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

AND IN THE MATTER OF an Application by Niagara-on-the-Lake Hydro Inc. for an Order or Orders approving just and reasonable rates and other service charges for the distribution of electricity, effective.

INTERROGATORIES

OF THE

SCHOOL ENERGY COALITION

NIAGARA-ON-THE-LAKE HYDRO INC. RESPONSE

Rate Base and Capital Expenditures

1. Exhibit 2, Tab 2: there are several references in the variation explanations to the Chatauqua Project "as part of our underground capital program". Please provide a more detailed description of this project as well as a business case.

Response

This Project is described in Exhibit 2, Tab 3, Schedule 1, and Page 3 of 35. Overhead system and equipment are over 50 years of age and in poor condition. Niagara-on-the-Lake Hydro's Conditions of Service page 55, as well as a Town by-law requires that any reconstruction of utility plant in the Chautauqua area is required to be of underground construction. Although overhead construction would be of less overall costs at the outset, our Conditions of Service and the municipal by-law do not allow that option. Therefore a business case for overhead versus underground was not conducted.

2. Exhibit 2, Tab 2, Schedule 3, pg. 6: Services and Meters capital expenditures:

   (a) NOTL plans on spending $20,000 on new meters in each of 2008 and 2009. Please confirm that these are traditional meters and discuss whether such expenditures are prudent in view of NOTL's stated intention of implementing a smart meter plan in 2009 [see Exhibit 9/1/1, pg. 7].

Response

With the onset of the smart meter installation plan scheduled for late 2009, Niagara-on-the-Lake Hydro undertook a comprehensive review of all its meter installations and a *review of meter options for all customers over 200kw. It is Niagara-on-the-Lake Hydro's intention to implement interval meters to all customers over 200kw. This methodology is consistent with our Conditions of Service update to be submitted to the OEB for review by year-end, and the 200kw threshold has become industry standard. Upon completion of the Interval Meter Program, NOTL Hydro will review the capital requirements and adjust the amount budgeted accordingly.*

(b) Please provide a more detailed explanation for the increase of the balance in account 1855 (Services). Specifically:

(i) What factors contributed to the increase from $1.026 million in 2006 Board approved to $1.624 in 2006 actual? The evidence states that the difference is due to the fact that the 2006 Board approved number is an average of actual 2003 and 2004 values. What increase in activity occurred in 2005 and 2006 such that the balance in this account increased by 58% over the 2003 and 2004 average?

Response

The chart below shows opening balance of Account 1855 (Services) in 2003 and Actual year over year costs associated with the Account.

Year	***Opening Balance***	***Actual Costs***	***Closing Balance***
2003	*$685,412.36*	*$230,055.90*	*$915,468.26*
2004	*$915,468.26*	*$221,882.77*	*$1,137,351.03*
2005	*$1,137,351.03*	*$248,731.62*	*$1,386,082.65*
2006	*$1,386,466.65*	*$238,117.66*	*$1,624,200.31*

2005 Actual over the 2003 and 2004 average of $225,969.36 is $22,762.29 for 2005 and $12,148.32 for 2006. Although slightly higher than the average of the preceding two years there was no abnormal activity in this account.

(ii) The evidence states that the increase in expenditures in 2007 over 2006 is due to "new residential customer servicing, and new general service connections." However, the number of residential and general service customers exhibited no growth in 2007 over 2006 (see Exhibit 3, Tab 2, Schedule 1, pg. 2). Please explain why expenditures on new connections would need to increase when the number of connections has been stable.

Response

Although the number of residential growth remained stable over this time period, Niagara-on-the-Lake Hydro was in the process of completing the customer connections for the new U/G system for the Queenston Village Project in early 2007. These new U/G connections represented 14 new primary transformer connections, and 53 new U/G connections to existing customers previously fed overhead.

3. Exhibit 2, Tab 2, Schedule 3, pg. 6: IT Assets: the evidence states that the increase in account 1925 (computer software) from 2006 Board Approved to 2006 actual is due to expenditures related to the new customer information system ("CIS"). The capital plan (Exhibit 2, Tab 3, Schedule 1, pg. 12) states that the cost of this system was $94,316. However, expenditures in this category continue to increase in 2007, 2008, and 2009. The explanation given is "costs associated with software upgrades and Information Technology consulting to ensure system reliability and compliance with Ontario Energy Board mandated requirements (see Ex. 2/3/1, pp. 20, 28, and 34). Please:

(a) Explain what is meant by "system reliability" and "Ontario Energy Board mandated requirements": what specific requirements are being addressed and what specific expenditures are aimed at addressing each.

Response

NOTL Hydro completed an assessment of CIS and financial system software options in 2003. Our current CIS system had a high annual maintenance cost and we were concerned with the company's ability to meet timelines and upset prices for system upgrades. Our financial system software provider at that time required us to upgrade to their latest version at an estimated cost of $80,000 to $100,000. We also wished to integrate the billing and financial systems.

As a result of our assessment, we chose our current vendor which would provide an integrated CIS and financial system. This system was chosen based on financial savings as well as its flexibility and utility source code ownership. Included in our study was the recognition that this software was new to the Ontario market and would require further development and customization. The initial $94,316 cost included software, licensing as well as conversion of data from our previous CIS and financial systems.

Since 2004, we have completed the following sample of 'system reliability' enhancements and mandated (Ontario Energy Board) 'mandated requirements:

- *Enhancements*
  -Deposit Refunds and T5s
  -Late Payment Charges
  -Multi Site Customers
  -Paymentus as a payment option
  -Post dated cheque handling
  -Bill Print changes
  -Rerouting for meter reader using Radix
  -Revenue Reporting for Board
  -Accounts Receivable for non-job cost invoices
  -Job Cost Invoicing
  -Job Cost Cash Receipt Deposits
  -Accounts Receivable Aging Reports selecting by post month and year
  -Accounts Payable Aging Reports selecting by post month and year
  -Receiving inventory receipts at actual cost instead of average cost

- *Regulatory/Industry Changes*
  -EBT Changes & Updates
  -Ontario Price Credit
  -Unbundled bill format
  -Rebundled bill format
  -Regulated Price Plan
  -BPPR/OPG Rebates
  -Provincial Benefit
  -IESO filings for Fixed Rate Customers
  -Changes to RRR Reporting
  -Final Variance Settlement Amount

4. Exhibit 2, Tab 2, Schedule 4: Other Distribution Assets (Account 1995):

   (a) The balance in Account 1995 increases by over 61% from 2006 Board Approved to 2006 actual (from $2,802,684 to $4,522,868). The only explanation given is that the 2006 Board Approved amount reflects the average of 2003 and 2004 and that the 2006 actual reflects "normal contribution" in the ensuing years. Please provide a more detailed breakdown of the expenditures in 2004, 2005 and 2006 that led to a 61% increase in account 1995 during those years.

Response
Contributions in 2005 were $479,588.86 which are slightly under the 2003 and 2004 average but are consistent with the average growth patterns in Niagara-on-the-Lake. In

2006 contributions showed a significant increase due to an unusually high number of new subdivision construction starts $209,234 over 2005, the expansion of the Queenston Plaza at the international border crossing with the contributed amount of $158,222, the installation by the Municipality of a new Pumping Station with a contribution of $126,597, and an increase in Customer projects over 2005 by $39,212. These Projects specifically contributed to the increase in Account 1995 for 2006.

Year	Opening Balance	Actual Contributions	Closing Balance
2003	$1,931,528.02	$629,125.32	$2,560,653.34
2004	$2,560,653.34	$484,062.14	$3,044,715.48
2005	$3,044,715.48	$479,588.86	$3,524,304.34
2006	$3,524,304.34	$998,563.90	$4,522,868.24

Operating Costs

5. Exhibit 4/2/3, pg. 1:

(a) please provide a table showing revenues from Energy Services Niagara Inc. from 2006 to 2009;

Response
Please see Table below:

From	To			
Energy Services Inc	NOTL Hydro Inc	Markup on services provided to ESNI (for details, see response to OEB Staff interrogatory # 1.12)	2006	$24,570
			2007	$25,224
			2008	$29,074
			2009	$30,000
		Interest revenue on loan to ESNI	2006	$43,594
			2007	$46,121
			2008	$40,909
			2009	$42,286

(b) please provide a copy of the shared services agreement with Energy Services Niagara Inc.

Response

Please see Appendix I.

6. Exhibit 4/2/7, pg. 1: NOTL's average total loss factor for the period from 2003 to 2007 is 1.0463. NOTL nonetheless proposes that the loss factor remained unchanged at 1.0501 "due to the remaining debit balance in the power purchase variance account (account 1588 of $264,801)

(a) Please explain the connection between the balance in the power purchase variance account and setting the total loss factor.

Response

The connection can be explained by the following generic situation. Assume:

- *the OEB approved NOTL loss factor applied to metered consumption on a customer's bill is x*
- *the actual loss factor from the grid to the customer's meter is y due to the specific circumstances in a given period*
- *the metered consumption in the given period is M kWh*
- *the price of power from the IESO and billed to the customer is $C per kWh*
- *balance in power variance account 1588 before this billing is B_0*
- *balance in power variance account 1588 after the RSVA adjustment corresponding to this billing is B_1*

Then:

- *revenue from the customer for power is CMx*
- *cost to NOTL for power is CMy*
- *the RSVA adjustment per OEB Accounting Procedures Handbook (Article 220, page 35) is:*
  - $B_1 = B_0 + CM(y - x)$.

Thus, if the actual loss factor (say y = 1.0463) is less than the approved factor (say x = 1.0501), then y – x is negative and the debit balance in the power variance account would decrease over time.

7. Exhibit 4, Tab 2, Schedule 2, pg. 4 Billing and Collection (account 5320)- This account has exhibited significant variations in expenditure, from $47,535 in 2006 Board approved to $103,092 in 2007 to a forecast of $76,368 in 2009. The evidence states that increase in 2007 was due to higher than normal collection activity "which is expected to resume a more normal level in 2008 and 2009."

(a) Please provide an explanation as to how the forecast for 2009, $76,368, which is 61% higher than the 2006 Board approved figure ($47,435), was arrived at given the statement that collection activity is expected to resume to a more normal level in 2009.

Response
The forecasts for 2008 and 2009 are based on estimated numbers of hours to be spent on collection by each staff member multiplied by their compensation hourly rate. The base data was 2008 actual hours available at the time of the rate application (mid-year). 2008 is considered to be at a normal level.

