

**Halton Hills Hydro Inc.
Responses to Board Staff Interrogatories
2008 Electricity Distribution Rates
EB-2007-0696**

**OPERATION, MAINTENANCE AND ADMINISTRATION
General**

1. Ref: Exhibit 4/ Tab 1/ Schedule 2/ Page 1

Please prepare a reconciliation comparing the 2006 Actual values to the 2006 audited financial statements.

Table 1 - 2006 Actual Values Reconciled to 2006 Audited Financial Statements

2006 Actual Values	
Total operating costs	42,788,079
2006 Audited Financial Statements	
Total operating expenses	40,294,651
Amortization	1,930,209
Provision for income taxes	729,981
Total	42,954,841
Difference between 2006 Actual & Audited Financial Statements	(166,762)
Differences between Actual Values & Audited Financial Statements due to:	
1. Deferred charge funds reclassification - CDM	206,368
2. Deferred charge funds reclassification - smart meters	(72,750)
3. Retailer revenue - cost offset reclassification	38,953
4. Cumulative minor adjustments	(5,809)
	166,762

2. Ref: Exhibit 4/ Tab 2/ Schedule 6/ Page 1

Halton Hills provides a comparison of total incentive amounts for Management from 2006 to 2008. Please provide details on Halton Hill's incentive guidelines, including how Management performance is measured and how the incentive level is determined.

Included below is an excerpt from Halton Hills Hydro Inc.'s Board of Director minutes dated February 19, 2004. Halton Hills Hydro Inc. management's incentives are industry average incentives. The criteria for safety is "no serious injuries". These incentives have proven effective as HHHI has completed 1,454 working days accident free (as of November 8, 2007), which equates to approximately 500,000 hours; a significant accomplishment. Any "non" LDC bonus is handled through inter-company charges so there is no impact to the LDC. The total of these charges was \$0.00 in 2006.

MANAGEMENT INCENTIVES

"It was RESOLVED that each member of Management of the Corporation whose position is set forth below is eligible to receive a bonus, not exceeding the percentage of their base salary set opposite their position below, determined by the Directors at the end of each calendar year taking into consideration the weighted criteria for the position set forth below:

<i>Position</i>	<i>Percentage Base Salary</i>	<i>Criteria</i>	<i>Weight</i>
<i>President</i>	<i>12.5%</i>	<i>Safety</i>	<i>33%</i>
		<i>LDC (NCFS) Before Tax Net Income</i>	<i>23%</i>
		<i>FIBRE (CFS) Before Tax Net Income</i>	<i>22%</i>
		<i>SWE (CFS) Before Tax Net Income</i>	<i>22%</i>
<i>Vice- President</i>	<i>10.0%</i>	<i>Safety</i>	<i>40%</i>
		<i>LDC (NCFS) Before Tax Net Income</i>	<i>25%</i>
		<i>SWE (CFS) Before Tax Net Income</i>	<i>35%</i>
<i>Chief Financial Officer</i>	<i>10.0%</i>	<i>Safety</i>	<i>33%</i>
		<i>LDC (NCFS) Before Tax Net Income</i>	<i>23%</i>
		<i>Fibre (CFS) Before Tax Net Income</i>	<i>22%</i>
		<i>SWE (CFS) Before Tax Net Income</i>	<i>22%</i>
<i>Engineering & Operations Manager</i>	<i>7.5%</i>	<i>Safety</i>	<i>50%</i>
		<i>LDC (NCFS) Before Tax Net Income</i>	<i>50%</i>
<i>Lines Supervisor</i>	<i>5.0%</i>	<i>Safety</i>	<i>50%</i>
		<i>LDC (NCFS) Before Tax Net Income</i>	<i>50%</i>

Engineering Supervisor	5.0%	Safety	50%
		LDC (NCFS) Before Tax Net Income	50%
Accounting Supervisor	5.0%	Safety	33%
		LDC (CFS) Before Tax Net Income	67%
Customer Care Super.	5.0%	Safety	33%
		LDC (CFS) Before Tax Net Income	67%
Executive Assistant	3.0%	Safety	33%
		LDC (CFS) Before Tax Net Income	67%

For these purposes "LDC" means the Corporation, "Fibre" means Halton Hills Fibre Optics Inc., "SWE" means SouthWestern Energy Inc. and Halton Hills Energy Services Inc., collectively, "Before Tax Net Income" means the before tax net income of the Corporation or the particular subsidiary of the Corporation determined as the case may be, on the basis of either the consolidated, where "(CFS)" is indicated, or the non-consolidated, where "(NCFS)" is indicated, audited financial statements for the Corporation and the financial statements approved for each of the Corporation's subsidiaries by those subsidiaries' directors. An employee shall qualify for a bonus in respect of a calendar year only if the employee is in the employ of the Corporation or a subsidiary of the Corporation at the time that the Directors determine a bonus in respect of such calendar year, it being the intent that, if the employment of an employee is terminated, by the employee or the Corporation or a subsidiary of the Corporation howsoever, before a bonus is determined by the Directors for such calendar year, the employee will not receive a bonus or any portion thereof in respect of such calendar year."

From HHHI Board of Directors February 19, 2004 minutes.

3. Ref: Exhibit 4 /Tab 2 /Schedule 4

Please provide a detailed description of the assumptions underlying the allocation of Halton Hills' corporate costs to its business units, if applicable. Please include relevant documentation of the overall methodology and policy. If not applicable, please explain why.

Water Billing: The allocation of costs for water billing includes:

Type of Cost	Allocator
Salaries and Benefits	Estimated time
Supplies – bills, envelopes, postage	% of water meters to total meters
Meter Reading	Actual # of reads
Occupancy	Sq footage of space
Office equipment	Estimate of usage

Salaries and Benefits:

Halton Hills Hydro Inc. performs water billing activities for the Region of Halton. The LDC allocates customer care staffing costs based on an estimate of time spent by staff to perform the water billing functions. The allocation includes a portion of our call centre staff, billing staff, payment processing staff and supervisory time.

Supplies:

Supplies include envelopes, bills, postage and printer supplies. Halton Hills Hydro Inc. divides the number of water bills by the total number of bills to determine the proper allocation.

Meter Reading:

Meter reading costs are split on a 50/50 basis for any dual read locations.

Occupancy:

HHLI allocates occupancy costs based on an estimate of square footage used to perform this service.

Office Equipment:

HHLI allocates a percentage of annual operating costs for printers, mailing machine and AS400 (system on which our database operates).

Hot Water Tank Rentals: The allocation of costs for water heater rentals includes:

Type of Cost	Allocator
Salaries and Benefits	Estimated time
Supplies – bills, envelopes, postage	% of bills
Occupancy	Sq footage of space
Office equipment	Estimate of usage

Salaries and Benefits:

Halton Hills Hydro Inc. performs water heater activities for the affiliate SouthWestern Energy Inc.. HHHI allocates operating staffing costs based on an estimate of time spent by staff to perform the water heater functions. The allocation includes a portion of stores and operations clerk plus supervisory time.

Supplies:

Supplies include envelopes, bills, postage and printer supplies. HHHI calculates the total number of bills that include water heater charges to determine the proper allocation.

Occupancy:

HHHI allocates occupancy costs based on an estimate of square footage used to perform this service.

Office Equipment:

HHHI allocates a percentage of annual operating costs for printers, mailing machine and AS400.

Fibre Optics Services: The allocation of costs for Fibre Optics Services:

Type of Cost	Allocator
Salaries and Benefits	Estimated time
Occupancy	Sq footage of space
Office equipment	Estimate of usage
Poles	# of poles

Salaries and Benefits:

Halton Hills Hydro Inc. performs billing activities for the affiliate Halton Hills Fibre Optics Inc.. HHHI allocates operating staffing costs based on an estimate of time spent by staff to perform the billing functions. The allocation includes a portion of accounts payable/receivable clerk and supervisory time.

Occupancy:

HHHI allocates occupancy costs based on an estimate of square footage used to perform this service.

Office Equipment:

HHHI allocates a percentage of annual operating costs for printers, mailing machine and AS400.

Poles:

HHHI charges Halton Hills Fibre Optics the same rate for pole attachment as is charged to Bell Canada.

Purchased services

4. Refs: Exhibit 4/ Tab 2 / Schedule 5 and Exhibit 4/ Tab 2 / Schedule 3/ **Page 1**

On pages 1 and 2, Halton Hills lists the services which it has purchased from other organizations. For each of the approaches used to award contracts e.g. tendering approach, cost approach, etc, please provide a more detailed description of the specific methodology used to determine the price.

Halton Hills Hydro Inc. defines the approaches as follows:

Tendering:

A tender is prepared outlining the corporation's requirements and is sent to qualified organizations that are prepared to perform duties as per the tendering document. A due date is set and the tenders are opened. Typically, all requirements being equal the lowest priced organization is awarded the work.

Cost Approach:

Typically we have worked with vendors in the past and set up budgetary restrictions on the amount to be spent. In some cases, there is only one vendor capable of delivering the service.

Quotation:

A work specification is sent to selected vendors detailing the services required by Halton Hills Hydro Inc.. Typically, all requirements being equal the lowest priced organization is selected.

Shared Services

5. Ref: Exhibit 4 /Tab 2 /Schedule 3/ Page 1

Halton Hills provides a summary of shared services. Please provide, in addition to this information, the total expense by service.

Table 2 -Total Expense by shared service

	2006 Actual	2007 Bridge	2008 Test
Shared Services Expense:			
Billing Services	54,000	55,500	56,500
Collecting Services	19,000	19,500	20,100
Customer Services ** Includes Bills, Postage, Meter Reading	112,000	115,800	117,700
Distribution Poles	48,600	49,800	50,000
Office Space	22,400	23,100	20,100
Office Equipment	22,550	23,200	23,900
Administration	75,000	82,000	54,500
Warehouse Services	4,800	4,900	5,000
Total Expense	358,350	373,700	329,700

6. Ref: Exhibit 4 /Tab 2 /Schedule 4/ Page 1

Halton Hills provides a summary of the allocators used for corporate cost allocation under a Service Agreement that is updated on yearly basis for the provision of any services performed for an affiliate. Please provide the rationale for the use of each of these allocators and how they would be used to calculate the total annual expense by service.

Please refer to the answer to Question #3. Halton Hills Hydro Inc. has included the rationale for use of these allocators in the response.

Pension Costs

7. Ref: Exhibit 4/ Tab 2/ Schedule 6/ Page 1

Halton Hills provides the status of its pension funding. Please provide summary data on the age distribution of the workforce and a forecast of retirements by employee category from 2007 to 2008.

Table 3 – Age Distribution of Workforce 2007

	20-30	30-40	40-50	50-60	Total
Management	-	3	4	3	10
Union	4	13	8	10	35

Based on current information we do not anticipate any employee retirements.

Low Voltage Charge

8. Ref: Exhibit 4/ Tab 1/ Schedule 2/ Page 1

The following table was prepared by Board staff to compare the application's 2006 Board Approved OM&A to the final 2006 EDR model for Halton Hills. Please review and explain the difference column, or revise the above referenced schedule for your application. Please note that the amount for Administrative and General Expenses has been adjusted by \$613,744 to reallocate the Low Voltage charge. This Low Voltage charge was handled as a pass through charge in the 2006 EDR model. It was included into rates as a rate adder and offset as a General and Administrative expense (or more intentionally as revenue offset). This amount therefore should not be included in the OM&A subtotal for comparative purposes. Please note that rounding differences may occur, but are immaterial to this question.

2006 Board Approved OM&A			
(\$)			
	Per Application	Per Board Staff	Difference
Operation	495,401	495,098	303
Maintenance	562,172	560,579	1,593
Billing & Collecting	873,784	835,191	38,593
Administrative and General Expenses	2,594,596	1,888,615	705,981
Insurance Expense	0	32,680	-32,680
Bad Debts	0	38,593	-38,593
Advertising Expenses	0	1,557	-1,557
Taxes other than income taxes	71,132	71,132	0
Subtotal	4,597,085	3,923,445	673,640
Low Voltage	0	613,744	-613,744
Community Relations (CDM)	88,690	88,690	0
Total OM&A Expenses	4,685,775	4,625,879	59,896
Amortization Expenses	1,846,338	1,846,338	0
Total Distribution Expenses	6,532,113	6,472,217	59,896

Halton Hills Hydro Inc. confirms that the table prepared by Board staff is correct.

9. Ref: 2006 EDR Application Model, Sheet “7-2 ALLOCATION - LV-Wheeling”

In Halton Hills’ 2006 EDR Application Model, Sheet “7-2 ALLOCATION - LV-Wheeling”, Cell L120 has included the amount of \$613,744 for Low Voltage charges. This Low Voltage charge was handled as a pass through charge in the 2006 EDR model. It was included into rates as a rate adder on the above referenced worksheet and accounted for as General and Administrative expense (or more intentionally as a revenue offset). Please confirm whether or not Halton Hills has included a budget amount in the 2008 Cost of Service or OM & A budget for low voltage. If yes please state reasons for including and identify the amounts included, including detailed calculation. If not, please declare confirmation that no amounts have been included in Cost of Service or OM&A for Low Voltage.

Halton Hills Hydro Inc. has included a LV – Wheeling budget amount in Appendix D/ Exhibit 4/ Tab 2/ Schedule 1/ Page 2, a 2007 Bridge year amount of \$636,500 and a 2008 Test year amount of \$660,000. The calculation is as follows:

Table 4– LV Wheeling

	2007 Bridge	2008 Test
kW	1,005,529	1,042,654
LV Charge	\$0.633	\$0.633
Cost	\$636,500	\$660,000

Loss factors

10. Refs: Exhibit 1/ Tab 2/ Schedule 1/ Page 6 and Exhibit 4/ Tab 2/ Schedule 8/ Page 1

- a) *Please confirm that the loss factors filed in Schedule 10-5 of EDR 2006 application (RP-2005-0020/EB-2005-0374) were 1.0207, 1.0365 and 1.0371 respectively for 2002, 2003 and 2004.*
- b) *Please confirm that loss factors for 2004, 2005 and 2006 are as indicated in the Application, i.e. respectively 1.0509, 1.0637 and 1.0357.*
- c) *Noting that the 2004 loss factor in the latter is 1.0509, as distinct from 1.0371 in the former, please indicate which data is correct. If the larger figure in the latter is correct, please explain what information became available in the period after filing the EDR 2006 application to rationalize the revision.*
- d) *Please provide a brief explanation of why the loss factor in 2005 (and in 2004 if the revised figure is correct) appears to be substantially above the average over the longer period 2002-2006.*
- e) *Please provide a rationale for proposing that the 2008 loss factor be an average of the loss factors for 2004-2006 rather than some lower factor such as a replication of the 2007 loss factor of 1.0368 or the actual 2006 loss factor of 1.0357.*

- a) The loss factors are confirmed.
- b) The loss factors are confirmed.
- c) The loss factor of 1.0509 for 2004 is correct. Since the EDR 2006 application, Halton Hills Hydro Inc. has reviewed information gathering methods and determined a more accurate method. In addition, internal procedures have been improved to ensure more accurate data.
- d) The loss factor in 2005 and 2004 is substantially above the average over the longer period 2002-2006 due to the more accurate information gathering and internal procedures that have been initiated since the submission of the 2006 EDR.
- e) Due to previously less accurate data gathering, the 2007 loss factor of 1.0368 and the actual 2006 loss factor of 1.0357 were incorrectly determined. In addition, an increase in the discovery of un-metered power has resulted in historical loss factors being under calculated.

2008 PILs PROXY

11. General

For fiscal and tax year 2006, please provide the following:

- a) Actual federal T2 tax return and supporting schedules;*
- b) Actual Ontario CT23 tax return and supporting schedules;*
- c) Financial statements that were submitted with the tax returns for each tax year to the Ministry of Finance; and*
- d) Notices of Assessment, and any Notice(s) of Re-assessment, including Statement of Adjustments, received from the Ministry of Finance for each tax year.*

For fiscal and tax year 2006:

- a) See Appendix A
- b) See Appendix A
- c) See Appendix A
- d) See Appendix A

12. Ref: Exhibit 4/ Tab 3/ Schedule 1/ Page 1

Income before PILs/Taxes

- a) Please provide the exhibit references for the source of the income before PILs/ taxes of \$1,895,292 for 2006; \$2,763,680 for 2007; and \$1,581,790 for 2008.
If there is no exhibit reference, please provide a summary showing the calculations of each amount.
Why will Halton Hills earn much more income before PILs/ taxes in 2007 than in 2008?***
- b) Please provide the current year forecast or estimate of income tax/ PILs instalments to be paid to the Ministry of Finance for the 2007 tax year.***

Table entitled "Income Taxes", Additions, for 2006, 2007 and 2008

- c) Please explain why non-deductible meals and entertainment expense should true up to the ratepayer. If these expenses are non-deductible for tax purposes, why should the shareholder not absorb the costs and the tax consequences?***
- d) Please provide a summary table of the various amounts included in "Reserves from financial statements" and explain why each item should be added back in the calculation of regulatory net income.***
- e) Please explain why interest expense has been added back in 2007 and 2008 but not in 2006.***
- f) Please explain why interest expense is added back in the calculation of regulatory income tax / PILs.***

Table entitled "Income Taxes", Deductions, for 2006, 2007 and 2008:

- g) Please provide a summary of the various amounts included in "Reserves from financial statements" and explain why each item should be deducted in the calculation of regulatory net income.***
- h) Please provide the exhibit reference for the calculation of the "Cumulative eligible capital deduction" for 2007 and 2008. If there is no exhibit, please provide the required calculations to support the deduction amounts. Please explain what the eligible capital is and how it arose.***

Income before PILs/Taxes

a) Appendix B outlines the 2006, 2007 and 2008 income before PILs / taxes as follows:

i. 2006 Income before PILs / Taxes – appears on 2006 audited financial statements – income statement in the amount of \$1,895,472. Balance on Exhibit 4/Tab 3/Schedule 1/Page 1 for 2006 income before PILs / taxes of \$1,895,292 different by \$180 transposition.

ii. 2007 Income before PILs / Taxes – 2007 Pro Forma Income Statement:

	\$
Grand total	1,582,680
Add back: Income taxes	<u>1,181,000</u>
Net income before PILs / taxes	<u>2,763,680</u>

iii. 2008 Income before PILs / Taxes – 2008 Pro Forma Income Statement:

	\$
Grand total	2,710,037
Add back: Income taxes	<u>836,500</u>
Net income before PILs / taxes	<u>3,546,537</u>

The net income before PILs / Taxes of \$1,581,780 as used in Exhibit 4/Tab 3/Schedule 1/Page 1 for 2008 Test Income before PILs / Taxes represents the deemed return on equity as calculated for 2008.

The PILs model is operating as follows for the Test Year: the Net Income Before PILs / Taxes equals the deemed return on equity; the deemed net income Halton Hills Hydro Inc. should earn in the Test Year. After the PILs are calculated, a gross-up is applied to once again set net income to the deemed return on equity.

In the Bridge Year the PILs model is only used to project the PILs expense. In the Test Year, the PILs model calculates the PILs that will result from a given net income requirement, which will be used to project the distribution revenue requirement that covers distribution expenses, PILs and return on capital.

b) Halton Hills Hydro Inc. estimates that income tax / PILs in the amount of \$732,000 will be paid to the Ministry of Finance for the 2007 tax year.

Table entitled "Income Taxes", Additions, for 2006, 2007 and 2008

- c) Non-deductible meals and entertainment expenses in the table entitled "Income Taxes, Additions for 2006, 2007 and 2008", should read non-deductible meals. No entertainment expenses were or are projected to be incurred by Halton Hills Hydro Inc..

The Income Tax Act, in determining that meals expenditures are only 50% deductible for tax purposes, has set a proxy rate for the portion of these expenditures that are personal in nature. Inherent in the provision of meals is the fact that these benefit the individual consuming the foodstuffs; there is an inevitable personal benefit in the expenditure.

As to whether the expenditures should true up to the shareholder or ratepayer, as these are expenditures incurred in carrying on the business activities of the company, the ratepayer should be responsible for absorbing the costs.

- d) Reserves from financial statements on the "Additions for 2006, 2007 and 2008" include a general reserve for bad debts and accrued employee future benefits. These expenses are added back to regulatory net income as the actual costs of these items are deductible for tax purposes. Estimate of the actual costs for these expenses have been deducted under the "Deductions for 2006, 2007 and 2008." Please refer to Table 5 for a breakdown of these reserves.

Note that the add back used for accrued employee future benefits in the bridge and test years was the balance sheet rather than the expense amount. As the add back and the deduction amounts are assumed the same for the bridge and test years (whether the balance sheet or expense amount is used), the effect on taxable income is nil.

Table 5 – Reserves from Financial Statements

	2006 Board <u>Approved</u>	2006 <u>Actual</u>	2007 <u>Bridge</u>	2008 <u>Test</u>
General reserve for bad debts	38,593	42,000	89,550	89,550
Accrued employee future benefits	40,768	25,736	457,000	457,000
	<u>79,361</u>	<u>67,736</u>	<u>546,550</u>	<u>546,550</u>

- e) Actual interest expense has been added back for 2007 and 2008, with deemed interest subsequently deducted under the deductions section. This is in accordance with the interest deductibility restriction per the 2007 Ontario budget. For 2006 Board Approved, the net interest adjustment is shown under 'excess interest' in the deductions section. No effect of the difference between regulatory and actual interest is contemplated in the 2006 tax filing, as there are no interest deduction restrictions for actual tax filing purposes.
- f) Actual interest expense has been added back for 2007 and 2008, with deemed interest subsequently deducted under the deductions section. Deemed interest (rate based x deemed debt portion x effective interest rate) is deducted as this more appropriately reflects the interest that would be expensed.

Table entitled "Income Taxes", Deductions, for 2006, 2007 and 2008:

- g) Reserves from financial statements on the "Deductions for 2006, 2007 and 2008" include a general reserve for bad debts and accrued employee future benefits. The actual expenses are deducted from regulatory net income as the actual costs of these items are deductible for tax purposes. Accruals for these expenses have been added back under the "Additions for 2006, 2007 and 2008." Please refer to Table 6 for a breakdown of these reserves.

Note that the deduction used for accrued employee future benefits in the bridge and test years was the balance sheet rather than the expense amount. As the add back and the deduction amounts are assumed the same for the bridge and test years (whether the balance sheet or expense amount is used), the effect on taxable income is nil.

Table 6 – Reserves from Financial Statements

	2006 Board <u>Approved</u>	2006 <u>Actual</u>	2007 <u>Bridge</u>	2008 <u>Test</u>
General reserve for bad debts	24,694	55,986	89,550	89,550
Accrued employee future benefits	20,269	15,835	457,000	457,000
	44,963	71,821	546,550	546,550

- h) Cumulative eligible represents the expenditures of Halton Hills Hydro Inc. to acquire intangible capital property (eligible capital property). Eligible capital property of the Company includes goodwill, reorganization and incorporation costs. Please refer to Table 7 for the eligible capital property details.

Table 7 – Cumulative Eligible Capital Deduction

i) Detail of cumulative eligible capital:

Incorporation and reorganization costs	345,495
Goodwill on acquisition of subsidiaries	359,705
Allocation to goodwill arising from the	
revaluation of tangible assets as at Dec 31/01	<u>900,686</u>
	<u>1,605,886</u>

ii) Calculation of the cumulative eligible capital deduction:

Cumulative eligible capital - original cost	1,605,886
Cumulative eligible capital - deduction %	75%
Cumulative eligible capital deduction available	<u> </u>
for taxation year ended Dec 31/01	<u>1,204,415</u>

Tax year deduction 7% of net cumulative balance:

Dec 31/01	21,254
Dec 31/02	82,821
Dec 31/03	77,024
Dec 31/04	71,632
Dec 31/05	66,618
Dec 31/06	61,955
Dec 31/07	57,618
Dec 31/08	53,585

13. Ref: Exhibit 4/Tab 3/Schedule 2/Page 1

Please explain why the excess interest calculated on schedule Exhibit 4/Tab 3/Schedule 2/Page1 has not been carried forward to Exhibit 4/Tab 3/Schedule 1/Page 2. Would it change the calculation of income taxes in Test Year 2008 if the amount were carried forward? If yes, please provide a revised calculation.

Excess interest per Exhibit 4/Tab 3/Schedule 2/Page 1 was actually carried forward to Exhibit 4/Tab 3/Schedule 1/Page 2. Instead of using the excess interest net number as per Exhibit 4/Tab 3/Schedule 2/Page 1, the actual interest of is added back and the deemed interest deducted. For the 2008 Test year, actual interest of \$1,266,740 is added back and deemed interest of \$1,087,945 is deducted; the net effect being an add-back of excess interest of \$215,055. No change in calculation of income taxes for the Test year is applicable.

14. Ref: Appendix B/E 1 Exhibit 4/Tab 3/Schedule 2/Page1

a) *Please explain why interest expense shown on this schedule does not agree with interest expense shown in Appendix B/E1/T3/S2/P4 for 2007 and on E1/T3/S2/P10 for 2008.*

b) *Capital Cost Allowance (CCA) Deduction:*

i. *Appendix D/ E4/T3/S3/P3: Please explain why Class 47 was not used for additions to the distribution system.*

ii. *For 2006, 2007 and 2008 please provide the exhibit reference, or provide a summary if the evidence is missing, to support the additions amounts in E4/T3/S3/P3-5: \$3,270,475 on page 3; \$5,447,216 on page 4; and \$4,831,010 on page 5.*

iii. *Please identify the applicable years for pages 3, 4 and 5.*

iv. *Please agree the amounts shown above in (ii) to the capital budget sections: 2006 - E2/T3/S1/P1; 2007 - E2/T3/S1/P2-4; 2008 - E2/T3/S1/P5-7; and show how the additions in the tax calculations were derived.*

c) *Please provide an exhibit reference for construction work in progress. If no exhibit has been submitted, please provide a schedule showing the opening CWIP balance, plus capital expenditures for the year, minus transfers to finished plant, and the closing balance in CWIP for each of 2006, 2007 and 2008. Please disclose any interest improvement separately from the principal balances of CWIP. Please show how the amounts transferred to finished plant are the same amounts shown in the CCA calculations for each year.*

a) Interest expense per Appendix B/Exhibit 1/Tab 3/Schedule 2/Page 4 for 2007 in the amount of \$997,951 includes an offset for capitalized interest in the amount of \$25,049. Exhibit 4/Tab 3/Schedule 2/Page 1 adds the capitalized interest of \$25,049 back, giving an actual gross income tax expense of \$1,023,000.

Interest expense per Appendix B/Exhibit 1/Tab 3/Schedule 2/Page 10 for 2008 in the amount of \$1,266,740 includes an offset for capitalized interest in the amount of \$36,260. Exhibit 4/Tab 3/Schedule 2/Page 1 adds the capitalized interest back, giving an actual gross income tax expense of \$1,303,000.

b) Capital Cost Allowance (CCA) deduction:

- i. The class for distribution system adds in Appendix D/Exhibit 4/Tab 3/Schedule 3/Page 3 was entitled '49' in error. This should read '47'.
- ii. Exhibit references for 2006, 2007 and 2008 capital additions are as follows: 2006 – Exhibit 2/Tab 3/Schedule 1/Page 1;
2007 – Exhibit 2/Tab 3/Schedule 1/Page 2;
2008 – Exhibit 2/Tab 3/Schedule 1/Page 3.

These tables are amended to reconcile with the capital continuities per the attached schedules represented by Tables 8, 9 and 10. Evidence for material capital additions for each year is outlined per Exhibit 2/Tab 3/Schedule 1/Pages 1–7

Table 8 –Capital Budget by Project 2006 Actual

<u>Project Description</u>	<u>Account</u>	<u>Service Year</u>	<u>Spend Year</u>	<u>Amount</u>	<u>Reference</u>
<u>Projects in service:</u>					
Building upgrade	1808	Hist	Hist	29,799	1
Distribution station upgrade	1820	Hist	Hist	130,415	10
OH upgrade	1830	Hist	Hist	672,455	10
OH upgrade	1835	Hist	Hist	443,199	10
UG upgrade	1840	Hist	Hist	37,892	10
UG upgrade	1845	Hist	Hist	148,340	10
Tx upgrade	1850	Hist	Hist	319,504	10
Service upgrade	1855	Hist	Hist	548,053	10
Metering upgrade	1860	Hist	Hist	270,787	10
Office furniture upgrade	1915	Hist	Hist	50,915	3
Computer equipment upgrade	1920	Hist	Hist	149,217	8
Computer software upgrade	1925	Hist	Hist	204,394	6
Truck replacements	1930	Hist	Hist	52,428	5
Stores equipment upgrade	1935	Hist	Hist	2,144	4
Tool replacements	1940	Hist	Hist	50,897	2
Load control equipment upgrade	1970	Hist	Hist	612,620	9
System supervisory equipment upgrade	1980	Hist	Hist	97,487	7
Contributed capital	1995	Hist	Hist	-543,189	10
<u>Construction in progress:</u>					
Distribution station upgrade	1820	Bridge	Hist	673,208	
Computer software upgrade	1825	Bridge	Hist	20,000	
Subdivision builds	1845	Future	Hist	29,362	
Truck replacements	1930	Bridge	Hist	73,940	
				<u>796,510</u>	
Total expenditures				<u>4,073,867</u>	

Less:

Construction in progress	796,510	
Retirements - office furniture	<u>6,882</u>	3
	<u>803,392</u>	

Capitalized projects 2006	<u>3,270,475</u>

Reconciliation to tax calculation additions:

<u>Asset CCA class</u>	<u>Reference</u>	<u>Total</u>
Building & fixtures	1	29,799
Major tools	2	50,897
Office equipment	3	44,033
Stores equipment	4	2,144
Fleet	5	52,428
Computer software	6	204,394
Scada communications equipment	7	97,487
Computer hardware	8	149,217
Conservation demand equipment	9	612,620
Distribution system	10	2,027,456
		<u>3,270,475</u>

Table 9 – Capital Budget by Project 2007 Bridge

<u>Project Description</u>	<u>Account</u>	<u>Service Year</u>	<u>Spend Year</u>	<u>Amount</u>	<u>Reference</u>
<u>Projects in service:</u>					
OH upgrade	1830	Bridge	Bridge	1,248,000	5
Tx upgrade	1850	Bridge	Bridge	575,500	5
UG upgrade	1845	Bridge	Bridge	334,500	5
OH upgrade	1835	Bridge	Bridge	332,000	5
Service upgrade	1855	Bridge	Bridge	138,930	5
UG upgrade	1840	Bridge	Bridge	<u>73,000</u>	5
				2,701,930	
Distribution station upgrade	1820	Bridge	Bridge	1,020,396	5
Contributed capital	1995	Bridge	Bridge	<u>-427,135</u>	5
				<u>3,295,191</u>	

Metering upgrade	1860	Bridge	Bridge	592,000	5
Truck replacements	1930	Bridge	Bridge	230,000	2
Load control equipment upgrade	1970	Bridge	Bridge	169,520	1
Computer equipment upgrade	1920	Bridge	Bridge	141,200	4
Computer software upgrade	1925	Bridge	Bridge	101,800	3
Tool replacements	1940	Bridge	Bridge	57,000	1
Office furniture upgrade	1915	Bridge	Bridge	27,500	1
System supervisory equipment upgrade	1980	Bridge	Bridge	27,500	1

Construction in progress:

New transformer station	1815	Future	Bridge	<u>200,000</u>	

Total expenditures				<u>4,841,711</u>	

Add: Expenditures in historical year capitalized in bridge

Distribution station				673,208	5
Computer software				20,000	3
Truck				<u>73,940</u>	2
				<u>767,148</u>	

Add: Capitalized interest on construction in progress

Distribution station				33,660	5
Truck				3,697	2
Computer software				<u>1,000</u>	3
				<u>38,357</u>	

Less: Construction in progress				<u>200,000</u>	

Capitalized projects 2007				<u>5,447,216</u>	

Reconciliation to tax calculation additions:

<u>Asset CCA class</u>	<u>Reference</u>	<u>Total</u>	
Office / stores / tools	1	281,520	
Fleet	2	307,637	
Computer software	3	122,800	A
Computer hardware	4	141,200	
Distribution system	5	4,594,059	B
		<u>5,447,216</u>	

Note: \$21,000 reclassification from distribution system to computer software outstanding.

2007 Bridge CCA would increase by \$9,660 as a result of this reclassification
(10,500 additional CCA for class 12; 840 reduction for class 47)

A -computer software understated by \$21,000 in CCA class 12

B -distribution system overstated by \$21,000

Table 10 – Capital Budget by Project 2008 Test

<u>Project Description</u>	<u>Account</u>	<u>Service Year</u>	<u>Spend Year</u>	<u>Amount</u>	<u>Reference</u>
<u>Projects in service:</u>					
OH upgrade	1830	Test	Test	1,320,000	6
Tx upgrade	1850	Test	Test	590,000	6
OH upgrade	1835	Test	Test	337,000	6
UG upgrade	1845	Test	Test	337,000	6
Service upgrade	1855	Test	Test	140,500	6
UG upgrade	1840	Test	Test	84,000	6
				<u>2,808,500</u>	
Distribution station upgrade	1820	Test	Test	1,313,240	6
Land acquisition	1805	Future	Test	300,000	
Contributed capital	1995	Test	Test	-700,330	6
				<u>3,721,410</u>	
Computer equipment upgrade	1920	Test	Test	337,000	5
Building upgrade	1808	Test	Test	285,000	1
Truck replacements	1930	Test	Test	280,000	3
System supervisory equipment upgrade	1980	Test	Test	152,800	2
Metering upgrade	1860	Test	Test	139,400	6
Computer software upgrade	1925	Test	Test	83,700	4
Office furniture upgrade	1915	Test	Test	82,000	2
Tool replacements	1940	Test	Test	49,700	2
<u>Construction in progress:</u>					
New transformer station	1815	Future	Test	<u>700,000</u>	
Total expenditures				<u>5,831,010</u>	
Less:					
Construction in progress - new transformer station				700,000	
- land acquisition				<u>300,000</u>	
				<u>1,000,000</u>	
Capitalized projects 2008				<u>4,831,010</u>	

Reconciliation to tax calculation additions:

<u>Asset CCA class</u>	<u>Reference</u>	<u>Total</u>
Building	1	285,000
Office / stores / tools	2	284,500
Fleet	3	280,000
Computer software	4	83,700
Computer hardware	5	337,000
Distribution system	6	3,560,810
		4,831,010

iii. Pages 3, 4 and 5 are for years 2006, 2007 Bridge and 2008 Test respectively.

iv. Please see Tables 8, 9 and 10 above for a reconciliation of the total capital adds to the capital budget sections.

c) Construction work-in-progress – see Table 11 for the construction work in progress schedule.

