0030	250	-$ 0.75	$ 0.30	-28.57%
Lost Revenue Adjustment Mechanism (LRAM)	kWh	$ -	250	$ -	$ -	250	$ -	$ -	
Low Voltage Service Charge	kWh	$ 0.0004	250	$ 0.10	$ 0.0004	250	$ 0.10	$ -	
Smart Meter Entity Charge	Monthly	$ -		$ -	$ -		$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 23.15**			**$ 23.73**	**$ 0.59**	**2.53%**
RTSR - Network	kWh	$ 0.0068	262	$ 1.78	$ 0.0066	262	$ 1.73	-$ 0.05	-2.94%
RTSR - Line and Transformation Connection	kWh	$ 0.0046	262	$ 1.21	$ 0.0046	262	$ 1.21	$ -	
Sub-Total C - Delivery (including Sub-Total B)				**$ 26.13**			**$ 26.67**	**$ 0.53**	**2.04%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0044	262	$ 1.15	$ 0.0036	262	$ 0.94	-$ 0.21	-18.18%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	262	$ 0.34	$ 0.0013	262	$ 0.34	$ -	
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	$ -	
Ontario Electricity Support Program (OESP)					$ 0.0011	262	$ 0.29	$ 0.29	100.00%
Non-Retailer Avg. Prive	kWh	$ 0.0954	250	$ 23.85	$ 0.0954	250	$ 23.85	$ -	
Total Bill on TOU (before Taxes)				**$ 53.48**			**$ 54.09**	**$ 0.61**	**1.14%**
HST		13%		$ 6.95	13%		$ 7.03	$ 0.08	1.14%
Total Bill (including HST)				$ 60.43			$ 61.12	$ 0.69	1.14%
Ontario Clean Energy Benefit 1				$ -			$ -	$ -	
Total Bill on TOU (including OCEB)				**$ 60.43**			**$ 61.12**	**$ 0.69**	**1.14%**

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.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Bill Impacts

Customer Class:	**Sentinel Lighting**
	non-RPP
TOU / non-TOU:	non-TOU
Current Loss Factor	**1.0479**
Consumption	**44** kWh
Demand	**0.12** kW

	Charge Unit	Current Board-Approved Interim Rate ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Monthly Service Charge	Monthly	$ 16.9500	1	$ 16.95	17.1481	1	$ 17.15	$ 0.20	1.17%
Distribution Volumetric Rate	kW	$ 21.1488	0.12	$ 2.54	$ 21.3923	0.12	$ 2.57	$ 0.03	1.15%
Fixed rate riders	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric rate riders	kW	$ -	0.12	$ -		0.12	$ -	$ -	
Sub-Total A (excluding pass through)				$ 19.49			$ 19.72	**$ 0.23**	**1.17%**
Line Losses on Cost of Power	kWh	$ 0.0954	2	$ 0.20	$ 0.0954	2	$ 0.20	$ -	
Total Deferral/Variance Account Rate Riders	kW	$ 2.4588	0.12	$ 0.30	-$ 1.1122	0.12	-$ 0.13	-$ 0.43	-145.23%
Lost Revenue Adjustment Mechanism (LRAM)	kW	$ -	0.12	$ -	$ -	0.12	$ -	$ -	
Low Voltage Service Charge	kW	$ 0.1347	0.12	$ 0.02	$ 0.1347	0.12	$ 0.02	$ -	
Smart Meter Entity Charge	Monthly	$ -		$ -	$ -		$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 20.00**			**$ 19.80**	**-$ 0.20**	**-1.01%**
RTSR - Network	kW	$ 2.0858	0.12	$ 0.25	$ 2.0198	0.12	$ 0.24	-$ 0.01	-3.16%
RTSR - Line and Transformation Connection	kW	$ 1.5386	0.12	$ 0.18	$ 1.5440	0.12	$ 0.19	$ 0.00	0.35%
Sub-Total C - Delivery (including Sub-Total B)				**$ 20.44**			**$ 20.23**	**-$ 0.21**	**-1.02%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0044	46	$ 0.20	$ 0.0036	46	$ 0.17	-$ 0.04	-18.18%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	46	$ 0.06	$ 0.0013	46	$ 0.06	$ -	
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	$ -	
Ontario Electricity Support Program (OESP)					$ 0.0011	46	$ 0.05	$ 0.05	100.00%
Non-Retailer Avg. Prive	kWh	$ 0.0954	44	$ 4.20	$ 0.0954	44	$ 4.20	$ -	
Total Bill on TOU (before Taxes)				**$ 25.45**			**$ 25.26**	**-$ 0.19**	**-0.76%**
HST		13%		$ 3.31	13%		$ 3.28	-$ 0.03	-0.76%
Total Bill (including HST)				$ 28.76			$ 28.54	-$ 0.22	-0.76%
Ontario Clean Energy Benefit 1				$ -			$ -	$ -	
Total Bill on TOU (including OCEB)				**$ 28.76**			**$ 28.54**	**-$ 0.22**	**-0.76%**