With regard to the variation from 2006 approved (which is 2004 actual data per the 2006 EDR rate model) through 2007, NOTL's ability to collect on overdue accounts was limited from April 2004 due to billing software conversion issues. These and related issues were resolved by mid-year 2006 and collections resumed. For the rest of 2006 and into 2007, the collection effort was intense in order to catch up the backlog. For 2008 to date, collections have evened out and are expected to continue at this level going forward.

Cost of Debt

8. Exhibit 6/1/3, pg. 1:

   (a) Please provide a copy of the promissory note supporting the long-term debt issued to the Town of Niagara-on-the-Lake.

Response
Please see Appendix II.

   (b) The Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario Electricity Distributors, dated December 20, 2006, states, at pg. 14, that for "all affiliate debt that is callable on demand the Board will use the current deemed long-term debt rate." If the Promissory Note to the Town of Niagara-on-the-Lake is a demand note, please explain why NOTL proposes to use the nominal interest rate of 7.25% rather than the Board's deemed long-term debt rate.

Response
The note is not callable on demand.

Operating Revenue

9. Exhibit 3, Tab 2, Schedule 1, pg.6:

   (a) Account 4335, Profits and Losses from Financial Instrument Hedges: please explain specifically how these revenues are derived and why they appear for the first time in 2007.

Response

SEC is requested to refer to the explanation on pages 9 and 10 of NOTL's 2007 Audited Financial Statements ("Note 2 – Accounting Change"). These pages can be found on pages 188 and 189 of the pdf version of the NOTL rate application.

Load Forecast

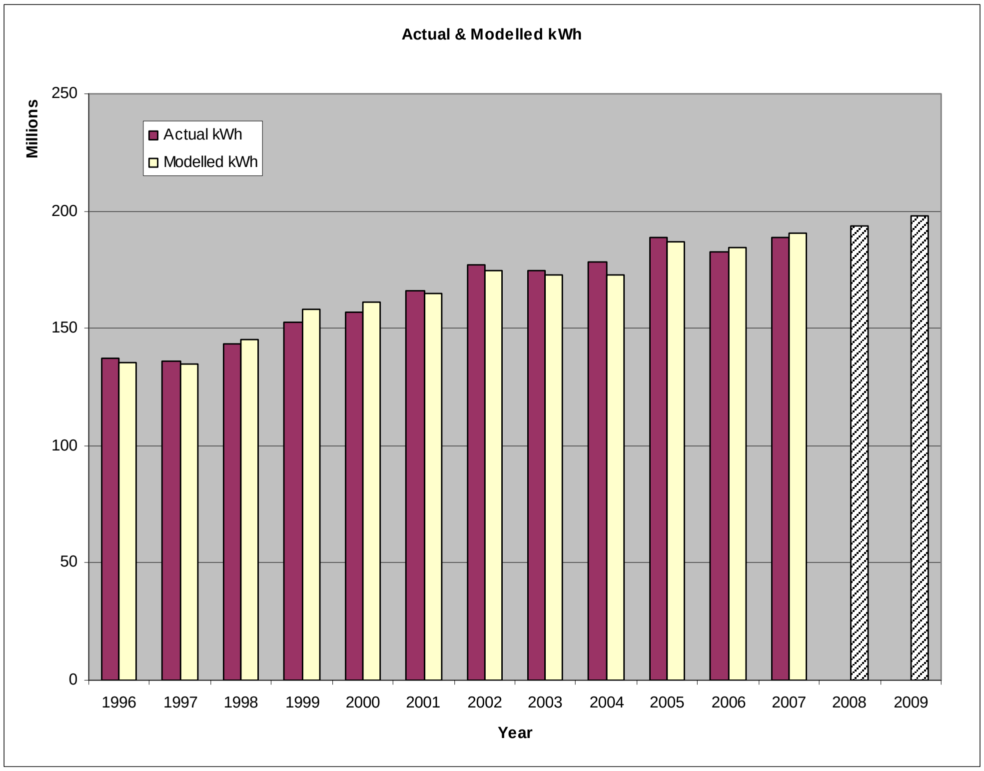
10. Exhibit 3, Tab 2, Schedule 2:

(a) Pg. 13: NOTL's model results in underestimating actual load for 8 out of the 12 years from 1996 to 2007. Discuss whether this demonstrates a bias in the model.

Response

The following Table and Chart taken from Page 13 indicates that the model underestimates for 7 of the 12 years (not 8). Also, the sum of the modeled kWh over the period exceeds the actual kWh by 206,915 kWh, or 0.01%. On this basis, NOTL believes that a bias is not demonstrated.

Year	Actual kWh	Modelled kWh	% Difference
1996	137,138,484	135,141,514	-1.5%
1997	135,913,545	134,814,460	-0.8%
1998	143,381,600	145,004,214	1.1%
1999	152,311,035	158,211,646	3.9%
2000	156,667,497	161,051,779	2.8%
2001	165,931,549	164,655,659	-0.8%
2002	176,920,133	174,825,155	-1.2%
2003	174,477,589	172,577,753	-1.1%
2004	178,152,405	172,657,905	-3.1%
2005	188,569,914	186,725,048	-1.0%
2006	182,453,427	184,179,306	0.9%
2007	188,506,590	190,786,244	1.2%



(b) Pg. 14-15: regarding the adjustments to the model to reflect the loss of the Cangro customer, wouldn't the regression model itself capture the impact of changes in customer counts such that a specific adjustment for the loss of one customer is unnecessary?

Response

In developing the forecasting approach for the application, NOTL considered whether or not a special adjustment to the output of the regression model in order to reflect the Cangro closure would provide a better forecast of consumption. It was noted that that regression model is based on kWh data from 1996 to 2007, prior to the closure occurring. The loss of such a major customer (NOTL's largest customer representing approx. 7% of the GS>50 class) is a unique and highly significant event that could not be represented by the parameters of the best-fit regression model resulting from analysis of the 1996 to 2007 data. It was therefore concluded that a special adjustment was required, because the regression alone would significantly overestimate kWh consumption.

(c) Pg. 16: regarding the adjustment for CDM, please provide a summary of the 3rd Tranche CDM programs and their impact on load. To what extent are these load reductions over and above natural conservation that would be captured in the load regression model?

Response
Summaries for 3rd Tranche CDM programs are provided in Appendix III.

The third tranche program summaries accounted for 'free ridership' established by the OEB in the TRC calculations. We consider this to be the natural conservation effect that you reference.

(d) Pg. 20: why is the geometric mean growth rate for the 2002 to 2007 period considered appropriate as an estimator of customer counts from 2008 to 2009 for the GS<50 and GS>50 rate classes and not for the Residential class?

Response

[Note – This question is similar to OEB Staff IR 7.2 b)]

The residential class customer growth in Niagara-on-the-Lake is driven by the number of lots in subdivisions known to be under development, including location and timing, as well as an estimate of in-fill opportunities. A total of 190 lots in 9 specific sub-divisions are forecast to come on stream through 2008 and 2009, plus 20 in-fill lots, for a total of 210 – 85 in 2008 and 125 in 2009 as indicated in the application. Using the geometric mean growth rate would contradict and be inconsistent with these known subdivision plans.

The customer growth in the general service and streetlight classes does not bring NOTL Hydro into advanced planning to the same degree as sub-divisions and often business customers request to be connected at relatively short notice. Thus, the specific customers are not known in advance and only a historical growth rate approach is feasible.

Cost Allocation and Rate Design

11. Ref: Exhibit 8, Tab 1, Schedule 2, pg. 5:

(a) According to Table 5 on pg. 5 of Exhibit 8/1/2, the GS>50 rate class will continue to over-contribute to NOTL's revenue requirement by $322,541 in 2009 [proposed revenue for rate class of $1,121,414 versus revenue assuming 100% R/C ratio of $798,873]. The Streetlighting class will continue to under-contribute in the amount of $154,690. Please confirm the above numbers and explain why NOTL has not taken more aggressive action in reducing cross-subsidization.

Response
NOTL confirms SEC's calculation of the numbers, $322,541 and $154,690.

With regard to the level of aggressiveness in reducing cross-subsidization, NOTL believes its application reflects significant aggressiveness in reducing the GS>50kW ratio by approx. 38% (from 183.49% to 145.15%) and meets the OEB mandate to move ratios outside the target range to points within the range (see last paragraph, Page 29 of the Board's EB-2007-0693 regarding Wellington North's 2008 rates). NOTL feels it has applied the OEB guidelines and recent decisions as best as it can to determine appropriate revenue/cost ratios for 2009. Please also note that VECC (Interrogatory #3) proposes a much less aggressive alternative approach with the GS>50 ratio at 180%, a reduction of only approx. 3%.

Rate Design

12. Ref: Exhibit 8, Tab 1, Schedule 2, pg. 4; and Exhibit 9, Tab 1, Schedule 9, pg. 1:

(a) The revenue to cost ratios for Residential and GS<50kW rate classes are moving from 88.74% to 94.37% for Residential and from 91.74% to 95.87% for GS<50kW rate classes. Although the revenue to cost ratios are increasing at about the same rate, the distribution rate impacts from this application are much higher for the GS classes- 12.9% for a typical residential customer versus 22.34% for a GS<50kW customer. Please explain.

Response

Although the revenue to cost ratios are of course a factor in calculating the impacts, the % changes do not translate directly into % bill impacts. These bill impacts can best be explained by reference to the following Table which uses proportion data (shares of revenue) from Table 6 in Exhibit 8 Tab 1 Schedule 2 Page 6:

Class Impacts	**At Proposed Rates**		**At Existing Rates**		**Revenue**
Customer Class	**Proportion**	**Base Revenue**	**Proportion**	**Base Revenue**	**% Impact**
Residential	49.65%	$2,186,384	47.25%	$2,196,016	-0.44%
GS <50 kW	24.60%	$1,112,222	21.31%	$990,623	12.28%
GS>50 kW	23.22%	$1,395,896	30.20%	$1,403,805	-0.56%
Street Light	2.17%	$104,405	0.82%	$38,280	172.74%
Sentinel	N/A	N/A	0.00%	$0	
Unmetered Scattered Load	0.36%	$16,527	0.41%	$18,936	-12.72%
Total	100.00%	$4,815,433	100.00%	$4,647,660	3.61%

This Table shows how much revenue comes from each class for existing rates vs proposed rates, and as such better reflects the resulting bill impacts for the typical customers referred to in the interrogatory. Please note that the bill impacts referred to by SEC include the smart meter rate rider - the above Table refers to the distribution charges only.