Table 11 – Construction Work in Progress 2006-2008

<u>2006</u>	<u>Account</u>	<u>Service Year</u>	<u>Spend Year</u>	<u>Amount</u>
Opening				(5,695)
Distribution station upgrade	1820	Bridge	Hist	673,208
Computer software upgrade	1825	Bridge	Hist	20,000
Subdivision builds	1845	Future	Hist	29,362
Truck replacements	1930	Bridge	Hist	73,940
				790,815

2007

Opening				790,815
Capitalized interest on opening WIP				38,357
Transfer to finished plant agrees to #14 b) ii) CCA reconciliation:				
Distribution station				(673,208)
Distribution station - capitalized interest				(33,660)
Computer software				(20,000)
Computer software - capitalized interest				(3,697)
Truck replacements				(73,940)
Truck replacements - capitalized interest				(1,000)
New transformer station	1815	Future	Bridge	200,000
Capitalized interest	1815	Future	Bridge	<u>10,359</u>
				<u>210,359</u>

2008

Opening				210,359
New transformer station	1815	Future	Test	700,000
Land acquisition	1805	Future	Test	300,000
Capitalized interest				<u>36,260</u>
				<u>1,246,619</u>

RATE BASE
Capital Budget

15. Ref: Exhibit 2/Tab 3/ Schedule 1/ Page 5

Please verify the total amount of the Projects is \$5,831,010 rather than \$9,552,420 as shown. Alternatively, indicate how that amount is determined.

The amount of the projects should total \$5,831,010.

16. Ref: Exhibit 2/ Tab 3/ Schedule 2/ Page 6

For the Project described as “Expansion refunds”, and referred to as Ref A please:

- a) provide the detailed reference for the Need;**
- b) provide the economic evaluation model mentioned under “Scope”;**
- c) provide details of to whom and why refunds are due;**
- d) provide the detailed calculation leading to the amount of \$750,000; and**
- e) Indicate if this project could be deferred, and what would be the consequences of doing so.**

For the Project described as “Expansion refunds” and referred to as Ref A:

- a.) The detailed reference for the need is found in Halton Hills Hydro Inc.’s Conditions of Service which states:

“Hydro calculates the Operations, Maintenance & Amortization charges allowed by the Distribution System Code economic evaluations framework and reimburses the developer up to the level of investment that can be committed given the calculated revenue stream”

Further, the Ontario Energy Board’s Distribution System Code states:

“3.2.1 If a distributor must construct new facilities to its main distribution system or increase the capacity of existing distribution system facilities in order to be able to connect a specific customer or group of customers, the distributor shall perform an initial economic evaluation based on estimated costs and forecasted revenues, as described in Appendix B, of the expansion project to determine if the future revenue from the customer(s) will pay for the capital cost and on-going maintenance costs of the expansion project.

3.2.2 If the distributor's offer was an estimate, the distributor shall carry out a final economic evaluation once the facilities are energized. The final economic evaluation shall be based on forecasted revenues, actual costs incurred (including, but not limited to, the costs for the uncontestable work, and any transfer price paid by the distributor to the customer) and the methodology described in Appendix B.”

- b.) Attached as Appendix B is Halton Hills Hydro Inc.’s generic Economic Evaluation Model that is customized by development project.
- c.) Table 12 shows the developments in Halton Hills that are subject to the economic evaluation model.

Table 12 – Developments in Halton Hills subject to economic evaluation

Subdivision	Energized	Assumed	Lots
Arbor Valley (Arbor Glen)	2-Feb-05	2-Feb-07	179
Fernbrook Homes (Mountainview)	22-Jul-05	22-Jul-07	382
Halton Hills Village Homes (HHVH PH4 S1)	24-Jun-05	24-Jun-07	43
Halton Hills Village Homes (HHVH PH4 S2)	24-Jun-05	24-Jun-07	153
Honeyfield Phase 1	22-Jan-04	22-Jan-06	227
Southbrook Homes (Hawthorne Glen)	2-Aug-05	30-Aug-07	70
Sundale Investments (Meadowglen/Georgetown Estates)	15-Oct-03	15-Oct-05	102
Total	1,156		

Past practice indicates that “economic refunds” on a per lot basis is in the range of \$632 to \$815.

- d.) As stated above in (c), indicates Halton Hills Hydro Inc. has economic refunds due in the range of \$730,592 ($\$632 \times 1,156$) to \$942,140 ($\$815 \times 1,156$).
- e.) This project cannot be deferred. This project has been previously deferred.

17. Ref: Exhibit 2/ Tab 3/ Schedule 1/ Page 6 and Exhibit 2/ Tab 3/ Schedule 2/ Page 5

For the Project titled "Winston Churchill- 5SDRD to Steeles", ref B

- a) Please provide the economic assessment which determined that the Load Transfer customers would be more economically serviced by Halton Hills Hydro, rather than by permanent transfer to Brampton Hydro.***
- b) Please provide the details of the load growth i.e. initial and future number of customers, growth and their load requirement.***
- b) Please indicate if this project could be deferred, and what would be the consequences of doing so.***

For the Project titled "Winston Churchill- 5SDRD to Steeles", Ref B:

The driver of this project is two-fold:

- 1.) To make a permanent load transfer arrangement; and
- 2.) To facilitate a road widening project along Winston Churchill Blvd. by the Region of Peel.

Discussions concerning the best method to manage this project have been on-going with Hydro One Brampton for more than 18 months. Upon analysis, it was decided the most economical method was to share the cost of the line construction.

- a.) The driver to this project is a road widening by the Region of Peel. The need to serve load transfer customers is a side benefit to this project. The fact that neighbouring Utilities can reach a cost sharing agreement demonstrates economic due diligence. Total project costs are the same, whether a single Utility performs the work, or the costs are shared. The rates of either Halton Hills Hydro Inc. and/or Hydro One Brampton will be affected. Therefore, it is beneficial for both Utilities to split the cost so that no one set of ratepayers will be negatively affected with the entire cost of the project. Both Utilities have approximately the same number of customers affected.
- b.) Winston Churchill Blvd will be a future developing employment area mimicking the Steeles Ave area. The population of Georgetown is expected to increase by 20,000 to 60,000 people and as such, infrastructure has to come first. Further growth is expected due to a new 400 series highway cutting through the North corner of Winston Churchill Blvd. Our Municipal planners expect that this new highway will bring an increase in commercial interest to the area.
- c.) The project cannot be deferred due to the road widening aspect of the project. The project has already been designed and engineered.

18. Ref: Exhibit 2/ Tab 3/ Schedule 1/ Page 6

The explanation for the 2008 Test year developments at Cross substation (Project Ref C) is indicated on Exhibit 2/Tab 3/Schedule 2/page 6 as “new switchgear installation requirement”.

- a) Please indicate if this new switchgear is a replacement or is for the purpose of supplying new customers, and***
i. If the installation is to replace old facilities, please provide details and results of the assessment process which led to replacement; or
ii. If the installation is for new customers, please indicate number of customers, the load capability of the facilities and the expected load.
b) Please indicate if this project could be deferred, and what would be the consequences of doing so.

The explanation for the 2008 Test year developments at Cross substation (Ref C) is indicated on Exhibit 2/Tab 3/Schedule 2/page 6 as “new switchgear installation requirement”.

- a) The new switchgear is a replacement.
- i.)The switchgear is 38 years old. Most electrical equipment of this vintage has a 35-40 year life cycle, assuming proper maintenance. Recent maintenance indicates this equipment should be replaced as soon as possible so that reliability is not impacted negatively. There have been recent failures of equipment including C-F3 circuit breaker, re-closing relays, roof leaks and substation service transformer. Also, there is presently no arc flash protection with the existing gear. Should repairs be necessary, it is difficult to locate replacement parts as the parts are no longer being manufactured. New switchgear will alleviate all the above listed concerns. An analysis of the potential cost to maintain the existing switchgear versus the cost of a new replacement indicated that it is more cost effective to replace the switchgear. Reliability has, of course, also been taken into consideration.
- ii. Not applicable.
- b) This project cannot be deferred. From a risk management perspective, this switchgear is part of the Georgetown 4kV system. The substations presently must be paralleled in order to perform major maintenance on one of them. A loss of a major piece of equipment in Georgetown requiring an extended, unplanned outage, would put the 4kV system in a vulnerable position without contingency.

19. Ref: Exhibit 2/ Tab 3/ Schedule 2/ Page 6.

The explanation for the 2008 Test year developments at River substation (Project Ref D on Exh2/T3/S1/p6) is indicated as “D-AS400 (new computer network operating system)”.

- a) Please confirm that the Ref D-AS400 should in fact be Ref E and that there should be a ref D for the River Substation Transformer project.***
- b) Please provide the project details description for the River Substation new transformer.***
- c) Please indicate if the River Substation “new transformer” is a replacement of an old one, or is for the purpose of supplying new customers, and***
 - i. If the installation is to replace old facilities, please provide details and results of the assessment process which led to replacement; or***
 - ii. If the installation is to service new customers, please indicate number of customers, the load capability of the facilities and the expected load.***
- d) Please indicate if this project could be deferred, and what would be the consequences of doing so.***

The explanation for the 2008 Test year developments at River substation (Project Ref D on Exhibit 2/Tab 3/Schedule 1/Page 6) is indicated as “D-AS400 (new computer network operating system)”.

- a) Ref D should in fact be River substation transformer project and Ref E should be AS400.
- b) The project involves the replacement of the current transformer (ONAN rating 7.5 MVA) with a new 10 MVA transformer.
- c) The River substation transformer project is for the replacement of an old, existing transformer.
 - i. There are 4 major factors necessitating the need for the new transformer:
 - 1-Sound issues
 - there have been complaints about the noise emanating from the transformer
 - sound mitigation techniques have been attempted with little success
 - 2-Oil Tests
 - oil test trends indicate past minor faults have occurred within the transformer

3-Age

- this unit was manufactured in 1979 and was purchased used by Halton Hills Hydro-Electric Commission
- maintenance prior to purchase is unknown, therefore expected life cannot be estimated accurately
- River is the oldest of the 4 transformers in Georgetown

4-Risk Management

- the Georgetown transformers are the most critical to HHHI's system
- in the case of a failure, the Georgetown stations would need to be paralleled
- River currently carries the second highest load and is essential to maintain acceptable voltage levels throughout Georgetown
- there are currently no 10 MVA spares and delivery of a new transformer currently 52 weeks.

ii. Not applicable.

d) This project cannot be deferred. From a risk management perspective alone, the transformer needs to be replaced to ensure reliability of the system. In addition, the annoyance of the sound created by the existing transformer is an unacceptable customer service issue.

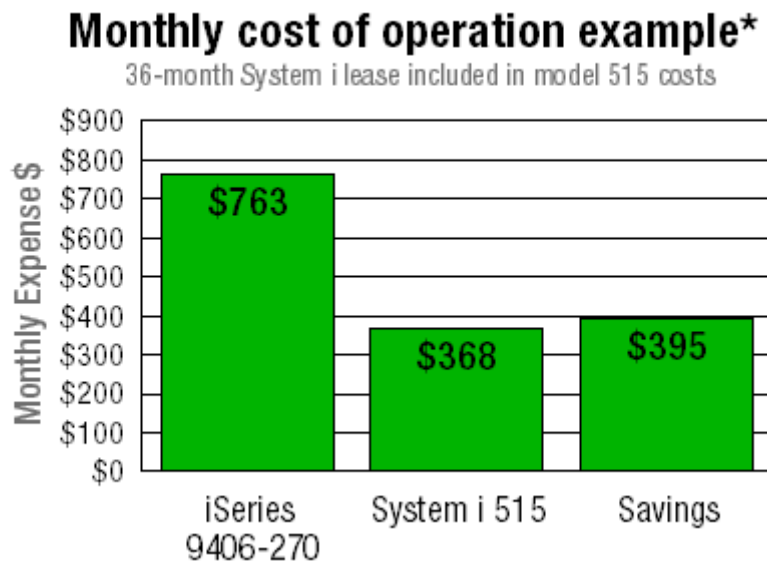
20. Ref: Exhibit 2/ Tab 3/ Schedule 1/ Page 6

Please provide:

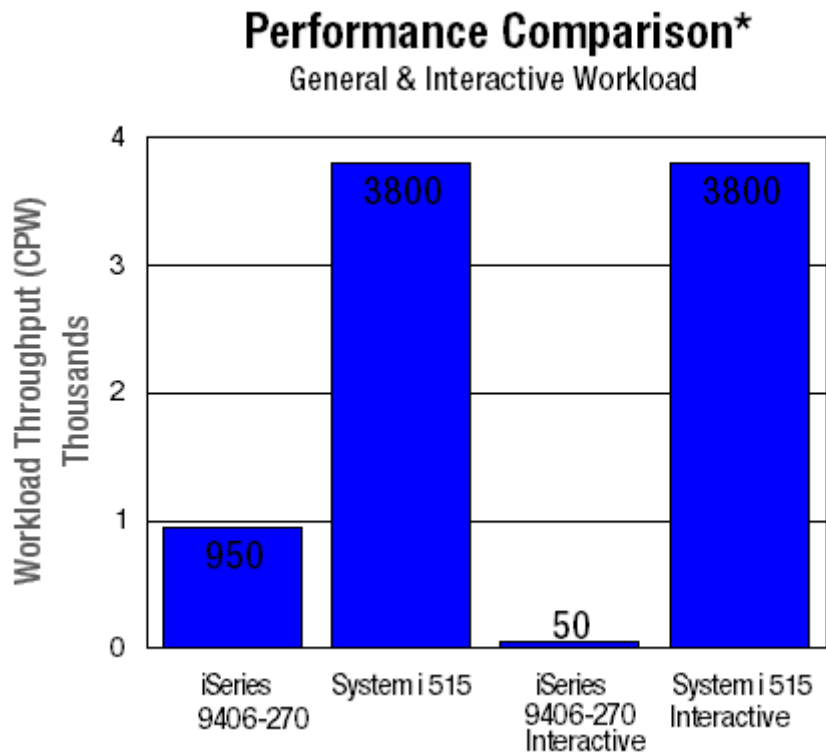
- a) a detailed description of the project referenced as project D (AS400);***
- b) a detailed explanation of the need for and scope of the project;***
- c) An economic justification for the project; and***
- d) Please indicate if this project could be deferred, and what would be the consequences of doing so.***

Project D AS400 Upgrade

Below is a cost comparison, showing our current system AS400-iSeries 270 compared with a new AS400-system i515:



The preceding graph shows a significant monthly savings over our current system.



The graph above shows a significant performance increase over our current system. This would allow for faster processing of jobs, and a quicker response time for our customer service representatives when handling customer inquiries over the telephone, thus improving customer relations.

Reasons to upgrade to a new server include:

- System i 515 will provide significantly lower software and hardware maintenance costs.
- Dramatic performance improvements over Model 270 to deliver better response times and batch processing throughput.
- New “Edition” packages cost-effectively address specific customer requirements. Model 515 Editions provide high performance and use terms and conditions tailored for Small/Medium Businesses. 515 Express editions provide low cost fully functional systems that include Hardware, Software and Support Services.
- POWER5+ 64-bit processors and other technology provide increased speed, reliability and serviceability. This can lead to enhanced “snappiness” of applications, shorter nightly “batch” run times, reduced backup times and/or less operator intervention.
- Consolidation of multiple operating systems onto a single easy to manage hardware platform. These include AIX, Linux, Windows Server 2003 (via iSCSI/IXA/IXS), and i5/OS. Support of multiple Operating Systems lets you select the best environment for each application

- Logical Partitioning (LPAR) enhancements include elimination of a “controlling partition” (hardware savings); improved functionality and system availability; and dynamic resource balancing between LPARs.
- i5/OS and the hypervisor used with the System i5 hardware provide “middleware” management assistance functions and faster speed of deployment for both traditional iSeries/AS/400 applications and other supported operating systems.
- System i and i5/OS provide “Virtualization” capabilities – Virtual Ethernet and Storage Area Network (SAN) functionality – between various partitions and Operating Systems running on the i5.
- Applications, connectivity and features not available on Model 270. These include: IP Telephony (with integration of telephony and IT functions); iSCSI connectivity (to IBM BladeCenters and System x servers), and “Smart IOA’s” that do not require IOPs (and make LPAR easier/cheaper to implement).
- The System i5 supports an ever-increasing application portfolio that now includes i5/OS, AIX, Linux, Windows, and telephony applications – and the ability to integrate within a single i5.
- This project cannot be deferred due to the age of the existing AS400 that is leading to reliability issues.

21. Ref: Exhibit 2/ Tab 3/ Schedule 1/ Page 6

Please provide:

- a) a description of the details for the project referenced as project E (Building Upgrade);***
- b) the economic justification for the project; and***
- c) Please indicate if this project could be deferred, and what would be the consequences of doing so.***

For Ref E (Building Upgrade):

- a) The building upgrade project involves the replacement of the roof systems to the offices of Halton Hills Hydro Inc., located at 43 Alice Street, Acton, ON;
- b) Halton Hills Hydro Inc. contracted a company to perform an assessment on the current roof systems. The company determined that the existing roof systems are nearing the end of their life expectancy and need replacement. The assessment described instances of leaking, vegetation growth, compromised seals and membranes and cracked flashings among other issues. The building has already experienced leaking and water damage.
- c) This project cannot be deferred based on the information listed in (b).

22. Ref: Exhibit 2/ Tab 3/ Schedule 1/ Page 7

For the “Construction in Progress” – Hornby & Trafalgar Rd. area project, please provide:

- a) a description of the projected growth in this subdivision and the load requirement; and***
- b) Please indicate if this project could be deferred, and what would be the consequences of doing so.***

For the “Construction in Progress” – Hornby & Trafalgar Rd. area project, please provide:

- a) The GTA West Supply Study found in Appendix C provides a description of projected growth and load requirement ; and
- b) This project cannot be deferred for reasons stated in the GTA West Supply Study found in Appendix C.

23. Ref: Appendix C referring to Exh2, Tab 2, Schedules 1 pages 1 through 27:

The Continuity statements do not appear to include interest during construction and all overheads. Please provide revised tables or indicate why these should not be required.

- a) Please provide the summary and continuity statements for Gross Assets by function (i.e. sustaining capital, development capital) for the Historical Actual, Bridge and Test years.***
- b) Please confirm that Halton Hills Hydro has no projects that require an application for Leave to Construct under section 92.***

The continuity statements do include interest on construction and overheads as per Appendix D.

- a) See Appendix D.
- b) Halton Hills Hydro Inc. has no projects that require an application for Leave to Construct under section 92.

RETURN ON RATE BASE

24. Refs: Exhibit 6/ Tab1/ Schedule1 and Exhibit 6/ Tab 1/ Schedule 4 –

Return on Equity

Halton Hills Hydro states that it is “requesting an 8.93% return on equity for 2008 rates”. Summary data are shown in the table “Return on Equity Calculation” at the top of page 3 of Exhibit 6/ Tab 1/ Schedule 4.

a) Please confirm if Halton Hills Hydro is seeking a fixed return of 8.93%, or is proposing that, for purposes of setting Halton Hills Hydro’s revenue requirement for the 2008 rate year, the ROE be updated using January 2008 Consensus Forecasts and Bank of Canada data when these become available, in accordance with the methodology documented in Appendix A of the Board Report on Cost of Capital and 2nd Generation Incentive Regulation Mechanism for Ontario’s electricity distributors, issued December 20, 2006 (the “Board Report”). If Halton Hills Hydro is proposing a fixed ROE of 8.93%, please provide an explanation for departing from the Board’s Cost of Capital guidelines.

b) Please provide the derivation of the proposed ROE of 8.93%, showing the calculation and the source data, including the identification of all data sources used.

a.) Halton Hills Hydro Inc. is proposing a 8.93% ROE for purposes of the application. We are not seeking to depart from the Board’s Cost of Capital guidelines. We expect the rate to be updated using January 2008 Consensus Forecasts.

b.)

Table 13 - Derivation of proposed ROE

<u>Government of Canada Bond Yields</u>	
3-month forecast of the 10-year bond yield	4.80%
12-month forecast of the 10-year bond yield	4.90%
Average actual prior month 30-year bond yield	4.20%
Average actual prior month 10-year bond yield	4.11%
Long Canada Bond Forecast (LCBF)	4.94%
Return On Equity	8.93%

Appendix E – Rates on Survey Data – 10 year Government Bond Yield – End Oct 07, End Jul 08

Bank of Canada Website

**25. Refs: Exhibit 6/ Tab1/ Schedule 2 and Exhibit 6/ Tab1/ Schedule 3 –
Capital Structure and Cost of Debt**

In Exhibit 6/ Tab1/ Schedule 2, Halton Hills Hydro includes Deposits in its capital structure for each of the 2006 historical, 2007 bridge and 2008 forward test years, with a value of \$500,000 for each year. However, under Cost of Debt shown in Exhibit6/Tab1/Schedule3, Halton Hills Hydro shows \$371,888 for TD Bank Deposits under Long-term debt and \$250,000 under Deposits categorized as Short-term Debt for each of 2006 actual and 2007 bridge years, and \$250,000 as Deposits under Short-Term Debt for the 2008 test year.

- a) Please provide further explanation on each of “TD Bank Deposits” and “Deposits” as shown in Exhibit 6/Tab 1/Schedule 3. Are these related to security deposits or to Contributed Capital/Contributions in Aid of Construction?***
- b) Please reconcile the short-term debt shown under Capital Structure (Exhibit6 /Tab1/Schedule2) and Cost of Debt (Exhibit 6/Tab 1/ Schedule 3). Provide updates to these schedules if necessary.***

- a.) The amounts shown as “TD Bank Deposits” and “Deposits” are related to security deposits.
- b.) Exhibit 6/Tab 1/Schedule 2 has been updated (Table 14). This revised schedule matches the information provided in Exhibit 6/Tab 1/Schedule 2.

**Table 14 – Capital Structure
2006 Board Approved**

Elements	Dollars (\$)	Ratio (%)	Cost Rate (%)	Return (%)
Long-term debt- Municipal	16,141,970	49.20	6.25	
Deposits	500,000	1.50	Prime-2%	
Common equity	16,161,063	49.30		9.00
Total	32,803,033			

2007 Bridge

Elements	Dollars (\$)	Ratio (%)	Cost Rate (%)	Return (%)
Long-term debt- Municipal	16,141,970	42.41	6.25	
Deposits	621,888	1.63	Prime-2%	
Common equity	21,297,057	55.96		9.00
Total	38,060,915			

2008 Test

Elements	Dollars (\$)	Ratio (%)	Cost Rate (%)	Return (%)
Long-term debt- Municipal	16,141,970	34.97	6.25	
Long-term debt- Financial Institution	7,200,000	15.60	5.78	
Deposits	621,888	1.35	Prime-2%	
Common equity	22,201,336	48.08		8.93
Total	46,165,194			

26. Refs: Exhibit 6/Tab 1/Schedule 2 and Exhibit 6/Tab1/Schedule 3 – Cost of Short Term Debt

On these two schedules the Cost Rate (%) shown for “Deposits” and “TD Bank Deposits” are listed as “Prime – 2%”.

Please identify the exact actual or forecasted rate used in these schedules and for calculating the weighted average Cost of Capital. Please identify all calculations, data used and the sources of the data.

Table 15 – Regulated Rate of Return

	<i>Deemed Portion</i>	<i>Effective Rate</i>
Cost Of Debt	49.33%	6.00%
Short-Term Debt	4.00%	6.00%
Return On Equity	46.67%	8.93%
Regulated Rate of Return	100.00%	7.45%

27. Ref: Exhibit 6/Tab1/Schedule 2 – Equity Capitalization
Halton Hills Hydro shows equity capitalization as follows:

<i>Year</i>	<i>2006 Board-approved</i>	<i>2007 bridge year</i>	<i>2008 test year</i>
<i>Common equity capitalization</i>			
<i>\$</i>	<i>16,161,063</i>	<i>21,297,057</i>	<i>22,201,336</i>
<i>% of total capitalization</i>	<i>49.30</i>	<i>56.13</i>	<i>48.21</i>

Please provide an explanation of the increase in equity capitalization from 2006 to 2007 and 2008.

Halton Hills Hydro Inc. equity capitalization table is made up of two parts:

Table 16 – Equity Capitalization Table

	2006 – Board Approved	2007	2008
Common Shares	16,161,063	16,161,063	16,161,063
Retained Earnings		5,135,994	6,040,273
Totals	16,161,063	21,297,057	22,201,336

As can be seen in Table 16, the common share equity has not increased in the years 2006-2008.

28. Ref: Exhibit 6/Tab1/Schedule 2 – Capital Structure and Weighted Average Cost of Capital

Please expand the tables in Exhibit 6/Tab1/Schedule 2 showing Halton Hill Hydro's capital structure to additionally provide 2006 actuals, in the format shown for the 2006 Board approved, 2007 bridge and 2008 test years. In these tables, please also show the weighted average cost of capital, and its derivation as the weighted average of the ROE and long- and short-term debt rates, as applicable, for each year.

**Table 17 – Capital Structure
2006 Actual**

Elements	Dollars (\$)	Ratio (%)	Cost Rate (%)	Return (%)
Long-term debt- Municipal	16,141,970	43.44	6.25%	
Deposits	621,888	1.67	Prime-2%	
Shareholders equity	20,392,778	54.88		5.72%**
Total	37,156,636			

**Return Calculated as:

2006 Net Income after tax \$1,165,491/Shareholders Equity \$20,392,778 = 5.72%

FORECAST

29. Refs: Exhibit 3/ Tab 2/ Schedule 1/ Page 1 and Exhibit 3/ Tab 2/ Schedule 2/ Page 1

In Schedule 1, page 1, the Applicant explains that it is providing normalized historical and forecast throughput data and, where required, weather-normalized throughput data for 2004. In Schedule 2, page 1, the Applicant states that it has not used “weather sensitive load in the calculation of the Load Forecast” though in the table immediately following this statement, “Normalized Consumption” data is provided.

In Schedule 1, page 1, the Applicant explains that weather-normalized throughput was generated by Hydro One for the Applicant. However, the Applicant explains that, upon review, it concluded that the Hydro One-produced weather-normalized data provided “skewed results that did not present a realistic forward scenario. For this reason we developed our Load Forecast based on actual consumption data.”

Please explain:

- a) What does the Applicant mean by “normalized” data as distinct from “weather-normalized” data?***
- b) If “normalized” data have not been the result of a weather-conversion process, what were the “base” data that existed prior to the normalization process?***
- c) What was the process used to convert the base data to normalized data?***
- d) What were the conversion values (for each year) used to convert from base data to normalized data, and what was the source(s) of these conversion values?***
- e) Why did the Applicant only, apparently, produce weather-normalized data for 2004 and not for every historical year upon which the Applicant would have relied to develop a forecast?***
- f) What does the Applicant mean by “skewed results”; is the term skewed being used in the statistical sense or in some other sense?***
- g) The characteristics of the results produced by Hydro One that caused the Applicant to disregard these results.***
- h) Since it is normal load forecasting practice to base the forecast on weather-corrected data, if the Applicant found the Hydro One results quite unacceptable, why did the Applicant not develop its own weather-corrected historical data?***
- i) What degree of confidence the Applicant has in its load forecast for a “weather-corrected” year (as the year 2008 and any future year can only be regarded) if the forecast is based on non-weather-corrected data?***
- j) What tests did the Applicant conduct to verify the reasonableness of its forecast?***

In response to this question Halton Hills Hydro submits additional information to support its 2008 Test Year Volume Forecast in Exhibit 3/Tab 2/Schedule 2/Page 2.

Weather Normalized Consumption 2004-2008

Expansion of Exhibit 3/Tab 2/Schedule 2/Tab 1

Note: Corrected for typographical errors

Table 18

	Residential	General Service less than 50 kW	General Service 50 to 999 kW	General Service 1,000 to 4,999 kW	Un- metered Scattered Load	Street Lighting	Sentinel Lighting	Total
2004 Weather Normalized Consumption	204,663,794	57,905,967	80,509,486	123,666,357	951,100	2,558,657	362,210	470,617,571
2004 # of Customers	17006	1154	153	10	141	3944	173	
Normalized consumption/customer	12,035	50,178	526,206	12,366,636	6,745	649	2,093	
2005 # of customer	17682	1533	172	10	137	4144	177	
2005 Weather Normalized consumption	212,799,318	63,497,744	96,836,585	123,666,357	979,705	2,636,269	370,585	500,786,563
2006 # of customer	18201	1482	178	12	136	4289	178	
2006 Weather Normalized consumption	219,045,379	61,385,295	100,214,605	148,399,628	972,554	2,728,513	372,679	533,118,653
2007 # of customers	18335	1550	179	12	136	4444	179	
2007 Weather Normalized consumption	220,661,725	64,201,894	100,777,608	148,399,628	972,554	2,827,119	374,772	538,211,618
2008 # of customers	18900	1600	180	12	136	4450	179	
2008 Weather Normalized consumption	227,461,500	66,272,923	101,340,612	148,399,628	972,554	2,830,936	374,772	547,649,128

Explanatory Notes:

Weather normalized consumption/customer is calculated by dividing 2004 weather normalized consumption by 2004 actual customer. The result is then multiplied by actual customer numbers for 2005 and 2006 and forecasted customer numbers for 2007 and 2008.

Weather Normalized Wholesale Consumption vs. Actual Wholesale Consumption

Table 19

	Weather Normalized Wholesale Consumption	Actual Wholesale Consumption	Difference
2004	470,617,571	468,337,202	.49%
2005	500,786,563	495,175,531	1.13%
2006	533,118,653	493,166,270	8.10%

Explanatory Notes:

As the reader can see the table above highlights the trending difference between Weather Normalized consumption compared to Actual Wholesale consumption.

Rationale for Halton Hills Hydro's Load Forecast –Exhibit 3, Tab 2, Schedule 2, Page 2 - updated

Table 20

	Residential	General Service less than 50 kW	General Service 50 to 999 kW	General Service 1,000 to 4,999 kW	Un-metered Scattered Load	Street Lighting	Sentinel Lighting	Total
2008 Weather Normalized consumption	227,461,500	66,272,923	101,340,612	148,399,628	972,554	2,830,936	374,772	547,649,128
Proposed Loss Factor 4.99%	11,350,139	3,307,019	5,056,897	7,405,141	48,531	141,264	18,701	11,350,139
2008 Revised Weather Normalized consumption	216,107,564	62,965,904	96,283,715	140,994,486	924,023	2,689,672	356,071	520,321,437
2008 Load Forecast of Halton Hills Hydro	220,790,841	58,287,111	126,131,349	94,784,230	1,018,946	2,689,946	323,275	504,025,698
Difference - %	+2.2%	-7.4%	+31%	-32.8%	+10.3	0%	-9.25	-3.1%
Billing determinant	kWh	kWh	kW	kW	kWh	kW	kW	

Explanatory Notes:

As the reader can see the table above highlights the differences between the calculated weather normalized data and Halton Hills Hydro's forecast data. The table is further highlighted by the fact that kWh billing determinant rate classes are in two cases higher than Weather Normalized consumption and one case where is lower.

In addition, the weather normalized data does not provide assistance with kW demand volumes. Halton Hills Hydro has projected in Exhibit 3, Tab 2, Schedule 2, page 2 a large kW increase from 2006 of 257,481 kW to 2007 of 306,000 kW (18.8%) and then to 2008 of 316,000 kW (3.3%) in the General Service 1,000 – 4,999 rate class.

The Load growth and customer growth forecasts come from a number of documents that culminate into the evidence filed in the Application. Those documents include:

- a. Municipal Subdivision information
- b. Ongoing residential subdivision occupancy
- c. Load projections by feeder
- d. New residential subdivision development
- e. New Commercial Subdivision development
- f. Residential/Commercial "in-fill" information

30. Ref: Exhibit3/ Tab 2/ Schedule2/ Page1

In the table in Schedule 2, page 1, the Applicant provides for each customer class and for each of the years 2004, 2005 and 2006, the Normalized Consumption and Number of customers. In a number of cases, the same data is shown (or can be calculated using the data provided) for two or more years; specifically:

- The Normalized Consumption per Customer for Residential customers for each of the years 2004, 2005 and 2006 is precisely the same (i.e. 12,035 – units not stated but assumed to be kWh);***
- The Normalized Consumption for General Service 1,000-4,999 kW Customers for each of the years 2004, 2005 and 2006 is precisely the same (i.e. 123,666,357 – assumed to be kWh);***
- The Normalized Consumption for Un-metered Scattered Load for each of the years 2005 and 2006 is precisely the same value (i.e. 979,705 – assumed to be kWh); and***
- The Normalized Consumption for Street Lighting for each of the years 2005 and 2006 is precisely the same value (i.e. 2,636,269 – assumed to be kWh).***

a) How does the Applicant explain these precise values occurring in multiple years?

b) Please re-file the table if it is determined to contain any inaccuracies.

c) Please file the table (original or corrected) but now populated with non-Normalized Consumption data.

Please see information in Question 29 for details.

31. Ref: Exhibit 3/ Tab 2/ Schedule 2/ Pages1 & 2

In pages 1 and 2, different consumption values are shown for the year 2006; i.e. “Normalized” consumption, “Historical Board Approved” consumption and “Historical Actual” consumption. In page 2, year 2007 (Bridge) and year 2008 (Forecast) values are shown together with only one year’s historical data – year 2006.

Please explain:

- a) To the extent not already explained in these Board Staff interrogatories, the relationship among the three 2006 values;***
- b) Which year’s/years’ data were used as the basis immediately preceding the determination of the Bridge and Forecast values; i.e. did the Normalized consumption for the years 2004, 5 and 6 (per page 1), the Historical Actual consumption for 2006 (per page 2), or some other data provide the data points through which the trend line was extrapolated to arrive at the 2007 and 2008 values?***

- a.) Exhibit 3/Tab 2/Schedule 2/Page 1 = Weather Normalized Wholesale
Exhibit 3/Tab 2/Schedule 2/Page 2 = Historical Board Approved –
From EDR Model, Historical Averages
Exhibit 3/Tab 2/Schedule 2/Page 2 = Historical Actual
- b.) Please see information in Question 29 for details.

32. Ref: Exhibit 3/Tab 2/ Schedule 2/ Page 3

Schedule 2, page 3, contains the heading “Halton Hills Hydro Inc.” but is otherwise blank.

Please provide the missing page of data.

Exhibit 3/Tab 2/Schedule 2/Page 3 should read “Page left intentionally blank”. There is no missing data. The final sentence of Exhibit 3/Tab 2/Schedule 2/Page 2 should read “Therefore, Halton Hills Hydro Inc. has used the load and customer forecasted numbers in the PRECEDING table”.

COST ALLOCATION AND RATE DESIGN

33. Refs: Exhibit 7/Tab 1/Schedule 1 and Exhibit 10/Tab 1/Schedule 8
a) Please reconcile the calculation of the revenue requirement in Exhibit 7, at approximately \$10.5 million, with the distribution revenue in Exhibit 10, at approximately \$11.2 million.

- a) The calculation in Exhibit 7/Tab 1/Schedule1 should read 2007 Test Volumes @2007 Rates which is approximately \$9,672,375 in Distribution Revenue plus \$960,000 in Other Operating Revenue. The purpose of this calculation was to demonstrate a Revenue deficiency exists for Halton Hills Hydro Inc..

The calculation in Exhibit 10/Tab 1/Schedule 8 is 2008 Test Volumes @ 2008 proposed Rates which is approximately \$11,162,240. The purpose of this calculation was to demonstrate the 2008 Distribution Revenue of Halton Hills Hydro Inc..