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.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Bill Impacts

Customer Class: **Street Lighting**
non-RPP

TOU / non-TOU: non-TOU

Current Loss Factor **1.0479**

Consumption **50** **kWh**
Demand **0.13** **kW**

		Current Board-Approved Interim			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 1.2100	1	$ 1.21	1.2227	1	$ 1.22	$ 0.01	1.05%
Distribution Volumetric Rate	kW	$ 4.6966	0.13	$ 0.61	$ 4.7480	0.13	$ 0.62	$ 0.01	1.09%
Fixed rate riders	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric rate riders	kW	$ -	0.13	$ -		0.13	$ -	$ -	
Sub-Total A (excluding pass through)				$ 1.82			$ 1.84	**$ 0.02**	**1.06%**
Line Losses on Cost of Power	kWh	$ 0.0954	2	$ 0.23	$ 0.0954	2	$ 0.23	$ -	
Total Deferral/Variance Account Rate Riders	kW	-$ 0.6068	0.13	-$ 0.08	-$ 1.0585	0.13	-$ 0.14	-$ 0.06	74.44%
Lost Revenue Adjustment Mechanism (LRAM)	kW	$ -	0.13	$ -	$ -	0.13	$ -	$ -	
Low Voltage Service Charge	kW	$ 0.1239	0.13	$ 0.02	$ 0.1239	0.13	$ 0.02	$ -	
Smart Meter Entity Charge	Monthly	$ -		$ -	$ -		$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 1.99**			**$ 1.95**	**-$ 0.04**	**-1.98%**
RTSR - Network	kW	$ 2.1297	0.13	$ 0.28	$ 2.0624	0	$ 0.27	-$ 0.01	-3.16%
RTSR - Line and Transformation Connection	kW	$ 1.4147	0.13	$ 0.18	$ 1.4197	0	$ 0.18	$ 0.00	0.35%
Sub-Total C - Delivery (including Sub-Total B)				**$ 2.45**			**$ 2.40**	**-$ 0.05**	**-1.94%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0044	52	$ 0.23	$ 0.0036	52	$ 0.19	-$ 0.04	-18.18%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	52	$ 0.07	$ 0.0013	52	$ 0.07	$ -	
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	$ -	
Ontario Electricity Support Program (OESP)					$ 0.0011	52	$ 0.06	$ 0.06	100.00%
Non-Retailer Avg. Prive	kWh	$ 0.0954	50	$ 4.77	$ 0.0954	50	$ 4.77	$ -	
Total Bill on TOU (before Taxes)				**$ 8.12**			**$ 8.08**	**-$ 0.03**	**-0.39%**
HST		13%		$ 1.06	13%		$ 1.05	-$ 0.00	-0.39%
Total Bill (including HST)				$ 9.17			$ 9.13	-$ 0.04	-0.39%
Ontario Clean Energy Benefit 1				$ -			$ -	$ -	
Total Bill on TOU (including OCEB)				**$ 9.17**			**$ 9.13**	**-$ 0.04**	**-0.39%**

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.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.