LIST OF APPENDICES to RESPONSE

APPENDIX I. Shared services agreement with Energy Services Niagara Inc.

This Agreement made as of this 1st day of November, 2000

AMONG:

NIAGARA-ON-THE-LAKE HYDRO INC.
(*hereinafter called "the Wires Company")*

OF THE FIRST PART,

-and-

ENERGY SERVICES NIAGARA INC.
(hereinafter called "the Retail Company")

OF THE SECOND PART,

WHEREAS the Wires Company and the Retail Company have both been incorporated under the *Business Corporations Act (Ontario)* pursuant to section 142 of the *Electricity Act, 1998*, in order to comply with the *Energy Competition Act*;

AND WHEREAS the Ontario Energy Board (the "Board") has created an *Affiliate Relationship Code for Electricity Distributors and Transmitters* (the "Code") which applies to the Wires Company and its Affiliates, including the Retail Company;

AND WHEREAS the Code applies to all electricity distributors and transmitters licensed by the Board, including the Wires Company;

AND WHEREAS the purpose of the Code is to establish the standards and conditions for the interaction between electricity distributors or transmitters and their respective affiliate companies so as to minimize the potential for an electricity distributor or transmitter to cross-subsidize competitive or non-monopoly activities, protect the confidentiality of consumer information collected by a distributor or transmitter and to ensure there is no preferential access to regulated utility services;

AND WHEREAS the Wires Company may supply management, administration, and staffing services to the Retail Company in accordance with this agreement,

NOW THEREFORE IN CONSIDERATION OF the mutual covenants herein contained and the provision of other good and valuable consideration by each party hereto to each of the others (the receipt and adequacy of which is acknowledged) the parties hereto have agreed as follows:

I . Definitions

In this agreement,

(a) "Act" means the *Ontario Energy Board Act, 1998*;
(b) "affiliate" with respect to a corporation, has the same meaning as in the *Business Corporations Act (Ontario)* and may include HoldCo, WiresCo, ServeCo, RetailCo and GenCo;

(c) “agent” means a person acting on behalf of a utiliy and includes persons contracted to provide services to a utility;

(d) “Board” means the Ontario Energy Board;

(e) “Code” means the *Affiliate Relationship Code for Electricity Distributors and Transmitters;*

(f) “fair market value” means the price reached in an open and unrestricted market between informed and prudent parties, acting at arms length and under no compulsion to act;

(g) "Schedules" means the schedules annexed to and forming part of this agreement;

(h) “Services Agreement” means an agreement between a utility and its affiliate(s) for the purpose of subsection 2.2 of the Code;

(i) “utility” means an electricity distributor or transmitter that is licensed under Part V of the Act.

II . Schedules

The Schedules annexed to and forming part of this agreement identify and describe the activities to be carried on by the Wires Company which, (for the purposes of the Code), interact with the Retail Company, the standards to which those activities will be performed, and estimates of the costs of those activities.

III. Work to be performed

(a) The Wires Company shall perform the activities identified and described in the Schedules (hereinafter simply referred to as “Services”), for the benefit of the Retail Company in accordance with the descriptions set forth in the Schedules.

(b) The necessary adjustments shall be made in the payment of remuneration to account for the fact that the Retail Company will not be in business for a full year in the year 2000 and for any effect due to a delay in market opening.

IV. Annual Review of Schedules

(a) The parties shall review the contents of each Schedule on an annual basis. The purpose of such review shall be to determine whether the activities described in each Schedule continue to be accurate. In the event that during such a review, disagreements arise with respect to suggested amendments to any Schedule and these disagreements cannot be settled by the parties, any party shall have the ability to require the contents of the Schedule or Schedules under disagreement to be submitted to arbitration in accordance with the provisions of this agreement.

(b) The review described in (a) above shall be commenced within sufficient time so that the parties might reasonably have completed their review in time for their annual budget and estimates process.

V. Remuneration

(a) The Retail Company shall pay remuneration to the Wires Company in accordance with the costs experienced by the Wires Company in performing the services set forth in the schedules. In addition to full recovery of all direct and indirect costs of providing services, the Retail Company shall pay to the Wires Company a further 10 to 20 % of such costs, and the combination of the costs so recovered plus the additional 10 to 20 % shall be the remuneration payable to the Wires Company pursuant to this agreement. The parties agree that such remuneration represents the fair market value for those services as of the date of this agreement.

> ***NOTE: The additional percentage increase is referred to by the Board as a "return on invested capital", which must be the higher of the utilities approved rate of return or the bank prime rate. (2.3.3)***

(b) The aggregate remuneration payable to the Wires Company in respect of the services provided by the Wires Company to the Retail Company shall be requested in periodic invoices delivered by the Wires Company to the Retail Company, such invoices to be delivered not more frequently than monthly. The terms of any such invoice, whether so marked or not, shall be net 30 days.

VI. <u>Dispute Resolution</u>

(a) In the event that either party hereto has any complaint or grievance with respect to the meaning or operation of this agreement, including the calculation of remuneration for any services provided hereunder, such complaint or grievance shall be resolved through binding arbitration pursuant to the provisions of the Arbitrations Act (Ontario). Any arbitrator so appointed shall apply the principles in this agreement in making a determination, particularly those principles set forth in the Interpretation section herein. It is agreed that such arbitration shall be final and that there shall be no right of recourse to the Courts for review or appeal of any award made in the course of such arbitration.

(b) Before submitting any question to arbitration, the parties shall have submitted the matter in dispute to a Joint Committee composed of members of the Board of Directors of both parties. Resort shall be had to arbitration only after the Joint Committee meeting has occurred and the dispute has not been resolved, or 45 days have elapsed since the matter was submitted to the Joint Committee and no meeting has occurred.

VII. <u>Audit</u>

Subject to Article X, a party to this agreement may, at reasonable intervals, upon reasonable notice and at reasonable times during normal business hours, have such access to the records of the other party as is necessary for purposes of auditing and investigating compliance with this agreement.

<u>VIII. Term</u>

(a) This agreement is effective immediately following signing by all parties hereto.

(b) This agreement is a continuing one, and there is no general right of any party to terminate its participation in this agreement, either in whole or in part, except as set forth herein or as may otherwise be agreed-upon by the parties by subsequent written agreement.

(c) The Wires Company shall be entitled to terminate this agreement if the Retail Company ceases to be controlled, directly or indirectly, by the same shareholder as the Wires Company or if the Retail Company breaches any obligation to the Wires Company hereunder. In the event that the Wires

Company terminates this agreement in whole or in part in accordance with the foregoing, the Retail Company shall indemnify and save harmless the Wires Company for the separation costs of any employees of the Wires Company fully engaged in providing services to Retail Company, and shall pay any other costs of disentanglement. In the event of termination for other reasons, the terms of such termination shall be in accordance with any applicable legal requirement, or the terms of any agreement in relation thereto by the parties.

IX. Force Majeure

It shall not be a breach of this agreement if any party to this agreement fails to perform its obligations to provide services, work, or the supply of goods and materials to any other party by reason of war, insurrection, tempest, labour disputes, or any other event beyond the reasonable control of that party. The foregoing shall not apply to an obligation to pay money.

X. Confidentiality and Ownership of Information

(a) It is agreed that confidential information from the Wires Company shall be kept in strict confidence by the Wires Company, and details of the operations of the Wires Company shall not be shared with the Retail Company, and vice versa.

(b) The parties shall take such measures as are necessary in order to comply with the confidentiality obligations under (a) above.

(c) Information stored or produced by any party to this agreement on the sole behalf of another party to this agreement, shall be the property of the party on whose sole behalf such information is stored or produced. Where such information consists of an original report, computer programme, information, or intellectual property produced by a party to this agreement for the sole purpose of supplying services to that other party and the cost of producing such report is included in the remuneration payable by such other party, the property (including copyright and moral rights) to such original report, computer programme, information, or intellectual property shall belong to such other party. The foregoing shall not apply were information is stored or produced by a party to this agreement on behalf of a third party to this agreement, or where the information is stored and produced by a party to this agreement for the mixed benefit of another party and the party which produced the information.

XI. Entire Agreement

The agreement, together with the Schedules, constitutes the entire Services Agreement between the parties as required by section 2.2.1 of the Code. This agreement may not be amended or modified except by written instrument signed by both parties.

XII. Successors and Assigns

This agreement shall ensure to the benefit of and be finding upon the parties hereto and their respective successors and assigns, provided that there shall be no assignment of this agreement without the prior written consent of the parties hereto. The foregoing shall not prevent the Wires Company from contracting out the performance of any of its obligations hereunder, however the Wires Company shall still be responsible as between it and the Retail Company for the performance of such obligations.

XIII. Interpretation

(a) This agreement shall be interpreted and applied in a manner which results in the greatest overall benefit to the citizens of Niagara-on-the-Lake.

(b) This agreement will be deemed to have been automatically amended to the minimum extent necessary to achieve compliance with all applicable statutory or regulatory requirements, however no such deemed amendment shall be effective unless and until the parties have concluded that the agreement cannot proceed as written, or that they cannot reasonably apply for an exemption (if such an exemption is available) that would alleviate such non-compliance. The parties agree to cooperate as necessary in order to proceed with any reasonable application which would legitimize any portion of this agreement that would otherwise be non-compliant.

(c) Subject headings are for purposes of convenience of reference only, and are not part of this agreement.

(d) Compliance with applicable laws is deemed to be a component of the description of every Service described in the Schedules, and the presence or absence of any reference to such compliance in any particular Schedule is insignificant. It is also to be assumed that basic supervision and management is included within the description of services in each Schedule, however special provision is made for certain forms of supervision and management services which are not contained within a single Schedule.