34. Ref: Exhibit 3/ Tab 1/ Schedule 2 –

- a) Please explain why “Other Distribution Revenue” decreases in the Test Year relative to previous years.***
- b) Please show how “Other Distribution Revenue” is included in the reconciliation of planned revenue and the revenue requirement in the previous Interrogatory.***

Summary of Operating Revenue Table

- c) For 2006 Board Approved no numbers are shown for Other Distribution Revenue. Please confirm that this is because no number is intended to be in this column for that item. However, if this is an oversight, please provide the appropriate amount.***
- d) Please explain the \$97,720 variance from 2006 Board Approved versus 2006 Actual for Late Payment Charges.***

- a) Other Distribution Revenue decreases – Exhibit 3/Tab 1/Schedule 2 outlines the aggregate of other distribution revenues, depicting a variance of approximately \$417,000 between 2006 actual and 2008 test year revenues.

Exhibit 3/Tab 3/Schedule 1/Page 1 details the items included in other distribution revenue.

The primary sources of the decrease in other revenues are:

- *Other Electric Revenues* – for 2006, these are wheeling and transformation charges to Hydro One Networks Inc. (HONI). For 2007 and thereafter, HONI is a metered customer. Variance = \$210,000
- *Inter-department Rents* – Rent from Electric Property – these charges represent billings for joint use pole rentals. During 2006, revenues are higher than normal due to catch-up billings that were completed in 2006. For 2007 and thereafter, \$80,000 is the expected annual amount that will be generated from joint use pole rentals. Variance = \$60,000
- *Miscellaneous Service Revenues* – miscellaneous service revenues which are projected to differ for the test year from 2006 actual represent one-time items such as inventory sales, scrap material sales, and layout fees. These one-time items are not projected to generate significant revenues for the test year. Variance = \$130,000

- b) Please refer to Interrogatory question # 33 for clarification.

Summary of Operating Revenue Table

- c) Summary of Operating Revenue Table – 2006 Board Approved Other Distribution Revenues did exclude Other Distribution Revenue in error. The Board Approved amount for Other Distribution Revenue for 2006 was \$529,115. As well, the Board Approved Specific Service Charges for 2006 should be \$319,620.
- d) Late Payment Charge variance: 2006 Actual versus 2006 Board Approved – 2006 actual late payment charges included revenues for late payment charges (\$103,371), collection charges (\$103,442) and reconnection charges (\$16,752), for a total of \$223,565. Collection and reconnection charges should have been allocated to specific service charge revenue. As a result of this reclassification, the difference between approved (\$125,845) and actual results (\$103,371) for late payment charges is \$22,474.

35. Ref: Cost Allocation Informational Filing EB -2007-0001

a) Does Run 1 or Run 2 of the Informational Filing more closely represent the customer classification in the Application? Please file it as an official part of the record in this Application.

b) Please provide a table that shows

- i. the proposed customer classes,**
- ii. the class revenue requirements in the informational filing, expressed as a percentage of the total revenue requirement,**
- iii. the proposed 2008 revenue requirement from distribution rates (ie total revenue requirement, net of revenue from specific service charges) X the percentages calculated in column ii,**
- iv. the proposed revenue at proposed rates per Exhibit 10 Tab 1 Schedule 8.**

c) Please provide a table that shows

- i. the revenue to cost ratios from the preferred version of the informational filing,**
- ii. the ratio of column d to column c in the preceding part of this interrogatory.**

a.) Halton Hills Hydro Inc. believes Run 2 more closely represents the customer classification in this Application. A copy of the Cost Allocation Run 2 filing is included as Appendix E of these interrogatory responses.

b.)

Table 21

	(1)	(2)	(3)
Proposed Customer Classes	Information Filing Class Revenue Requirements %	2008 Proposed Revenue Requirement times (1)	Exhibit 10/ Tab 1/ Schedule 8
Residential	51.8%	5,782,040	6,066,295
Residential TOU	-	-	1,122
General Service less than 50 kW	9.5%	1,060,413	1,288,536
General Service 50 kW to 999kW	20.8%	2,321,746	2,187,968
General Service 1,000 kW to 4,999kW	17%	1,897,581	1,469,242
Un-metered Scattered Load	.31%	34,603	32,212
Sentinel Lighting	.06%	6,697	10,642
Street Lighting	.53%	59,260	106,223
Total	100%	11,162,240	11,162,240

c.)
Table 22

Proposed Customer Classes	Revenue to Costs Ratios from Informational Filing	Column (3) /Column (2) from item b above
Residential	88.34%	104.9%
Residential TOU	-	-
General Service less than 50 kW	81.75%	121.5%
General Service 50 kW to 999kW	156.93%	94.2%
General Service 1,000 kW to 4,999kW	164.17%	77.4%
Un-metered Scattered Load	106.77%	93.1%
Sentinel Lighting	15.14%	158.91%
Street Lighting	36.74%	179.25%

36. Ref: Exhibit 10/ Tab 1/ Schedule 8

- a) Please provide a table that shows, for each class:**
- i. a calculation of the revenue that is proposed from applying the proposed fixed charge X the forecast number of customers,**
 - ii. a calculation of the revenue that is proposed from applying the proposed volumetric charge times the forecast volume,**
 - iii. sum of column i and column ii, verifying that it is the same as the final column in Schedule 8,**
 - iv. column i expressed as a percentage of column iii.**
- b) Please provide, in the same table or a separate table, for each class:**
- v. a calculation of the revenue that is proposed from applying the existing approved fixed charge times the forecast number of customers,**
 - vi. a calculation of the revenue that is proposed from applying the existing approved volumetric charge times the forecast volume,**
 - vii. sum of column v and column vi,**
 - viii. column v expressed as a percentage of column vii.**
- c) Please compare columns iv and viii, and provide an explanation of any large shifts or any consistent pattern that is apparent in the comparison.**

a)

Table 23

Proposed Customer Classes	Proposed Fixed Charge Revenue	Proposed Volumetric Charge Revenue	Total	%
Residential	2,921,184	3,135,230	6,066,295	48.2%
Residential TOU	229	893	1,122	20.4%
General Service less than 50 kW	540,096	746,075	1,288,536	41.9%
General Service 50 kW to 999kW	174,463	2,013,490	2,187,968	8.0%
General Service 1,000 kW to 4,999kW	26,742	1,442,508	1,469,242	1.8%
Un-metered Scattered Load	20,612	11,616	32,212	64.0%
Sentinel Lighting	4,038	6,604	10,642	37.9%
Street Lighting	53,934	52,290	106,223	50.8%

b)

Table 24

Proposed Customer Classes	Existing Fixed Charge x Forecast Customers	Existing Volumetric Charge x Forecast Volume	Total	%
Residential	2,574,180	2,539,095	5,113,275	50.3%
Residential TOU	255	900	1,155	22.1%
General Service less than 50 kW	475,008	582,871	1,057,879	44.9%
General Service 50 kW to 999kW	202,327	2,097,843	2,300,170	8.8%
General Service 1,000 kW to 4,999kW	29,840	1,358,768	1,388,608	2.1%
Un-metered Scattered Load	19,959	10,189	30,149	66.2%
Sentinel Lighting	2,534	3,987	6,522	38.9%
Street Lighting	27,768	25,838	53,606	51.8%

c)

Table 25

Proposed Customer Classes	(a) %	(b) %
Residential	48.2%	50.3%
Residential TOU	20.4%	22.1%
General Service less than 50 kW	41.9%	44.9%
General Service 50 kW to 999kW	8.0%	8.8%
General Service 1,000 kW to 4,999kW	1.8%	2.1%
Un-metered Scattered Load	64.0%	66.2%
Sentinel Lighting	37.9%	38.9%
Street Lighting	50.8%	51.8%

As you can see from the above table there are no large shifts in the comparison

REVENUE REQUIREMENT

37. Ref: Exhibit 7 Tab 1 Schedule 1 Page 1

- a) The calculation of 2008 Test Year Distribution Revenue for use in the calculation of revenue sufficiency or deficiency is the product of the 2008 forecasted billing determinants applied to the applicant's current rates. On Exhibit 7 Tab 1 Schedule 1 Page 1 the 2008 Test Year Distribution Revenue is reported as \$9,672,375. The application reference Exhibit 3 Tab 1 Schedule 2 identifies this value as the 2007 Bridge value. Please confirm the number as presented as correct or provide a corrected amended schedule.***
- b) The value used in the 2008 Test Year Other Operating Revenue (net) on Exhibit 7 Tab 1 Schedule 1 Page 1 is reported as \$960,000. The application reference Exhibit 3 Tab 1 Schedule 2 identifies this value as the 2007 Bridge value. Please confirm the number as presented as correct or provide a corrected amended schedule.***
- c) The value used in the 2008 Test Year Operation & Maintenance on Exhibit 7 Tab 1 Schedule 1 Page 1 is reported as \$5,093,000. No application cross reference is provided for this value.***
 - i. Please identify any supporting cross reference schedule in the application where this value is calculated and provide justification for the amount.. If no supporting schedule exists, please prepare a supporting schedule as required.***
 - ii. Please confirm the number as presented as correct. If value presented is incorrect please provide a corrected amended schedule.***
- d) The value used in the 2008 Test Year Depreciation on Exhibit 7 Tab 1 Schedule 1 Page 1 is reported as \$2,190,723. No application reference is provided for this value.***
 - i. Please identify any supporting schedule in the application where this value is calculated and justified. If no supporting schedule exists, please prepare a supporting schedule as required.***
 - ii. Please confirm the number as presented as correct. If the value presented is incorrect please provide a corrected amended schedule.***
- e) The value used in the 2008 Test Year Property and Capital Taxes on Exhibit 7 Tab 1 Schedule 1 Page 1 is reported as \$195,000. No application cross reference is provided for this value.***
 - i. Please identify any supporting cross reference schedule in the application where this value is calculated and justified. If no supporting schedule exists, please prepare a supporting schedule as required.***
 - ii. Please confirm the number as presented as correct. If the value presented is incorrect please provide a corrected amended schedule.***

- f) The value used in the 2008 Test Year Interest on Exhibit 7 Tab 1 Schedule 1 Page 1 is reported as \$1,266,740. No application cross reference is provided for this value.**
- i. Please identify any supporting cross reference schedule in the application where this value is calculated and justified. If no supporting schedule exists, please prepare a supporting schedule as required.**
 - ii. Please confirm the number as presented as correct. If the value presented is incorrect please provide a corrected amended schedule.**
- g) The value used in the 2008 Test Year Income Taxes on Exhibit 7 Tab 1 Schedule 1 Page 1 is reported as \$836,500. No application cross reference is provided for this value.**
- i. Please identify any supporting cross reference schedule in the application where this value is calculated and justified. If no supporting schedule exists, please prepare a supporting schedule as required.**
 - ii. Please confirm the number as presented as correct. If the value presented is incorrect please provide a corrected amended schedule.**
- h) The value used in the 2008 Test Year Utility Proposed Rate Base on Exhibit 7 Tab 1 Schedule 1 Page 1 is reported as \$37,954,174. No application cross reference is provided for this value. Rate Base is the product of two components, average net fixed assets and working capital allowance. The calculation of average net fixed assets for OEB regulatory purposes is normally the method as prescribed in the 2006 EDR Rate Handbook. The calculation of working capital allowance for OEB regulatory purposes is normally the method as prescribed in the 2006 EDR Rate Handbook. Working capital allowance is the product of two components; working capital and working capital allowance percentage (not exceeding maximum value of 15%).**
- i. Please identify any supporting cross reference schedule in the application where the value of average net fixed assets is calculated. If no supporting schedule exists, please prepare a supporting schedule as required.**
 - ii. Please confirm that the methodology used for the calculation of average net fixed assets is in compliance with the 2006 EDR Rates handbook. If an alternative methodology was applied please identify complete details of the calculation, justification supporting use of alternate methodology (including references to specific regulatory cases accepting the proposed methodology), and a detailed comparison and reconciliation to the product resulting from the application of the 2006 EDR Rate Handbook methodology.**

- iii. Please confirm the number as presented as correct. If the value presented is incorrect please provide corrected amended schedule(s).**
- iv. Please identify any supporting cross reference schedules in the application where the value of working capital allowance is calculated. If no supporting schedule exists, please prepare a supporting schedule as required.**
- v. Please confirm that the methodology used for the calculation of working capital is in compliance with the 2006 EDR Rates Handbook. If an alternative methodology was applied please identify complete details of the calculation, justification supporting use of alternate methodology (including references to specific regulatory cases accepting the proposed methodology), and a detailed comparison and reconciliation to the product resulting from application of the 2006 EDR Rate Handbook methodology.**
- vi. Please confirm the number as presented as correct. If the value presented is incorrect please provide corrected amended schedule(s).**

i) Board Staff have prepared the following table which shows the calculation of Halton Hills Revenue Requirement from Distribution Rates and Revenue Requirement from Rate Riders from the 2006 EDR. Revenue Requirement from Distribution Rates can be confirmed by applying the 2006 EDR distribution billing determinants times the Board approved May 1, 2006 distributions rates. Please note that some differences will occur due to rounding.

- a) A corrected amended schedule is shown as Appendix F.
- b) A corrected amended schedule is shown as Appendix F.
- c) The value used in the 2008 Test Year Operation & Maintenance on Exhibit 7/Tab 1/Schedule 1/Page 1 is reported as \$5,093,000. No application cross reference is provided for this value.
 - i. The supporting schedule can be found in Appendix D of the Application. The schedule can also be found in Table 26 following these responses.
 - ii. The number presented is correct.
- d) The value used in the 2008 Test Year Depreciation on Exhibit 7/Tab 1/Schedule 1/Page 1 is reported as \$2,190,723. No application reference is provided for this value.
 - i. The supporting schedule can be found in Appendix D of the Application. The schedule can also be found in Table 26 following these responses.
 - ii. The number presented is correct.

- e) The value used in the 2008 Test Year Property and Capital Taxes on Exhibit 7/Tab 1/Schedule 1/Page 1 is reported as \$195,000. No application cross reference is provided for this value.
 - i. The supporting schedule can be found in Appendix D of the Application. The schedule can also be found in Table 26 following these responses.
 - ii. The number presented is correct.
- f) The value used in the 2008 Test Year Interest on Exhibit 7/Tab 1/Schedule 1/Page 1 is reported as \$1,266,740. No application cross reference is provided for this value.
 - i. The supporting schedule can be found in Appendix D of the Application. The schedule can also be found in Table 26 following these responses.
 - ii. The number presented is correct.
- g) The value used in the 2008 Test Year Income Taxes on Exhibit 7/Tab 1/Schedule 1/Page 1 is reported as \$836,500. No application cross reference is provided for this value.
 - i. The supporting schedule can be found in Appendix D of the Application. The schedule can also be found in Table 26 following these responses.
 - ii. The number presented is correct.

Table 26 – OM&A schedule

					VARIANCES					
	2006 Board	2006	2007	2008	2006 ACTUAL FROM BOARD		2007 BRIDGE FROM 2006		2008 TEST FROM 2007	
	Approved	Actual	Bridge	Test	APPROVED	REF	ACTUAL	REF	BRIDGE	REF
Distribution Expenses - Operation										
5005-Operation Supervision and Engineering	161,630	208,732	213,000	218,000	47,102		4,268		5,000	
5012-Station Buildings and Fixtures Expense	2,329	700	1,000	1,000	(1,629)		300		-	
5016-Distribution Station Equipment - Operation Labour	15,961	25,243	25,000	28,000	9,282		(243)		3,000	
5017-Distribution Station Equipment - Operation Supplies and Expenses	5,858	4,311	4,000	4,000	(1,547)		(311)		-	
5020-Overhead Distribution Lines and Feeders - Operation Labour	58,678	89,737	90,000	100,000	31,059		263		10,000	
5045-Underground Distribution Lines & Feeders - Operation Supplies & Exp	9,916	4,635	5,000	5,000	(5,281)		365		-	
5055-Underground Distribution Transformers - Operation	44,987	68,798	61,000	69,000	23,811		(7,798)		8,000	
5065-Meter Expense	87,804	81,741	69,000	71,000	(6,063)		(12,741)		2,000	
5070-Customer Premises - Operation Labour	11,268	58,077	91,000	115,000	46,809		32,923		24,000	
5075-Customer Premises - Materials and Expenses	409	1,086	58,000	65,000	677		56,914		7,000	
5085-Miscellaneous Distribution Expense	4,634	16,906	1,000	1,000	12,272		(15,906)		-	
5050-Underground Subtransmission Feeders - Operation	91,927	140,587	97,000	107,000	48,660		(43,587)		10,000	
Distribution Expenses - Operation Total	495,401	700,553	715,000	784,000	205,152		14,447		69,000	

Distribution Expenses - Maintenance										
5105-Maintenance Supervision and Engineering	102,165	132,414	132,000	132,000	30,249		(414)		-	
5114-Maintenance of Distribution Station Equipment	109,960	101,361	141,000	159,000	(8,599)		39,639		18,000	
5120-Maintenance of Poles, Towers and Fixtures	42,329	46,911	47,000	53,000	4,582		89		6,000	
5125-Maintenance of Overhead Conductors and Devices	98,769	112,026	125,000	149,000	13,257		12,974		24,000	
5130-Maintenance of Overhead Services	56,758	73,565	74,000	82,000	16,807		435		8,000	
5135-Overhead Distribution Lines and Feeders - Right of Way	68,110	88,276	88,000	99,000	20,166		(276)		11,000	
5145-Maintenance of Underground Conduit	5,547	9,820	10,000	11,000	4,273		180		1,000	
5150-Maintenance of Underground Conductors and Devices	16,062	35,277	35,000	39,000	19,215		(277)		4,000	
5155-Maintenance of Underground Services	19,631	43,117	42,000	45,000	23,486		(1,117)		3,000	
5160-Maintenance of Line Transformers	36,627	47,482	43,000	48,000	10,855		(4,482)		5,000	
5175-Maintenance of Meters	4,621	4,303	0	0	(318)		(4,303)		-	
5165-Maintenance of Street Lighting and Signal Systems	1,593	0	4,000	4,000	(1,593)		4,000		-	
Distribution Expenses - Maintenance Total	562,172	694,552	741,000	821,000	132,380		46,448		80,000	
Billing and Collecting										
5305-Supervision	67,783	81,276	81,000	81,000	13,493		(276)		-	
5310-Meter Reading Expense	124,505	136,677	131,000	147,000	12,172		(5,677)		16,000	
5315-Customer Billing	368,547	338,442	349,000	383,000	(30,105)		10,558		34,000	
5320-Collecting	274,356	309,341	306,000	362,000	34,985		(3,341)		56,000	
5330-Collection Charges	0	1,009	0	0	1,009		(1,009)		-	
5335-Bad Debt Expense	38,593	42,000	1,000	1,000	3,407		(41,000)		-	

5325-Collecting- Cash Over and Short	0	104	55,000	65,000	104		54,896		10,000	
Billing and Collecting Total	873,784	908,849	923,000	1,039,000	35,065		14,151		116,000	
Community Relations										
5425-Miscellaneous Customer Service and Informational Expenses	0	29	0	0	29		(29)		-	
5515-Advertising Expense	0	2,216	0	0	2,216		(2,216)		-	
5415-Energy Conservation	88,690	0	2,000	2,000	(88,690)	A	2,000		-	
Community Relations Total	88,690	2,245	2,000	2,000	(86,445)		(245)		-	
Administrative and General Expenses										
5605-Executive Salaries and Expenses	492,621	492,390	503,000	522,000	(231)		10,610		19,000	
5610-Management Salaries and Expenses	203,955	206,716	237,000	390,000	2,761		30,284		153,000	A
5615-General Administrative Salaries and Expenses	390,820	499,181	503,000	604,000	108,361	B	3,819		101,000	B
5620-Office Supplies and Expenses	47,147	40,833	62,000	52,000	(6,314)		21,167		(10,000)	
5630-Outside Services Employed	156,855	115,923	92,000	103,000	(40,932)		(23,923)		11,000	
5635-Property Insurance	32,680	43,192	49,000	51,000	10,512		5,808		2,000	
5640-Injuries and Damages	40,764	37,596	46,000	63,000	(3,168)		8,404		17,000	
5645-Employee Pensions and Benefits	61,918	25,736	19,000	21,000	(36,182)		(6,736)		2,000	
5655-Regulatory Expenses	74,628	66,168	87,000	68,000	(8,460)		20,832		(19,000)	
5660-General Advertising Expenses	1,557	8,053	8,000	2,000	6,496		(53)		(6,000)	
5665-Miscellaneous General Expenses	671,304	70,972	74,000	75,000	(600,332)	C	3,028		1,000	
5675-Maintenance of General Plant	420,347	481,999	490,000	496,000	61,652		8,001		6,000	
Administrative and General Expenses Total	2,594,596	2,088,759	2,170,000	2,447,000	(505,837)		81,241		277,000	

Amortization Expense										
5705-Amortization Expense - Property, Plant, and Equipment	1,833,134	1,917,005	2,116,165	2,177,519	83,871	D	199,160	A	61,354	
5715-Amortization of Intangibles and Other Electric Plant	13,204	13,204	13,204	13,204	-		-		-	
Amortization Expense Total	1,846,338	1,930,209	2,129,369	2,190,723	83,871		199,160		61,354	
Power Supply Expenses										
4705-Power Purchased	23,050,889	27,767,404	28,455,000	29,388,000	4,716,515	E	687,596	B	933,000	C
4708-Charges-WMS	2,878,234	2,501,240	2,563,000	2,647,000	(376,994)	E	61,760	B	84,000	C
4714-Charges-NW	2,539,613	2,651,515	2,717,000	2,806,000	111,902	E	65,485	B	89,000	C
4716-Charges-CN	2,215,067	2,210,183	2,265,000	2,339,000	(4,884)	E	54,817	B	74,000	C
4750-Charges-LV	0	409,163	636,500	660,000	409,163	F	227,337	C	23,500	
Power Supply Expenses Total	30,683,803	35,539,505	36,636,500	37,840,000	4,855,702		1,096,995		1,203,500	
Taxes Other Than Income Taxes										
6105-Taxes Other Than Income Taxes	71,132	189,020	190,000	195,000	117,888	G	980		5,000	
Taxes Other Than Income Taxes Total	71,132	189,020	190,000	195,000	117,888		980		5,000	
Extraordinary & Other Items										
6205-Donations	0	2,901	20,000	33,000	2,901		17,099		13,000	
Extraordinary & Other Items Total	0	2,901	20,000	33,000	2,901		17,099		13,000	

Income Taxes										
6110-Income Taxes	502,007	731,486	980,000	836,500	229,479	H	248,514	D	(143,500)	D
Income Taxes Total	502,007	731,486	1,181,000	836,500	229,479		449,514		(344,500)	
Total Operating Costs	37,717,923	42,788,079	44,707,869	46,188,223	5,070,156		1,919,790		1,480,354	

- h)
- i. The supporting schedule can be found in Exhibit 2/Tab 1/Schedule 2/Page 1 of the Application.
 - ii. The methodology used for the calculation is compliant with the 2006 EDR Rates handbook.
 - iii. The number presented is correct.
 - iv. The supporting schedule can be found in Appendix C of the Application.
 - v. The methodology used for the calculation is compliant with the 2006 EDR Rates handbook.
 - vi. The number presented is correct.

i)

Revenue Requirement - 2006 OEB Approved

2006 EDR Model				2006 OEB Approved
	Worksheet	Cell		
Net Fixed Assets	3-1 RATE BASE	F12	\$ 24,244,338	A
Working Capital Allowance Base			\$35,309,680	B
Working Capital Allowance	3-1 RATE BASE	F16	15%	C
			\$ 5,296,452	D
Rate Base	3-1 RATE BASE	F21	\$ 29,540,790	E
Interest			3.13%	
Return on Equity			4.50%	
	5-1 SERVICE REVENUE REQUIREMENT	F15	7.63%	F
			\$ 2,252,486	G
OM&A			\$ 3,923,445	H
Amortization			\$ 1,846,338	I
Low Voltage			\$ 613,744	J
Incremental CDM	5-1 SERVICE REVENUE REQUIREMENT	F17	\$ 88,690	K
PILs	5-1 SERVICE REVENUE REQUIREMENT	F21		
Transformer Allowance	6-3 Trfmr Ownership (Input)	R120		
			\$ 938,649	M
			\$ 165,383	N
Revenue Offsets				
Specific Service Charges			-\$ 319,620	O
Late Payment Charges			-\$ 125,845	P
Other Distribution Income			-\$ 192,783	Q
Other Income and Deductions	5-5 BASE REVENUE REQUIREMENT	F25	-\$ 336,332	R
			-\$ 974,580	S
Smart Meters			\$ 136,800	T
Revenue Requirement from Distribution Rates			\$ 8,990,955	U
Regulatory Assets	Reg Asset Model 2: Rate Riders Calculation	C53	\$ 1,663,845	V
LRAM & SSM			\$ -	W
Revenue Requirement from Rate Riders			\$ 1,663,845	X
Revenue Requirement from Distribution Rates			N/A	
2008 Forecast Billing Determinants Time Current Rates			N/A	
Revenue Sufficiency/Deficiency			N/A	

- i. Halton Hills Hydro Inc. agrees with the values in the table above.
- ii. See Table 27.

Table 27 – Revenue Sufficiency/Deficiency Calculation 2008 Test Year

		\$	<u>Reference</u>
Net fixed assets		31,484,974	Exhibit 2 / Tab 1 / Schedule 1 / Page 1
Working capital allowance base	43,128,000		
Working capital allowance	<u>15%</u>	<u>6,469,200</u>	Exhibit C - Exhibit 2 / Tab 4 / Schedule 1 / Page 3
Rate base		<u>37,954,174</u>	
Interest	3.274%	1,242,620	
Return on equity	<u>4.177%</u>	<u>1,585,346</u>	
	<u>7.451%</u>	<u>2,827,966</u>	
OM&A	5,288,000		Exhibit 4 / Tab 2 / Schedule 2 / Page 1
Amortization	2,190,723		Exhibit 4 / Tab 2 / Schedule 2 / Page 1
Low voltage	660,000		Interrogatory response Question 8
Incremental CDM	<u>-</u>	<u>8,138,723</u>	
PILS			
Income taxes	771,049		Exhibit 4 / Tab 3 / Schedule 1 / Page 2
Gross-up rate (1 - tax rate = 34.5%)	<u>0.655</u>		
	<u>1,177,174</u>		
Capital taxes	<u>65,419</u>	<u>1,242,593</u>	Exhibit 4 / Tab 3 / Schedule 1 / Page 3

Transformer allowance	183,000	Exhibit 10 / Tab 1 / Schedule 7 / Page 5
Revenue offsets	(1,103,000)	Exhibit 3 / Tab 3 / Schedule 1 / Page 1
Smart meters	-	
Revenue requirement from distribution rates	<u>11,289,282</u>	
Deferral and variance accounts	479,301	Exhibit 5 / Tab 1 / Schedule 3 / Page 1
LRAM & SSM	42,304	Exhibit 9 / Tab 1 / Schedule 5 / Page 1
Revenue requirement from rate riders	<u>521,605</u>	
Revenue requirement from distribution rates	11,289,282	
2008 forecast billing determinants time current rates	<u>9,951,365</u>	
Revenue Sufficiency / Deficiency	<u>1,337,917</u>	

Note: transformer allowance and low voltage amounts were excluded from the revenue requirement stated in Exhibit 1/Tab 2/Schedule 1/ Page 1 as follows:

	\$
Revenue requirement – E1/T2/S1/P1	10,446,283
Low voltage	660,000
Transformer allowance	<u>183,000</u>
Total revenue requirement	<u><u>11,289,283</u></u>

- iii. Comparison of 2006 Board approved with 2008 Test year application and 2006 actual compared to 2006 Board approved for each of the following per the included references:
- I) Net fixed assets – materiality analysis per Exhibit 2/Tab 2/Schedule 3/Page 1 and capital project review per Exhibit 2/Tab 3/Schedule 1/Pages 1 – 7
 - II) Working capital allowance – review of 2006 Board approved, 2006 actual, 2007 bridge and 2008 test per Appendix C – Exhibit 2 / Tab 4 / Schedule 1 / Pages 1 – 9
 - III) Rate base – variance analysis per Exhibit 2/Tab 1/Schedule 3/Page 1
 - IV) Interest and return on equity – discussed per Exhibit 6.
 - V) OM&A / amortization / PILs – materiality analysis per Exhibit 4/Tab 2/Schedule 2/Page 1 and discussion of detailed costs table per Appendix D.
- iv. Comparison of Revenue Sufficiency or Deficiency values per Exhibit 7/Tab 1 Schedule 1/Page 1 to recalculation above:

The main difference between the calculation for Revenue Sufficiency or Deficiency values per Exhibit 7/Tab 1/Schedule 1/Page 1 and the recalculation pertains to the calculation of revenues. Exhibit 7/Tab 1/Schedule 1/Page 1 calculated revenues based on 2007 rates and 2007 volumes, whereas the recalculation determines revenues based on 2007 rates with 2008 volumes. The difference between these two values is approximately \$279,000.

REVENUE OFFSETS

38. Ref: Exhibit 3/ Tab 3/ Schedule 1

For 2006 Board Approved no numbers are shown for:

***Retail Services Revenues
Service Transaction Requests (STR) Revenues
Rent from Electric Property
Miscellaneous Service Revenues
Provision for Rate Refunds Interest***

Please confirm that it is because no numbers are intended to be in this column for these items and explain why no amounts were included. If this is an oversight, please provide the appropriate amounts.

- a) It is shown that the Rent from Electric property decreases significantly in 2008 Test to \$80,000 from the 2006 Actual level of \$140,157. Please provide an explanation of this change.***
- b) For 2007 Bridge and 2008 Test, no numbers are shown for Other Distribution Revenue – Other Electric Revenues, please confirm that it is because no number is intended to be in the two columns for that item and provide an explanation. If this is an oversight, please provide the appropriate amounts.***
- c) Please explain the drop in Miscellaneous Service Revenue in 2008 Test to \$60,000 from the 2006 Actual level of \$199,593. Please provide an explanation of this decrease.***

Halton Hills Hydro Inc. confirms that certain items were omitted in the Other Distribution Revenue schedule per Exhibit 3/Tab 3/Schedule 1/Page 1 for 2006 Board Approved. The revised column for 2006 Board Approved should be as follows:

<u>Other Distribution Revenue</u>	\$
Retail Service Revenues	29,274
Service Transaction Revenues	281
Rent from Electric Property	135,873
Other Utility Operating Income	319,620
Other Electric Revenues	27,355
Late Payment Charges	125,845
Miscellaneous Service Revenues	35,379
Provision for Rate Refunds Interest	<u>300,953</u>
Total	<u>974,580</u>

- a) Rent from Electric property decreases significantly from 2006 Actual to 2008 Test as 2006 Actual included true-ups for prior year's billing. Ongoing fees generated from Rent from Electric property on an annual basis are expected to approximate \$80,000 as included in the 2007 Bridge and 2008 Test years.
- b) For 2007 Bridge and 2008 Test, no numbers are intended to be included for Other Electric Revenues. For 2006, these charges represent wheeling and transformation charges to Hydro One Networks Inc. (HONI). For 2007 and thereafter, HONI is a metered customer.
- c) Miscellaneous Service Revenues – miscellaneous service for 2006 actual represent one-time items including inventory sales, scrap material sales, and layout fees. These one-time items are not projected to generate significant revenues for either the bridge or test years, generating a decrease in Miscellaneous Service Revenues of approximately \$130,000.

CDM**39. Ref: Exhibit 9/Tab1/Schedules1-5**

In the Board's "Filing Requirements for Transmission and Distribution Applications" issued on November 14, 2006, it outlines on page 39 the information that is required when filing an application for LRAM or SSM. Please provide the following:

a) kW or kWh impacts net of free riders for each program and each rate class;

b) Verification of participation levels; and

c) Duration of the programs in years and months.

a.)

Table 28 - CDM Load Impacts by Program and Class – Net of Free Riders

Rate Classification	Water Heater Load Control	Lighting	Capacitor Installation	Equipment Replacement
Residential	102,897 kWh			
General Service Less than 50 kW		63,179 kWh	142,600 kWh	379,749 kWh

b.) We do not have any independent verification of our CDM programs, however we submit the following program participation information:

Table 29 - CDM Participation Levels by Program and Class

Rate Classification	Water Heater Load Control Participation	Lighting	Capacitor Installation	Equipment Replacement
Residential	132 Customer			
General Service less than 50 kW		1 Customer	1 Customer	1 Customer

c.)

Table 30 - CDM Duration Levels by Program and Class

Rate Classification	Water Heater Load Control Participation	Lighting	Capacitor Installation	Equipment Replacement
Residential	12 Years			
General Service Less than 50 kW		5 Years	10 Years	20 Years

40. Ref: Exhibit 9/Tab1/Schedules1-5

Please identify any residential, commercial, or industrial program(s) where load impacts were not calculated using the measure-specific values in the Board's TRC Guide. For any program that did not use the measure-specific values in the TRC Guide, please provide the supporting documentation on how these load impacts were calculated.

The Capacitor Installation did not use the specific values in the TRC guide. HHHI calculated the Load impact as follows:

Projected Annual Savings = 11.19%
Guaranteed Annual Savings = 9.53%
Assumed 10% Annual Savings for TRC

Savings were determined using the base year actual costs of \$0.095/kWh escalated by 2% per year for 10 years (projected life of the equipment). Annual usage in the base year was 1,426,000 kWh. (Base year = Nov 2004 to Oct 2005, inclusive.)

Free rider rate was assumed to be 0% based on the requirement to sell this project on a cost/benefit basis including the HHHI incentive.

41. Ref: Exhibit 9/Tab1/Schedule 3

The evidence states that “in accordance with the Board’s Decision in EB-2007-0096, Halton Hills Hydro Inc. has not reduced the calculated load reduction for free ridership.” Please explain why Halton Hills Hydro Inc. finds it appropriate not to adjust LRAM amounts for free riders, given that the Board confirmed its position in the Decision and Order, issued September 11, 2007, in EB-2007-0096, that free riders must be included in the calculation of the LRAM.

Halton Hills Hydro Inc. filed its application on August 15, 2007 prior to the Ontario Energy Board confirming its position dated September 11, 2007. However, Halton Hills Hydro has recalculated LRAM to include the Board’s LRAM position.

Table 31

Residential - LRAM	kWh	Rate	LRAM
2005	50,625	\$.0113	\$572
2006	52,272	\$.0113	\$591
Total	102,897		\$1,163

General Service <50 kW - LRAM	kWh	Rate	LRAM
2005	142,600	\$.0093	\$1,326
2006	442,928	\$.0124	\$5,492
Total	585,528		\$6,818

42. Ref: Exhibit 9/Tab1/Schedule 2

Halton Hills Hydro Inc. has stated that “the SSM amount included for recovery in this rate application is calculated by grossing up the after tax amount of \$21,453 by the marginal tax rate of 36.12% to calculate a pre-tax amount for recovery of \$33,583. This is consistent with the Board’s Decision in EB-2007-0096.

- a) Please explain why Halton Hills finds it appropriate to gross-up the SSM amount for taxes, given that the Board confirmed its position in the Decision and Order, issued September 11, 2007, in EB-2007-0096, that it was not appropriate to do so.***
- b) Please confirm whether SSM amounts have been adjusted for free riders.***
- c) Please provide the calculations and inputs and assumptions that were used to determine the SSM and LRAM amounts.***

- a.) Halton Hills Hydro Inc. filed its application on August 15, 2007 prior to the Ontario Energy Board confirming its position dated September 11, 2007. However, Halton Hills Hydro Inc. has recalculated SSM to include the Board’s SSM position.