(e) The costing provisions in each of the Schedules are intended to provide a general description of the underlying theory for the payment of the fee to the Wires Company by the Retail Company, but under no circumstances shall any Schedule be limited to the estimates described therein. In every case, the Wires Company shall receive the full cost (which shall include both direct and indirect costs) of providing services to the Retail Company pursuant to this agreement, whether or not such full cost is adequately (or at all) estimated, explained, or described in any particular Schedule, plus an additional 10 to 20% above such cost, and no more or less, despite the fact that the estimates contained in a particular Schedule may be greater than or less than such full cost. As an example, if the Wires Company incurs additional costs for Workplace Health and Safety Insurance in consequence of providing services to the Retail Company, such costs shall be recovered by the Wires Company (plus an additional 10 to 20%) from the Retail Company despite the absence of any specific mention of such right of recovery. Without limiting the generality of the foregoing, the Wires Company shall always be entitled to additional remuneration in accordance with the foregoing if:

  (i) It has agreed to provide or has been required by law to provide Services which exceed those described on the applicable Schedule; or,

  (ii) It has agreed to provide or has been required by law to provide Services at a level which exceeds the level described on the applicable Schedule.

(f) Where the Wires Company provides Services to the Retail Company, the Wires Company shall use its best efforts to minimize the actual costs of providing such services while still complying with all applicable standards.

(g) It is acknowledged that there will be some duplication in the description of services between particular Schedules. Any such duplication is deemed to be insignificant and does not imply that there is multiple costing for those services. The parties agree that no such multiple costing is present.

(h) The remuneration payable to the Board of Directors of the Retail Company shall be paid directly by the Retail Company out of its own resources. In the event that the Retail Company has no resources, and the Wires Company advances money to the Board of Directors of the Retail Company, the payment of such costs shall subsequently be recovered from the Retail Company plus 7.25% interest.

(i) Where the Retail Company has receivables, such receivables shall be assets of the Retail Company and not assets of the Wires Company. Any late payment charges or risks of failing to recover such receivables shall lie entirely with the Retail Company and not the Wires Company.

(j) Assets which are acquired for the sole purpose of becoming integrated into the distribution system for electrical energy, hydro inventory, and rolling stock used primarily for electricity purposes, shall be obtained in the name of the applicable corporation. The purchase price of any such asset, the proceeds of disposition of any such asset (where such asset is sold), and the costs of obsolescence for any such asset shall be paid, received, or recorded, as the case may be, on the books of such corporation.

(k) Assets which are acquired, either in whole or in part, for purposes of permitting the Wires Company to comply with its contractual obligations hereunder to provide services to the Retail Company, but which are not referred to in (j) above shall generally be taken in the name of the Wires Company and the cost for same recovered from the Retail Company plus an additional 10 to 20%.

(l) Where outside forces are engaged for the purpose of obtaining or producing the assets described in (j) above, the contracts in respect of same shall be taken in the name of the Wires Company or the Retail Company as the case may be. In other cases, the contract shall be taken in the name of the Wires Company and that portion of the contract price which relates to the Retail Company as the benefiting party shall be recovered from the Retail Company, plus an additional 10 to 20%.

(m) Where the Schedules describe services to be performed by the Wires Company for the Retail Company pursuant to this agreement, the Retail Company shall only obtain such services from the Wires Company and not elsewhere, unless the Wires Company should otherwise agree. In those circumstances where the Retail Company obtains such separate services or pays for goods or services otherwise than through the Wires Company, out of their own resources, all such transactions (subject to any contrary requirements in this agreement) shall only be recorded on the books of the Retail Company and shall not generate any entitlement on the part of the Wires Company to any payment of 10 to 20 % above cost.

XIV. Responsibility and Indemnification

(a) The Wires Company and the Retail Company shall bear all risks associated with any assets owned by them, including environmental risks;

(b) The Retail Company shall reimburse, indemnify and save harmless the Wires Company against any costs, causes of action, claims, demands, expenses, or liabilities of any description incurred by the Wires Company for the benefit of the Retail Company, whether such reimbursement and indemnification is explicit within this agreement or otherwise.

XV. Joint Committee

(a) It is a matter of importance to the parties that there shall be proper consultation and involvement by the Retail Company in the performance of services for it under this agreement. For that reason, a Joint Committee, composed of an equal number of representatives from both the Wires and Retail Companies, shall be formed and shall meet on a regular basis, and otherwise as necessary, in order to identify, resolve, and coordinate matters of common concern in relation to the services performed hereunder by the Wires Company to the Retail Company.

(b) Either party to this agreement shall have the right to requisition a meeting of the said Joint Committee at any time upon five (5) days notice to the other.

(c) Where a member is unable to be present at any meeting of the said Joint Committee, he or she may substitute another individual to attend and participate at any such meeting in his or her stead.

IN WITNESS WHEREOF THE PARTIES HAVE EXECUTED THIS AGREEMENT.

Energy Services Niagara Inc.

Per:

____
President

____
Secretary

Niagara-on-the-Lake Hydro Inc.,

Per:

____
Chair

____
General Manager

Schedule A

Amended: August 31, 2005

<u>Activities to be performed by Wires Company</u>

1. Provide customer service representatives to perform billing, collecting and customer inquiry research for Retail company rental water heater and water/wastewater customer accounts.

2. Provide accounting/administrative personnel to provide accounting and administrative service.

3. Provide line and engineering personnel to provide street light maintenance, water heater service, fibre optics service.

4. Provide management personnel to oversee billing, accounting, administration, engineering and line staff.

5. Provide contractors, materials and equipment, for Wires Company staff to perform the above functions.

6. Provide office space for Retail company to carry on their business activities.

Schedule B

Effective: January 1, 2002

Standards of activities to be performed by Wires Company

Wires company activities will be conducted on a daily basis in accordance to the highest quality standards. Wires company will comply with all statutory and regulatory requirements and all applicable laws.

Schedule C

Effective: January 1, 2002

<u>Services Fees</u>

The following pricing will be in effect;

Item	**Price**	**Allocation method**
Labour	Cost plus 20%	Job Costs
Material	Cost plus 10%	Job Costs
Truck Expense	Cost plus 10%	Job Costs
Contractor	Cost plus 10%	Job Costs
Stores Overhead	10% of Materials plus 10%	Stores Allocation entry
Building Overhead	5% of Costs plus 10%	Square footage of occupation

[*APPENDIX II. Promissory Note*]

PROMISSORY NOTE

FOR VALUE RECEIVED, Niagara-on-the-Lake Hydro Inc. ("WiresCo") hereby promises to pay to or to the order of The Corporation of the Town of Niagara-on-the-Lake (the "Town") the principal sum of $6,566,333.12 (the "Principal") with interest at the rate specified herein, on August 1, 2018.

Interest

The outstanding Principal shall bear interest at 7.25%, such interest to be paid monthly, not in advance. Interest shall accrue until the Principal is paid in full.

Renewal

This Promissory Note shall be automatically renewed for an additional ten (10) year term upon its maturity on the same terms and conditions contained herein, save as to any further right of renewal, unless either the Town or WiresCo gives ninety (90) days' prior written notice to the other that the Promissory Note shall not be renewed.

Adjustments

The Promissory Note is not assignable by the Town without the consent of WiresCo, such consent not to be unreasonably withheld.

Replacement Note

This Promissory Note replaces the Promisory Note executed by WiresCo in favour of the Town dated as of the 1st day of Novemeber, 2000 and remains in accordance with Town of Niagara-on-the-Lake By-law No. 3531-01.

Dated as of the 15th day of July, 2008.

NIAGARA-ON-THE-LAKE HYDRO INC.

____
Authorized Signing Officer

____
Authorized Signing Officer

APPENDIX III. 3rd Tranche CDM Programs

2005 OEB Annual

Conservation and Demand Management Report

RP-2004-0203/EB-2004-0523

Submitted By Niagara-on-the-Lake Hydro Inc.

March 31, 2006

Table of Contents

1.0 Introduction

Niagara-on-the-Lake Hydro Inc. distributes electricity to approximately 8000 customers within the municipal boundaries of the Town of Niagara-on-the-Lake. We have a mix of urban and rural customers within our 132 square kilometers of operating area. Apart from the "Old Town", the urban customer base is primarily concentrated in four hamlets, namely, Virgil, St. Davids, Queenston and Glendale, while the rural customer base are primarily agricultural based amongst orchards and vineyards.

Recognizing the critically short supply of electricity in Ontario, our goal is ultimately the development of a sustainable conservation culture with our customers. In order to achieve this goal more effectively we chose a regional approach to program development to derive economies of scales but to also create consistent regional information to the customers across 11 LDC's, known as NEPPA (Niagara Erie Public Power Alliance).

The NEPPA group has long be known in the Industry as a leader in facilitating regional understanding of regulatory changes, public safety messaging, co-ordination of training and now conservation and demand management.

Our Conservation and Demand Management (CDM) plan was prepared as a NEPPA initiative. Together we represented 525,000 customers and a total of $5.5 million dollars of CDM funding. Our primary goal is to leverage common solutions and deliverables to maximize results when ever feasible.

During 2005, our primary concentration was to plan and create our foundation. High on the list was securing a customer communication branding to begin changing and building awareness for the long term. In 2006 our customers will enjoy further localized programming as well as our support for programming designed and delivered by the OPA.

The following table shows the approved plan expenditures by project as well as actual expenditures to December 31, 2005.[1]
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Project	Target Customers	Approved Expenditures	Actual Expenditure to Dec. 31, 2005
Co-branded Mass Market Program	LDC Program aimed to benefit all customers	20,000	$12,077.93[2]
Smart Metering/Prepaid Metering Program	Residential and Small Commercial	$10,000	$8,764.36
Energy Audit/Feasibility Audits	All Customer Classes	$10,000	$88.89
LED Traffic Light Retrofits	Municipalities	$10,000	$9,114.98
Load Management/Load Control Programs	Residential & Small Commercial	$10,000	$1,500.00
Distribution Loss Reduction	All Customer Classes	$128,440	$83,680.57
Project and Budget Totals		**$198,440.00**	**$115,226.73**

[1] All programs completed or started in 2005 will be accompanied by Appendix B with accumulated results in Appendix A. Actual reported spending varies from our 4th quarter filing spending by $3,275.39 to account for final expenditures for Mass Market Programs Lighten Your Electricity Bill coupon event and Conserver Joe as well as Energy Audits Program CEEA Webinars.
[2] Co-Branded Mass Market expenditures as reported in fourth OEB Quarterly Filings was $8,891.43. We have opted to include additional expenditures that were spent in 2006 and accrued to 2005. First Quarter 2006 filings for OEB CDM reporting will reflect the new information.

2.0 Evaluation of the CDM Plan

Niagara-on-the-Lake Hydro Inc. has, or is in the process of, implementing CDM projects that will effectively reduce 115 kW in demand with annual savings of 207,311 kWh and total project savings over the lifespan of the technology of 1,721,530 kWh.