Table 32 – SSM recalculation

Residential - SSM	TRC	TRC Rate	SSM
2005	12,034	5%	\$602
2006	93,993	5%	\$4,700
Total			\$5,302

General Service <50 kW - SSM	TRC	TRC Rate	SSM
2005	48,609	5%	\$2,430
2006	274,436	5%	\$13,722
Total			\$16,152

b.) Table 32 above has been adjusted for free riders. The recalculated impacts are:

Table 33

Rate Class	Amounts (2005 + 2006)		Billing Units (2006)		Rate Riders		
	LRAM	SSM			LRAM	SSM	Total
	\$	\$			\$/unit (kWh or kW)	\$/unit (kWh or kW)	\$/unit (kWh or kW)
Residential	\$ 1,163	\$ 5,302	208,116,543	kWh	0.00000	.00003	.00003
General Service less than 50 kW	\$ 6,818	\$ 16,152	54,412,911	kWh	0.00013	.00030	.00043
Total	\$ 7,981	\$ 21,454					

c.) The original application was filed with these calculations:

Table 34 - LRAM

Residential - LRAM	kWh	Rate	LRAM
2005	56,250	\$.0113	\$636
2006	58,080	\$.0113	\$656
Total	114,330		\$1,292

General Service <50 kW - LRAM	kWh	Rate	LRAM
2005	142,600	\$.0093	\$1,326
2006	492,142	\$.1240	\$6,103
Total	634,742		\$7,429

Table 35 - SSM

Residential - SSM	TRC	TRC Rate	SSM
2005	12,034	5%	\$602
2006	93,993	5%	\$4,700
Total			\$5,302
PILS Gross-up			2,997
			\$8,299

General Service <50 kW - SSM	TRC	TRC Rate	SSM
2005	48,609	5%	\$2,430
2006	274,436	5%	\$13,722
Total			\$16,152
PILS Gross-up			9,133
			\$25,285

43. Ref: Exhibit 9/Tab 1/Schedule 2

Halton Hills Hydro Inc. has stated that “certain CDM programs were jointly sponsored with other regulated distributors and in these cases Halton Hills Hydro Inc. apportioned the savings in accordance with the TRC Guide and the Board’s EB-2005-0523 Decision.”

- a) Please confirm which programs were jointly sponsored with other regulated distributors.***
 - b) Please confirm that there has not been any double counting of TRC benefits in any program that was jointly sponsored.***
 - c) Please confirm what percentage of the electricity savings Halton Hills is claiming.***
 - d) Please confirm whether and how Halton Hills Hydro Inc. has met the test of centrality established by the Board in RP-2005-0020/EB-2005-0523, and set out in the Board’s TRC Guide.***
-
- a.) Halton Hills Hydro Inc. jointly sponsored an energy savings school initiative in Halton Region and participated in a variety of coupon programs. None of the programs for which LRAM or SSM was requested were jointly sponsored.
 - b.) Halton Hills Hydro Inc. confirms there has been no double counting of TRC benefits.
 - c.) As stated in (a) above Halton Hills Hydro Inc. has not included any jointly sponsored programs in the application.
 - d.) Please refer to (a) above.

44. Ref: Exhibit 9/Tab1/Schedules 2 & 4

On Schedule 1 it states that Halton Hills Hydro Inc. is proposing a one year recovery period effective until April 30, 2009. However, on Schedule 4 it states that the recovery period would be effective May 1, 2008 for a period of three years ending April 30, 2011.

a) Please verify whether the proposed recovery period is one year or three years.

Halton Hills Hydro Inc. is requesting a one year recovery of LRAM and SSM amounts.

45. Ref: Exhibit 9/Tab1/Schedule 4

Halton Hills Hydro Inc. states that “In accordance with the Guidelines for applying for SSM incentive, Halton Hills Hydro is only making application for customer focused initiatives that reduce the demand for electricity.” However, SSM amounts are provided for a “Capacitor Installation” program and “Equipment Replacement” program, which appear to be utility-side programs.

a) Please clarify the nature of the Capacitor Installation” and “Equipment Replacement” programs.

b) Please confirm that Halton Hills Hydro Inc. is not claiming SSM amounts for utility-side programs.

a) *Capacitor Installation* -At the Mold-Masters SportsPlex, in Georgetown. Capacitors were installed on certain key operating motors in order to increase the power factor of the equipment.

Equipment Replacement – At Halton Hills Hydro Inc. and inefficient electric boiler was replaced with a new gas fired high efficiency boiler.

b) Halton Hills Hydro Inc. is claiming SSM amounts on utility side programs.

SMART METERS

Halton Hills Hydro Inc. is not one of the thirteen licensed distributors authorized by Ontario Regulation 427/06 to conduct discretionary metering activities with respect to smart meters. In its decision on Halton Hills Hydro Inc.'s 2007 IRM application (EB-2007-0536), the Board confirmed its understanding that Halton Hills Hydro Inc. would not be undertaking any smart metering activity (i.e. discretionary metering activity) in 2007.

46. Ref: Exhibit 1 /Tab 1 /Schedule 6 /Page 1: DRAFT ISSUES LIST

Under "Draft Issues List", Halton Hills Hydro Inc. states: "In the rate application, Halton Hills Hydro Inc. has not included any costs related to Smart Metering. In decision EB-2007-0536 dated April 12, 2007, Halton Hills Hydro Inc. applied for \$1.18 to embark on its Smart Metering Plan filed with the Ontario Energy Board December 15, 2006. However, the Ontario Energy Board only approved \$0.26 due to Regulation 153/07. At the present time, it is unclear how Smart Metering costs will be recovered and therefore we request to be included in any provincial mandate of Smart Metering Costs recovery."

Please:

- a) Confirm if any costs have been incurred by Halton Hills Hydro Inc. with respect to Smart Metering until the date of the filing of this application; if so, please provide:**
 - i. An itemized cost breakdown; and**
 - ii. Associated number of smart meter installations.**

- b) Confirm if Halton Hills Hydro Inc. is applying for Smart Metering cost recovery for Bridge Year 2007 and Test Year 2008; if so, please provide:**
 - i. The reasons for the inclusion of Smart Metering costs in this application, although Halton Hills Hydro Inc. is not one of the thirteen licensed distributors authorized by Ontario Regulation 427/06 to conduct discretionary metering activities with respect to smart meters;**
 - ii. An itemized cost breakdown; and**
 - iii. Associated number of smart meter installations for Bridge Year 2007 and Test Year 2008.**

- c) Confirm if, in Test Year 2008, Halton Hills Hydro Inc. is going to maintain its current rate adder which was approved by the Board in the April 12, 2007 Decision and Order (EB-2007-0536). If not,:**
- i. What is the Smart Meter Rate Adder Halton Hills is intending to implement in Test Year 2008?**
 - ii. Please provide justification for the amount of this Smart Meter Rate Adder.**
- a) Halton Hills Hydro Inc. has incurred approximately \$40,000 in Smart Metering Costs.
- i) The costs were expended as follows:
 - Request For Proposal Costs - \$31,850
 - Preparation
 - Demonstrations
 - Evaluations
 - Field Demonstrations
 - Communications Study - \$8,150
 - ii) No Smart Meters have been installed
- b) Halton Hills Hydro Inc. is not applying for Smart Meter cost recovery in this application.
- c) Halton Hills Hydro Inc. does not confirm the use of the current rate rider approved by the Board April 12, 2007 (EB-2007-0536).
- i. Halton Hills Hydro Inc. applies for a rate rider of \$1.18/customer/month.
 - ii. On December 15, 2006 Halton Hills Hydro Inc. filed its Smart Meter Investment Plan (Appendix G) with the Board. Halton Hills Hydro Inc. is of the opinion that the Plan is still valid and justifies the rate rider of \$1.18 /customer/month.

DEFERRAL ACCOUNTS

47. Ref: Exhibit1/Tab3/Schedule 2/Page1

Included in your hard copy filing are your 2007 and 2008 pro-forma income statement and balance sheet. Only 2007 pro-forma balance is included in your electronic filing. Please update your electronic filing to include your 2007 and 2008 pro-forma income statement and balance sheet.

An updated electronic filing has been submitted and includes the 2007 and 2008 pro-forma income statement and balance sheet.

48. Ref: Exhibit 5/Tab1/Schedule 2/Page 1

Please provide a brief description, describing the component entries, of all outstanding deferral and variance accounts outlined on Exhibit 5, Tab 1, Schedule 2, Page 1.

Component entries of deferral and variance accounts outlined in Exhibit 5/Tab 1/ Schedule 2/Page 1 follow the guidelines set out in the Accounting Procedures Handbook and Uniform System of Accounts (revised July 31, 2007):

- i. 1588 – Retail Settlement Variance Account – Power – component entries include cost of power charges from the Independent Electricity System Operator (IESO), Hydro One Networks (HONI) and load transfers from neighbouring utilities, net of customer billings, plus carrying charges.
- ii. 1518 – Retail Cost Variance Account – Retail – component entries include retailer service agreement, variable, bill ready and fixed charges net of marginal costs of providing these services to retailers.
- iii. 1548 – Retail Cost Variance Account – STR – component entries include EBT / STR charges to retailers net of marginal costs of providing these services to retailers.
- iv. 1580 – Wholesale Market Service Charges – component entries include wholesale market service charges collected from customers net of wholesale market charges from the IESO and HONI, plus carrying charges.
- v. 1582 – One-Time Market Service Charges – component entries include one-time market service charges charged from the IESO and HONI, plus carrying charges.
- vi. 1584 – Retail Transmission Network Charges – component entries include transmission network charges collected from customers net of transmission network charges from the IESO and HONI, plus carrying charges.
- vii. 1586 – Retail Transmission Connection Charges – component entries include transmission connection charges collected from customers net of transmission connection charges from the IESO and HONI, plus carrying charges.
- viii. 1508 – Other Regulatory Assets – component entries include costs for OEB cost assessments and OMERS pension deferral amounts in accordance with questions 10 and 11 respectively from the OEB Accounting Procedures Handbook FAQ's December 2005, plus carrying charges.

- ix. 1525 – Miscellaneous Deferred Debits – component entries include the cost of issuing refund cheques/credits to electricity consumers in accordance with government legislation, regulations or Board requirements: Phase 1 (2002), Phase 2 (2003), and Ontario Price Credit rebates (2005).
- x. 1550 – LV Variance – component entry includes the net of low voltage charges billed from HONI and low voltage charges billed to customers, plus carrying charges.
- xi. 1562 – Deferred Payments in Lieu of Taxes – this account includes the difference between actual PILs / income taxes collected and the approved proxy for the years 2001 – 2006 to Dec 31/06 in this account. PILs variance costs subsequent to April 30, 2007 were also recorded in account 1562.
- xii. 1570 – Qualifying Transition Costs – this account records transition costs which meet the four qualifying criteria established in the 2000 Electricity Distribution Rate Handbook, plus carrying charges. Approved recoveries exceeded actual expenditures. As a result, a small non-material credit balance exists in this account.
- xiii. 1571 – Pre-Market Energy Variances – this account includes the difference between purchased cost of power for time-of-use and the amounts billed to non-time-of-use customers subsequent to January 1, 2001 and market opening, plus carrying charges. This account is in a small credit balance due to a back-billed customer.

49. Ref: Exhibit 5/Tab1/Schedule 2/Page 1

- (a) Are you currently using account 1590?**
- (b) If not, why?**
- (c) If so, have you transferred previous Board-approved amounts for regulatory asset recovery to 1590?**
- (d) Please update Exhibit 5, Tab 1, Schedule 2, Page1 and Exhibit 5, Tab 1, Schedule 3, Page1 to reflect the appropriate transfers and include account 1590.**
- (e) If transfers of Board-approved amounts for regulatory asset recovery to 1590 have occurred, why is Halton Hills applying for disposition of accounts 1570 and 1571?**

- a) Account 1590 – Halton Hills Hydro Inc. is using account 1590.
- b) Not applicable.
- c) Previous Board-approved amounts – these have previously been transferred to account 1590.
- d) Account 1590 update – please refer to Table 36 for updates to Exhibit 5/Tab 1/Schedule 2/Page 1 and Exhibit 5/Tab 1/Schedule 3/Page 1.
- e) Disposition of 1570 and 1571 – Halton Hills Hydro Inc. has over-recovered these accounts and is proposing to settle the over-recovery.

Table 36 – Regulatory Asset Recovery Account 1590 - Continuity

i) Update to Exhibit 5 / Tab 1 / Schedule 2 /

Page 1

Calculation of balances by account

	Opening December 31, 2006 Balance	Carrying Costs	Accruals	Ending April 30, 2008 Balance
1590 Recovery of regulatory asset balances	2,388,821	77,203	(2,335,514)	130,510
Totals	3,264,633	89,533	(1,783,961)	1,570,205

ii) Update to Exhibit 5 / Tab 1 / Schedule 3 /

Page 1

	Ending April 30, 2008 Balance	Allocation Basis	Residential	GS<50kW	GS 50- 999	GS1000- 4999	UMSL	Sentinel	Street Light	Res TOU	Total
1590 Recovery of regulatory asset balances	130,510	kWh	67,596	15,990	16,314	29,568	144	153	745	23	130,533
Total	1,570,214		712,193	174,739	369,921	301,579	2,587	531	8,463	224	1,570,237
Disposal period - 3 years			237,398	58,246	123,307	100,526	862	177	2,821	75	523,412
Projected 2008 rate riders			0.0011	0.001	0.2716	0.3181	0.0008	0.2214	0.3761	0	

50. Ref: Exhibit 5/Tab1/Schedule 2/Page1

Halton Hills is applying for disposition of regulatory variance accounts as per schedule Exhibit 5/Tab1/Schedule 2. These totals do not correspond to totals reported to the Board as per 2.1.1 of the Reporting and Record Keeping Requirements for the period ending December 31st, 2006 plus interest accrued on those balances to April 30th 2008. Please provide the information as shown in the attached continuity schedule for regulatory assets and provide a further schedule reconciling the continuity schedule with the amounts requested for disposition.

Please see Regulatory Asset Continuity Schedule (Appendix H).

Note that the December 31, 2006 totals are per the year-end trial balance filing, not the Reporting and Record Keeping Requirements (RRR) 2.1.1. The RRR filing does not include a number of accruals and year-end entries; these items are not available until subsequent to the RRR filing due date.

Table 37 – Deferral and Variance Accounts
– Amounts Requested for Disposition

<u>Account</u> #	<u>Description</u>	<u>Total Claim per</u> <u>Regulatory Asset</u> <u>Continuity</u>
1508	Other Regulatory Assets - aggregated	243,904
1518	Retail Cost Variance Account - Retail	12,288
1525	Misc. Deferred Debits	59,814
1548	Retail Cost Variance Account - STR	(3,102)
1550	LV Variance Account	21,164
1562	PILs variance	(152,368)
1570	Qualifying Transition Costs	(4,494)
1571	Pre-Market Opening Energy Variances	(20,603)
1580	RSVA - Wholesale Market Service Charge	251,077
1582	RSVA - One-time Wholesale Market Service Charge	54,703
1584	RSVA - Retail Transmission Network Charge	19,766
1586	RSVA - Retail Transmission Connection Charge	(579,951)
1588	RSVA - Power	1,654,427
1590	Recovery of Regulatory Asset Balances	130,510
Total requested for disposition		<u>1,687,135</u>

51. Ref: Exhibit1/Tab2/Schedule 3/Page1

What are the interest rates being used to calculate carrying charges for each regulatory deferral and variance account for the period from January 1, 2005 to present?

Interest rates used to calculate carrying charges on regulatory deferral and variance accounts from Jan 1/05 to present are as follows:

Jan 1/05 – Mar 31/06 –	7.25%
Apr 1/06 – Jun 30/06 –	4.14% **
Jul 1/06 – Sep 30/07 –	4.59%**
Oct 1/07 – Dec 31/07 –	5.14% **

The only difference in interest rate application for applicable deferral and variance accounts is 1508, which has carrying costs charged at 3.88% for Jan – Dec 2005.

Note: ** as per OEB prescribed interest rates.

52. Ref: Exhibit 5/Tab1/Schedule 2/Page1

Please indicate what PILs method the Applicant followed in calculating the balances in account 1562 (and 1563 if applicable) by reference to the Board's FAQs dated April 2003.

Halton Hills Hydro Inc. applied PILs method 3 in calculating the balances of 1562. Account 1563, however, was not utilized in the booking of PILs entries. Although account 1563 was not utilized, there is no impact to this rate filing.

53. Ref: Exhibit 5/Tab1/Schedule 2/Page1

Did the Applicant change PILs accounting methods at anytime from October 1, 2001 to April 30, 2006? If yes, please explain the impacts of the change.

Halton Hills Hydro Inc. did not change PILs accounting methods over the period from October 1/01 to April 30/06. Account 1563 was not utilized in booking of PILs entries; offsets were instead posted to 4080.

54. Ref: Exhibit 5/Tab1/Schedule 2/Pages1&2

- a) Please provide a continuity schedule that shows how the transaction amounts in the PILs account 1562 (and 1563 if applicable) were recorded in the general ledger as at each year end since the period beginning October 1, 2001. Please separate the PILs proxy or allowance in rates, amounts billed or collected, adjustments, and interest. Please explain any adjustments.**
- b) Please provide an analysis for each year end from October 1, 2001 through December 31, 2006. The schedule should show:**
- **The PILs proxy or allowance approved in rates;**
 - **The amounts billed to or collected from customers;**
 - **Adjustments calculated by the Board's methodology for true-up and deferral account entries;**
 - **Any other adjustments recorded by the Applicant;**
 - **The interest carrying charge calculations and an explanation of how the interest amounts were calculated;**
 - **Excess interest claw-back, if applicable.**
- c) Please explain any differences between the two analyses requested above.**
- d) Where the Applicant deviated from the Board's PILs and SIMPIL methodology, please provide a description of each deviation and the reasons for each.**
- e) What assumptions did the Applicant make for the following items in calculating its account balance to be disposed :**
- **Interest and penalties on unpaid or under-paid taxes;**
 - **Non-deductible expenses like: meals, club dues, car expenses;**
 - **Donations paid to registered charities or municipal owners;**
 - **Joint ventures, subsidiary companies, equity income;**
 - **Costs disallowed by the Board in any proceeding;**
 - **Profit or losses on disposals of fixed assets for accounting purposes;**
 - **Capital gains or capital losses on disposals of capital assets for tax purposes;**
 - **Regulatory asset write-offs and recoveries for tax purposes.**
- f) Are there Board precedents on which the Applicant has relied? Please provide the proceeding case docket references.**
- g) Should the expensing or recovery of regulatory assets be included In the calculation of regulatory PILs taxes? What Board precedents are being relied on in making this assertion? Please describe how the Applicant processed these transactions in the PILs calculations to determine the balance in account 1562.**

- h) If a regulatory asset amount is denied collection by the Board, how should the denial be treated in the PILs tax calculations and reconciliation of the 1562 account?***
- i) What assumptions has the Applicant made in recording transactions in 1562 subsequent to April 30, 2006?***
- j) Please provide the following tax-related documents for each tax year from 2001 through 2006:***
- ***Federal T2 tax return and supporting schedules – original and any returns that were subsequently amended and re-filed.***
 - ***Ontario CT 23 tax return and supporting schedules – original and any returns that were subsequently amended and re-filed.***
 - ***Financial statements for each year that were submitted with the tax returns.***
 - ***Notice of Assessment received from the Ontario Ministry of Finance, Corporations Tax Branch.***
 - ***Notice of Reassessment from the Ontario Ministry of Finance Corporations Tax Branch.***
 - ***Correspondence between the Applicant and the Ministry of Finance concerning disputes or disagreements regarding the calculations of PILs income tax, Large Corporation Tax and Ontario Capital Tax in any tax return for any year.***

a) Please refer to Table 38 for a continuity of PILS variance. There is no difference between continuities as revised.

Table 38 – PILS Continuity

Recording PILS transaction amounts in GL

<u>Dec 31/01</u>	<u>Acct #</u>	<u>Dr</u>	<u>Cr</u>
- no entries (see Dec 31/04)			
<u>Dec 31/02</u>			
- no entries (see Dec 31/04)			
<u>Dec 31/03</u>			
- no entries (see Dec 31/04)			
<u>Dec 31/04</u>			
Deferred payments in lieu of taxes	1562		210,132
Deferred payments in lieu of taxes - interest	1562		4,242
Distribution services revenue	4080	214,374	

Original continuity of PILS to December 31, 2004:

	<u>31-Dec 2001</u>	<u>31-Dec 2002</u>	<u>31-Dec 2003</u>	<u>31-Dec 2004</u>
Opening	-	236,647	81,863	76,261
Initial PILs Rate Adjustment	236,647	659,170	798,868	961,540
True-up Adjustments	-	(149,011)	(35,250)	(322,403)
Carrying Charges - cumulative	-	2,863	4,159	(4,242)
PILS collected from customers	-	(667,806)	(773,379)	(925,530)
Ending balance	<u>236,647</u>	<u>81,863</u>	<u>76,261</u>	<u>(214,374)</u>

Notes:

1. No entries made for OEB trial balance purposes until Dec 31/04 as PILS variance minimal and in favour of Halton Hills Hydro.
2. PILs continuity revisited as unable to conceptualize balance of PILS account.

<u>Dec 31/05</u>	<u>Acct #</u>	<u>Dr</u>	<u>Cr</u>
Deferred payments in lieu of taxes	1562	117,359	
Deferred payments in lieu of taxes - interest	1562		1,492
Distribution services revenue	4080		115,867

- entries bring deferred PILS balance to \$98,507 credit balance

<u>Dec 31/05</u>			
Deferred payments in lieu of taxes	1562		45,801
Deferred payments in lieu of taxes - interest	1562		8,060
Distribution services revenue	4080	53,861	

- entries bring deferred PILS balance to \$152,368 credit balance

Revised PILS continuity:

	<u>31-Dec 2001</u>	<u>31-Dec 2002</u>	<u>31-Dec 2003</u>	<u>31-Dec 2004</u>	<u>31-Dec 2005</u>	<u>31-Dec 2006</u>
Opening	-	246,317	528,512	517,232	60,395	(98,507)
Initial PILs Rate Adjustment	246,317	899,961	1,146,278	961,540	899,961	934,394
True-up Adjustments	-	3,472	(149,011)	(322,403)	(22,843)	(25,734)
Deferral Account Variance Adjustment	-	43,705			(130,756)	
Carrying Charges - cumulative	-	2,863	4,159	(4,242)	(5,734)	(13,794)
PILS collected from customers	-	(667,806)	(1,012,706)	(1,091,732)	(899,530)	(948,727)
Ending balance	246,317	528,512	517,232	60,395	(98,507)	(152,368)

Notes:

1. PILs balances re-visited and adjusted December 31, 2005.
2. Uncovered differences in determination of PILs collected; initial PILs rate adjustments and true-ups didn't agree to filings.
3. Carrying charges determined using simple interest at year-end based on average balance over the year.

b) Please refer to Table 39 for a continuity of PILS variance. There is no difference between continuities as revised.

Table 39 – PILS Continuity

Original continuity of PILS to December 31, 2004:

	31-Dec <u>2001</u>	31-Dec <u>2002</u>	31-Dec <u>2003</u>	31-Dec <u>2004</u>
Opening	-	236,647	81,863	76,261
Initial PILs Rate Adjustment	236,647	659,170	798,868	961,540
True-up Adjustments	-	(149,011)	(35,250)	(322,403)
Carrying Charges	-	2,863	4,159	(4,242)
PILS collected from customers	-	(667,806)	(773,379)	(925,530)
Ending balance	236,647	81,863	76,261	(214,374)

Notes:

1. No entries made for OEB trial balance purposes until Dec 31/04 as PILS variance minimal and in favour of Halton Hills Hydro.
2. PILs continuity schedule reviewed and revised below.

Revised PILS continuity:

	31-Dec <u>2001</u>	31-Dec <u>2002</u>	31-Dec <u>2003</u>	31-Dec <u>2004</u>	31-Dec <u>2005</u>	31-Dec <u>2006</u>
Opening	-	246,317	528,512	517,232	60,395	(98,507)
Initial PILs Rate Adjustment	246,317	899,961	1,146,278	961,540	899,961	934,394
True-up Adjustments	-	3,472	(149,011)	(322,403)	(22,843)	(25,734)
Deferral Account Variance Adjustment	-	43,705			(130,756)	
Carrying Charges	-	2,863	4,159	(4,242)	(5,734)	(13,794)
PILS collected from customers	-	(667,806)	(1,012,706)	(1,091,732)	(899,530)	(948,727)
Ending balance	246,317	528,512	517,232	60,395	(98,507)	(152,368)

Notes:

1. PILs balances re-visited and adjusted December 31, 2005.
2. Uncovered differences in determination of PILs collected; initial PILs rate adjustments and true-ups didn't agree to filings.
3. Carrying charges determined using simple interest at year-end based on average balance over the year.

c) There is no difference between continuities as revised.

d) Halton Hills Hydro Inc. did not utilize account #1563 as the contra account for 1562. Instead, PILs offsets were posted to 4080.

e) Assumptions made for the following items in calculating the account balance to be disposed:

- interest & penalties on unpaid / underpaid taxes – excluded from determination of PILS balance
- non-deductible expenses – excluded
- donations to charities / municipal owners – included
- subsidiary companies – included
- costs disallowed – excluded
- profit / loss on disposals of fixed assets – included
- capital gains / losses for tax – included
- regulatory asset write-offs and recoveries – no impact

f) There are no Board precedents on which Halton Hills Hydro Inc. has relied.

g) Expensing and recovery of regulatory assets: The expensing and recovery of regulatory assets should be included in the calculation of PILs. Halton Hills Hydro Inc. has included regulatory asset recovery in revenues and booked the approved recovery as an offset for each annual period. As a result, there is no impact on PILS account 1562 as the revenues and offsets balance to nil.

h) If a regulatory asset amount is denied collection by the Board, for PILS tax and account 1562 reconciliation this amount should similarly be excluded.

i) For PILS transactions subsequent to April 30, 2006, Halton Hills Hydro Inc. has used the 2005/06 initial estimate PILS rate adjustment and true-up variance and offset against actual 2006 amounts collected.

j) One hard copy of the following documentation has been delivered to the OEB. The following documentation has been scanned and is available electronically. However, due to the size of the file, it will be forwarded upon request.

- Federal T2 returns and schedules
- Ontario CT23 returns and schedules
- Financial statements for each year
- Notices of assessment and re-assessment
- Correspondence re 2001 – 2004 audit adjustments

RETAIL TRANSMISSION RATES (RTR) General

55.

The Wholesale Network Transmission Rate will decrease 28% effective November 1 2007.

For each rate class, please provide a revised RTR – Network Service Rate that would be revenue neutral over the 12 month period beginning May 1, 2008. (i.e. The amount collected by the revised RTR – Network Service Rate for each rate class equals the amount paid for the Wholesale Transmission Rate.)

Halton Hills Hydro Inc. proposed Retail Transmission Rates by rate class based on the 18% decrease in the Wholesale Network Transmission Rate that will be revenue neutral is as follows:

Table 40 – Proposed Retail Transmission Rates - Network

Rate Class	Existing	Proposed
Residential	\$0.0057	\$0.0053
General Service less than 50 kW	\$0.0052	\$0.0049
General Service 50 to 4,999 kW	\$2.2535	\$2.1120
Street Lights	\$1.6002	\$1.4997
Sentinel Lights	\$1.6083	\$1.5073
Un-metered Scattered Load	\$0.0052	\$0.0049

Please note that the change in wholesale rates has been transposed between Board Staff Interrogatory Question #55 and #56. The Wholesale Network Transmission Rate will decrease 18% and the Wholesale Connection Transmission Rate will decrease 28%.

56.

***The Wholesale Connection Transmission Rate will decrease 18% and the Wholesale Transformation Connection Transmission Rate will increase 7% effective November 1 2007.
For each rate class, please provide a revised RTR – Line and Transformation Connection Service Rate that would be revenue neutral over the 12 month period beginning May 1, 2008. (i.e. The amount collected by the RTR - Line and Transformation Connection Service Rate for each rate class should equal the amount paid for the Wholesale Connection Transmission Rate and the Wholesale Transformation Connection Transmission Rate.)***

Halton Hills Hydro Inc. proposed Retail Transmission Rates by rate class based on the 28% decrease in the Wholesale Connection Transmission Rate that will be revenue neutral is as follows:

Table 41 – Proposed Retail Transmission Rates - Connection

Rate Class	Existing	Proposed
Residential	\$0.0050	\$0.0047
General Service less than 50 kW	\$0.0045	\$0.0042
General Service 50 to 4,999 kW	\$1.9603	\$1.8271
Street Lights	\$1.3824	\$1.2884
Sentinel Lights	\$1.4113	\$1.3154
Un-metered Scattered Load	\$0.0045	\$0.0042

Please note that the change in wholesale rates has been transposed between Board Staff Interrogatory Question #55 and #56. The Wholesale Network Transmission Rate will decrease 18% and the Wholesale Connection Transmission Rate will decrease 28%.

Deferral and Variance Accounts 1584 & 1586

57.

Utilities have been required to provide information on Account 1584 RSVA NW and 1586 RSVA CN to the Board as part of the quarterly RRR filings.

a) Please provide the quarterly balances for the first three quarters of 2007 for accounts 1584 RSVA NW and 1586 RSVA CN and reconcile any variations with the quarterly balances reported as part of the Board's Record Keeping and Reporting Requirements.

b) Please explain how your balances in Accounts 1584 RSVA NW and 1586 RSVA CN have trended or fluctuated since January 1 2005.

Deferral and variance accounts 1584 RSVA network and 1586 RSVA connection review:

- a) Please refer to Table 42 for a review of 1584 and 1586 quarterly balances for the first three quarters of 2007.

Table 42 –Deferral Accounts 1584 and 1586 Review

		2007 Quarter-end Balances		
	<u>Account #</u>	<u>Mar 31</u>	<u>Jun 30</u>	<u>Sept 30</u>
RSVA network	1584	(165,894)	167,280	53,516
RSVA connection	1586	(937,698)	(613,042)	(663,239)

Note: Mar 31 balances have been adjusted for reclassification to the regulatory asset recovery account for purposes of this comparison. Actual filed balances for Mar 31 did not reclassify approved recovery items as this recovery was not booked until Jun 2007 as previously indicated to Board staff.

- b) Please refer to Table 43 for a review of 1584 and 1586 trends from 2005 - 2007. The balance in account 1584 has remained fairly constant over the past few years, with an insubstantial under-recovery at Dec 31/06. The balance in account 1586 has continued to be in a credit position; over-recovery of the connection charge is increasing over the previous few years.

Table 43 – Deferral Accounts 1584 and 1586 Trend Review

		2004	2005	2006	2007	Average Balance
	<u>Account #</u>	<u>Dec 31</u>	<u>Dec 31</u>	<u>Dec 31</u>	<u>Sept 30</u>	<u>2004-2007</u>
RSVA network	1584	199,760	135,935	17,586	53,516	101,699
RSVA connection	1586	(768,661)	(388,867)	(566,413)	(663,239)	(596,795)
Notes:						
1. Each year-end account balances has been adjusted for the reclassification of approved regulatory asset recovery balance through 2006 rates.						
This reclassification will allow for better overall view of trends in these accounts.						
Amounts reclassified from these accounts are as follows: 1584 - \$701,005;						
1586 - \$1,210,436.						
2. Dec balances per reconciled year-end TB reporting.						

OEB STAFF INTERROGATORIES

APPENDIX A

2006 Tax Returns, Financial Statements, Notices



This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec, Ontario, or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporate return.

Parts, sections, subsections, and paragraphs mentioned on this return refer to the *Income Tax Act*. This return may contain changes that had not yet become law at the time of printing. For more information on how to complete the return, see the *T2 Corporation - Income Tax Guide* (T4012).

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax services office or tax centre. You have to file the return within six months after the end of the corporation's tax year. For more information on when and how to file T2 returns, refer to the Guide under the heading "Before you start."

055 Do not use this area**Identification****Business Number (BN)** 001 867429623 **R C** 0001**Corporation's name**

002 HALTON HILLS HYDRO INC.

Has the corporation changed its name since the last time you filed your T2 return? 003 1 Yes ☐ 2 No ☒If Yes, do you have a copy of the articles of amendment? (**Do Not Submit**) 004 1 Yes ☐ 2 No ☐**Address of head office**Has this address changed since the last time you filed your T2 return? 010 1 Yes ☐ 2 No ☒
(If Yes, complete lines 011 to 018)

011 43 ALICE STREET

012

City Province, territory, or state
015 ACTON 016 ONCountry (other than Canada) Postal code/Zip code
017 018 L7J2A9**To which tax year does this return apply?**Tax year start Tax year-end
060 2006/01/01 061 2006/12/31
YYYY MM DD YYYY MM DDHas there been an acquisition of control to which subsection 249(4) applies since the previous tax year? 063 1 Yes ☐ 2 No ☒If Yes, provide the date control was acquired 065
YYYY MM DD**Mailing address (if different from head office address)**Has this address changed since the last time you filed your T2 return? 020 1 Yes ☐ 2 No ☒
(If Yes, complete lines 021 to 028)

021 c/o

022

023

City Province, territory, or state
025 ACTON 026 ONCountry (other than Canada) Postal code/Zip code
027 028**Location of books and records**Has the location of books and records changed since the last time you filed your T2 return? 030 1 Yes ☐ 2 No ☒
(If Yes, complete lines 031 to 038)

031 43 ALICE STREET

032

City Province, territory, or state
035 ACTON 036 ONCountry (other than Canada) Postal code/Zip code
037 038 L7J2A9**040 Type of corporation at the end of the tax year**

- 1 ☒ Canadian-controlled private corporation (CCPC) 4 ☐ Corporation controlled by a public corporation
- 2 ☐ Other private corporation 5 ☐ Other corporation (specify, below)
- 3 ☐ Public corporation

If the type of corporation changed during the tax year, provide the effective date of the change

043

YYYY MM DD

Is the corporation a professional corporation that is a member of a partnership? 067 1 Yes ☐ 2 No ☒**Is this the first year of filing after:**
Incorporation? 070 1 Yes ☐ 2 No ☒
Amalgamation? 071 1 Yes ☐ 2 No ☒

If Yes, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? 072 1 Yes ☐ 2 No ☒
If Yes, complete and attach Schedule 24.**Is this the final tax year before amalgamation?** 076 1 Yes ☐ 2 No ☒**Is this the final return up to dissolution?** 078 1 Yes ☐ 2 No ☒**Is the corporation a resident of Canada?**080 1 Yes ☒ 2 No ☐

If No, give the country of residence on line 081 and complete and attach Schedule 97.

081

Is the non-resident corporation claiming an exemption under an income tax treaty? 082 1 Yes ☐ 2 No ☒
If Yes, complete and attach Schedule 91.**If the corporation is exempt from tax under section 149, tick one of the following boxes:**

- 085
- 1 ☐ Exempt under paragraph 149(1)(e) or (l)
- 2 ☐ Exempt under paragraph 149(1)(j)
- 3 ☐ Exempt under paragraph 149(1)(t)
- 4 ☐ Exempt under other paragraphs of section 149



Ministry of Finance
Corporations Tax Branch - Hydro PIL
PO Box 620
33 King Street West
Oshawa ON L1H 8E9

Account No.
1800262

35
PX5003

HALTON HILLS HYDRO INC.
C/O ARTHUR SKIDMORE
43 ALICE ST

ACTION
L7J 2A9

ON

Remittance Advice - Payment-in-Lieu (PIL)

Electricity Act, 1998

Corporations Tax Act, R.S.O. 1990

Taxation Year End: (YYYYMMDD)

Payment Amount: \$

Taxation Year End: (YYYYMMDD)

2	0	0	6	1	2	3	1

Payment Amount: \$

Total Payment
Enclosed: \$



Ministry of Finance
Corporations Tax Branch - Hydro PIL
PO Box 620
33 King Street West
Oshawa ON L1H 8E9

Keep this portion for your records.

Notice of Assessment

Electricity Act, 1998 • Corporations Tax Act, R.S.O. 1990
from 2006/01/01 to 2006/12/31

HALTON HILLS HYDRO INC.

ASSESSMENT NO. 191

Account No.

1800262

Assessment Date
(year, month, day)

2007/07/26

Page

1 of 1

Tax: Federal and Provincial PIL
Assessment Interest

Total Assessment Liability

768,102.00
4,190.58CR
763,911.42

SUMMARY OF 2006/12/31 TAXATION YEAR TRANSACTIONS

Payments/Transfers

900,000.00CR

Sub-Total

CREDIT BALANCE AVAILABLE IN THIS TAXATION YEAR

900,000.00CR
136,088.58CR

In accordance with s.s.80(8) of the Corporations Tax Act, as made applicable
by s.95 of the Electricity Act, 1998, notice is hereby given of the amount of
tax, penalty and interest for which you are assessed.

Total tax assessed as per company estimate

Tax (Re)Assessment Enquiries:

- Toronto (416) 730-5585
- FAX (416) 730-5593

Account Billing Enquiries & Change of Address Information:

- Oshawa and Local (905) 433-6708
- Toll-Free 1-800-262-0784 ext. 3036
- Toronto (416) 920-9048 ext. 3036
- FAX (905) 433-5197

Account Description	Account Number	Dec31/06 Balance	Apr 30/08 Balance	Allocation Basis	Residential	GS < 50 KW	GS 50-999 KW
Unrecovered Plant and Regulatory Study Costs	1505	-	-				
Other Regulatory Assets	1508	231,182	243,905	KWh	106,828	28,202	61,028
Preliminary Survey and Investigation Charges	1510	-	-				
Emission Allowance Inventory	1515	-	-				
Emission Allowances Withheld	1516	-	-				
Retail Cost Variance Account - Retail	1518	11,582	12,291	# Customers	11,056	936	105
Power Purchase Variance Account	1520	-	-				
Misc. Deferred Debits - incl. Rebate Cheques	1525	79,181	82,684	Rebate cheques	82,684	-	-
Deferred Losses from Disposition of Utility Plant	1530	-	-				
Unamortized Loss on Reacquired Debt	1540	-	-				
Development Charge Deposits/ Receivables	1545	-	-				
Retail Cost Variance Account - STR	1548	(2,962)	(3,143)	# Customers	(2,828)	(239)	(27)
LV Variance Account	1550	19,874	21,164	KWh	9,270	2,447	5,295
Smart Meter Capital Variance Account	1555	-	-				
Smart Meters OM&A Variance Account	1556	-	-				
Deferred Development Costs	1560	-	-				
Deferred Payments in Lieu of Taxes	1562	(152,368)	(160,849)	KWh	(70,450)	(18,598)	(40,246)
PILS Contra Account	1563	-	-				
CDM Expenditures and Recoveries	1565	-	-				
CDM Contra Account	1566	-	-				
Qualifying Transition Costs	1570	(65,042)	(73,664)	# Customers	(66,266)	(5,610)	(631)
Pre-Market Opening Energy Variances Total	1571	(19,008)	(25,313)	KWh for Non TOU Customers	(13,758)	(3,632)	(7,860)
Extra-Ordinary Event Losses	1572	-	-				
Deferred Rate Impact Amounts	1574	-	-				
RSVA - Wholesale Market Service Charge	1580	239,054	247,106	KWh	108,230	28,572	61,829
RSVA - One-time Wholesale Market Service	1582	51,737	54,139	KWh	23,712	6,260	13,546
RSVA - Retail Transmission Network Charge	1584	17,586	11,626	KWh	5,092	1,344	2,909
RSVA - Retail Transmission Connection Charge	1586	(546,413)	(584,240)	KWh	(255,892)	(67,554)	(146,184)
RSVA - Power	1588	1,011,418	1,614,000	KWh	706,919	186,621	403,842
Deferred PILS Account	1592	-	-				
Other Deferred Credits	2425	-	-				
Sub-total to Dispose at May1/08 or Dec31/06?	Apr30/08	875,821	1,439,704		644,597	158,749	353,607
Clear residual 1590 balance as of April 30/08?	YES				67,596	15,990	16,314
Total to Dispose at May1/08					712,193	174,739	369,922
Disposal period?	3 YEARS				237,398	58,246	123,307
Projected 2008 Rate Riders							
Rate Determinant					0.0011 kWh	0.0010 kWh	0.2716 kW

Account Description	GS 1000-4999	Intermediate	Large Users	Unmetered Scattered Load	Standby Power	Sentinel	Street Light	Residential TOU
Unrecovered Plant and Regulatory Study Costs								
Other Regulatory Assets	45,861	-	-	493	-	156	1,302	35
Preliminary Survey and Investigation Charges								
Emission Allowance Inventory								
Emission Allowances Withheld								
Retail Cost Variance Account - Retail				80	-	105	1	1
Power Purchase Variance Account	7	-	-	-	-	-	-	-
Misc. Deferred Debits - incl. Rebate Cheques	-	-	-	-	-	-	-	-
Deferred Losses from Disposition of Utility Plant								
Unamortized Loss on Reacquired Debt								
Development Charge Deposits/ Receivables								
Retail Cost Variance Account - STR	(2)	-	-	(20)	-	(27)	(0)	(0)
LV Variance Account	3,979	-	-	43	-	14	113	3
Smart Meter Capital Variance Account								
Smart Meters OM&A Variance Account								
Deferred Development Costs								
Deferred Payments in Lieu of Taxes	(30,244)	-	-	(325)	-	(103)	(358)	(23)
PILS Contra Account								
CDM Expenditures and Recoveries								
CDM Contra Account								
Qualifying Transition Costs	(42)	-	-	(477)	-	(628)	(4)	(7)
Pre-Market Opening Energy Variances Total	-	-	-	(63)	-	-	-	-
Extra-Ordinary Event Losses								
Deferred Rate Impact Amounts								
RSVA - Wholesale Market Service Charge	46,463	-	-	499	-	158	1,319	35
RSVA - One-time Wholesale Market Service	10,180	-	-	109	-	35	289	8
RSVA - Retail Transmission Network Charge	2,186	-	-	23	-	7	62	2
RSVA - Retail Transmission Connection Charge	(109,853)	-	-	(1,181)	-	(375)	(3,118)	(83)
RSVA - Power	303,476	-	-	3,262	-	1,035	8,613	231
Deferred PILs Account								
Other Deferred Credits								
Sub-total to Dispose at May1/08 or Dec31/06?	272,011	-	-	2,443	-	378	7,718	201
Clear residual 1590 balance as of April 30/08?	29,568	-	-	144	-	153	745	23
Total to Dispose at May1/08	301,579	-	-	2,587	-	531	8,462	223
Disposal period?	100,526	-	-	862	-	177	2,821	74
Projected 2008 Rate Riders	0.3181	kW	kW	0.0008	kWh	0.2214	0.3761	0.0000
Rate Determinant								

Account Description	Additional Customer Class 2	Additional Customer Class 3	Additional Customer Class 4	Totals	
Unrecovered Plant and Regulatory Study Costs	-	-	-	-	-
Other Regulatory Assets	-	-	-	243,905	-
Preliminary Survey and Investigation Charges	-	-	-	-	-
Emission Allowance Inventory	-	-	-	-	-
Emission Allowances Withheld	-	-	-	-	-
Retail Cost Variance Account - Retail	-	-	-	12,291	-
Power Purchase Variance Account	-	-	-	-	-
Misc. Deferred Debits - incl. Rebate Cheques	-	-	-	82,684	-
Deferred Losses from Disposition of Utility Plant	-	-	-	-	-
Unamortized Loss on Recquired Debt	-	-	-	-	-
Development Charge Deposits/ Receivables	-	-	-	-	-
Retail Cost Variance Account - STR	-	-	-	(3,143)	-
LV Variance Account	-	-	-	21,164	-
Smart Meter Capital Variance Account	-	-	-	-	-
Smart Meters OM&A Variance Account	-	-	-	-	-
Deferred Development Costs	-	-	-	-	-
Deferred Payments in Lieu of Taxes	-	-	-	(160,849)	-
PILS Contra Account	-	-	-	-	-
CDM Expenditures and Recoveries	-	-	-	-	-
CDM Contra Account	-	-	-	-	-
Qualifying Transition Costs	-	-	-	(73,664)	-
Pre-Market Opening Energy Variances Total	-	-	-	(25,313)	-
Extra-Ordinary Event Losses	-	-	-	-	-
Deferred Rate Impact Amounts	-	-	-	-	-
RSVA - Wholesale Market Service Charge	-	-	-	247,106	-
RSVA - One-time Wholesale Market Service	-	-	-	54,139	-
RSVA - Retail Transmission Network Charge	-	-	-	11,626	-
RSVA - Retail Transmission Connection Charge	-	-	-	(584,240)	-
RSVA - Power	-	-	-	1,614,000	-
Deferred PILs Account	-	-	-	-	-
Other Deferred Credits	-	-	-	-	-
Sub-total to Dispose at May1/08 or Dec31/06?	-	-	-	1,439,704	OK
Clear residual 1590 balance as of April 30/08?	-	-	-	130,533	-
Total to Dispose at May1/08	-	-	-	1,570,237	-
Disposal period?	-	-	-	523,412	-
Projected 2008 Rate Riders	0.0000				
Rate Determinant					

Checks All
Totals Aga
to Recover
May1/08 or
31/06

Test Year (2008) Allocations

Customer Class	Metric	kW	KWh	# Customers	KWh for Non TOU Customers	Dx Revenue	# Customers w/Rebate Cheques
Residential	kWhs	0%	44%	90%	54%		
GS < 50 KW	kWhs	0%	12%	8%	14%		
GS 50-999 kW	kW	58%	25%	1%	31%		
GS 1000-4999	kW	41%	19%	0%			
Intermediate	kW	0%	0%	0%			
Large Users	kW	0%	0%	0%			
Unmetered Scattered Load	kWhs	0%	0%	1%	0%		
Standby Power	kW	0%	0%	0%			
Sentinel	kW	0%	0%	1%			
Street Light	kW	1%	1%	0%			
Residential TOU	kWhs	0%	0%	0%			
Additional Customer Class 2		0%	0%	0%			
Additional Customer Class 3		0%	0%	0%			
Additional Customer Class 4		0%	0%	0%			
Totals		100%	100%	100%	100%	0%	0%

Test Year (2008) Allocations

Customer Class	Rebate cheques	Additional Allocator 2	Additional Allocator 3
Residential	100%		
GS < 50 KW	0%		
GS 50-999 kW	0%		
GS 1000-4999	0%		
Intermediate	0%		
Large Users	0%		
Unmetered Scattered Load	0%		
Standby Power	0%		
Sentinel	0%		
Street Light	0%		
Residential TOU	0%		
Additional Customer Class 2	0%		
Additional Customer Class 3	0%		
Additional Customer Class 4	0%		
Totals	100%	0%	0%

Non-Consolidated Financial Statements of

HALTON HILLS HYDRO INC.

December 31, 2006

Auditors' Report

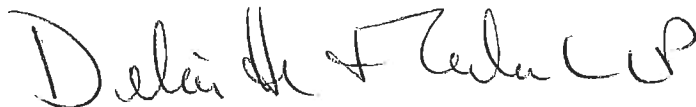
To the Directors of
Halton Hills Hydro Inc.

We have audited the non-consolidated balance sheet of Halton Hills Hydro Inc. as at December 31, 2006 and the non-consolidated statements of income and retained earnings and of cash flows for the year then ended. These financial statements have been prepared on a non-consolidated basis for income tax purposes. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these non-consolidated financial statements present fairly, in all material respects, the financial position of the company as at December 31, 2006 and the results of its operations and its cash flows for the year then ended in accordance with the basis of accounting disclosed in Note 3 to the financial statements.

These financial statements, which have not been, and were not intended to be, prepared in accordance with Canadian generally accepted accounting principles, are solely for the information and use of the Directors of Halton Hills Hydro Inc. and the provincial income tax authorities, for income tax purposes. The financial statements are not intended to be and should not be used by anyone other than the specified users or for any other purpose.



Chartered Accountants
Licensed Public Accountants

March 29, 2007

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HALTON HILLS HYDRO INC.**Non-Consolidated Statement of Income and Retained Earnings****Year Ended December 31, 2006**

	2006	2005
REVENUE		
Service revenue (Note 16)	\$ 45,619,622	\$ 45,731,875
Other income	1,514,435	1,116,930
	<u>47,134,057</u>	<u>46,848,805</u>
OPERATING EXPENSES		
Power costs	35,130,342	36,847,936
Salaries and benefits	3,636,852	3,489,322
Material costs	2,690,912	1,514,086
Contract services	2,102,678	2,704,632
Property costs	521,663	517,652
Other expenses	855,429	753,768
Communication costs	268,081	260,991
Capital taxes	101,683	68,445
Allocated to capital	(5,012,989)	(4,702,453)
	<u>40,294,651</u>	<u>41,454,379</u>
INCOME BEFORE THE UNDERNOTED	<u>6,839,406</u>	<u>5,394,426</u>
RECOVERY OF REGULATORY ASSETS	1,471,724	1,004,331
AMORTIZATION	1,930,209	1,884,106
INTEREST EXPENSE	1,542,001	1,188,834
	<u>4,943,934</u>	<u>4,077,271</u>
INCOME BEFORE INCOME TAXES	<u>1,895,472</u>	<u>1,317,155</u>
PROVISION FOR INCOME TAXES (Note 17)		
Current	729,981	646,313
NET INCOME	<u>1,165,491</u>	<u>670,842</u>
RETAINED EARNINGS, BEGINNING OF THE YEAR	3,065,624	2,394,782
RETAINED EARNINGS, END OF THE YEAR	<u>\$ 4,231,115</u>	<u>\$ 3,065,624</u>

HALTON HILLS HYDRO INC.
Non-Consolidated Balance Sheet
December 31, 2006

	2006	2005
ASSETS		
CURRENT		
Cash and cash equivalents	\$ 1,600,010	\$ 2,085,729
Accounts receivable (Note 4)	3,402,683	3,389,257
Unbilled revenue	5,677,289	5,519,301
Inventory	1,087,028	995,697
Due from related companies (Note 5)	1,341,153	1,334,080
Prepaid expenses and deposits	248,551	286,144
	13,356,714	13,610,208
NOTES RECEIVABLE (Note 6)	865,551	865,551
REGULATORY ASSETS (Note 7)	3,046,254	4,468,443
LONG-TERM INVESTMENTS (Note 8)	906,370	904,773
CAPITAL ASSETS (Note 9)	26,948,895	24,809,367
GOODWILL	352,881	352,881
DEFERRED CHARGES	47,787	79,645
	\$ 45,524,452	\$ 45,090,868
LIABILITIES		
CURRENT		
Accounts payable and accrued liabilities (Note 10)	\$ 7,588,026	\$ 8,228,664
Deferred revenue (Note 11)	322,890	456,507
Current portion of consumer deposits	250,000	250,000
	8,160,916	8,935,171
NOTE PAYABLE TO PARENT (Note 12)	16,141,970	16,141,970
CONSUMER DEPOSITS	371,888	339,440
EMPLOYEE FUTURE BENEFITS (Note 13)	456,900	447,000
	25,131,674	25,863,581
CONTINGENT LIABILITIES (Note 14)		
SHAREHOLDER'S EQUITY		
Capital stock (Note 15)	16,161,663	16,161,663
Retained earnings	4,231,115	3,065,624
	20,392,778	19,227,287
	\$ 45,524,452	\$ 45,090,868

APPROVED BY THE BOARD

Rupul Royce Director
J. M. Nelson Director

HALTON HILLS HYDRO INC.
Non-Consolidated Statement of Cash Flows
Year Ended December 31, 2006

	2006	2005
OPERATING ACTIVITIES		
Cash from operations		
Net income	\$ 1,165,491	\$ 670,842
Items not affecting cash:		
Amortization	1,930,209	1,884,106
Gain on disposal of capital assets	(774)	(25,444)
Difference between employee future benefits expense and amount funded	9,900	12,500
Equity in loss (income) of limited partnership	(1,597)	1,297
	3,103,229	2,543,301
Change in regulatory assets	1,422,189	(498,847)
Changes in non-cash working capital (Note 18)	(1,602,598)	473,213
	2,922,820	2,517,667
FINANCING ACTIVITY		
Net consumer deposits received (repaid)	32,448	(355,417)
INVESTING ACTIVITIES		
Purchase of capital assets	(3,477,748)	(3,140,292)
Proceeds on disposal of capital assets	4,903	25,610
Deferred charges	31,858	(79,645)
	(3,440,987)	(3,194,327)
NET DECREASE IN CASH AND CASH EQUIVALENTS	(485,719)	(1,032,077)
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR	2,085,729	3,117,806
CASH AND CASH EQUIVALENTS, END OF YEAR	\$ 1,600,010	\$ 2,085,729
SUPPLEMENTAL DISCLOSURE		
Payments for interest	\$ 1,493,457	\$ 1,286,905
Net payments for income tax	\$ 636,269	\$ 826,758

1. NATURE OF OPERATIONS

Halton Hills Hydro Inc., the 'Company', is a wholly-owned corporation of the Town of Halton Hills, and was incorporated on April 13, 1999 under the laws of the Province of Ontario.

The principal activity of the Company is to provide electric power distribution throughout the municipality of Halton Hills.

2. REGULATION

Regulator

The Ontario Energy Board (OEB) has regulatory oversight of the electricity industry in the Province of Ontario. The Ontario Energy Board Act, 1998, the Electricity Act, 1998, the Electricity Restructuring Act, 2004 and a number of other provincial statutes set out the OEB's mandate and authority. The OEB prescribes and enforces licence requirements and conditions towards the following objectives as set out in the Electricity Restructuring Act, 2004:

- To protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service; and
- To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry.

The OEB's authority and responsibilities include the ability to approve and set rates for the transmission and distribution of electricity, to provide rate protection for various electricity consumers, and to ensure electricity distribution companies fulfill their customer service obligations.

Rate approval process

Rate applications are generally due on an annual basis, with the 2007 rate application due no later than January 26, 2007. The Company, OEB licence number ED-2002-0552, has complied with the filing deadline for the 2007 rate application. Rate adjustments for 2007 will be approved by and come into effect May 1, 2007. The OEB decision in regards to 2007 rates is expected in April 2007.

The rate application process includes oral or written public hearings whereby those who may be affected by the OEB's ruling have the opportunity to express their views.

The OEB Electricity Distribution Rate Handbook contains policies, guidelines and procedures used by Ontario electricity distributors in preparing applications for the 2006 distribution rates.

The OEB has traditionally regulated distribution rates based upon cost-of-service methodology. In 2007, however, the OEB has adopted an incentive rate setting mechanism (IRM) for electricity distributors. Incentive regulation is intended to provide distributors with the opportunity to increase returns to shareholders through the implementation of efficiency initiatives. These efficiencies are also intended to benefit ratepayers by reducing costs.

2. REGULATION (continued)

Type of regulation

The OEB initiated a process to update approved 2006 rates based on the "Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors". The objective of the 2nd generation IRM is to provide regulatory certainty to distributors as rate-related studies are carried out. The 2nd generation IRM will be in place for a maximum of three years. Distributor rates will not be rebased prior to implementing the incentive rate adjustment effective May 1, 2007. The OEB will rebase rates for distributors over three years, beginning in 2008. The Company has applied for a 2008 rebasing from the OEB.

The OEB has retained a price cap form of adjustment mechanism for the IRM. The price cap adjustment will be applied to distribution rates, uniformly across all customer classes and to both the monthly service charge and volumetric rate, including taxes. The adjustment is net of the smart meter funding, large corporation tax allowance, incremental 2006 CDM funding, regulatory assets rate rider and specific service charges. The OEB will use the Canada Gross Domestic Product Implicit Price Index for final domestic demand as the price cap escalator. For 2007, the price cap has been set at 1.92%

Offsetting the price cap, is a productivity differential. The OEB has determined that electricity distributors will be subject to a 1% productivity differential for the duration of the 2nd Generation IRM.

Thus, for 2007, with the price cap set at 1.92% and annual productivity gain of 1%, an increase in rates of 0.92% is anticipated.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of accounting

The financial statements have been prepared on a non-consolidated basis for income tax purposes and reflect the following significant accounting policies as set forth in the Accounting Procedures Handbook issued by the Ontario Energy Board (OEB) under the authority of the Ontario Energy Board Act, 1998. These financial statements materially differ from Canadian generally accepted accounting principles (GAAP) because they are non-consolidated. Consolidated financial statements have been presented to the shareholder.

Regulation

The following accounting policies under the regulated environment differ from GAAP for companies operating in an unregulated environment:

Contributions in aid of construction

Contributions in aid of construction consist of third party contributions toward the cost of constructing Company assets. Amortization of contributed capital is on a straight-line basis over 25 years. Capital contributions for the year of \$543,189 (2005 - \$1,043,632) have been charged as an offset to capital assets.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Regulatory assets

Regulatory assets represent future revenues associated with costs incurred in the current or prior periods, which are expected to be recovered from customers in future periods through the rate setting process.

Regulatory assets result from the provincially approved rate of the OEB and represent differences between costs incurred and those collected through rates. Regulatory assets on the balance sheet at year-end relate primarily to retail settlement variance accounts, pre-market opening cost of power variances and transition costs. Transition costs consist primarily of qualifying capital and related costs incurred in the preparation of market opening. Regulatory assets will be recognized for rate-setting and financial statement purposes only to the extent allowed by the regulator.

The regulatory assets are recovered through incremental amounts charged to consumers as approved by the OEB and included in service revenue. The related reduction of the regulatory assets is disclosed separately on the Statement of Income.

The Ontario Energy Board Amendments Act (Electricity Pricing), 2003, in conjunction with Bill 4, allows for recovery of regulatory assets. The 2006 rate decision included approval to recover regulatory asset balances to December 31, 2004 based on a variable charge over a two-year period beginning with the rate change on May 1, 2006. Transition costs recoveries were approved after a write-down of 10% of the total balance recoverable as at May 1, 2006 (including interest) which was charged to income during the year.

Payment in lieu of income taxes

Under the Electricity Act, 1998, the Company is required to make payments-in-lieu of corporate income taxes (PILs) to the Ontario Electricity Financial Corporation (OEFC). These payments are recorded in accordance with the rules for computing income taxes, taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Corporation Tax Act (Ontario) and modified by the Electricity Act, 1998, and related regulations.

The Company, regulated by the OEB, provides for PILs using the taxes payable method.

Under the taxes payable method, no provision is made for future income taxes as a result of temporary differences between the tax basis of assets and liabilities and their carrying values for accounting purposes. Future income taxes are expected to be reflected in future rates, and, accordingly, are not recognized in the financial information.

Future PILs disclosures are included in Note 17.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Deferred revenue

Deferred revenue consists of deferred Conservation and Demand Management (CDM) revenues and deferred Smart Metering revenues.

Deferred CDM revenues consist of the net amount of the final one-third market-based revenue requirement adjustment, and incremental CDM funding approved through the 2006 rate setting process, in excess of funds expended on CDM activities. The 2005 rates included the final one-third adjustment, as approved by the OEB in March 2005, to bring the Company to its market-based rate of return. The rate adjustment is subject to a financial commitment by the Company to invest an amount equivalent to the final one-third increase, \$715,000 in CDM activities over the next three years. The 2006 rates include incremental operating and capital CDM funds totalling \$179,669.

Deferred Smart Metering revenues consist of funding to begin the transition of the Company's legacy metering assets to smart meters. The basis for the installation of 800,000 smart meters in Ontario by the end of 2007 and all homes and businesses by the end of 2010 is outlaid in the Energy Conservation Responsibility Act, 2006. These meters will have the capacity to measure and report usage over certain periods, be read remotely and provide customers with access to information about their consumption. The 2006 rates of the Company included \$136,800 to begin smart meter deployment.

Use of estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Significant estimates include unbilled revenue. Actual results could differ from those estimates.

Revenue recognition

Service revenue is recorded on the basis of regular meter readings and estimated power usage since the last meter reading date to the year-end. The related cost of power is recorded on the basis of power used.

Other revenues, which include pole attachment rentals, customer requested services and other miscellaneous revenues, are recognized as the service activity is performed.

Cash and cash equivalents

Cash and cash equivalents consist of cash on hand, balances with banks, and investments in money market instruments, with maturities of 90 days or less at acquisition. Investing and financing activities that do not require the use of cash or cash equivalents are excluded from the Statement of Cash Flows and disclosed separately.

Inventory

Inventory is valued at the lower of average cost and net realizable value.

HALTON HILLS HYDRO INC.
Notes to the Non-Consolidated Financial Statements
December 31, 2006

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Long-term investments

Long-term investments in subsidiary companies are recorded at cost.

The Company follows the equity method of accounting for its investment in a limited partnership. Under this method, the investment is initially recorded at cost and is adjusted for the Company's proportionate share of any post-acquisition earnings, losses and distributions.

Capital assets

Capital assets are recorded at cost. Amortization is provided on a straight-line basis over the useful service life as follows:

Distribution system	25 years
Plant	25 - 60 years
Fleet	5 - 8 years
Other equipment	10 - 15 years
Computer equipment and software	1 - 5 years
General office	10 years
Stores equipment	10 years

Capital assets are tested for recoverability whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. An impairment loss is recognized when their carrying value exceeds the total undiscounted cash flows expected from their use and eventual disposition. The amount of the impairment loss is determined as the excess of the carrying value of the asset over its fair value.

Deferred charges

Deferred charges consist of expenditures that provide future benefit. These charges are amortized on a straight-line basis over 3 years.

Goodwill

Goodwill is recorded at amortized cost as at December 31, 2001. The carrying value of goodwill is tested against the fair values of the entities which generated the goodwill on an annual basis. If the carrying amount exceeds fair value, an impairment loss is recognized in the statement of income in an amount equal to the excess. Management has reviewed the fair values of the entities and has determined that no impairment of goodwill exists.

Employee future benefits

The Company provides its current and retired employees with life insurance and medical benefits beyond those provided by government-sponsored plans. The cost of these benefits is expensed as earned through employment service.

HALTON HILLS HYDRO INC.
Notes to the Non-Consolidated Financial Statements
December 31, 2006

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Asset retirement obligations

The Company recognizes the liability for an asset retirement that results from acquisition, construction, development or normal operations. The liability for an asset retirement is initially recorded at its fair value in the year in which it is incurred and when a reasonable estimate of fair value can be made. The corresponding cost is capitalized as part of the related asset and is amortized over the asset's useful life. In subsequent years, the liability is adjusted for changes resulting from the passage of time and revisions to either the timing or the amount of the original estimate of the undiscounted cash flows. The accretion of the liability to its fair value as a result of the passage of time is charged to earnings.

4. ACCOUNTS RECEIVABLE

	<u>2006</u>	<u>2005</u>
Electric service revenue	\$ 3,052,241	\$ 2,371,474
Miscellaneous	394,414	907,762
Town of Halton Hills	45,578	213,558
	<u>3,492,233</u>	<u>3,492,794</u>
Less allowance for doubtful accounts	(89,550)	(103,537)
	<u>\$ 3,402,683</u>	<u>\$ 3,389,257</u>

The accounts receivable from the Town of Halton Hills arose in the normal course of operations and is due under normal terms of trade.

Miscellaneous accounts receivable includes \$18,514 (2005 - \$24,342) due from related companies. These receivables arose in the normal course of operations and are due under normal terms of trade.

5. DUE FROM RELATED COMPANIES

The Company performs billing and collecting services, capital asset maintenance, finance functions, as well as certain engineering and information system services for related companies.

Amounts due from related companies at December 31st for transactions in the normal course of operations are as follows:

	<u>2006</u>	<u>2005</u>
Halton Hills Fibre Optics Inc.	\$ 891,957	\$ 1,017,204
Southwestern Energy Inc.	305,685	27,830
Halton Hills Energy Services Inc.	135,935	283,550
Halton Hills Energy Inc.	7,576	5,496
	<u>\$ 1,341,153</u>	<u>\$ 1,334,080</u>

HALTON HILLS HYDRO INC.

Notes to the Non-Consolidated Financial Statements

December 31, 2006

5. DUE FROM RELATED COMPANIES (continued)

Repayments of advances to Halton Hills Fibre Optics Inc. for capital initiatives amounted to \$250,000 during the year (2005 - \$100,000 advanced). The net amount advanced for capital initiatives of \$350,000 (2005 - \$600,000) is unsecured, bears interest at the prime rate less ½ % and has no specific repayment terms.

Other than the above, these receivables are unsecured and have no specific interest or repayment terms.

Administrative services provided by the Company to related companies during the year are as follows:

	<u>2006</u>	<u>2005</u>
Halton Hills Fibre Optics Inc.	\$ 79,476	\$ 63,480
SouthWestern Energy Inc.	308,008	271,506
	<u>\$ 387,484</u>	<u>\$ 334,986</u>

6. NOTES RECEIVABLE

The Company holds the following notes receivable:

	<u>2006</u>	<u>2005</u>
Halton Hills Energy Services Inc., unsecured, non-interest bearing, no fixed terms of repayment, due December 31, 2010	\$ 171,853	\$ 171,853
Halton Hills Fibre Optics Inc., unsecured, bears interest at prime less 1%, no fixed repayment terms for principal, due December 31, 2010	693,698	693,698
	<u>\$ 865,551</u>	<u>\$ 865,551</u>

7. REGULATORY ASSETS

Regulatory assets are as follows:

	<u>2006</u>	<u>2005</u>
Pre-market opening energy variance	\$ 323,328	\$ 337,166
Retail settlement variance	2,150,514	3,737,662
Retail cost variance	165,841	11,949
Transition costs	406,571	381,666
	<u>\$ 3,046,254</u>	<u>\$ 4,468,443</u>

HALTON HILLS HYDRO INC.

Notes to the Non-Consolidated Financial Statements

December 31, 2006

7. REGULATORY ASSETS (continued)

Management expects that regulatory assets attained during 2005 and 2006 will be recovered through future rate increases. If in a future decision, the regulator determines that the existing regulatory treatment is no longer applicable, the regulatory assets would be charged to operations.

In the absence of rate regulation, GAAP would require that the actual purchased power costs (including any variances arising from electricity commodity, retail transmission and wholesale market costs), as well as transition costs, be recognized as an expense when incurred.

In the absence of rate regulation, power costs for the year would have been lower (higher) by \$1,581,331 (2005 - \$(202,466)) and interest income would have been lower by \$159,142 (2005 - \$296,381). The net effect, in the absence of rate regulation, is a pre-tax increase (decrease) in net income of \$1,422,189 (2005 - \$(498,847)).

8. LONG-TERM INVESTMENTS

The Company holds the following investments, all of which are wholly-owned, except for the investment in EnerConnect Inc., a limited partnership investment, of which 46,389 units (1.5865% share of partnership) are held:

	<u>2006</u>	<u>2005</u>
Halton Hills Energy Inc.	\$ 1	\$ 1
SouthWestern Energy Inc.	171,853	171,853
Halton Hills Fibre Optics Inc.	693,698	693,698
EnerConnect Inc.	40,818	39,221
	<u>\$ 906,370</u>	<u>\$ 904,773</u>

The investment in EnerConnect includes the proportionate share of the company's income (loss) for the year of \$1,597 (2005 - \$(1,297)).

HALTON HILLS HYDRO INC.**Notes to the Non-Consolidated Financial Statements**

December 31, 2006

9. CAPITAL ASSETS

	2006			2005
	Cost	Accumulated Amortization	Net Book Value	Net Book Value
Distribution system	\$ 27,382,836	\$ 6,444,355	\$ 20,938,481	\$19,694,821
Plant	8,793,468	1,883,420	6,910,048	6,377,933
Fleet	1,507,255	1,003,043	504,212	521,345
Other equipment	2,066,430	518,743	1,547,687	907,691
Computer equipment and software	1,462,107	1,059,459	402,648	260,240
General office	310,200	159,524	150,676	136,300
Stores equipment	53,151	33,237	19,914	23,146
Contributed capital	(3,872,520)	(347,749)	(3,524,771)	(3,112,109)
	\$ 37,702,927	\$ 10,754,032	\$ 26,948,895	\$24,809,367

During the year, the Company recorded capital asset additions of \$4,073,866 (2005 - \$2,671,398), of which \$724,605 (2005 - \$128,487) were recorded in accounts payable at year-end.

10. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

Accounts payable and accrued liabilities includes an amount of \$Nil (2005 - \$1,124,680) due to low volume and designated customers arising from the Ontario Price Credit (OPC) rebate program. The rebate funds were received by the Company from the Ontario Electricity Financial Corporation (OEFC) through the Independent Electricity System Operator. The OPC rebate represents the OEFC surplus between fixed and wholesale electricity commodity prices during the period April 1, 2004 and March 31, 2005.

Accounts payable and accrued liabilities also includes \$1,081 (2005 - \$5,778) due to related companies. These payables arose in the normal course of operations and are due under normal terms of trade.

11. DEFERRED REVENUE

During the year, the Company collected \$330,990 (2005 - \$595,833), for a total of \$926,823 to date of revenue related to the final one-third market-based rate of return adjustment, 2006 CDM and 2006 Smart Meter funding. Also, during the year, the Company expended \$464,607 (2005 - \$139,326), for a total of \$603,933 to date towards CDM and Smart Metering activities. The net balance of revenues over expenditures to date totals \$322,890 (2005 - \$456,507).

In the absence of rate regulation, service revenue for the year would have been higher by \$322,890 (2005 - \$456,507), resulting in a pre-tax increase in net income of \$322,890 (2005 - \$456,507).

HALTON HILLS HYDRO INC.

Notes to the Non-Consolidated Financial Statements

December 31, 2006

12. NOTE PAYABLE

The note payable is due to the Town of Halton Hills, bears interest at a prescribed rate set annually by the Town and is due December 31, 2010. For 2006, the prescribed interest was set at 9.16%. In 2007, the prescribed rate of interest is 8.93%. There are no fixed terms for the repayment of principal.