Appendix A depicts our overall CDM portfolio summarizing both programs with qualitative and quantitative results. Our overall TRC value is calculated at $100,187 with total projected spending of $171,721.11. We have opted to project TRC calculations for projects not completed by December 31, 2005. These programs include the CEEA TIDE Cold Water Wash Program recently completed and the projected Distribution Loss Program

Some programs are not designed to have specific quantifiable energy savings but are nevertheless effective and important in our view. Examples of this second category of program include:

- Educational components like the "Conserver Family" information
- Active participation in the implementation study of smart meters for low volume customers in Ontario
- Staff development and education in CDM

3.0 Discussion of the Programs

Below is a brief summary of our specific CDM activities completed and/or started in 2005. Appendix B included details on programs with TRC values listed below.

Projects

Co-branded Mass Market Program
1) Lighten Your Electricity Bill – Canadian Tire Coupon Program **2) CEEA TIDE Cold Water Wash** **3) Conserver Joe Family Educational Program**
Net TRC Benefit $23,240.63

Lighten Your Electricity Bill
In conjunction with other NEPPA members and LDC's across the province, we participated in a coupon campaign that offered customers the opportunity to purchase energy efficient products at Canadian Tire between October 1 to December 31, 2005.

All of our customers received their Lighten Your Electricity Bill coupon via a special unaddressed package containing, Conserver Joe Pamphlet and a coupon for Cold Water Wash Tide. In total 7500 packages were mailed to both our individually metered and bulk metered residential customers. In summary, the response amounted to a 10% participation and 806 products purchased according to the project administrator SeeLine Group Inc. The most popular products purchased were, LED Christmas Lights and Compact Fluorescents lights. A very positive Net TRC value resulted from this program.

CEEA - TIDE Cold Water Wash

This program involved the insertion of $1 off TIDE Cold Water Wash detergent sent out to our entire customer base in a mass mailing in conjunction with the Lighten Your Electricity Bill coupon. This program also had a large positive Net TRC value. The final invoice for participation in this program was received in early 2006 but was included in the calculations. CEEA, the program administrator has indicated that an average of 3% of coupons were redeemed. Based on this figure, we used 180 coupons as the value for our TRC calculations.

Conserver Joe Family Educational Program

In partnership with the NEPPA group, we developed a diversified customer education package referred to as our media kit. The media kit is built around Conserver Joe and his family. The development of the kit was designed around the concept of a family approach. Each family member brings their own special touch to encouraging and sharing conservation.

We know that changing consumer habits to sustain ongoing support and belief in conservation would take the resources of the working folks, as well as the push and enthusiasm of our youth. The media kit was developed with the knowledge that the product could be further expanded including; for example, interactive youth website, school educational programs, updates on new technology and specific programming messaging.

To assist in local use of the Conserver Family, Product Use guidelines have been developed to keep our Conserver Family used in a consistent manner.

Conserver Joe and his family will be making appearances in various media as follows.

- ***Conservation Handbook*** **–** advises residential customers how to seasonally tune up their home to optimize energy use.
- ***Newsletter*** **–** a tabloid designed to share the success stories across LDCs utilizing the Conserver Joe.
- ***Bill Inserts*** **–** Initially 10 bill inserts have been developed each sharing a single conservation message. All four family members share a tips on saving energy.
- ***Website*** **–** www.conserverjoe.com – the website was developed to create a consistent message and branding. All NEPPA participants are able to use the website links.
- ***Print Ads*** **–** a selection of print ads have been developed for easy and quick circulation.

LED Traffic Light Retrofits

1) Old Town Decorative Christmas Light Conversion to LED
2) Town of NOTL Decorative Christmas Light Conversion to LED

Net TRC Benefit $73,700.00

Old Town Decorative Christmas Light Conversion to LED

This plan involved replacing 367 strings of incandescent decorative Christmas lights in the downtown commercial core with 350 LED efficient lights. The energy savings on this project produced a NPV TRC result of $68,400 and was appreciated by the Downtown merchants who stand to save thousands of dollars in annual energy costs.

Town of Niagara-on-the-Lake Decorative Christmas Light Conversion to LED

Similar to the Old Town LED conversion, this plan replaced 29 strings of incandescent decorative Christmas lights across the municipality with 30 LED efficient lights strings. The energy savings on this project produced a NPV TRC result of $5,300. The future savings will benefit the municipality and ultimately, the entire customer base.

Regional Municipality of Niagara Traffic Light Conversions to LED (future)

This program is not included in the submission but will be completed in 2006. The traffic signals at three locations in Niagara-on-the-Lake will be converted to energy efficient LED's with a subsidy provided by NOTL Hydro Inc. as part of our plan.

Energy Audits / Feasibility Audits
1) CEEA Webinar participation 2) Industry Specific Conservation Training Sessions (Future)
Net TRC Value Qualitative

CEEA Webinars

Along with our NEPPA members, Niagara-on-the-Lake Hydro is participating in C&DM focused 'Webinars" featuring speakers such as Peter Love from the Conservation Bureau. These seminars have and continue to benefit our staff in developing future efficient C&DM programs through learning and interaction with participants and speakers. The TRC benefit is immeasurable.

Industry Specific Conservation Training Sessions

Niagara-on-the-Lake Hydro is in the process of co-organizing industry specific seminars with neighbouring NEPPA LDC's. Seminars focusing on the Wine Industry, Agricultural Industry and Hospitality Industry are planned that will involve conservation experts from the industry as well as the IESO. This program is expected to primarily benefit commercial/agricultural customers. NOTL Hydro will attempt to measure the results of any individual energy efficient improvements that result fro the seminars.

Smart Meter Program
1) OUSM Working Group Participation (Ongoing) 2) Interval Meter Installations
Net TRC Value Qualitative

OUSM Working Group Participation

NOTL Hydro is an active member of the Ontario Utility Smart Meter (OUSM) Working Group. This working group has made tremendous strides in advancing the implementation of Smart Meters, widely seen as a tool for customers to shift their electrical consumption from peak usage times. We are much more confident that the 'smart meter' system that we will ultimately choose for our customers will be the most effective tool as a result of our participation in this program. A regional or NEPPA smart meter network is our preferred option. Costs reported are for membership fees in the OUSM.

Interval Meter Installations (In Progress)

Commercial or industrial customers interested in converting their current conventional meters to that of 'interval' normally pay the additional cost of the interval technology versus the conventional meter. Commencing in 2006, customers that we mutually agree can utilize the interval technology as a tool to reduce their peak demands and shift load to off peak periods will be offered an interval meter at no additional cost. The TRC costs submitted represent the additional cost of the interval meters purchased for this program versus conventional meters. The results of this program are immeasurable but are expected to assist in meeting government goals of having this technology installed on all customers.

Distribution Loss Reduction (In Progress)
1) Reconductoring and Conversion Projects
Net TRC Benefit $13,600

Reconductoring and Conversion Project
NOTL Hydro recently purchased a software package recognized as an industry leader in evaluation distribution system losses and optimization. Prior to this purchase, we did not have the ability to determine high loss feeders or more efficient means of supply configurations. As a result, we have embarked on a multi-stage project(s) to oversize existing lower amperage conductors as well as convert existing 4 kV customers to lower loss 3-phase 27.6 kV. Although this work is in progress, the TRC results provided show only preliminary results from the reconductoring and not the 4 kV conversion. As a result, we expect to show even greater benefits in next year's annual report as the plan nears completion and the benefits of the 4 kV conversion are reflected. The TRC costs shown to date in this report include the purchase and setup costs of the software and the line improvement work to date (end 2005). This program will benefit all customer classes as the line loss factor on their bill is expected to be reduced as system losses are reduced.

Load Management Programs (In Progress)
1) TRC Tool **2) Website Improvements and Link to Conservation Site** **3) Load Control in Conjunction with Smart Meters**
Net TRC Benefits - Future

TRC Tool
NOTL Hydro purchased and received training on an EnerSpectrum TRC calculator. This is a very useful tool, not only for preparing this report, but also evaluating future potential C&DM programs for optimal value. The costs submitted in this report are for the software purchase.

Website Improvements and Link to Conservation Website
A number of improvements to our website aimed to focus users on conservation tips was completed in 2005 (but not as yet invoiced). NOTL Hydro also participated in a joint NEPPA initiative to link to a common Conserver Joe site (not yet invoiced).

Load Control in Conjunction with Smart Meters (Future)
With the installation of smart meters in 2006 or early 2007, NOTL Hydro plan to embark on a pilot program to test the value of controlling customer loads, such as air conditioners, in reducing our system load.

4.0 Lessons Learned

Smaller LDC Challenges

Niagara-on-the-Lake Hydro Inc. is a smaller LDC with only 17 employees. We found it most difficult to put forth a concerted effort to implement efficient C&DM programs while minimizing costs by not employing high-priced consultants. As a result, a great deal of extra staff time was spent on program setup, implementation and training. We are proud of our achievements despite the ‘stressed’ situation.

Distribution System Loss Improvements

With our new loss evaluation and system optimization software tool, we now have the opportunity to fine tune our system losses. The benefits of reduced system losses are great as system losses are at their maximum levels during peak load periods. It is the objective of our company to continue to reduce these losses and reduce the loss factor on all of our customer bills. We also plan to run the model on future capital projects to identify potential system improvements, such as over sizing conductors that will have a clear future TRC benefit.

LED Conversion Projects and Coupon Campaign

The two completed and one proposed LED conversion projects have a large TRC benefit. We will continue to seek out future LED projects to implement. The Lighten Your Electricity Bill coupon program through Canadian Tire also produced positive results.

NEPPA Participation

The NEPPA C&DM group joint efforts in initiating our C&DM plans and individual projects proved to be invaluable. The group effort was instrumental in addressing a number of concerns related to lack of additional human resources at a smaller LDC discussed above. NEPPA participation also allowed us to send out a common and consistent ‘conservation culture’ message across the regions of Niagara and Erie-Grand at reduced costs due to greater economies of scale. We look forward to continued involvement in the NEPPA C&DM working group.

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5.0 Conclusion

In 2005 we initiated a number of concurrent C&DM programs and experienced a number of early positive results. We continue to investigate and evaluate future C&DM opportunities through our participation in the CEEA webinars and NEPPA group participation. It is also our goal to reduce program costs going forward by sharing resources and program costs with neighbouring LDC’s and NEPPA members.

In 2006 and 2007 we are forging ahead with plans to host industry specific conservation theme seminars while continuing with system line loss reduction plans. We are also excited by the opportunity to explore the benefits of load control devices in conjunction with smart meter installations.

We are committed to local delivery of CDM programming to our customers and look forward to continued cost effective innovative solutions.

Appendix A - Evaluation of the CDM Plan

	Total	Residential	Commercial	Institutional	Industrial	Agricultural	LDC System	Other 1	Other 2	Other 3	Other 4
Net TRC value ($):	*$100,187*	$23,241	$ 68,400.00	$ 5,300.00			$ 13,600.00	-$ 1,500.00	-$ 88.89	-$ 8,764.36	
Benefit to cost ratio:	24.334	5.715	9.147	8.365			1.106				
Number of participants or units delivered:	8870	8486	350	30			1	1	1	1	
Total KWh to be saved over the lifecycle of the plan (kWh):	1721530	900386	528882	41645			250617				
Total in year kWh saved (kWh):	207311	178268	17629	1388			10025				
Total peak demand saved (kW):	*115*	46.12	44.05	3.47			21.34				
Total kWh saved as a percentage of total kWh delivered (%):	0.1103	0.0948	0.0094	0.0007			0.0053				
Peak kW saved as a percentage of LDC peak kW load (%):	0.3026	0.1214	0.1159	0.0091			0.0562				
Gross in year C&DM expenditures ($):	*$171,721.11*	$ 12,078.08	$ 8,395.38	$ 719.60			$ 140,174.80	$1,500.00	$88.89	$8,764.36	
Expenditures per KWh saved ($/kWh):*	*$0.6059*	$0.0134	$0.0159	$0.0173			$0.559				
*Expenditures per KW saved ($/kW)**:*	*$7,229*	$ 261.87	$190.58	$207.46			$6,569				

Utility discount rate (%):	7.8

*Expenditures include all utility program costs (direct and indirect) for all programs which primarily generate energy savings.
**Expenditures include all utility program costs (direct and indirect) for all programs which primarily generate capacity savings.

Appendix

A. **Name of the Program:** NOTL Hydro Summary

Description of the program (including intent, design, delivery, partnerships and evaluation):

Summary of all 2005 Programs complete and in progress

Measure(s):

	Measure 1	Measure 2 (if applicable)
Base case technology:		
Efficient technology:		
Number of participants or units delivered:		
Measure life (years):		

B. **TRC Results:**

TRC Benefits ($):		*$ 100,187.38*
TRC Costs ($):		
	Utility program cost (less incentives):	$ 171,591.66
	Participant cost:	$ 7,197.20
	Total TRC costs:	$ 178,788.86
Net TRC (in year CDN $):		-$ 78,601.48
Benefit to Cost Ratio (TRC Benefits/TRC Costs):		$ 0.56

C. **Results:** (one or more category may apply)

Conservation Programs:

Demand savings (kW):	*Summer*	6.329011989
	Winter	87.31368065
	lifecycle	*in year*
Energy saved (kWh):	*1470913*	197286
Other resources saved :		
Natural Gas (m3):		
Other (specify):		

Demand Management Programs:

Controlled load (kW)
Energy shifted On-peak to Mid-peak (kWh):
Energy shifted On-peak to Off-peak (kWh):
Energy shifted Mid-peak to Off-peak (kWh):

Demand Response Programs:

Dispatchable load (kW):
Peak hours dispatched in year (hours):

Power Factor Correction Programs:

Amount of KVar installed (KVar):
Distribution system power factor at begining of year (%):
Distribution system power factor at end of year (%):

Line Loss Reduction Programs:

Peak load savings (kW):		21.34
	lifecycle	*in year*
Energy savngs (kWh):	250617	10025

Distributed Generation and Load Displacement Programs:

Amount of DG installed (kW):
Energy generated (kWh):
Peak energy generated (kWh):
Fuel type:

Other Programs (specify):

Metric (specify):

D. **Program Costs*:**

Utility direct costs ($):	*Incremental capital:*	$ 144,914.80
	Incremental O&M:	$ 24,158.31
	Incentive:	
	Total:	$ 169,073.11
Utility indirect costs ($):	*Incremental capital:*	
	Incremental O&M:	
	Total:	
Participant costs ($):	*Incremental equipment:*	
	Incremental O&M:	
	Total:	

E. **Comments:**

*Please refer to the TRC Guide for the treatment of equipment cost in the TRC Test.

Appendix A - Evaluation of the CDM Plan

	Total	Residential	Commercial	Institutional	Industrial	Agricultural	LDC System	Other 1	Other 2	Other 3	Other 4
Net TRC value ($):	$ 23,240.63	$ 23,240.63									
Benefit to cost ratio:	5.715	5.715									
Number of participants or units delivered:	8486	8486									
Total KWh to be saved over the lifecycle of the plan (kWh):	900386	900386									
Total in year kWh saved (kWh):	178268	178268									
Total peak demand saved (kW):	46.122	46.122									
Total kWh saved as a percentage of total kWh delivered (%):	*0.09482*	*0.09482*									
Peak kW saved as a percentage of LDC peak kW load (%):	*0.121375*	*0.121375*									
Gross in year C&DM expenditures ($):	$ 12,078.08	$ 12,078.08									
Expenditures per KWh saved ($/kWh):*	*$ 0.0134*	*$ 0.0134*									
*Expenditures per KW saved ($/kW)**:*	*$ 261.87*	*$ 261.87*									

Utility discount rate (%):	7.8

*Expenditures include all utility program costs (direct and indirect) for all programs which primarily generate energy savings.
**Expenditures include all utility program costs (direct and indirect) for all programs which primarily generate capacity savings.

Appendix B - Discussion of the Program

A. **Name of the Program:** Co-Brand Mass Marketing

Description of the program (including intent, design, delivery, partnerships and evaluation):

Includes Canadian Tire Coupon Campaign, Conserver Joe Development and Educational Program and CEEA TIDE Cold Water Wash Coupons

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Measure(s):

	Measure 1	Measure 2 (if applicable)	Measure 3 (if applicable)
Base case technology:	Conserver Joe Development	Canadian Tire Coupon Campaign	TIDE Cold Water Wash CEEA Coupon Capaign
Efficient technology:	Promote C&DM	LED's, CFL's Pstats, Timers	Cold water wash
Number of participants or units deliv	7500	806	180
Measure life (years):			

B. **TRC Results:**

TRC Benefits ($):	*$*	*42,386.46*
TRC Costs ($):		
Utility program cost (less incentives):	$	11,948.63
Participant cost:	$	7,197.20
Total TRC costs:	$	19,145.83
Net TRC (in year CDN $):	$	23,240.63
Benefit to Cost Ratio (TRC Benefits/TRC Costs):	$	2.21

C. **Results:** (one or more category may apply)

Conservation Programs:

Demand savings (kW):	*Summer*	6.329011989
	Winter	39.79348065
	lifecycle	*in year*
Energy saved (kWh):	*900385.5397*	178268.4856
Other resources saved :		
Natural Gas (m3):		
Other (specify):		

Demand Management Programs:

Controlled load (kW)
Energy shifted On-peak to Mid-peak (kWh):
Energy shifted On-peak to Off-peak (kWh):
Energy shifted Mid-peak to Off-peak (kWh):

Demand Response Programs:

Dispatchable load (kW):
Peak hours dispatched in year (hours):

Power Factor Correction Programs:

Amount of KVar installed (KVar):
Distribution system power factor at begining of year (%):
Distribution system power factor at end of year (%):

Line Loss Reduction Programs:

Peak load savings (kW):

	lifecycle	*in year*
Energy savngs (kWh):		

Distributed Generation and Load Displacement Programs:

Amount of DG installed (kW):
Energy generated (kWh):
Peak energy generated (kWh):
Fuel type:

Other Programs (specify):

Metric (specify):

D. **Program Costs*:**

Utility direct costs ($):	*Incremental capital:*	$	-
	Incremental O&M:	$	9,430.08
	Incentive:		
	Total:	$	9,430.08
Utility indirect costs ($):	*Incremental capital:*		
	Incremental O&M:		
	Total:		
Participant costs ($):	*Incremental equipment:*		
	Incremental O&M:		
	Total:		

E. Comments:

NOTL Hydro in conjunction with the NEPPA group developed a customer educational program with bill inserts and a booklet to promote C&DM. The promotional was targeted at the family unit. We expect that a cultural shift r

*Please refer to the TRC Guide for the treatment of equipment cost in the TRC Test.

Appendix A - Evaluation of the CDM Plan

	Total	Residential	Commercial	Institutional	Industrial	Agricultural	LDC System	Other 1	Other 2	Other 3	Other 4
Net TRC value ($):	*-$ 88.89*							-$ 88.89			
Benefit to cost ratio:											
Number of participants or units delivered:											
Total KWh to be saved over the lifecycle of the plan (kWh):											
Total in year kWh saved (kWh):											
Total peak demand saved (kW):											
Total kWh saved as a percentage of total kWh delivered (%):											
Peak kW saved as a percentage of LDC peak kW load (%):											
Gross in year C&DM expenditures ($):	*88.89*							$88.89			
Expenditures per KWh saved ($/kWh):*											
*Expenditures per KW saved ($/kW)**:*											

Utility discount rate (%):	7.8

*Expenditures include all utility program costs (direct and indirect) for all programs which primarily generate energy savings.
**Expenditures include all utility program costs (direct and indirect) for all programs which primarily generate capacity savings.