13. EMPLOYEE FUTURE BENEFITS

The Company pays certain medical and life insurance benefits on behalf of its retired employees. The Company recognizes these post-retirement costs in the period in which employees' services were rendered. The accrued benefit liability at December 31, 2006 of \$456,900 (2005 - \$447,000) and the expense for the year then ended was determined by actuarial valuation using a discount rate of 5.0%.

Information regarding the defined benefit plan of the Company is as follows:

	<u>2006</u>	<u>2005</u>
Accrued benefit liability at January 1	\$ 447,000	\$ 434,500
Expense for the year ended December 31	25,735	29,220
Benefits paid during the year	(15,835)	(16,720)
Projected accrued benefit obligation at December 31 determined by actuarial valuation using a 5.0% discount rate	<u>\$ 456,900</u>	<u>\$ 447,000</u>

The main actuarial assumptions utilized for the valuation are as follows:

General Inflation – future general inflation levels, as measured by the changes in the Consumer Price Index (CPI), were assumed at 2.0% in 2006 and thereafter.

Discount (Interest) Rate – the obligation as at December 31, 2006 of the present value of future liabilities and the expense for the year then ended were determined using a discount rate of 5.0%. This corresponds to the assumed CPI rate plus an assumed real rate of return of 3.0%.

Salary levels – future general salary and wage levels were assumed to increase at the CPI rate plus productivity, merit and promotion gains of 1.3% per annum.

Medical costs – medical costs were assumed to increase at the CPI rate plus 8% in 2006. Thereafter, medical costs are assumed to decline by 1% per annum from the 2006 rate.

Dental costs – dental costs were assumed to increase at the CPI rate plus 3.0%.

HALTON HILLS HYDRO INC.

Notes to the Non-Consolidated Financial Statements

December 31, 2006

14. CONTINGENT LIABILITIES

A class action claiming \$500 million in restitutionary payments plus interest was served on Toronto Hydro on November 18, 1998. The action was initiated against the former Toronto Hydro Electric Commission as the representative of the Defendant Class consisting of all municipal electric utilities in Ontario which have charged Late Payment charges on overdue utility bills at any time after April 1, 1981.

The claim is that late payment penalties result in the municipal electric utilities receiving interest at effective rates in excess of 60% per year, which is illegal under Section 347(1)(b) of the Criminal Code.

The Company collected total late payment interest of \$1,786,238 from January 1995 to December 2006. No determination of the portion of these payments which may have constituted interest at impermissible rates has been made.

The Electricity Distributors Association is undertaking the defence of this class action. At this time it is not possible to quantify the effect, if any, on the financial statements of the Company.

15. CAPITAL STOCK

	<u>2006</u>	<u>2005</u>
Authorized		
Unlimited number of preference shares		
Unlimited number of common shares		
Issued and fully paid		
1,152 common shares	\$ 16,161,663	\$ 16,161,663

16. SERVICE REVENUE

Service revenue consists of:

	<u>2006</u>	<u>2005</u>
Cost of power	\$ 35,130,342	\$ 36,847,936
Distribution	10,489,280	8,883,939
	<u>\$ 45,619,622</u>	<u>\$ 45,731,875</u>

HALTON HILLS HYDRO INC.
Notes to the Non-Consolidated Financial Statements
December 31, 2006

17. PROVISION FOR TAXES

For the year ended December 31, 2006, the provision for PILs was \$715,000 (2005 - \$596,000). Actual expense for the year amounted to \$729,981 (2005 - \$646,313)

Future income taxes are not included in the tax provision for the company. If future income taxes were included, a future income tax asset of \$715,000 (2005 - \$1,045,000) and a future income tax cost (benefit) of \$330,000 (2005 - \$(185,000)) would have been recorded.

18. CHANGES IN NON-CASH WORKING CAPITAL

The net change in non-cash working capital consists of the following:

	<u>2006</u>	<u>2005</u>
Accounts receivable	\$ (13,426)	\$ (219,865)
Unbilled revenue	(157,988)	(1,104,815)
Inventory	(91,331)	(108,735)
Prepaid expenses and deposits	37,593	(39,880)
Accounts payable and accrued liabilities	(1,236,756)	1,725,227
Due from related companies	(7,073)	(235,226)
Deferred revenue	(133,617)	456,507
	<u>\$ (1,602,598)</u>	<u>\$ 473,213</u>

19. COMMITMENTS

The Company has minimum annual lease commitments for office equipment and software support in the following approximate amounts:

2007	\$ 4,900

There are no further commitments after 2007.

20. CREDIT FACILITIES

a) Credit limit:

The Company has available credit from a financial institution in the amount of \$3,500,000 (2005 - \$3,327,426). Credit is available to the Company in the form of prime based loans, bankers' acceptances, letters of credit or stand-by letters of guarantee. Interest on prime based loans is at prime less 0.55%. At year-end, only the letter of credit per b) below is outstanding. Security in the form of a first charge over the Company's assets and undertakings and an assignment of liability / fire insurance has been provided.

20. CREDIT FACILITIES (continued)

b) Security on Electricity purchases

As of May 2002, in order for the Company to obtain the electricity it requires to distribute to its customers, the Company is required to provide security to the Independent Electricity System Operator based on its estimated usage. The security obtained was a letter of credit issued in the amount of \$1,952,426 (2005 - \$1,952,426) from a financial institution.

c) Covenants

The above credit facilities require an interest coverage ratio of not less than 2.0 to 1, and a total interest bearing debt to capitalization ratio not greater than 0.55 to 1. As at December 31, 2006, the Company is in compliance with these covenants.

21. PENSION AGREEMENT

The Company and its employees contribute to the Ontario Municipal Employee's Retirement System (OMERS), a defined benefit pension plan for the employees of Ontario municipalities. As the Company is only liable for the contributions, defined contribution plan accounting is used by the Company. The Company's contribution for employees' current service for the year ended December 31, 2006 was \$206,651 (2005 - \$170,947).

22. FINANCIAL INSTRUMENTS

Financial risk

Financial risk is the risk to the company's earnings that arises from fluctuations in interest rates, foreign exchange rates and the degree of volatility of these rates. The Company does not use derivative instruments to reduce its exposure to interest and foreign exchange risk as management does not consider financial risk to be material.

Credit risk

The Company is exposed to credit risk from its customers, however, the concentration of this risk is minimized due to the large number of diverse customers.

Fair value

The fair value of cash, and cash equivalents, accounts receivable, unbilled revenue, notes receivable, due from related parties, accounts payable and accrued liabilities and deferred revenue was equal to the book value given the short-term nature of these items. As there is no secondary market for consumer deposits, the calculation of a fair value with appropriate reliability is impractical.

It is not practicable within the constraint of cost to determine the fair value of the note payable to parent with sufficient reliability.



Ontario

Ministry of Finance

Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

2007

CT23 Corporations Tax and

Annual Return

For taxation years commencing
after December 31, 2004

Corporations Tax Act - Ministry of Finance (MOF)

Corporations Information Act - Ministry of Government Services (MGS)

This form is a combination of the Ministry of Finance (MOF) CT23 Corporations Tax Return and the Ministry of Government Services (MGS) Annual Return. Page 1 is a common page required for both Returns. For tax purposes, depending on which criteria the corporation satisfies, it must complete either the **Exempt from Filing (EFF)** declaration on page 2 or file the CT23 Return on pages 3 - 17. Corporations that do not meet the EFF criteria but do meet the Short-Form criteria, may request and file the CT23 Short-Form Return (see page 2).

The Annual Return (common page 1 and MGS Schedule A on pages 18 and 19, and Schedule K on page 20) contains non-tax information collected under the authority of the *Corporations Information Act* for the purpose of maintaining a public database of corporate information. This return must be completed by Ontario share-capital corporations or Foreign-Business share-capital corporations that have an extra-provincial licence to operate in Ontario.

MGS Annual Return Required? (Not required if already filed or
Annual Return exempt. Refer to Guide)☐ Yes ☒ No

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Ministry Use

Corporation's Legal Name (including punctuation) HALTON HILLS HYDRO INC.			Ontario Corporations Tax Account No. (MOF) 1800262														
Mailing Address 43 ALICE STREET ACTON ON L7J2A9			This Return covers the Taxation Year Start <table><tr><td>year</td><td>month</td><td>day</td></tr><tr><td>2006</td><td>01</td><td>01</td></tr></table> End <table><tr><td>year</td><td>month</td><td>day</td></tr><tr><td>2006</td><td>12</td><td>31</td></tr></table>			year	month	day	2006	01	01	year	month	day	2006	12	31
year	month	day															
2006	01	01															
year	month	day															
2006	12	31															
Has the mailing address changed since last filed CT23 Return? ☐ Yes	Date of Change	year month day	Date of Incorporation or Amalgamation year month day 1999/04/13														
Registered/Head Office Address 43 ALICE STREET ACTON ON L7J2A9			Ontario Corporation No. (MGS) 1349889														
Location of Books and Records 43 ALICE STREET ACTON ON L7J2A9			Canada Revenue Agency Business No. If applicable, enter 867429623 RC 0001														
Name of person to contact regarding this CT23 Return	Telephone No.	Fax No.	Jurisdiction Incorporated														
ARTHUR SKIDMORE	(519) 853-3700	(519) 853-4148	ONTARIO														
Address of Principal Office in Ontario (Extra-Provincial Corporations only) (MGS)			If not incorporated in Ontario, indicate the date Ontario business activity commenced and ceased: Commenced <table><tr><td>year</td><td>month</td><td>day</td></tr></table> Ceased <table><tr><td>year</td><td>month</td><td>day</td></tr></table> ☒ Not Applicable			year	month	day	year	month	day						
year	month	day															
year	month	day															
Former Corporation Name (Extra-Provincial Corporations only) ☒ Not Applicable (MGS)			Preferred Language / Langue de préférence ☒ English anglais ☐ French français														
Information on Directors/Officers/Administrators must be completed on MGS Schedule A or K as appropriate. If additional space is required for Schedule A, only this schedule may be photocopied. State number submitted (MGS). If there is no change to the Directors'/Officers'/Administrators' information previously submitted to MGS, please check ☒ this box. Schedule(s) A and K are not required (MGS). No. of Schedule(s) <table><tr><td></td></tr></table> ☒ No Change				Ministry Use 													

Certification (MGS)

I certify that all information set out in the Annual Return is true, correct and complete.

Name of Authorized Person (Print clearly or type in full)

Title ☐ Director ☒ Officer ☐ Other individuals having knowledge of the Corporation's business activities

Note: Sections 13 and 14 of the Corporations Information Act provide penalties for making false or misleading statements or omissions.

CT23 Corporations Tax Return

Identification continued (for CT23 filers only)

Please check applicable ☒ box(es) and complete required information.

Type of corporation

- ☒ 1 ☒ Canadian-controlled Private (CCPC) all year (Generally a private corporation of which 50% or more shares are owned by Canadian residents.) (fed.s.125(7)(b))
- 2 ☐ Other Private
- 3 ☐ Public
- 4 ☐ Non-share Capital
- 5 ☐ Other (specify) ▼

Share Capital with full voting rights (nearest percent)
owned by Canadian Residents %

- ☐ 2 1 ☐ Family Farm corporation s.1(2)
- 2 ☐ Family Fishing corporation s.1(2)
- 3 ☐ Mortgage Investment corporation s.47
- 4 ☐ Credit Union s.51
- 5 ☐ Bank Mortgage subsidiary s.61(4)
- 6 ☐ Bank s.1(2)
- 7 ☐ Loan and Trust corporation s.61(4)
- 8 ☐ Non-resident corporation s.2(2)(a) or (b)
- 9 ☐ Non-resident corporation s.2(2)(c)
- 10 ☐ Mutual Fund corporation s.48
- 11 ☐ Non-resident owned Investment corporation s.49
- 12 ☐ Non-resident ship or aircraft under reciprocal agreement with Canada s.28(b)
- 14 ☐ Bare Trustee corporation
- 15 ☐ Branch of Non-resident s.63(1)
- 16 ☐ Financial institution prescribed by Regulation only
- 17 ☐ Investment Dealer
- 18 ☐ Generator of electrical energy for sale or producer of steam for use in the generation of electrical energy for sale
- 19 ☒ Hydro successor, municipal electrical utility or subsidiary of either
- 20 ☐ Producer and seller of steam for uses other than for the generation of electricity
- 21 ☐ Insurance Exchange s.74.4
- 22 ☐ Farm Feeder Finance Co-operative corporation
- 23 ☐ Professional corporation (incorporated professionals only)

- ☐ This is the first year filing after incorporation or an amalgamation (If checked, attach Ontario Schedule 24.)
- ☐ Amended Return
- ☐ Taxation year end change - Canada Revenue Agency approval required
- ☐ Final taxation year up to dissolution (Note: for discontinued businesses, see guide.)
- ☐ Final taxation year before amalgamation
- ☐ The corporation has a floating fiscal year end
- ☐ There has been a transfer or receipt of asset(s) involving a corporation having a Canadian permanent establishment outside Ontario
- ☐ There was an acquisition of control to which subsection 249(4) of the federal *Income Tax Act* (ITA) applies since the previous taxation year
- If checked, date control was acquired
- ☐ The corporation was involved in a transaction where all or substantially all (90% or more) of the assets of a non-arm's length corporation were received in the taxation year and subsection 85(1) or 85(2) of the federal ITA applied to the transaction (If checked, attach Ontario Schedule 44.)
- ☐ First year filing of a parent corporation after winding-up a subsidiary corporation(s) under section 88 of the federal ITA during the taxation year. (If checked, attach Ontario Schedule 24.)
- ☐ Section 83.1 of the CTA applies (redirection of payments for certain electricity corporations)

Yes No

- ☐ ☒ Was the corporation inactive throughout the taxation year?
- ☒ ☐ Has the corporation's Federal T2 Return been filed with the Canada Revenue Agency?
- Are you requesting a refund due to:
- ☐ ☒ the Carry-back of a Loss?
- ☒ ☐ an Overpayment?
- ☐ ☒ a Specified Refundable Tax Credit?
- ☒ ☐ Are you a member of a Partnership or Joint Venture?

Complete if applicable

Ontario Retail Sales Tax Vendor
Permit no. (Use head office no.)

Specify major business activity

DISTRIBUTION OF ELECTRICITY

Ontario Employer Health Tax
Account no. (Use head office no.)

Corporation's Legal Name
HALTON HILLS HYDRO INC.

Ontario Corporations Tax Account No. (MOF)
1800262

Taxation Year End
2006/12/31

CT23 Page 5 of 20

DOLLARS ONLY

Income Tax continued from Page 4

Number of Days in Taxation Year

Calculation of IDSBC Rate

7.0% X

Days after
Dec. 31, 2002 and
before Jan. 1, 2004
31 ÷ 73 365

Total Days

365

= + 89

8.5% X

Days after
Dec. 31, 2003
34 ÷ 73 365

Total Days

365

= + 90

8.5000

IDSBC Rate for Taxation Year

89 + 90

= 78

8.5000

Claim From 60 400,000 X From 78 8.5000 % = 70 34,000

Corporations claiming the IDSBC must complete the Surtax section below if the corporation's taxable income (or if associated, the associated group's taxable income) is greater than the amount in 114 below.

Surtax on Canadian-controlled Private Corporations (s.41.1)

Applies if you have claimed the Incentive Deduction for Small Business Corporations.

Associated Corporation - The Taxable Income of associated corporations is the taxable income for the taxation year ending on or before the date of this corporation's taxation year end.

*Taxable Income of the corporation From 10 (or 20 if applicable) + 80 1,921,918

If you are a member of an associated group (X) 81 X (Yes)

Name of associated corporation (Canadian & foreign)
(If insufficient space, attach schedule)

Ontario Corporations Tax
Account No. (MOF)
(if applicable)

Taxation Year End

*Taxable Income
(if loss, enter nil)

Aggregate Taxable Income 80 + 82 + 83 + 84, etc = 85 1,921,918

Number of Days in Taxation Year

320,000 X

Days after
Dec. 31, 2002 and
before Jan. 1, 2004
31 ÷ 73 365

= + 115

400,000 X

Days after
Dec. 31, 2003
34 ÷ 73 365

= + 116

400,000

115 + 116

=

400,000

114 400,000

(If negative, enter nil) = 86 1,521,918

Number of Days in Taxation Year

Calculation of Specified Rate for Surtax

4.667% X

Days after
Dec. 31, 2002
38 ÷ 73 365

Total Days

365

= + 97

4.6670

From 86 1,521,918

X

From 97

4.6670 %

= 87

71,028

From 87 71,028

X

From 60

400,000 ÷

From 114

400,000

= 88

71,028

Surtax Lesser of 70 or 88 = 100 34,000

* **Note: Short Taxation Years** - Special rules apply where the taxation year is less than 51 weeks for the corporation and/or any corporation associated with it.

continued on Page 6

Corporation's Legal Name
HALTON HILLS HYDRO INC.

Ontario Corporations Tax Account No. (MOF)
1800262

Taxation Year End
2006/12/31

CT23 Page 6 of 20

DOLLARS ONLY

Income Tax continued from Page 5

Additional Deduction for Credit Unions (s.51(4)) (Attach schedule 17) - - - - -

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Manufacturing and Processing Profits Credit (M&P) (s.43)

Applies to Eligible Canadian Profits from manufacturing and processing, farming, mining, logging and fishing carried on in Canada, as determined by regulations.

Eligible Canadian Profits from mining are the "resource profits from the mining operations", as determined for Ontario depletion purposes, after deducting depletion and resource allowances but excluding amounts from sale of Canadian resource property, rentals or royalties. If you are claiming this credit, attach a copy of Ontario schedule 27.

The whole of the active business income qualifies as Eligible Canadian Profits if: a) your active business income from sources other than manufacturing and processing, mining, farming, logging or fishing is 20% or less of the total active business income and b) the total active business income is \$250,000 or less.

Eligible Canadian Profits - - - - - + 120

Subtract: Income eligible for the Incentive Deduction for Small Business Corporations (IDSBC) - - - - - From 56 400,000

Add: Adjustment for Surtax on Canadian-controlled private corporations

From 100 34,000 ÷ From 30 100.0000 % ÷ From 78 8.5000 % = 121 400,000

*Ontario Allocation

Lesser of 56 or 121 - - - - - + 122 400,000

120 - 56 + 122 - - - - - = 130

Taxable Income - - - - - + From 10 1,921,918

Subtract: Income eligible for the Incentive Deduction for Small Business Corporations (IDSBC) - - - - - From 56 400,000

Add: Adjustments for Surtax on Canadian-controlled private corporations - - - - - + From 122 400,000

Subtract: Taxable Income 10 X Allocation % to jurisdictions outside Canada - - - - - 140

Subtract: Amount by which Canadian and foreign investment income exceeds net capital losses - - - - - 141

10 - 56 + 122 - 140 - 141 - - - - - = 142 1,921,918

Claim

Number of Days in Taxation Year

Days after Dec. 31, 2002
and before Jan. 1, 2004

Total Days

33 ÷ 73 365

Days after Dec. 31, 2003

Total Days

34 365 ÷ 73 365

143 Lesser of 130 or 142 X From 30 100.0000 % X 1.5% X

143 Lesser of 130 or 142 X From 30 100.0000 % X 2.0% X

M&P claim for taxation year 154 + 156 - - - - - = 160

*Note: Ontario Allocation for M&P Credit purposes may differ from 30 if Taxable Income is allocated to foreign jurisdictions. See special rules (s.43(1))

Manufacturing and Processing Profits Credit for Electrical Generating Corporations

= 161

Manufacturing and Processing Profits Credit for Corporations that Produce and Sell Steam for uses other than the Generation of Electricity

= 162

Credit for Foreign Taxes Paid (s.40)

Applies if you paid tax to a jurisdiction outside Canada on foreign investment income (Int.B. 3001R). (Attach schedule)

170

Credit for Investment in Small Business Development Corporations (SBDC)

Applies if you have an unapplied, previously approved credit from prior years' investments in new issues of equity shares in Small Business Development Corporations. Any unused portion may be carried forward indefinitely and applied to reduce subsequent years' income taxes. (Refer to the former *Small Business Development Corporations Act*)

Eligible Credit

175

Credit Claimed

180

Subtotal of Income Tax 40 - 70 + 100 - 110 - 160 - 161 - 162 - 170 - 180 - - - - - = 190 269,069

continued on Page 7

Corporation's Legal Name HALTON HILLS HYDRO INC.	Ontario Corporations Tax Account No. (MOF) 1800262	Taxation Year End 2006/12/31

Income Tax *continued from Page 6*

DOLLARS ONLY

Specified Tax Credits (Refer to Guide)**Ontario Innovation Tax Credit (OITC) (s.43.3)** *Applies to scientific research and experimental development in Ontario.*Eligible Credit From **5620** OITC Claim Form (Attach original Claim Form) - - - - - + **191****Co-operative Education Tax Credit (CETC) (s.43.4)** *Applies to employment of eligible students.*Eligible Credit From **5798** CT23 Schedule 113 (Attach Schedule 113) - - - - - + **192****Ontario Film & Television Tax Credit (OFTTC) (s.43.5)***Applies to qualifying Ontario labour expenditures for eligible Canadian content film and television productions.* Name of Production **204**Eligible Credit From **5850** of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC) (Attach the original Certificate of Eligibility) - - - - - + **193****Graduate Transitions Tax Credit (GTTC) (s.43.6)**No. of Graduates From **6596***Applies to employment of eligible unemployed post secondary graduates, for employment commencing prior to July 6, 2004 and expenditures incurred prior to January 1, 2005.* **194**Eligible Credit From **6598** CT23 Schedule 115 (Attach Schedule 115) - - - - - + **195****Ontario Book Publishing Tax Credit (OBPTC) (s.43.7)***Applies to qualifying expenditures in respect of eligible literary works by eligible Canadian authors.*Eligible Credit From **6900** OBPTC Claim Form (Attach both the original Claim Form and the Certificate of Eligibility)- - - - - + **196****Ontario Computer Animation and Special Effects Tax Credit (OCASE) (s.43.8)***Applies to labour relating to computer animation and special effects on an eligible production.*Eligible Credit From **6700** of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC) (Attach the original Certificate of Eligibility) - - - - - + **197****Ontario Business-Research Institute Tax Credit (OBRITC) (s.43.9)***Applies to qualifying R&D expenditures under an eligible research institute contract.*Eligible Credit From **7100** OBRITC Claim Form (Attach original Claim Form) - - - - - + **198****Ontario Production Services Tax Credit (OPSTC) (s.43.10)***Applies to qualifying Ontario labour expenditures for eligible productions where the OFTTC has not been claimed.*Eligible Credit From **7300** of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC) (Attach the original Certificate of Eligibility) - - - - - + **199****Ontario Interactive Digital Media Tax Credit (OIDMTC) (s.43.11)***Applies to qualifying labour expenditures of eligible products for the taxation year.*Eligible Credit From **7400** of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC) (Attach the original Certificate of Eligibility) - - - - - + **200****Ontario Sound Recording Tax Credit (OSRTC) (s.43.12)***Applies to qualifying expenditures in respect of eligible Canadian sound recordings.*Eligible Credit From **7500** OSRTC Claim Form (Attach both the original Claim Form and the Certificate of Eligibility) - - - - - + **201****Apprenticeship Training Tax Credit (ATTC) (s.43.13)**No. of Apprentices From **5896***Applies to employment of eligible apprentices.* **202** 2Eligible Credit From **5898** CT23 Schedule 114 (Attach Schedule 114) - - - - - + **203** 10,000**Total Specified Tax Credits** **191** + **192** + **193** + **195** + **196** + **197** + **198** + **199** + **200** + **201** + **203** = **220** 10,000**Specified Tax Credits Applied to reduce Income Tax** - - - - - = **225** 10,000**Income Tax** **190** - **225** OR Enter NIL if reporting Non-Capital loss (amount cannot be negative) - - - = **230** 259,069To determine if the Corporate Minimum Tax (CMT) is applicable to your Corporation, see **Determination of Applicability** section for the CMT on **Page 8**. If CMT is not applicable, transfer amount in **230** to Income Tax in **Summary** section on **Page 17**.

OR

If CMT is not applicable for the current taxation year but your corporation has CMT Credit Carryovers that you want to apply to reduce income tax otherwise payable, then proceed to and complete the **Application of CMT Credit Carryovers** section part B, on **Page 8**.

Corporation's Legal Name
HALTON HILLS HYDRO INC.

Ontario Corporations Tax Account No. (MOF)
1800262

Taxation Year End
2006/12/31

DOLLARS ONLY

Corporate Minimum Tax (CMT)

Total Assets of the corporation - - - - - + [240] 45,524,452
Total Revenue of the corporation - - - - - + [241] 47,165,520

The above amounts include the corporation's and associated corporations' share of any partnership(s) / joint venture(s) total assets and total revenue.

If you are a member of an associated group (x) [242] ☒ (Yes)

Name of associated corporation (Canadian & foreign) (if insufficient space attach schedule)	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End	Total Assets	Total Revenue
See attached schedule			+ [243] 5,741,629	+ [244] 2,416,228
			+ [245]	+ [246]
			+ [247]	+ [248]
Aggregate Total Assets	[240] + [243] + [245] + [247], etc		= [249] 51,266,081	
Aggregate Total Revenue	[241] + [244] + [246] + [248], etc			= [250] 49,581,748

Determination of Applicability

Applies if either Total Assets [249] exceeds \$5,000,000 or Total Revenue [250] exceeds \$10,000,000.

Short Taxation Years - Special rules apply for determining total revenue where the taxation year of the corporation or any associated corporation or any fiscal period of any partnership(s) / joint venture(s) of which the corporation or associated corporation is a member, is less than 51 weeks.

Associated Corporation - The total assets or total revenue of associated corporations is the total assets or total revenue for the taxation year ending on or before the date of the claiming corporation's taxation year end.

If CMT is applicable to current taxation year, complete section Calculation: CMT below and Corporate Minimum Tax Schedule 101.

Calculation: CMT (Attach Schedule 101.)

Gross CMT Payable - - CMT Base From Sch. 101 [2136] 1,895,292	X From [30] 100.0000 % X 4% =	[276] 75,812
if negative, enter zero		Ontario Allocation
Subtract: Foreign Tax Credit for CMT purposes (Attach schedule) - - - - -	-	[277]
Subtract: Income Tax - - - - -	- From [190]	269,069
Net CMT Payable (if negative, enter Nil on Page 17.) - - - - -	=	[280] -193,257

If [280] is less than zero and you do not have a CMT credit carryover, transfer [230] from Page 7 to Income Tax Summary, on Page 17.

If [280] is less than zero and you have a CMT credit carryover, complete A & B below.

If [280] is greater than or equal to zero, transfer [230] to Page 17 and transfer [280] to Page 17, and to Part 4 of

Schedule 101: Continuity of CMT Credit Carryovers.

CMT Credit Carryover available From Schedule 101 From [2333]

Application of CMT Credit Carryovers

A. Income Tax (before deduction of specified credits) - - - - -	+ From [190]	269,069
Gross CMT Payable - - - - -	+ From [276]	75,812
Subtract: Foreign Tax Credit for CMT purposes - - - - -	- From [277]	
If [276] - [277] is negative, enter NIL in [290] =		[290] 75,812
Income Tax eligible for CMT Credit - - - - -	=	[300] 193,257
B. Income Tax (after deduction of specified credits) - - - - -	+ From [230]	259,069
Subtract: CMT credit used to reduce income taxes - - - - -	- [310]	
Income Tax - - - - -	=	[320] 259,069

If A & B apply, [310] cannot exceed the lesser of [230], [300] and your CMT credit carryover available [2333].

If only B applies, [310] cannot exceed the lesser of [230] and your CMT credit carryover available [2333].

Transfer to page 17

Capital Tax (Refer to Guide and Int.B. 3011R)

If your corporation is a Financial Institution (s.58(2)), complete lines 480 and 430 on page 10 then proceed to page 13.

If your corporation is not a member of an associated group and/or partnership and the Gross Revenue and Total Assets as calculated on page 10 in 480 and 430 are both \$3,000,000 or less, your corporation is exempt from Capital Tax for the taxation year, except for a branch of a non-resident corporation. A corporation that meets these criteria should disregard all other Capital Tax items (including the calculation of Taxable Capital). Enter NIL in 550 on page 12 and complete the return from that point. All other corporations must compute their Taxable Capital in order to determine their Capital Tax payable.

Members of a partnership (limited or general) or a joint venture, must attach all financial statements of each partnership or joint venture of which they are a member. The Paid-up Capital of each corporate partner must include its share of liabilities that would otherwise be included if the partnership were a

corporation. If Investment Allowance is claimed, Total Assets must be adjusted by adding the corporation's share of the partnership's Total Assets and by deducting investments in the partnership as it appears on the corporation's balance sheet, in addition to any other required adjustments (s.61(5)). Special rules apply to limited partnerships (Int.B. 3017R).

Any Assets and liabilities of a corporation that are being utilized in a joint venture must be included along with the corporation's other Assets and liabilities when calculating its Taxable Paid-up Capital.

Special rules and rates apply to Non-Resident corporations (s.63, s.64 and s.69(3)).

Paid-up Capital of Non-resident: Paid-up capital employed in Canada of a non-resident subject to tax by virtue of s.2(2)(a) or 2(2)(b), and whose business is not carried on solely in Canada is deemed to be the greater of (1) taxable income in Canada divided by 8 percent or (2) total assets in Canada minus certain indebtedness in accordance with the provisions of s.63(1)(a) (Int.B. 3010).

Paid-up Capital

Paid-up capital stock (Int.B. 3012R and 3015R)	- - - - -	+	350	16,161,663
Retained earnings (if deficit, deduct) (Int.B. 3012R)	- - - - -	±	351	4,231,115
Capital and other surpluses, excluding appraisal surplus (Int.B.3012R)	- - - - -	+	352	
Loans and advances (Attach schedule) (Int.B. 3013R)	- - - - -	+	353	17,024,242
Bank loans (Int.B. 3013R)	- - - - -	+	354	
Bankers acceptances (Int.B. 3013R)	- - - - -	+	355	
Bonds and debentures payable (Int.B. 3013R)	- - - - -	+	356	
Mortgages payable (Int.B. 3013R)	- - - - -	+	357	
Lien notes payable (Int.B. 3013R)	- - - - -	+	358	
Deferred credits (including income tax reserves, and deferred revenue where it would also be included in paid-up capital for the purposes of the large corporations tax) (Int.B. 3013R)	- - - - -	+	359	
Contingent, investment, inventory and similar reserves (Int.B. 3012R)	- - - - -	+	360	
Other reserves not allowed as deductions for income tax purposes (Attach schedule) (Int.B. 3012R)	- - - - -	+	361	456,900
Share of partnership(s) or joint venture(s) paid-up capital (Attach schedule(s)) (Int.B. 3017R)	- - - - -	+	362	17,545
Subtotal	- - - - -	=	370	37,891,465
Subtract: Amounts deducted for income tax purposes in excess of amounts booked (Retain calculations. Do not submit.) (Int.B. 3012R)	- - - - -	-	371	-661,085
Deductible R&D expenditures and ONTTI costs deferred for income tax if not already deducted for book purposes (Int.B. 3015R)	- - - - -	-	372	
Total Paid-up Capital	- - - - -	=	380	38,552,550
Subtract: Deferred mining exploration and development expenses (s.62(1)(d)) (Int.B. 3015R)	- - - - -	-	381	
Electrical Generating Corporations Only - All amounts with respect to electrical generating assets, except to the extent that they have been deducted by the corporation in computing its income for income tax purposes for the current or any prior taxation year, that are deductible by the corporation under clause 11(10)(a) of the Corporations Tax Act, and the assets are used both in generating electricity from a renewable or alternative energy source and are qualifying property as prescribed by regulation	- - - - -	-	382	
Net Paid-up Capital	- - - - -	=	390	38,552,550

Eligible Investments (Refer to Guide and Int.B.3015R)

Attach computations and list of corporation names and investment amounts. Short-term investments (bankers acceptances, commercial paper, etc.) are eligible for the allowance only if issued for a term of and held for 120 days or more prior to the year end of the investor corporation.

Bonds, lien notes and similar obligations, (similar obligations, e.g. stripped interest coupons, applies to taxation years ending after October 30, 1998)	- - - - -	+	402	
Mortgages due from other corporations	- - - - -	+	403	
Shares in other corporations (certain restrictions apply) (Refer to Guide)	- - - - -	+	404	865,552
Loans and advances to unrelated corporations	- - - - -	+	405	
Eligible loans and advances to related corporations (certain restrictions apply) (Refer to Guide)	- - - - -	+	406	865,551
Share of partnership(s) or joint venture(s) eligible investments (Attach schedule)	- - - - -	+	407	
Total Eligible Investments	- - - - -	=	410	1,731,103

continued on Page 10

Capital Tax *continued from Page 9***Total Assets** (Int.B.3015R)

Total Assets per balance sheet	- - - - -	+	420	45,524,452
Mortgages or other liabilities deducted from assets	- - - - -	+	421	
Share of partnership(s)/joint venture(s) total assets (Attach schedule)	- - - - -	+	422	
Subtract: Investment in partnership(s)/joint venture(s)	- - - - -	-	423	
Total Assets as adjusted	- - - - -	=	430	45,524,452
Amounts in 360 and 361 (if deducted from assets)	- - - - -	+	440	456,900
Subtract: Amounts in 371, 372 and 381	- - - - -	-	441	-661,085
Subtract: Appraisal surplus if booked	- - - - -	-	442	
Add or Subtract: Other adjustments (specify on an attached schedule)	- - - - -	±	443	
Total Assets	- - - - -	=	450	46,642,437

Investment Allowance (410 ÷ 450) X 390 - - - - - **Not to exceed** 410 = 460 1,430,852**Taxable Capital** 390 - 460 - - - - - = 470 37,121,698**Gross Revenue** (as adjusted to include the share of any partnership(s)/joint venture(s) Gross Revenue)- 480 47,165,520**Total Assets** (as adjusted) - - - - - From 430 45,524,452**Calculation of Capital Tax for all Corporations except Financial Institutions****Note:** This version (2007) of the CT23 may only be used for a taxation year that commenced after December 31, 2004.

Financial Institutions use calculations on page 13.

Important:If the corporation is a family farm corporation, family fishing corporation or a credit union that is not a Financial Institution, complete only **Section A** below.**OR** If the corporation is **not** a member of an associated group and/or partnership, complete **Section B** below, then review only the Capital Tax calculations in **Section C** on page 11, selecting and completing the one specific subsection (e.g. C3) that applies to the corporation.**OR** If the corporation is a member of an associated group and/or partnership, complete **Section B** below and **Section D** on page 11, and if applicable, complete **Section E** or **Section F** on page 12. Note: If the corporation is a member of a connected partnership, please refer to the CT23 Guide for additional instructions before completing the Capital Tax section.**SECTION A**

This section applies only if the corporation is a family farm corporation, a family fishing corporation or a credit union that is not a Financial Institution (Int.B.3018).

Enter NIL in 550 on page 12 and complete the return from that point.