Appendix

A. **Name of the Program:** Energy Audits

Description of the program (including intent, design, delivery, partnerships and evaluation):

To date we have participated in the CEEA Webinars. Seminars targeting specific Customer Groups ar

Measure(s):

	Measure 1	Measure 2 (if applicable)
Base case technology:		
Efficient technology:	Promote C&DM	
Number of participants or units delivered:		
Measure life (years):		

B. **TRC Results:**

TRC Benefits ($):		
TRC Costs ($):		
	Utility program cost (less incentives):	$ 88.89
	Participant cost:	
	Total TRC costs:	$ 88.89
Net TRC (in year CDN $):		-$ 88.89
Benefit to Cost Ratio (TRC Benefits/TRC Costs):		$ -

C. **Results:** (one or more category may apply)

Conservation Programs:

		lifecycle	in year
Demand savings (kW):	*Summer*		
	Winter		
Energy saved (kWh):			
Other resources saved :			
	Natural Gas (m3):		
	Other (specify):		

Demand Management Programs:

Controlled load (kW)

Energy shifted On-peak to Mid-peak (kWh):

Energy shifted On-peak to Off-peak (kWh):

Energy shifted Mid-peak to Off-peak (kWh):

Demand Response Programs:

Dispatchable load (kW):

Peak hours dispatched in year (hours):

Power Factor Correction Programs:

Amount of KVar installed (KVar):

Distribution system power factor at begining of year (%):

Distribution system power factor at end of year (%):

Line Loss Reduction Programs:

Peak load savings (kW):

	lifecycle	in year
Energy savngs (kWh):		

Distributed Generation and Load Displacement Programs:

Amount of DG installed (kW):

Energy generated (kWh):

Peak energy generated (kWh):

Fuel type:

Other Programs (specify):

Metric (specify):

D. **Program Costs*:**

Utility direct costs ($):	*Incremental capital:*	
	Incremental O&M:	$ 88.89
	Incentive:	
	Total:	$ 88.89
Utility indirect costs ($):	*Incremental capital:*	
	Incremental O&M:	
	Total:	
Participant costs ($):	*Incremental equipment:*	
	Incremental O&M:	
	Total:	

E. **Comments:**

NOTL Hydro will be hosting Industry specific seminars to educate our customers on C&DM

*Please refer to the TRC Guide for the treatment of equipment cost in the TRC Test.

Appendix A - Evaluation of the CDM Plan

	Total	Residential	Commercial	Institutional	Industrial	Agricultural	LDC System	Other 1	Other 2	Other 3	Other 4
Net TRC value ($):	*$ 73,700.00*		$ 68,400.00	$ 5,300.00							
Benefit to cost ratio:	*17.513*		9.147	8.365							
Number of participants or units delivered:	*380.000*		350	30							
Total KWh to be saved over the lifecycle of the plan (kWh):	*570527.521*		528882	41645							
Total in year kWh saved (kWh):	*19017.584*		17629	1388							
Total peak demand saved (kW):	*47.520*		44.0515	3.4687							
Total kWh saved as a percentage of total kWh delivered (%):	*0.010116*		0.009377	0.000738							
Peak kW saved as a percentage of LDC peak kW load (%):	*0.125053*		0.115925	0.009128							
Gross in year C&DM expenditures ($):	$ 9,114.98		$ 8,395.38	$ 719.60							
Expenditures per KWh saved ($/kWh):*	$ 0.0332		$0.0159	$0.0173							
*Expenditures per KW saved ($/kW)**:*	$ 398.0363		$190.58	$207.46							

Utility discount rate (%):	7.8

*Expenditures include all utility program costs (direct and indirect) for all programs which primarily generate energy savings.
**Expenditures include all utility program costs (direct and indirect) for all programs which primarily generate capacity savings.

Appendix B - Discussion of the Program

A. **Name of the Program:** LED Lights

Description of the program (including intent, design, delivery, partnerships and evaluation):

Conversion of Regional, Municipal and Commercial Incadescent Lights to LED. Commercial and Municipal completed in 2005

Measure(s):

	Measure 1	Measure 2 (if applicable)	Measure 3 (if applicable)
Base case technology:	Incadescent Lighting Downtown	Incadescent Lighting Town	
Efficient technology:	LED Lighting	LED Lighting	
Number of participants or units delive	350	30	
Measure life (years):	30	30	

B. **TRC Results:**

TRC Benefits ($):		*$ 82,814.98*
TRC Costs ($):		
	Utility program cost (less incentives):	$ 9,114.98
	Participant cost:	
	Total TRC costs:	$ 9,114.98
Net TRC (in year CDN $):		$ 73,700.00
Benefit to Cost Ratio (TRC Benefits/TRC Costs):		$ 9.09

C. **Results:** (one or more category may apply)

Conservation Programs:

Demand savings (kW):	*Summer*	
	Winter	47.5202
	lifecycle	*in year*
Energy saved (kWh):	*570527.5212*	19017.58404
Other resources saved :		
Natural Gas (m3):		
Other (specify):		

Demand Management Programs:

Controlled load (kW)	
Energy shifted On-peak to Mid-peak (kWh):	
Energy shifted On-peak to Off-peak (kWh):	
Energy shifted Mid-peak to Off-peak (kWh):	

Demand Response Programs:

Dispatchable load (kW):	
Peak hours dispatched in year (hours):	

Power Factor Correction Programs:

Amount of KVar installed (KVar):	
Distribution system power factor at begining of year (%):	
Distribution system power factor at end of year (%):	

Line Loss Reduction Programs:

Peak load savings (kW):		
	lifecycle	*in year*
Energy savngs (kWh):		

Distributed Generation and Load Displacement Programs:

Amount of DG installed (kW):	
Energy generated (kWh):	
Peak energy generated (kWh):	
Fuel type:	

Other Programs (specify):

Metric (specify):	

D. **Program Costs*:**

Utility direct costs ($):	*Incremental capital:*	
	Incremental O&M:	$ 9,114.98
	Incentive:	
	Total:	$ 9,114.98
Utility indirect costs ($):	*Incremental capital:*	
	Incremental O&M:	
	Total:	
Participant costs ($):	*Incremental equipment:*	
	Incremental O&M:	
	Total:	

E. Comments:

Very successful program

*Please refer to the TRC Guide for the treatment of equipment cost in the TRC Test.

Appendix A - Evaluation of the CDM Plan

	Total	Residential	Commercial	Institutional	Industrial	Agricultural	LDC System	Other 1	Other 2	Other 3	Other 4
Net TRC value ($):	*-$ 1,500.00*							-$ 1,500.00			
Benefit to cost ratio:											
Number of participants or units delivered:	*1*							1			
Total KWh to be saved over the lifecycle of the plan (kWh):											
Total in year kWh saved (kWh):											
Total peak demand saved (kW):											
Total kWh saved as a percentage of total kWh delivered (%):											
Peak kW saved as a percentage of LDC peak kW load (%):											
Gross in year C&DM expenditures ($):	$1,500							$1,500			
Expenditures per KWh saved ($/kWh):*											
*Expenditures per KW saved ($/kW)**:*											

Utility discount rate (%):	7.8

*Expenditures include all utility program costs (direct and indirect) for all programs which primarily generate energy savings.
**Expenditures include all utility program costs (direct and indirect) for all programs which primarily generate capacity savings.

Appendix B - Discussion of the Program

A. **Name of the Program:** Load Management

Description of the program (including intent, design, delivery, partnerships and evaluation):

Purchase of a TRC tool in 2005. Website improvements to promote conservation including a link to a NEPPA conservation site (costs to appear in 2006).

Measure(s):

	Measure 1	Measure 2 (if applicable)	Measure 3 (if applicable)
Base case technology:			
Efficient technology:	Promote C&DM		
Number of participants or units delive	1		
Measure life (years):			

B. **TRC Results:**

TRC Benefits ($):	
TRC Costs ($):	
Utility program cost (less incentives):	$ 1,500.00
Participant cost:	
Total TRC costs:	$ 1,500.00
Net TRC (in year CDN $):	-$ 1,500.00
Benefit to Cost Ratio (TRC Benefits/TRC Costs):	$ -

C. **Results:** (one or more category may apply)

Conservation Programs:

		lifecycle	in year
Demand savings (kW):	*Summer*		
	Winter		
Energy saved (kWh):			
Other resources saved :			
	Natural Gas (m3):		
	Other (specify):		

Demand Management Programs:

Controlled load (kW)
Energy shifted On-peak to Mid-peak (kWh):
Energy shifted On-peak to Off-peak (kWh):
Energy shifted Mid-peak to Off-peak (kWh):

Demand Response Programs:

Dispatchable load (kW):
Peak hours dispatched in year (hours):

Power Factor Correction Programs:

Amount of KVar installed (KVar):
Distribution system power factor at begining of year (%):
Distribution system power factor at end of year (%):

Line Loss Reduction Programs:

	lifecycle	in year
Peak load savings (kW):		
Energy savngs (kWh):		

Distributed Generation and Load Displacement Programs:

Amount of DG installed (kW):
Energy generated (kWh):
Peak energy generated (kWh):
Fuel type:

Other Programs (specify):

Metric (specify):

D. **Program Costs*:**

Utility direct costs ($):	*Incremental capital:*	$ 1,500.00
	Incremental O&M:	
	Incentive:	
	Total:	$ 1,500.00
Utility indirect costs ($):	*Incremental capital:*	
	Incremental O&M:	
	Total:	
Participant costs ($):	*Incremental equipment:*	
	Incremental O&M:	
	Total:	

E. Comments:

*Please refer to the TRC Guide for the treatment of equipment cost in the TRC Test.

Appendix A - Evaluation of the CDM Plan

	Total	Residential	Commercial	Institutional	Industrial	Agricultural	LDC System	Other 1	Other 2	Other 3	Other 4
Net TRC value ($):	-$ 8,764.36							-$ 8,764.36			
Benefit to cost ratio:											
Number of participants or units delivered:											
Total KWh to be saved over the lifecycle of the plan (kWh):											
Total in year kWh saved (kWh):											
Total peak demand saved (kW):											
Total kWh saved as a percentage of total kWh delivered (%):											
Peak kW saved as a percentage of LDC peak kW load (%):											
Gross in year C&DM expenditures ($):	$8,764							$8,764.36			
Expenditures per KWh saved ($/kWh):*											
*Expenditures per KW saved ($/kW)**:*											

Utility discount rate (%):	7.8

*Expenditures include all utility program costs (direct and indirect) for all programs which primarily generate energy savings.
**Expenditures include all utility program costs (direct and indirect) for all programs which primarily generate capacity savings.