SECTION B**B1. Calculation of Taxable Capital Deduction (TCD) Number of Days in Taxation Year**

7,500,000	X	Days after Dec. 31, 2004 and before Jan. 1, 2006	÷	Total Days	= +	
		36		73 365		
10,000,000	X	Days after Dec. 31, 2005 and before Jan. 1, 2007	÷	Total Days	= +	
		37 365		73 365		10,000,000
12,500,000	X	Days after Dec. 31, 2006 and before Jan. 1, 2008	÷	Total Days	= +	
		38		73 365		
15,000,000	X	Days after Dec. 31, 2007	÷	Total Days	= +	
		39		73 365		
Taxable Capital Deduction (TCD)					=	503 10,000,000

B2. This section applies to corporations to calculate the prorated capital tax rate.

Calculation of Capital Tax Rate

Number of Days in Taxation Year

0.3%	X	Days before Jan. 1, 2007	÷	Total Days	= +	
		556 365		73 365		0.3000 %
0.285%	X	Days after Dec. 31, 2006 and before Jan. 1, 2009	÷	Total Days	= +	
		557		73 365		%
Capital Tax Rate					=	511 + 512 0.3000 %

continued on Page 11

Capital Tax Calculation *continued from Page 10***SECTION C**

This section applies if the corporation is **not** a member of an associated group and/or partnership.

- C1.** If and on page 10 are both \$3,000,000 or less, enter NIL in on page 12 and complete the return from that point.
- C2.** If Taxable Capital in is equal to or less than the TCD in , enter NIL in on page 12 and complete the return from that point.
- C3.** If Taxable Capital in exceeds the TCD in , complete the following calculation and transfer the amount from to on page 12, and complete the return from that point.

+	From	470	37,121,698	
-	From	503		
=		471		
			X From 30	
			100.0000 %	
			X From 516	
			0.3000 %	
			X 555	
			365	
			=+	523

Ontario Allocation Capital Tax Rate 365 (366 if leap year)
If floating taxation year, refer to Guide.

Transfer to on page 12 and complete the return from that point

SECTION D

This section applies **ONLY** to a corporation that is a member of an associated group (excluding Financial Institutions and corporations exempt from Capital Tax) and/or partnership. You must check either or and complete this section before you can calculate your Capital Tax Calculation under either Section E or Section F.

- D1.** ☐ (X if applicable) All corporations that you are associated with do **not** have a permanent establishment in Canada.
- If Taxable Capital on page 10 is equal to or less than the TCD on page 10, enter NIL in on page 12 and complete the return from that point.
- If Taxable Capital on page 10 exceeds the TCD on page 10, proceed to **Section E**, enter the TCD amount in in Section E, and complete Section E and the return from that point.

- D2.** ☒ (X if applicable) One or more of the corporations that you are associated with **maintains** a permanent establishment in Canada.

You and your associated group may continue to allocate the TCD by completing the Calculation below. Or, the associated group **may file an election** under subsection 69(2.1) of the *Corporations Tax Act*, whereby total assets are used to allocate the TCD among the associated group. Once a ss.69(2.1) election is filed, all members of the group will then be required to file in accordance with the election and allocate a portion (portion is henceforth referred to as **Net Deduction**) of the capital tax effect relating to the TCD to each corporation in the group on the basis of the ratio that each corporation's total assets multiplied by its Ontario allocation is to the total assets of the group.

The total asset amounts and Ontario allocation percentages to be used for this calculation must be taken from each corporation's financial information from its last taxation year ending in the immediately preceding calendar year.

In addition, although each corporation in the associated group may deduct its Net Deduction amount as apportioned by the total asset formula, the group may, at the group's option, reallocate the group's total Net Deduction among the group on what ever basis the corporate group wishes, as long as the total of the reallocated amounts does not exceed the group's total Net Deduction amount originally calculated for the associated group.

D2. Calculation is on next page

Capital Tax *continued from Page 12*

Calculation of Capital Tax for Financial Institutions

1.1. Credit Unions only

For taxation years commencing **after May 4, 1999** enter NIL in on page 12, and complete the return from that point.

1.2. Other than Credit Unions

(Retain details of calculations for amounts in boxes and . Do not submit with this tax return.)

565	X	567	% X From	30	100.0000	% X	555	Days in taxation year 365	= +	569
Lesser of adjusted Taxable Paid Up Capital and Basic Capital Amount in accordance with Division B.1		Capital Tax Rate (1) (Refer to Guide)		Ontario Allocation				*365 (366 if leap year)		

570	X	571	% X From	30	100.0000	% X	555	Days in taxation year 365	= +	574
Adjusted Taxable Paid Up Capital in accordance with Division B.1 in excess of Basic Capital Amount		Capital Tax Rate (2) (Refer to Guide)		Ontario Allocation				*365 (366 if leap year)		

Capital Tax for Financial Institutions - other than Credit Unions (before Section 2) + - - - - - =

* If floating taxation year, refer to Guide.

2. Small Business Investment Tax Credit

(Retain details of eligible investment calculation and, if claiming an investment in CSBIF, retain the original letter approving the credit issued in accordance with the Community Small Business Investment Fund Act. Do not submit with this tax return.)

Allowable Credit for Eligible Investments - - - - -
 Financial Institutions: Claiming a tax credit for investment in Community Small Business Investment Fund (CSBIF)? (X) ☐ Yes

Capital Tax - Financial Institutions - - - - - - =

Transfer to on Page 12

Premium Tax (s.74.2 & 74.3) (Refer to Guide)

(1) Uninsured Benefits Arrangements - - - - - X 2% - - - - - =
Applies to Ontario-related uninsured benefits arrangements.

(2) Unlicensed Insurance (enter premium tax payable in and attach a detailed schedule of calculations. If subject to tax under (1) above, add both taxes together and enter total tax in .)
Applies to Insurance Brokers and other persons placing insurance for persons resident or property situated in Ontario with unlicensed insurers.

Deduct: Specified Tax Credits applied to reduce premium tax (Refer to Guide) - - - - -

Premium Tax - - - - - - =

Transfer to page 17

Reconcile net income (loss) for federal income tax purposes with net income (loss) for Ontario purposes if amounts differ

Net Income (loss) for federal income tax purposes, per federal T2 Schedule 1 ± 600 1,921,918.

Transfer to Page 15

Add:

Federal capital cost allowance - - - - -	+	601	1,902,072	•
Federal cumulative eligible capital deduction - - - - -	+	602	61,955	•
Ontario taxable capital gain - - - - -	+	603		•
Federal non-allowable reserves. Balance beginning of year - - - - -	+	604		•
Federal allowable reserves. Balance end of year - - - - -	+	605		•
Ontario non-allowable reserves. Balance end of year - - - - -	+	606		•
Ontario allowable reserves. Balance beginning of year - - - - -	+	607		•
Federal exploration expenses (e.g. CEDE, CEE, CDE, COGPE) - - - - -	+	608		•
Federal resource allowance (Refer to Guide) - - - - -	+	609		•
Federal depletion allowance - - - - -	+	610		•
Federal foreign exploration and development expenses - - - - -	+	611		•
Crown charges, royalties, rentals, etc. deducted for Federal purposes (Refer to Guide) - - - - -	+	617		•
Management fees, rents, royalties and similar payments to non-arm's length non-residents ▼				

Number of Days in Taxation Year

612 • X $5_{/12.5}$ x

Days after Dec. 31, 2002 and before Jan. 1, 2004	Total Days
33	73 365

 = + 633 •

612 • X $5_{/14.0}$ x

Days after Dec. 31, 2003	Total Days
34 365	73 365

 = + 634 •

Total add-back amount for Management fees, etc. 633 + 634 = 613 •

Federal Scientific Research Expenses claimed in year from line 460 of fed. form T661 excluding any negative amount in 473 from Ont. CT23 Schedule 161 - - - - - + 615 •

Add any negative amount in 473 from Ont. CT23 Schedule 161 - - - - - + 616 27,781 •

Federal allowable business investment loss - - - - - + 620 •

Total of other items not allowed by Ontario but allowed federally (Attach schedule) - - - + 614 •

Total of Additions 601 to 611 + 617 + 613 + 615 + 616 + 620 + 614 = 1,991,808 640 1,991,808.

Transfer to Page 15

Deduct:

Ontario capital cost allowance (excludes amounts deducted under 675) - - - - -	+	650	1,902,072	•
Ontario cumulative eligible capital deduction - - - - -	+	651	61,955	•
Federal taxable capital gain - - - - -	+	652		•
Ontario non-allowable reserves. Balance beginning of year - - - - -	+	653		•
Ontario allowable reserves. Balance end of year - - - - -	+	654		•
Federal non-allowable reserves. Balance end of year - - - - -	+	655		•
Federal allowable reserves. Balance beginning of year - - - - -	+	656		•
Ontario exploration expenses (e.g. CEDE, CEE, CDE, COGPE) (Retain calculations. Do not submit.) - - - - -	+	657		•
Ontario depletion allowance - - - - -	+	658		•
Ontario resource allowance (Refer to Guide) - - - - -	+	659		•
Ontario current cost adjustment (Attach schedule) - - - - -	+	661		•
CCA on assets used to generate electricity from natural gas, alternative or renewable resources. - - - - -	+	675		•

Subtotal of deductions for this page 650 to 659 + 661 + 675 - - - - - = 681 1,964,027 •

Transfer to Page 15

continued on Page 15

Corporation's Legal Name
HALTON HILLS HYDRO INC.

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DOLLARS ONLY

**Reconcile net income (loss) for federal income tax purposes with net income (loss)
for Ontario purposes if amounts differ**

continued from Page 14

Net Income (loss) for federal income tax purposes, per federal Schedule 1 - - - - - From ± 600 1,921,918.
Total of Additions on page 14 - - - - - From = 640 1,991,808.
Sub Total of deductions on page 14 - - - - - From = 681 1,964,027.

Deduct:

Ontario New Technology Tax Incentive (ONTTI) Gross-up

(Applies only to those corporations whose Ontario allocation is less than 100% in the current taxation year.)

Capital Cost Allowance (Ontario)(CCA) on prescribed qualifying
intellectual property deducted in the current taxation year - - 662

ONTTI Gross-up deduction calculation:

From 662	Gross-up of CCA	X	100	- From 662	=	663
	From 30		100.0000			
	Ontario allocation					

Workplace Child Care Tax Incentive (WCCT)

(Applies to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: 665	X 30% X	100	=	666
	From 30	100.0000		
	Ontario allocation			

Workplace Accessibility Tax Incentive (WATI)

(Applies to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: 667	X 100% X	100	=	668
	From 30	100.0000		
	Ontario allocation			

Number of Employees accommodated 669

Ontario School Bus Safety Tax Incentive (OSBSTI)

(Applies to the eligible acquisition of school
buses purchased after May 4, 1999 and before January 1, 2006.)(Refer to Guide)

Qualifying expenditures: 670	X 30% X	100	=	671
	From 30	100.0000		
	Ontario allocation			

Educational Technology Tax Incentive (ETTI)

(Applies to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: 672	X 15% X	100	=	673
	From 30	100.0000		
	Ontario allocation			

Ontario allowable business investment loss - - - - - + 678

Ontario Scientific Research Expenses claimed in year in 477
from Ont. CT23 Schedule 161 - - - - - + 679

Amount added to income federally for an amount that was negative on federal
form T661, line 454 or 455 (if filed after June 30, 2003) - - - - - + 677 27,781.

Total of other deductions allowed by Ontario (Attach schedule) - - - - - + 664

Total of Deductions

681 + 663 + 666 + 668 + 671 + 673 + 678 + 679 + 677 + 664 - - - - - = 1,991,808. 680 1,991,808.

Net income (loss) for Ontario Purposes 600 + 640 - 680 - - - - - = 690 1,921,918.

Transfer to Page 4

Continuity of Losses Carried Forward

	Non-Capital Losses (1)	Total Capital Losses	Farm Losses	Restricted Farm Losses	Listed Personal Property Losses	Limited Partnership Losses (6)
Balance at Beginning of Year	700 (2)	710 (2)	720 (2)	730	740	750
Add:						
Current year's losses (7)	701	711	721	731	741	751
Losses from predecessor corporations (3)	702	712	722	732		752
Subtotal	703	713	723	733	743	753
Subtract:						
Utilized during the year to reduce taxable income	704 (2)	715 (2)(4)	724 (2)	734 (2)(4)	744 (4)	754 (4)
Expired during the year	705		725	735	745	
Carried back to prior years to reduce taxable income (5)	706 (2) to Page 17	716 (2) to Page 17	726 (2) to Page 17	736 (2) to Page 17	746	
Subtotal	707	717	727	737	747	757
Balance at End of Year	709 (8) <NIL>	719 <NIL>	729 <NIL>	739 <NIL>	749 <NIL>	759 <NIL>

Analysis of Balance at End of Year by Year of Origin

Year of Origin (oldest year first) year month day	Non-Capital Losses	Non-Capital Losses of Predecessor Corporations	Total Capital Losses from Listed Personal Property only	Farm Losses	Restricted Farm Losses
800 9th preceding taxation year 1997/12/31	817 (9)	860 (9)		850	870
801 8th preceding taxation year 1998/12/31	818 (9)	861 (9)		851	871
802 7th preceding taxation year 1999/12/31	819 (9)	862 (9)		852	872
803 6th preceding taxation year 2000/12/31	820	830	840	853	873
804 5th preceding taxation year 2001/12/31	821	831	841	854	874
805 4th preceding taxation year 2002/12/31	822	832	842	855	875
806 3rd preceding taxation year 2003/12/31	823	833	843	856	876
807 2nd preceding taxation year 2004/12/31	824	834	844	857	877
808 1st preceding taxation year 2005/12/31	825	835	845	858	878
809 Current taxation year 2006/12/31	826	836	846	859	879
Total	829 <NIL>	839 <NIL>	849 <NIL>	869 <NIL>	889 <NIL>

Notes:

- (1) Non-capital losses include allowable business investment losses, fed.s.111(8)(b), as made applicable by s.34.
 (2) Where acquisition of control of the corporation has occurred, the utilization of losses can be restricted. See fed.s.111(4) through 111(5.5), as made applicable by s.34.
 (3) Includes losses on amalgamation (fed.s.87(2.1) and s.87(2.11)) and/or wind-up (fed.s.88(1.1) and 88(1.2)), as made applicable by s.34.
 (4) To the extent of applicable gains/income/at-risk amount only.

- (5) Generally a three year carry-back applies. See fed.s.111(1) and fed.s.41(2)(b), as made applicable by s.34.
 (6) Where a limited partner has limited partnership losses, attach loss calculations for each partnership.
 (7) Include amount from 11 if taxable income is adjusted to claim unused foreign tax credit for federal purposes.
 (8) Amount in 709 must equal total of 829 + 839.
 (9) Include non-capital losses incurred in taxation years ending after March 22, 2004.

Corporation's Legal Name
HALTON HILLS HYDRO INC.Ontario Corporations Tax Account No. (MOF)
1800262Taxation Year End
2006/12/31

DOLLARS ONLY

Request for Loss Carry-Back (s.80(16))

Applies to corporations requesting a reassessment of the return of one or more previous taxation years under s.80(16) with respect to one or more types of losses carried back.

● If, after applying a loss carry-back to one or more previous years, there is a balance of loss available to carry forward to a future year, it is the corporation's responsibility to claim such a balance for those years following the year of loss within the limitations of fed.s.111, as made applicable by s.34.

● Where control of a corporation has been acquired by a person or group of persons, certain restrictions apply to the carry-forward and carry-back provisions of losses under fed.s.111(4) through 111(5.5), as made applicable by s.34.

● Refunds arising from the loss carry-back adjustment may be applied by the Minister of Finance to amounts owing under **any Act administered by the Ministry of Finance.**

● Any late filing penalty applicable to the return for which the loss is being applied will not be reduced by the loss carry-back.

● The application of a loss carry-back will be available for interest calculation purposes on the day that is the latest of the following:

- 1) the first day of the taxation year after the loss year,
- 2) the day on which the corporation's return for the loss year is delivered to the Minister, or
- 3) the day on which the Minister receives a request in writing from the corporation to reassess the particular taxation year to take into account the deduction of the loss.

● If a loss is being carried back to a **predecessor corporation**, enter the predecessor corporation's account number and taxation year end in the spaces provided under Application of Losses below.

Application of Losses

	Non-Capital Losses	Total Capital Losses	Farm Losses	Restricted Farm Losses
Total amount of loss	910	920	930	940
Deduct: Loss to be carried back to preceding taxation years and applied to reduce taxable income				
Predecessor Ontario Corporations's Tax Account No. (MOF)				
Taxation Year Ending year month day				
i) 3rd preceding 901 2003/12/31	911	921	931	941
ii) 2nd preceding 902 2004/12/31	912	922	932	942
iii) 1st preceding 903 2005/12/31	913	923	933	943
Total loss to be carried back	From 706	From 716	From 726	From 736
Balance of loss available for carry-forward	919	929	939	949

Summary

Income Tax - - - - + From 230 or 320 259,069 ●

Corporate Minimum Tax - - - - + From 280 ●

Capital Tax - - - - - + From 550 83,905 ●

Premium Tax - - - - - + From 590 ●

Total Tax Payable - - - - - = 950 342,974 ●

Subtract: Payments - - - - - - 960 474,872 ●

Capital Gains Refund (s.48) - - - - - 965 ●

Qualifying Environmental Trust Tax Credit (Refer to Guide) - - - - - 985 ●

Specified Tax Credits (Refer to Guide) - - - - - 955 ●

Balance - - - - - = 970 -131,898 ●

If payment due - - - - - Enclosed* 990 ●

If overpayment: Refund(Refer to Guide) = 975 131,898 ●

year month day

Apply to 980 ●

(Includes credit interest)

* Make your cheque (drawn on a Canadian financial institution) or a money order in Canadian funds, payable to the **Minister of Finance** and print your Ontario Corporation's Tax Account No. (MOF) on the back of cheque or money order.(Refer to Guide for other payment methods.)

Certification

I am an authorized signing officer of the corporation. I certify that this CT23 return, including all schedules and statements filed with or as part of this CT23 return, has been examined by me and is a true, correct and complete return and that the information is in agreement with the books and records of the corporation. I further certify that the financial statements accurately reflect the financial position and operating results of the corporation as required under section 75 of the *Corporations Tax Act*. The method of computing income for this taxation year is consistent with that of the previous year, except as specifically disclosed in a statement attached.

Name (please print)

ARTHUR SKIDMORE

Title

CHIEF FINANCIAL OFFICER

Full Residence Address

43 ALICE STREET

ACTON
L7J2A9

ON

Signature

Date

30/06/2007

Note: Section 76 of the *Corporations Tax Act* provides penalties for making false or misleading statements or omissions.

Corporate Minimum Tax (CMT)

CT23 Schedule 101

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
HALTON HILLS HYDRO INC.	1800262	2006/12/31

Part 1: Calculation of CMT Base

Banks - Net income/loss as per report accepted by Superintendent of Financial Institutions (SFI) under the Bank Act (Canada), adjusted so consolidation/equity methods are not used.

Life Insurance corporations - Net income/loss before Special Additional Tax as determined under s.57.1(2)(c) or (d)

Net Income/Loss (unconsolidated, determined in accordance with GAAP) - - - - - ± [2100] 1,165,491

Subtract (to the extent reflected in net income/loss):

Provision for recovery of income taxes / benefit of current income taxes - - + [2101] _____
 Provision for deferred income taxes (credits) / benefit of future income taxes - - + [2102] _____
 Equity income from corporations - - - - - + [2103] _____
 Share of partnership(s)/joint venture(s) income - - - - - + [2104] _____
 Dividends received/receivable deductible under fed.s.112 - - - - - + [2105] _____
 Dividends received/receivable deductible under fed.s.113 - - - - - + [2106] _____
 Dividends received/receivable deductible under fed.s.83(2) - - - - - + [2107] _____
 Dividends received/receivable deductible under fed.s.138(6) - - - - - + [2108] _____
 Federal Part VI.1 tax paid on dividends declared and paid, under fed.s.191.1(1) _____ X 3 - - + [2109] _____

Subtotal - - - - - = [2110] _____

Add (to extent reflected in net income/loss):

Provision for current taxes / cost of current income taxes - - - - - + [2111] 729,801
 Provision for deferred income taxes (debits) / cost of future income taxes - - + [2112] _____
 Equity losses from corporations - - - - - + [2113] _____
 Share of partnership(s)/joint venture(s) losses - - - - - + [2114] _____
 Dividends that have been deducted to arrive at net income per Financial Statements s.57.4(1.1) (excluding dividends under fed.s.137(4.1)) - - - - - + [2115] _____

Subtotal - - - - - = 729,801 + [2116] 729,801

Add/Subtract:

Amounts relating to s.57.9 election/regulations for disposals etc. of property for current/prior years

** Fed. s.85 - - - - - + [2117] _____ or - [2118] _____
 ** Fed. s.85.1 - - - - - + [2119] _____ or - [2120] _____
 ** Fed. s.97 - - - - - + [2121] _____ or - [2122] _____
 ** Amounts relating to amalgamations (fed.s.87) as prescribed in regulations for current/prior years + [2123] _____ or - [2124] _____
 ** Amounts relating to wind-ups (fed.s.88) as prescribed in regulations for current/prior years + [2125] _____ or - [2126] _____
 ** Amounts relating to s.57.10 election/regulations for replacement re fed.s.13(4), 14(6) and 44 for current/prior years + [2127] _____ or - [2128] _____

Interest allowable under ss. 20(1)(c) or (d) of ITA to the extent not otherwise deducted in determining CMT adjusted net income - [2150] _____

Capital gains on eligible donations of publicly-listed securities and ecologically sensitive land made after May 1, 2006 (to the extent reflected in net income/loss) - [2155] _____

Subtotal (Additions) - - - - - = + [2129] _____

Subtotal (Subtractions) - - - - - = [2130] _____

** Other adjustments - - - - - ± [2131] _____

Subtotal ± [2100] - [2110] + [2116] + [2129] - [2130] ± [2131] = [2132] 1,895,292

** Share of partnership(s)/joint venture(s) adjusted net income/loss - - - - - ± [2133] _____

Adjusted net income (loss) (if loss, transfer to [2202] in Part 2: Continuity of CMT Losses Carried Forward.) = [2134] 1,895,292

Deduct * CMT losses: pre-1994 Loss - - - - - + From [2210] _____

* CMT losses: other eligible losses - - - - - + [2211] _____

= [2135] _____

* CMT losses applied cannot exceed adjusted net income or increase a loss

** Retain calculations. Do not submit with this schedule.

CMT Base - - - - - = [2136] 1,895,292

**Corporate Minimum Tax (CMT)
CT23 Schedule 101**

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
HALTON HILLS HYDRO INC.	1800262	2006/12/31

Part 2: Continuity of CMT Losses Carried Forward

Balance at Beginning of year NOTES (1) , (2) - - - - - + 2201 _____

Add: Current year's losses - - - - - + 2202 _____

Losses from predecessor corporations on amalgamation NOTE (3) - - - - - + 2203 _____

Losses from predecessor corporations on wind-up NOTE (3) - - - - - + 2204 _____

Amalgamation (X) 2205 ☐ Yes Wind-up (X) 2206 ☐ Yes

Subtotal - - - - - = _____ ▶ + 2207 _____

Adjustments (attach schedule) - - - - - ± 2208 _____

CMT losses available 2201 + 2207 ± 2208 - - - - - = 2209 _____

Subtract: Pre-1994 loss utilized during the year to reduce adjusted net income - - - - - + 2210 _____

Other eligible losses utilized during the year to reduce adjusted net income NOTE (4) - - - - - + 2211 _____

Losses expired during the year - - - - - + 2212 _____

Subtotal - - - - - = _____ ▶ - 2213 _____

Balances at End of Year NOTE (5) 2209 - 2213 - - - - - = 2214 _____

Notes:

- (1) Pre-1994 CMT loss (see s.57.1(1)) should be included in the balance at beginning of the year. Attach schedule showing computation of pre-1994 CMT loss.
- (2) Where acquisition of control of the corporation has occurred, the utilization of CMT losses can be restricted. (see s.57.5(3) and s.57.5(7))
- (3) Include and indicate whether CMT losses are a result of an amalgamation to which fed.s.87 applies and/or a wind-up to which fed.s.88(1) applies. (see s.57.5(8) and s.57.5(9))
- (4) CMT losses must be used to the extent of the lesser of the adjusted net income 2134 and CMT losses available 2209.
- (5) Amount in 2214 must equal sum of 2270 + 2290.

Part 3: Analysis of CMT Losses Year End Balance by Year of Origin

For a pre-1994 loss, use the date of the last taxation year end before your corporation's first taxation year commencing after 1993.

	Year of Origin (oldest year first) year month day	CMT Losses of Corporation	CMT Losses of Predecessor Corporations
2240	1997/12/31	2260	2280
2241	1998/12/31	2261	2281
2242	1999/12/31	2262	2282
2243	2000/12/31	2263	2283
2244	2001/12/31	2264	2284
2245	2002/12/31	2265	2285
2246	2003/12/31	2266	2286
2247	2004/12/31	2267	2287
2248	2005/12/31	2268	2288
2249	2006/12/31	2269	2289
Totals		2270	2290

The sum of amounts 2270 + 2290
must equal amount in 2214.

Corporate Minimum Tax (CMT)
CT23 Schedule 101

Page 3 of 3

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
HALTON HILLS HYDRO INC.	1800262	2006/12/31

Part 4: Continuity of CMT Credit Carryovers

Balance at Beginning of year NOTE (1) - - - - - + 2301

Add: Current year's CMT credit (280 on page 8 of the CT23 or
347 on page 6 of the CT8. If negative, enter NIL) - - - + From 280 or 347

Gross Special Additional Tax NOTE (2) 312 on page 5 of CT8.
(Life Insurance corporations only. Others enter NIL.) + From 312

Subtract Income Tax
(190 on page 6 of the CT23 or page 4 of the CT8) - From 190 269,069

Subtotal (If negative, enter NIL) - - - - - = 2305

Current year's CMT credit (if negative, entre NIL) 280 or 347 - 2305 = + 2310

CMT Credit Carryovers from predecessor corporations NOTE (3) - - - - - + 2325

Amalgamation (X) 2315 Yes Wind-up (X) 2320 Yes

Subtotal 2301 + 2310 + 2325 = 2330

Adjustments (Attach schedule) - - - - - + 2332

CMT Credit Carryover available 2330 + 2332 = 2333

Transfer to Page 8 of the CT23 or Page 6 of the CT8

Subtract: CMT Credit utilized during the year to reduce income tax
(310 on page 8 of the CT23 or 351 on page 6 of the CT8.) + From 310 or 351

CMT Credit expired during the year - - - - - + 2334

Subtotal - - - - - = 2335

Balance at End of Year NOTE (4) 2333 - 2335 = 2336

Notes:

- Where acquisition of control of the corporation has occurred, the utilization of CMT credits can be restricted. (see s.43.1(5))
- The CMT credit of life insurance corporations can be restricted (see s.43.1(3)(b)).
- Include and indicate whether CMT credits are a result of an amalgamation to which fed.s.87 applies and/or a wind-up to which fed.s.88(1) applies. (see s.43.1(4))
- Amount in 2336 must equal sum of 2370 + 2390 .

Part 5: Analysis of CMT Credit Carryovers Year End Balance by Year of Origin

	Year of Origin (oldest year first) year month day	CMT Credit Carryovers of Corporation	CMT Credit Carryovers of Predecessor Corporation(s)
2340	1997/12/31	2360	2380
2341	1998/12/31	2361	2381
2342	1999/12/31	2362	2382
2343	2000/12/31	2363	2383
2344	2001/12/31	2364	2384
2345	2002/12/31	2365	2385
2346	2003/12/31	2366	2386
2347	2004/12/31	2367	2387
2348	2005/12/31	2368	2388
2349	2006/12/31	2369	2389
Totals		2370	2390

The sum of amounts 2370 + 2390
must equal amount in 2336 .

CAPITAL COST ALLOWANCE (CCA)

SCHEDULE 8 - Ontario

Corporation's Legal Name HALTON HILLS HYDRO INC.		Ontario Corporations Tax Account No. (MOF) 1800262		Taxation Year End 2006/12/31							
Is the corporation electing under regulation 1101(5q)?											
		1 Yes ☐	2 No ☒								
1 Class no.	Description	2 Ontario undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of the prior year's CCA schedule)	3 Cost of acquisitions during the year (new property must be available for use) See note 1 below	4 Net adjustments (show negative amounts in brackets)	5 Proceeds of dispositions during the year (amount not to exceed the capital cost)	6 Ontario undepreciated capital cost (column 2 plus column 3 or minus column 4 minus column 5)	7 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5) See note 2 below	8 Reduced undepreciated capital cost (column 6 minus column 7)	9 CCA rate %	10 Ontario capital cost allowance (column 8 multiplied by column 9; or a lower amount)	11 Ontario undepreciated capital cost at the end of the year (column 6 minus column 10)
1.0	Dist'n Syst	20,712,394				20,712,394		20,712,394	4.0	828,496	19,883,898
1.0	Buildings &	2,290,038	29,799			2,319,837	14,900	2,304,937	4.0	92,197	2,227,640
8.0	Major Tools	169,599	50,897			220,496	25,449	195,047	20.0	39,009	181,487
8.0	Office Equi	160,398	44,033			204,431	22,017	182,414	20.0	36,483	167,948
8.0	Stores Equi	20,366	2,144			22,510	1,072	21,438	20.0	4,288	18,222
10.0	Computer Ha	158,266				158,266		158,266	30.0	47,480	110,786
10.0	Fleet	458,204	52,428			510,632	26,214	484,418	30.0	145,325	365,307
12.0	Computer So	13,650	204,394			218,044		218,044	100.	218,044	<NIL>
8.0	Scada comm	160,505				160,505		160,505	20.0	32,101	128,404
46.0	Scada comm	25,773	97,487			123,260	48,744	74,516	30.0	22,355	100,905
45.0	Computer ha	93,511	149,217			242,728	74,609	168,119	45.0	75,654	167,074
43.1	Conservatn	65,464	612,620			678,084	306,310	371,774	30.0	111,532	566,552
49.0	Electricity	2,100,123	2,027,456			4,127,579	1,013,728	3,113,851	8.0	249,108	3,878,471
Totals		26,428,291	3,270,475			29,698,766	1,533,043	28,165,723		1,902,072	27,796,694

Note 1. Include any property acquired in previous years that has now become available for use. This property would have been previously

excluded from column 3. List separately any acquisitions that are not subject to the 50% rule. See Regulation 1100(2) and (2.2) of the *Income Tax Act* (Canada).

Note 2. The net cost of acquisitions is the cost of acquisitions plus or minus certain adjustments from column 4.

Note 3. If the taxation year is shorter than 365 days, prorate the CCA claim.

Note 4. Ontario recapture should be included in net income after deducting the federal recapture and the Ontario terminal loss
is deducted from net income after including the federal terminal loss.



Ontario

Ministry of Finance
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

CAPITAL COST ALLOWANCE (CCA)

SCHEDULE 8SUM - Ontario

Corporation's Legal Name

HALTON HILLS HYDRO INC.

Ontario Corporations Tax Account No. (MOF)

1800262

Taxation Year End

2006/12/31

Is the corporation electing under regulation 1101(5q)?

1 Yes ☐

2 No ☒

1 Class number	2 Ontario undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of the prior year's CCA schedule)	3 Cost of acquisitions during the year (new property must be available for use) See note 1 below	4 Net adjustments (show negative amounts in brackets)	5 Proceeds of dispositions during the year (amount not to exceed the capital cost)	6 Ontario undepreciated capital cost (column 2 plus column 3 or minus column 4 minus column 5)	7 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5) See note 2 below	8 Reduced undepreciated capital cost (column 6 minus column 7)	9 CCA rate %	10 Recapture of capital cost allowance	11 Terminal loss	12 Ontario capital cost allowance (column 8 multiplied by column 9; or a lower amount)	13 Ontario undepreciated capital cost at the end of the year (column 6 minus column 12)
reg	26,428,291	3,270,475			29,698,766	1,533,043	28,165,723				1,902,072	27,796,694
10.1												
13												
14												
24												
27												
29												
34												
43.3												
Rental												
Totals											1,902,072	

Note 1. Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule. See Regulation 1100(2) and (2.2) of the *Income Tax Act* (Canada).

Note 2. The net cost of acquisitions is the cost of acquisitions plus or minus certain adjustments from column 4.

Note 3. If the taxation year is shorter than 365 days, prorate the CCA claim.

Note 4. Ontario recapture should be included in net income after deducting the federal recapture and the Ontario terminal loss is deducted from net income after including the federal terminal loss.

Enter in boxes 650 650 650 on the CT23.



Ontario

Ministry of Finance

Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Ontario Cumulative Eligible Capital Deduction

Schedule 10 Page 1 of 2

For taxation years 2002 and later

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
HALTON HILLS HYDRO INC.	1800262	2006/12/31

- For use by a corporation that has eligible capital property.
- A separate cumulative eligible capital account must be kept for each business.

Part 1 - Calculation of current year deduction and carry-forward

Ontario Cumulative eligible capital - balance at end of preceding taxation year (if negative, enter zero) = + 885,066A

Add: Cost of eligible capital property acquired during the taxation year + B

Other adjustments + C

B + C = x 3/4 = D

Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002 x 1/2 = - E

D minus E (if negative, enter zero) = + F

Amount transferred on amalgamation or wind-up of subsidiary + G

Subtotal A + F + G = 885,066 H

Deduct: Ontario proceeds of sales (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year + I

The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7) of the *Income Tax Act* (Canada) + J

Other adjustments + K

I + J + K = x 3/4 = - L

Ontario cumulative eligible capital balance H minus L = 885,066 M

If M is negative, enter zero at line Q and proceed to Part 2, page 2.

Cumulative eligible capital for a property no longer owned after ceasing to carry on that business N

From M 885,066

From N -

Current year deduction M minus N = 885,066 x 7% = + 61,955 O

N + O = 61,955 P

Note: The maximum current year deduction is 7%. Any amount up to the maximum deduction of 7% may be claimed. For taxation years starting after December 21, 2000, the deduction may not exceed the maximum amount prorated for the number of days in the taxation year divided by 365 or 366 days.

Enter amount in box 651 of the CT23

Ontario cumulative eligible capital - closing balance M minus P (if negative, enter zero) = 823,111 Q

See page 2 - Part 2

Name of Corporation	Business Number	Tax year-end	Year	Month	Day
HALTON HILLS HYDRO INC.	867429623 RC 0001		2006	12	31

- File this schedule if the total taxable capital employed in Canada of the corporation (other than a financial institution or an insurance corporation) and its related corporations is greater than \$10,000,000.
- Even if there is no Part 1.3 tax payable for the days in the tax year that are after 2005, you must still complete this schedule (except parts 5 and 9).
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 181(1) defines the terms "financial institution," "long-term debt," and "reserves."
- Subsection 181(3) provides the basis to determine the carrying value of a corporation's assets or any other amount under Part 1.3 for its capital, investment allowance, taxable capital, or taxable capital employed in Canada, or for a partnership in which it has an interest.
- No Part 1.3 tax is payable for a taxation year by a corporation that was:
 - bankrupt [as defined by subsection 128(3)] at the end of the year;
 - a deposit insurance corporation throughout the year, as defined by subsection 137.1(5), or deemed to be a deposit insurance corporation by subsection 137.1(5.1);
 - exempt from tax under section 149 throughout the year on all of its taxable income;
 - neither resident in Canada nor carrying on a business through a permanent establishment in Canada at any time in the year; or
 - a corporation described in subsection 136(2) throughout the year, the principal business of which was marketing (including any related processing) natural products belonging to or acquired from its members or customers.
- File the completed Schedule 33 with the *T2 Corporation Income Tax Return* no later than six months from the end of the tax year.
- This schedule may contain changes that had not yet become law at the time of printing.