Appendix B - Discussion of the Program

A. **Name of the Program:** Smart Meter Research and Pilot Programs

Description of the program (including intent, design, delivery, partnerships and evaluation):

Participation in Ontario Utility Smart Meter Working Group (OUSM) and Interval Meter installations

Measure(s):

	Measure 1	Measure 2 (if applicable)	Measure 3 (if applicable)
Base case technology:	Non-TOU Metering		
Efficient technology:	Smart (TOU) Metering		
Number of participants or units delive	1		
Measure life (years):			

B. **TRC Results:**

TRC Benefits ($):	$ -
TRC Costs ($):	
Utility program cost (less incentives):	$ 8,764.36
Participant cost:	
Total TRC costs:	$ 8,764.36
Net TRC (in year CDN $):	-$ 8,764.36
Benefit to Cost Ratio (TRC Benefits/TRC Costs):	$ -

C. **Results:** (one or more category may apply)

Conservation Programs:

		lifecycle	in year
Demand savings (kW):	*Summer*		
	Winter		
Energy saved (kWh):			
Other resources saved :			
	Natural Gas (m3):		
	Other (specify):		

Demand Management Programs:

Controlled load (kW)
Energy shifted On-peak to Mid-peak (kWh):
Energy shifted On-peak to Off-peak (kWh):
Energy shifted Mid-peak to Off-peak (kWh):

Demand Response Programs:

Dispatchable load (kW):
Peak hours dispatched in year (hours):

Power Factor Correction Programs:

Amount of KVar installed (KVar):
Distribution system power factor at begining of year (%):
Distribution system power factor at end of year (%):

Line Loss Reduction Programs:

Peak load savings (kW):

	lifecycle	in year
Energy savngs (kWh):		

Distributed Generation and Load Displacement Programs:

Amount of DG installed (kW):
Energy generated (kWh):
Peak energy generated (kWh):
Fuel type:

Other Programs (specify):

Metric (specify):

D. **Program Costs*:**

Utility direct costs ($):	*Incremental capital:*	$ 3,240.00
	Incremental O&M:	$ 5,524.36
	Incentive:	
	Total:	$ 8,764.36
Utility indirect costs ($):	*Incremental capital:*	
	Incremental O&M:	
	Total:	
Participant costs ($):	*Incremental equipment:*	
	Incremental O&M:	
	Total:	

E. **Comments:**

There is no measureable benefit, however, the program has advanced smart metering capability and knowledge within our company.

*Please refer to the TRC Guide for the treatment of equipment cost in the TRC Test.

Appendix A - Evaluation of the CDM Plan

	Total	Residential	Commercial	Institutional	Industrial	Agricultural	LDC System	Other 1	Other 2	Other 3	Other 4
Net TRC value ($):	*$13,600*						$ 13,600.00				
Benefit to cost ratio:	1.10589						1.10589				
Number of participants or units delivered:	1						1				
Total KWh to be saved over the lifecycle of the plan (kWh):	250617						250617				
Total in year kWh saved (kWh):	10025						10025				
Total peak demand saved (kW):	21.34						21.34				
Total kWh saved as a percentage of total kWh delivered (%):	0.00533						0.00533				
Peak kW saved as a percentage of LDC peak kW load (%):	0.05616						0.05616				
Gross in year C&DM expenditures ($):	$ 140,174.80						$ 140,174.80				
Expenditures per KWh saved ($/kWh):*	$0.55932						$0.55932				
*Expenditures per KW saved ($/kW)**:*	*$6,569*						$6,569				

Utility discount rate (%):	7.8

*Expenditures include all utility program costs (direct and indirect) for all programs which primarily generate energy savings.
**Expenditures include all utility program costs (direct and indirect) for all programs which primarily generate capacity savings.

Appendix B - Discussion of the Program

A. **Name of the Program:** Distribution Line Loss Improvements

Description of the program (including intent, design, delivery, partnerships and evaluation):

Purchase of Line loss improvement software tool (2004). Reconductoring of main Feeder to reduced Line losses. Program to be complete in 2007

Measure(s):

	Measure 1	Measure 2 (if applicable)	Measure 3 (if applicable)
Base case technology:	Lower Amperage Conductor		
Efficient technology:	High Capacity Conductor		
Number of participants or units deliv	1		
Measure life (years):	25		

B. **TRC Results:**

TRC Benefits ($):		*$ 142,040.00*
TRC Costs ($):		
	Utility program cost (less incentives):	$ 128,440.00
	Participant cost:	
	Total TRC costs:	$ 128,440.00
Net TRC (in year CDN $):		$ 13,600.00
Benefit to Cost Ratio (TRC Benefits/TRC Costs):		$ 1.11

C. **Results:** (one or more category may apply)

Conservation Programs:

Demand savings (kW):	*Summer*	
	Winter	
	lifecycle	*in year*
Energy saved (kWh):		
Other resources saved :		
Natural Gas (m3):		
Other (specify):		

Demand Management Programs:

Controlled load (kW)
Energy shifted On-peak to Mid-peak (kWh):
Energy shifted On-peak to Off-peak (kWh):
Energy shifted Mid-peak to Off-peak (kWh):

Demand Response Programs:

Dispatchable load (kW):
Peak hours dispatched in year (hours):

Power Factor Correction Programs:

Amount of KVar installed (KVar):
Distribution system power factor at begining of year (%):
Distribution system power factor at end of year (%):

Line Loss Reduction Programs:

Peak load savings (kW):		21.34
	lifecycle	*in year*
Energy savngs (kWh):	250616.96	10024.6784

Distributed Generation and Load Displacement Programs:

Amount of DG installed (kW):
Energy generated (kWh):
Peak energy generated (kWh):
Fuel type:

Other Programs (specify):

Metric (specify):

D. **Program Costs*:**

Utility direct costs ($):	*Incremental capital:*	$ 140,174.80
	Incremental O&M:	
	Incentive:	
	Total:	$ 140,174.80
Utility indirect costs ($):	*Incremental capital:*	
	Incremental O&M:	
	Total:	
Participant costs ($):	*Incremental equipment:*	
	Incremental O&M:	
	Total:	

E. Comments:

DESS Software & support ($11,734.80) was utilized to calculate line loss savings. Seasonal factors were applied to DESS kW line los

*Please refer to the TRC Guide for the treatment of equipment cost in the TRC Test.

	Ontario Seasonal Average Avoided Energy Cost ($/MWh)																					
	Winter (December - March)									Summer (June - September)									Shoulder (April May October Nov			
	On Peak 7 - 11 am, 5 - 8 pm			Mid-Peak 11 am - 5 pm, 8 - 10 pm			Off Peak 10 pm - 7 am			On Peak 11 am - 5 pm			Mid-Peak 7 - 11 am, 5 - 10 pm			Off Peak 10 pm - 7 am			Mid-Peak 7 am - 10 pm			
Year	Hours	kW	kWh	Hours	kW	kWh	Hours	kW	kWh	Hours	kW	kWh	Hours	kW	kWh	Hours	kW	kWh	Hours	kW	kWh	Hours
Hours/Period	125			84			45			112			80			46			81			41
1	87	21	1,861	59	21	1,259	32	21	675	112	21	2,379	56	21	1,189	32	21	686	57	21	1,216	29
2	87	21	1,861	59	21	1,259	32	21	675	112	21	2,379	56	21	1,189	32	21	686	57	21	1,216	29
3	87	21	1,861	59	21	1,259	32	21	675	112	21	2,379	56	21	1,189	32	21	686	57	21	1,216	29
4	87	21	1,861	59	21	1,259	32	21	675	112	21	2,379	56	21	1,189	32	21	686	57	21	1,216	29
5	87	21	1,861	59	21	1,259	32	21	675	112	21	2,379	56	21	1,189	32	21	686	57	21	1,216	29
6	87	21	1,861	59	21	1,259	32	21	675	112	21	2,379	56	21	1,189	32	21	686	57	21	1,216	29
7	87	21	1,861	59	21	1,259	32	21	675	112	21	2,379	56	21	1,189	32	21	686	57	21	1,216	29
8	87	21	1,861	59	21	1,259	32	21	675	112	21	2,379	56	21	1,189	32	21	686	57	21	1,216	29
9	87	21	1,861	59	21	1,259	32	21	675	112	21	2,379	56	21	1,189	32	21	686	57	21	1,216	29
10	87	21	1,861	59	21	1,259	32	21	675	112	21	2,379	56	21	1,189	32	21	686	57	21	1,216	29
11	87	21	1,861	59	21	1,259	32	21	675	112	21	2,379	56	21	1,189	32	21	686	57	21	1,216	29
12	87	21	1,861	59	21	1,259	32	21	675	112	21	2,379	56	21	1,189	32	21	686	57	21	1,216	29
13	87	21	1,861	59	21	1,259	32	21	675	112	21	2,379	56	21	1,189	32	21	686	57	21	1,216	29
14	87	21	1,861	59	21	1,259	32	21	675	112	21	2,379	56	21	1,189	32	21	686	57	21	1,216	29
15	87	21	1,861	59	21	1,259	32	21	675	112	21	2,379	56	21	1,189	32	21	686	57	21	1,216	29
16	87	21	1,861	59	21	1,259	32	21	675	112	21	2,379	56	21	1,189	32	21	686	57	21	1,216	29
17	87	21	1,861	59	21	1,259	32	21	675	112	21	2,379	56	21	1,189	32	21	686	57	21	1,216	29
18	87	21	1,861	59	21	1,259	32	21	675	112	21	2,379	56	21	1,189	32	21	686	57	21	1,216	29
19	87	21	1,861	59	21	1,259	32	21	675	112	21	2,379	56	21	1,189	32	21	686	57	21	1,216	29
20	87	21	1,861	59	21	1,259	32	21	675	112	21	2,379	56	21	1,189	32	21	686	57	21	1,216	29
21	87	21	1,861	59	21	1,259	32	21	675	112	21	2,379	56	21	1,189	32	21	686	57	21	1,216	29
22	87	21	1,861	59	21	1,259	32	21	675	112	21	2,379	56	21	1,189	32	21	686	57	21	1,216	29
23	87	21	1,861	59	21	1,259	32	21	675	112	21	2,379	56	21	1,189	32	21	686	57	21	1,216	29
24	87	21	1,861	59	21	1,259	32	21	675	112	21	2,379	56	21	1,189	32	21	686	57	21	1,216	29
25	87	21	1,861	59	21	1,259	32	21	675	112	21	2,379	56	21	1,189	32	21	686	57	21	1,216	29
Total			**46,532**		**534**	**31,482**		**534**	**16,880**		**534**	**59,485**		**534**	**29,727**		**534**	**17,141**		**534**	**30,399**	

Total Project kWh	**250616.96**
Total Annual kWh	**10024.6784**
Total Kw Winter	**21**
Total Kw Summer	**21**

vember)	
Off Peak 10 pm - 7 am	
kW	kWh
21	609
21	609
21	609
21	609
21	609
21	609
21	609
21	609
21	609
21	609
21	609
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21	609
534	**15,237**