If the corporation was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada, go to Part 4, "Taxable capital employed in Canada."

Part 1 - Capital

Add the following amounts at the end of the year:

Reserves that have not been deducted in computing income for the year under Part I	101	456,900
Capital stock (or members' contributions if incorporated without share capital)	103	16,161,663
Retained earnings	104	4,231,115
Contributed surplus	105	
Any other surpluses	106	
Deferred unrealized foreign exchange gains	107	
All loans and advances to the corporation	108	17,024,242
All indebtedness of the corporation represented by bonds, debentures, notes, mortgages, hypothecary claims, bankers' acceptances, or similar obligations	109	
Any dividends declared but not paid by the corporation before the end of the year	110	
All other indebtedness of the corporation (other than any indebtedness for a lease) that has been outstanding for more than 365 days before the end of the year	111	661,085
Proportion of the amount, if any, by which the total of all amounts (see note below) for the partnership of which the corporation is a member at the end of the year exceeds the amount of the partnership's deferred unrealized foreign exchange losses	112	17,545
Subtotal		38,552,550

► 38,552,550 A

Deduct the following amounts:

Deferred tax debit balance at the end of the year	121	
Any deficit deducted in computing its shareholders' equity (including, for this purpose, the amount of any provision for the redemption of preferred shares) at the end of the year	122	
Any amount deducted under subsection 135(1) in computing income under Part I for the year, as long as the amount may reasonably be regarded as being included in any of lines 101 to 112 above	123	
The amount of deferred unrealized foreign exchange losses at the end of the year	124	
Subtotal		

► B

Capital for the year (amount A minus amount B) (if negative, enter "0") **190** 38,552,550

Note: Lines 101, 107, 108, 109, 111, and 112 are determined as follows:

- If the partnership is a member of another partnership (tiered partnerships), include the amounts of the partnership and tiered partnerships.
- Amounts for the partnership and tiered partnerships are those that would be determined for lines 101, 107, 108, 109, 111, and 112 as if they apply in the same way that they apply to corporations.
- Do not include amounts owing to the member or to other corporations that are members of the partnership.
- Amounts are determined at the end of the last fiscal period of the partnership ending in the year of the corporation.
- The proportion of the total amounts is determined by the corporation's share of the partnership's income or loss for the fiscal period of the partnership.

Name of Corporation	Business Number	Tax year-end	Year	Month	Day
HALTON HILLS HYDRO INC.	867429623 RC 0001		2006	12	31

Part 2 - Investment allowance

Add the carrying value at the end of the year of the following assets of the corporation:

A share of another corporation	401	865,552
A loan or advance to another corporation (other than a financial institution)	402	865,551
A bond, debenture, note, mortgage, hypothecary claim, or similar obligation of another corporation (other than a financial institution)	403	
Long-term debt of a financial institution	404	
A dividend receivable on a share of the capital stock of another corporation	405	
A loan or advance to, or a bond, debenture, note, mortgage, hypothecary claim, or similar obligation of, a partnership all of the members of which, throughout the year, were other corporations (other than financial institutions) that were not exempt from tax under Part I.3 (other than by reason of paragraph 181.1(3)(d))	406	
An interest in a partnership (see note 1 below)	407	
Investment allowance for the year (add lines 401 to 407)	490	1,731,103

Notes:

- Where the corporation has an interest in a partnership or in tiered partnerships, consider the following:
 - the investment allowance of a partnership is deemed to be the amount calculated at line 490 above, at the end of its fiscal period, as if it was a corporation;
 - the total of the carrying value of each asset of the partnership described in the above lines is for its last fiscal period ending at or before the end of the corporation's tax year; and
 - the carrying value of a partnership member's interest at the end of the year is its specified proportion [as defined in subsection 248(1)] of the partnership's investment allowance.
- Lines 401 to 405 should not include the carrying value of a share of the capital stock of, a dividend payable by, or indebtedness of a corporation that is exempt from tax under Part I.3 [other than by reason of paragraph 181.1(3)(d)].
- Where a trust is used as a conduit for loaning money from a corporation to another related corporation (other than a financial institution), the loan will be considered to have been made directly from the lending corporation to the borrowing corporation, according to subsection 181.2(6).

Part 3 - Taxable capital

Capital for the year (line 190)	38,552,550	C
Deduct: Investment allowance for the year (line 490)	1,731,103	D
Taxable capital for the year (amount C minus amount D) (if negative, enter "0")	500 36,821,447	

Part 4 - Taxable capital employed in Canada

To be completed by a corporation that was resident in Canada at any time in the year

Taxable capital for the year (line 500)	36,821,447	x	Taxable income earned in Canada	610 1,921,918	=	Taxable capital employed in Canada	690 36,821,447
			Taxable income	1,921,918			

- Notes:**
- Regulation 8601 gives details on calculating the amount of taxable income earned in Canada.
 - Where a corporation's taxable income for a tax year is "0", it shall, for the purposes of the above calculation, be deemed to have a taxable income for that year of \$1,000.
 - In the case of an airline corporation, Regulation 8601 should be considered when completing the above calculation.

To be completed by a corporation that was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada

Total of all amounts each of which is the carrying value at the end of the year of an asset of the corporation used in the year or held in the year, in the course of carrying on any business it carried on during the year through a permanent establishment in Canada	701

Deduct the following amounts:

Corporation's indebtedness at the end of the year [other than indebtedness described in any of paragraphs 181.2(3)(c) to (f)] that may reasonably be regarded as relating to a business it carried on during the year through a permanent establishment in Canada

711

Total of all amounts each of which is the carrying value at the end of the year of an asset described in subsection 181.2(4) of the corporation that it used in the year, or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada

712

Total of all amounts each of which is the carrying value at the end of the year of an asset of the corporation that is a ship or aircraft the corporation operated in international traffic, or personal or movable property used or held by the corporation in carrying on any business during the year through a permanent establishment in Canada (see note below)

713

Total deductions (add lines 711, 712, and 713)



E

Taxable capital employed in Canada (line 701 minus amount E) (if negative, enter "0") 790

Note: Complete line 713 only if the country in which the corporation is resident did not impose a capital tax for the year on similar assets, or a tax for the year on the income from the operation of a ship or aircraft in international traffic, of any corporation resident in Canada during the year.

Name of Corporation	Business Number	Tax year-end	Year	Month	Day
HALTON HILLS HYDRO INC.	867429623 RC 0001		2006	12	31

Part 5 - Calculation of gross Part I.3 tax

If the tax year starts after 2005, do not complete this part.

Taxable capital employed in Canada (line 690 or 790, whichever applies) 36,821,447

Deduct: Capital deduction claimed for the year (enter \$50,000,000 or, for related corporations, the amount allocated on Schedule 36) 801 44,995,000

Excess of taxable capital employed in Canada over capital deduction 811

Line 811 x Number of days in the tax year in 2004 x 0.002 = ... F

Number of days in the tax year 365

Line 811 x Number of days in the tax year in 2005 x 0.00175 = ... G

Number of days in the tax year 365

Subtotal (add amounts F and G) H

Note: The Part I.3 tax rate is reduced to 0% for the days in the tax year that are after 2005.

Where the tax year of a corporation is less than 51 weeks, calculate the amount of gross Part I.3 tax as follows:

Amount H x Number of days in the year (365) = ... I

365

Gross Part I.3 tax (amount H or I, whichever applies) 820

Part 6 - Calculation of gross Part I.3 tax for purposes of the unused surtax credit

Taxable capital employed in Canada (line 690 or 790, whichever applies) 36,821,447 J

Deduct: Line 801 above 44,995,000 x 1/5 = ... 8,999,000 K

Excess (amount J minus amount K) (if negative, enter "0") 27,822,447 L

Amount L 27,822,447 x 0.00225 = ... 62,601 M

Where the tax year of a corporation is less than 51 weeks, calculate the amount of gross Part I.3 tax for purposes of the unused surtax credit as follows:

Amount M 62,601 x Number of days in the year (365) = ... N

365

Gross Part I.3 tax for purposes of the unused surtax credit (amount M or N, whichever applies) 821 62,601

Name of Corporation HALTON HILLS HYDRO INC.	Business Number 867429623 RC 0001	Tax year-end	Year 2006	Month 12	Day 31

Part 7 - Calculation of current-year surtax credit available

- Corporations can claim a credit against their Part I.3 tax for the amount of Canadian surtax payable for the year. This is called the surtax credit.
- Any unused surtax credit can be carried back three years or carried forward seven years. Unused surtax credits must be applied in order of the oldest first.
- Refer to subsection 181.1(7) when calculating the amount deductible for a corporation's unused surtax credits where control of the corporation has been acquired between the year in which the credits arose and the year in which you want to claim them.

For a corporation that was a non-resident of Canada throughout the year, enter amount a or b at line O, whichever is less:

a) line 600 from the T2 return 21,525 a

b) line 700 from the T2 return 425,128 b

In any other case, enter amount c or d at line P, whichever is less:

c) line 600 from the T2 return 21,525 x $\frac{\text{line 690 of this schedule } 36,821,447}{\text{line 500 of this schedule } 36,821,447} =$ 21,525 c

d) line 700 from the T2 return 425,128 d

Current-year surtax credit available (amount O or P, whichever applies) 830 21,525 P

Part 8 - Calculation of current-year unused surtax credit

Current-year surtax credit available (line 830) 21,525

Less: Gross Part I.3 tax for purposes of the unused surtax credit (line 821) 62,601

Current-year unused surtax credit (if negative, enter "0") 850

Enter this amount at line 600 on Schedule 37.

Part 9 - Calculation of net Part I.3 tax payable

If the tax year starts after 2005, do not complete this part.

Gross Part I.3 tax (line 820) Q

Deduct:

Current-year surtax credit applied (line 820 or 830, whichever is less) 861

Unused surtax credit from previous years applied (amount from line 320 on Schedule 37) 862

Subtotal (cannot be more than amount on line 820) R

Net Part I.3 tax payable (amount Q minus amount R) 870

Enter this amount at line 704 of the T2 return.

Part 10 - Calculation for purposes of the small business deduction

This part is applicable only to corporations that are not associated in the current year, but were associated in the prior year.

Taxable capital employed in Canada (line 690 or 790, whichever applies) S

Deduct:

Capital deduction claimed for the year (enter \$10,000,000) T

Excess (amount S minus amount T) (if negative, enter "0") U

Gross Part I.3 tax for purposes of the small business deduction (Amount U x 0.00225) V

Enter this amount at line 415 of the T2 return

AGREEMENT AMONG RELATED CORPORATIONS - PART 1.3 TAX

Name of Corporation	Business Number	Tax year-end	Year	Month	Day
HALTON HILLS HYDRO INC.	867429623 RC 0001		2006	12	31

- Members of a related group of corporations should use this schedule to allocate the capital deduction of \$50,000,000 among the members of the related group. **Do not file this agreement if no members of the related group have to pay Part 1.3 tax.**
- In cases where a related corporation has more than one taxation year ending in a calendar year, it has to file an agreement for each of those taxation years.
- A corporation that is related to any other corporation at any time in a taxation year of the corporation that ends in a calendar year may file such an agreement.
- In accordance with subsection 181.5(7) of the federal *Income Tax Act*, a Canadian-controlled private corporation is not considered to be related to another corporation for purposes of the capital deduction unless it is also associated with that corporation.
- Attach additional schedules if space for agreement is not sufficient.

Agreement

Date filed (do not use this area) 010

Year	Month	Day

Is this an amended agreement? 020 1 Yes ☐ 2 No ☒

Calendar year to which the agreement applies 030

Year
2006

Note: This agreement must include all the information indicated below for all members of the related group, including members to which no amount of capital deduction is allocated for the year. However, any member that is exempt from Part 1.3 tax under subsection 181.1(3) does not have to be included.

Names of all corporations which are members of the related group 200	Business Number (if a corporation is not registered, enter "NR") 300	Allocation of capital deduction for the year \$ 400	Taxation year end to which this agreement applies* (YYYY/MM/DD) 500
1. HALTON HILLS HYDRO INC.	867429623 RC 0001	44,995,000	
2. HALTON HILLS FIBRE OPTICS INC.	886270727 RC 0001	3,500,000	
3. SOUTHWESTERN ENERGY INC.	870971181 RC 0001	500,000	
4. HALTON HILLS ENERGY INC.	873074876 RC 0001	5,000	
5. HALTON HILLS ENERGY SERVICES I	862448453 RC 0001	1,000,000	
6.			
7.			
8.			
9.			
10.			
11.			
12.			
13.			
Total (cannot be more than \$50,000,000)		50,000,000	

* Entries are only required in this column for a corporation that has more than one taxation year ending in the same calendar year and is related in two or more of those taxation years to another corporation that has a taxation year ending in that calendar year. The capital deduction of the first corporation for each such taxation year at the end of which it is related to the other corporation is an amount equal to its capital deduction for the first such taxation year. Enter the taxation year end to which this agreement applies.



SHAREHOLDER INFORMATION

SCHEDULE 50

Name of Corporation	Business Number	Tax year-end	Year	Month	Day
HALTON HILLS HYDRO INC.	867429623 RC 0001		2006	12	31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

Provide only one number per shareholder					
Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) 100	Business Number 200	Social insurance number 300	Trust number 350	Percentage common shares 400	Percentage preferred shares 500
1. TOWN OF HALTON HILLS	108126897RC0001			100.0	
2.					
3.					
4.					
5.					
6.					
7.					
8.					
9.					
10.					



Name of Corporation	Business Number	Tax year-end	Year	Month	Day
HALTON HILLS HYDRO INC.	867429623 RC 0001		2006	12	31

- If you are a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC), use this schedule to determine the general rate income pool (GRIP).
- When an eligible dividend was paid in the tax year, file a completed copy of this schedule with your *T2 Corporation Income Tax Return*. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- Subsections referred to in this schedule are from the *Income Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool, and low rate income pool.

Eligibility for the various additions

Is this the corporation's first taxation year that includes January 1, 2006?	☒ Yes	☐ No
If not, what is the date of the taxation year end of the corporation's first year that includes January 1, 2006?		
If yes, during that first year, was the corporation a CCPC or would it have been a CCPC if not for the election of subsection 89(11) ITA?	☒ Yes	☐ No
If yes, complete Part 5.		
Was the corporation a CCPC during its preceding taxation year?	☒ Yes	☐ No
- Corporations that become a CCPC	☐ Yes	☒ No
If yes, complete Part 4.		
- Corporations that were formed as a result of an amalgamation	☐ Yes	☒ No
Was one or more of the predecessor corporations neither a CCPC nor a DIC?	☐ Yes	☐ No
If yes, complete Part 4.		
Was one or more of the predecessor corporation a CCPC or a DIC during the taxation year that ended immediately before amalgamation?	☐ Yes	☐ No
If yes, complete Part 3.		
- Corporation that wound-up a subsidiary	☐ Yes	☒ No
Was the subsidiary neither a CCPC nor a DIC during its last taxation year?	☐ Yes	☐ No
If yes, complete Part 4.		
Was the subsidiary a CCPC or a DIC during its last taxation year?	☐ Yes	☐ No
If yes, complete Part 3.		

Part 1 - Calculation of general rate income pool (GRIP)

If the corporation's tax year includes January 1, 2006, complete "Part 5 - GRIP addition for 2006" and then line 050. Otherwise, complete line 100.

GRIP addition for 2006 (the greater of amount QQ from Part 5 or "0")	050	852,946	A
GRIP at the end of the previous tax year	100		B
Taxable income for the year (DICs enter "0")*	110	1,921,918	C
Income for the credit union deduction* amount E in Part 3 of Schedule 17)	120		
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less*	130		
For a CCPC, the lesser of aggregate investment income (line 440 of the T2 return) and taxable income*	140		
Subtotal (add lines 120, 130, and 140)			D
Income taxable at the general corporate rate (line C minus line D)	150	1,921,918	
After-tax income (line 150 multiplied by 68.00 %)	190	1,306,904	E
Eligible dividends received in the tax year	200		
Dividends deductible under section 113 received in the tax year	210		
Subtotal (add lines 200 and 210)			F
GRIP addition:			
Becoming a CCPC (line PP from Part 4)	220		
Post-amalgamation (total of lines EE from Part 3 and lines PP from Part 4)	230		
Post-wind-up (total of lines EE from Part 3 and lines PP from Part 4)	240		
Subtotal (add lines 220, 230, and 240)	290		G
Subtotal (add lines A or B (as applicable), E, F, and G)		2,159,851	H
Eligible dividends paid in the previous tax year	300		
Excessive eligible dividend designations made in the previous tax year	310		
Note: If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310.			
Subtotal (line 300 minus line 310)			I
GRIP before adjustment for specified future tax consequences (line H minus line I) (amount can be negative)	490	2,159,851	
Total GRIP adjustment for specified future tax consequences to previous tax years (amount Y from Part 2)	560		
GRIP at the end of the tax year (line 490 minus line 560)	590	2,159,851	

Enter this amount on line 160 on Schedule 55.

* Note: For lines 110, 120, 130, and 140, the income amount is the amount before considering specified future tax consequences. This phrase is defined in subsection 248(1). It includes the deduction of a loss carryback from subsequent tax years, a reduction of Canadian exploration expenses and Canadian development expenses that were renounced in subsequent tax years (e.g., flow-through share renunciations), reversals of income inclusions where an option is exercised in subsequent tax years, and the effect of certain foreign tax credit adjustments.

Part 2 - GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560 of page 1 or leave it blank.

First previous tax year 2005/12/31

Taxable income before specified future tax consequences from the current tax year 1,653,883 J1

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) ... K1

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less 300,000 L1

Aggregate investment income (line 440 of the T2 return) M1

Subtotal (add lines K1, L1, and M1) 300,000 ▶ 300,000 O1

Subtotal (line J1 minus line O1) (if negative, enter "0") 1,353,883 ▶ 1,353,883 P1

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year

Non-capital loss (paragraph 111(1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences Q1

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) ... R1

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less S1

Aggregate investment income (line 440 of the T2 return) T1

Subtotal (add lines R1, S1, and T1) ▶ V1

Subtotal (line Q1 minus line V1) (if negative, enter "0") ▶ W1

Subtotal (line P1 minus line W1) (if negative, enter "0") X1

GRIP adjustment for specified future tax consequences to first previous tax year (line X1 multiplied by 68.00 %). **500**

Second previous tax year 2004/12/31

Taxable income before specified future tax consequences from the current tax year: J2

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) ... K2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less L2

Aggregate investment income (line 440 of the T2 return) M2

Accelerated tax reduction (line 637 of T2 return)* multiplied by 100/7 N2

Subtotal (add lines K2, L2, M2, and N2) ▶ O2

Subtotal (line J2 minus line O2) (if negative, enter "0") ▶ P2

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year

Non-capital loss (paragraph 111(1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences Q2

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) ... R2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less S2

Aggregate investment income (line 440 of the T2 return) T2

Accelerated tax reduction (line 637 of T2 return)* multiplied by 100/7 U2

Subtotal (add lines R2, S2, T2, and U2) ▶ V2

Subtotal (line Q2 minus line V2) (if negative, enter "0") ▶ W2

Subtotal (line P2 minus line W2) (if negative, enter "0") X2

GRIP adjustment for specified future tax consequences to second previous year (line X2 multiplied by 68.00 %). **520**

Name of Corporation	Business Number	Tax year-end	Year	Month	Day
HALTON HILLS HYDRO INC.	867429623 RC 0001		2006	12	31

Part 2 - GRIP adjustment for specified future tax consequences to previous tax years (continued)

Third previous tax year 2003/12/31

Taxable income before specified future tax consequences from the current tax year: J3

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) K3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less L3

Aggregate investment income (line 440 of the T2 return) M3

Accelerated tax reduction (line 637 of T2 return)* multiplied by 100/7 N3

Subtotal (add lines K3, L3, M3, and N3) O3

Subtotal (line J3 minus line O3) (if negative, enter "0") P3

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year

Non-capital loss (paragraph 111(1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences Q3

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) R3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less S3

Aggregate investment income (line 440 of the T2 return) T3

Accelerated tax reduction (line 637 of T2 return)* multiplied by 100/7 U3

Subtotal (add lines R3, S3, T3, and U3) V3

Subtotal (line Q3 minus line V3) (if negative, enter "0") W3

Subtotal (line P3 minus line W3) (if negative, enter "0") X3

GRIP adjustment for specified future tax consequences to third previous tax year (line X3 multiplied by 68.00 %) 540

Total GRIP adjustment for specified future tax consequences to previous tax years:

(add lines 500, 520, and 540) (if negative, enter "0") Y

Enter line Y on line 560 on page 1.

* Note: The accelerated tax reduction was available for 2001 to 2004 tax years.

Part 3 - Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or DIC in its last tax year)

Post amalgamation ☐

Post Wind-up ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary corporation was a CCPC or DIC in its last tax year. In the calculation below, **corporation** means a predecessor or a subsidiary. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was a CCPC or DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Corporation's GRIP at the end of its last tax year AA

Eligible dividends paid by the corporation in its last tax year BB

Excessive eligible dividend designations made by the corporation in its last tax year CC

Subtotal (line BB minus line CC) DD

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or DIC in its last tax year) (line AA minus line DD) EE

After you complete this calculation for each predecessor and each subsidiary, calculate the total of all the EE lines. Enter this total amount on:

- line 230 on page 1 for post-amalgamation; or
- line 240 on page 1 for post-wind-up.

Name of Corporation	Business Number	Tax year-end	Year	Month	Day
HALTON HILLS HYDRO INC.	867429623 RC 0001		2006	12	31

Part 4 - Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or DIC in its last tax year), or the corporation is becoming a CCPC

Corporation becoming a CCPC ☐

Post amalgamation ☐

Post Wind-up ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or DIC in its last tax year. Also, use this part for a corporation becoming a CCPC. In the calculation below, corporation means a corporation becoming a CCPC, a predecessor, or a subsidiary.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was not a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of its previous/last tax year FF

The corporation's money on hand immediately before the end of its previous/last tax year GG

Unused and unexpired losses at the end of the corporation's previous tax year

Non-capital losses

Net capital losses

Farm losses

Restricted farm losses

Limited partnership losses

Subtotal ► HH

Subtotal (add lines FF, GG, and HH) II

All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year JJ

Paid up capital of all the corporation's issued and outstanding shares of capital stock immediately before the end of its previous/last tax year KK

All the corporation's reserves deducted in its previous/last tax year LL

The corporation's capital dividend account immediately before the end of its previous/last tax year MM

The corporation's low rate income pool immediately before the end of its previous/last tax year NN

Subtotal (add lines JJ, KK, LL, MM, and NN) OO

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or DIC in its last tax year), or the corporation is becoming a CCPC (line II minus line OO) (if negative, enter "0") PP

After you complete this worksheet for each predecessor and each subsidiary, calculate the total of all the PP lines. Enter this total amount on:

- line 220 on page 1 for a corporation becoming a CCPC;
- line 230 on page 1 for post-amalgamation; or
- line 240 on page 1 for post-wind-up.

Name of Corporation	Business Number	Tax year-end	Year	Month	Day
HALTON HILLS HYDRO INC.	867429623 RC 0001		2006	12	31

Part 5 - GRIP addition for 2006

Use this part to calculate the GRIP balance for a corporation that was a CCPC, or would have been but for an election under subsection 89(11), throughout the tax year that includes January 1, 2006.

	Tax years ending on				
	2001	2002	2003	2004	2005
1. Taxable income for the year*					1,653,883
2. Income for manufacturing and processing profits deduction* (lesser of amounts V and Y in Part 9 of Schedule 27)				NIL	NIL
3. Income for manufacturing and processing profits deduction - electrical energy, steam* (amount QQ from Part 13 of Schedule 27)				NIL	NIL
4. Taxable resource income* (line 435 of the T2 return)					
5. Income for the credit union deduction* (amount E in Part 3 of Schedule 17)					
6. Income for the small business deduction* (amount on line 400, 405, 410, and 425 of the T2 return, whichever is less)					300,000
7. Aggregate investment income* (line 440 of the T2 return)					
8. Income for the accelerated tax reduction* (line 637 of the T2 return multiplied by 100/7)					NIL
9. Subtotal (add rows 2 through 8)					300,000
10. Full rate taxable income before specified future tax consequences (row 1 minus row 9) (if negative, enter "0")					1,353,883
11. Multiply row 10 by 63.00 %					852,946
12. Dividends deductible under subsection 112(1) received from connected corporations, that are reasonably considered, to have been paid out of full rate taxable income in respect of the payer corporation	941	942	943	944	945
13. Subtotal (add row 11 and row 12)					852,946
14. Total taxable dividends paid by the corporation (greater of amounts on line 460 and line 500 on Schedule 3)					
15. GRIP addition (row 13 minus row 14) (if negative, enter "0")	951	952	953	954	955
					852,946

GRIP addition for 2006 (add lines 951, 952, 953, 954, and 955)

852,946 QQ

Enter the greater of amount QQ or "0" on line 050 on page 1.

* Note: For rows 1 to 8, all income amounts are before considering the specified future tax consequences for that tax year.



T7B-1

Name of Corporation HALTON HILLS HYDRO INC.		Business Number 867429623 RC 0001		Tax year-end	Year 2006	Month 12	Day 31
Name of corporation contact (for department enquiries)						Telephone Number	
Effective interest date from statement of account balance (where applicable)	Description (Instalment remittance, Split payment, Assessed credit)					Amount of Credit	
	INSTALMENT REMITTANCES					425,128	
Total Amount of Instalments claimed (Enter on line 840 on the front of T2 Return)						(A)	425,128
Total instalments credited to the taxation year, per last T9 statement of account balance						(B)	

CT16

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
HALTON HILLS HYDRO INC.	1800262	31/12/2006

CAPITAL TAX SUPPORTING SCHEDULE

PARTNERSHIPS / JOINT VENTURES INFORMATION:

Corporation's share of paid-up capital:

1. Enerconnect LP	17,545		
2.			
3.		to (362)	17,545

Corporation's share of gross revenue:

Corporation's own gross revenue			47,134,056

ADD:

1. Enerconnect LP	31,464		
2.			
3.			

Total gross revenue of corporation & partnerships		to (480)	47,165,520

ELIGIBLE INVESTMENTS:

Bonds & debentures of other corporations:

1.			
2.			
3.		to (402)	

Mortgages due from other corporations:

1.			
2.			
3.		to (403)	

Shares in other corporations:

1. Subsidiary companies	865,552		
2. EnerConnect LP			
3.		to (404)	865,552

Loans & advances to corporations (except amounts due from related corporations with head office outside Canada outstanding less than 120 days) or to a Government:

1.			
2.			
3.		to (405)	

Eligible loans and advances to related corporations s.62(5.1)(5.2) certain restrictions apply (Refer to Guide)

1. Halton Hills Fibre Optics	693,698		
2. Haton Hills Energy Services	171,853		
3.		to (406)	865,551

Shares of partnership(s) or joint venture(s) eligible investments:

1. Enerconnect LP			
2.			
3.		to (407)	

LOANS AND ADVANCES:

From corporations or government	983		
From shareholders or related persons	16,141,970		
From Pre-2001 contributed capital	259,401		
From Customer deposits	621,888	to (353)	17,024,242

Name of Corporation	Business Number	Tax year-end	Year	Month	Day
HALTON HILLS HYDRO INC.	867429623 RC 0001		2006	12	31

General Index of Financial Information (GIFI)

T2 SCH 100

Page 1 of 3

Balance Sheet Information

Assets

Description	GIFI	Amount	Prior year
Current assets			
Cash	1001	1,000	1,000
Deposits in Canadian banks and institutions - Canadian currency	1002	1,599,010	2,084,729
Trade accounts receivable	1062	9,071,986	8,502,692
Allowance for doubtful trade accounts receivable	1063	89,550	103,537
Trade accounts receivable from related parties	1064	64,092	237,900
Taxes receivable	1066	3,075	233,068
Interest receivable	1067	9,332	8,565
Holdbacks receivable	1068	1,710	7,857
Accounts receivable from employees	1071	19,327	22,013
Inventory parts and supplies	1122	1,087,028	995,697
Loans/advances due from related parties	1403	1,341,153	1,334,080
Prepaid expenses	1484	248,551	286,144
Total current assets	1599	13,356,714	13,610,208
Capital assets			
Land improvements	1601	354,871	354,871
Manufacturing and processing plant	1682	2,840,621	2,810,822
Accumulated amortization of manufacturing and processing plant	1683	342,582	282,802
Motor vehicles	1742	1,433,315	1,405,395
Accumulated amortization of motor vehicles	1743	1,003,043	884,050
Tools and dies	1744	412,228	361,331
Accumulated amortization of tools and dies	1745	213,689	182,247
Small tools	1770	53,151	51,007
Accumulated amortization of small tools	1771	33,237	27,861
Radio and communication equipment	1772	609,098	511,611
Accumulated amortization of radio and communication equipment	1773	171,709	132,933
Computer equipment/software	1774	1,442,107	1,088,496
Accumulated amortization of computer equipment/software	1775	1,059,459	828,256
Machinery and equipment under construction	1782	790,815	-5,695
Other machinery and equipment	1785	29,114,871	26,474,795
Accumulated amortization of other machinery and equipment	1786	7,684,749	6,310,230
Furniture and fixtures	1787	310,200	266,167
Accumulated amortization of furniture and fixtures	1788	159,524	129,867
Total tangible capital assets	2008	37,361,277	33,318,800
Total accumulated amortization of tangible capital assets	2009	10,667,992	8,778,246
Intangible Capital Assets			
Goodwill	2012	359,705	359,705
Accumulated amortization of goodwill	2013	6,824	6,824
Incorporation costs	2018	336,911	336,911
Accumulated amortization of incorporation costs	2019	86,040	72,837
Rights	2024	4,739	4,739
Total intangible capital assets	2178	701,355	701,355
Total accumulated amortization of intangible capital assets	2179	92,864	79,661
Long-Term Assets			
Loans/advances to Canadian related corporations	2243	865,551	865,551
Investment in Canadian related corporations at cost	2244	865,552	865,552
Other Canadian long-term investments	2311	40,818	39,221
Other deferred items/charges	2424	3,094,041	4,548,088
Total long-term assets	2429	4,865,962	6,318,412

Do not file with CRA. Submit the RSI for the only.

CT16

Assets held in trust

2590

Name of Corporation	Business Number	Tax year-end	Year	Month	Day
HALTON HILLS HYDRO INC.	867429623 RC 0001		2006	12	31

General Index of Financial Information (GIFI)

T2 SCH 100
Page 2 of 3

Balance Sheet Information

Liabilities

Description	GIFI	Amount	Prior year
Current liabilities			
Trade payables	2621	7,053,024	8,011,901
Trade payables to related parties	2622	1,081	5,778
Wages payable	2624	81,906	75,075
Bonuses payable	2626	66,840	90,800
Employee deductions payable	2627	31,098	22,744
Withholding taxes payable	2628	6,294	6,316
Interest payable	2629	171,754	
Taxes payable	2680	176,029	11,050
Deferred income	2770	322,890	461,507
Deposits received	2961	250,000	250,000
Total current liabilities	3139	8,160,916	8,935,171
Long-term liabilities			
Due to corporate shareholder(s)	3262	16,141,970	16,141,970
Long-term obligations/commitments/capital leases	3321	828,788	786,440
Total long-term liabilities	3450	16,970,758	16,928,410
Total liabilities *	3499	25,131,674	25,863,581

* Mandatory field

Name of Corporation	Business Number	Tax year-end	Year	Month	Day
HALTON HILLS HYDRO INC.	867429623 RC 0001		2006	12	31

General Index of Financial Information (GIFI)

T2 SCH 100

Page 3 of 3

Balance Sheet Information

Description	GIFI	Amount	Prior year
Shareholder Equity			
Common shares	3500	16,161,663	16,161,663
Retained earnings/deficit (from Item 3849)	3600	4,231,115	3,065,624
Total shareholder equity *	3620	20,392,778	19,227,287

* Mandatory field

Retained Earnings Information

Retained earnings/deficit			
Retained earnings/deficit - start	3660	3,065,624	2,394,782
Net income/loss	3680	1,165,491	670,842
Retained earnings/deficit - end (enter this amount at Item 3600)	3849	4,231,115	3,065,624
Total liabilities and shareholder equity	3640	45,524,452	45,090,868

Name of Corporation	Business Number	Tax year-end	Year	Month	Day
HALTON HILLS HYDRO INC.	867429623 RC 0001		2006	12	31

General Index of Financial Information (GIFI)

T2 SCH 125

Page 1 of 7

Income Statement Information

0001 Operating name - Required if different from corporation's legal name

0002 Description of the operation - Required if filing more than one GIFI 125 and the operation is different from the main activity

0003 Sequence Number

1

Revenue

Description	GIFI	Amount	Prior year
Trade sales of goods and services	8000	46,461,104	46,094,672
Sales of goods and services to related parties	8020	387,484	334,986
Total sales of goods and services	8089	46,848,588	46,429,658
Interest from other Canadian sources	8094	188,898	321,666
Deposits with banks interest	8103	81,599	60,734
Real estate rental revenue	8141	12,600	12,600
Realized gains/losses on sale of investments	8211	774	25,444
Other Revenue			
Income/loss of partnerships	8235	1,597	-1,297
Total revenue *	8299	47,134,056	46,848,805

* Mandatory field

Name of Corporation	Business Number	Tax year-end	Year	Month	Day
HALTON HILLS HYDRO INC.	867429623 RC 0001		2006	12	31

General Index of Financial Information (GIFI)

T2 SCH 125
Page 2 of 7

Income Statement Information

Cost of sales

Description	GIFI	Amount	Prior year
Purchases/cost of materials	8320	35,591,692	36,872,141
Cost of sales	8518	35,591,692	36,872,141
Gross profit/loss	8519	11,256,896	9,557,517

Name of Corporation	Business Number	Tax year-end	Year	Month	Day
HALTON HILLS HYDRO INC.	867429623 RC 0001		2006	12	31

General Index of Financial Information (GIFI)

T2 SCH 125

Page 3 of 7

Income Statement Information

Operating expenses

Description	GIFI	Amount	Prior year
Advertising	8521	18,254	28,094
Donations	8522		325,000
Meals and entertainment	8523	12,237	11,574
Promotion	8524	16,085	14,233
Amortization of intangible assets	8570	13,204	13,204
Bad debt expense	8590	42,000	70,004
Group insurance benefits	8621	66,584	64,010
Employer's portion of employee benefits	8622	187,442	177,049
Contributions to deferred income plans	8623	206,651	170,947
Amortization of tangible assets	8670	3,388,729	2,875,233
Insurance	8690	104,159	97,192
Interest on short-term debt	8711	13,739	13,425
Interest on long-term debt	8714	1,478,097	1,176,855
Bank charges	8715	23,638	23,628
Collection and credit costs	8717	34,032	3,077
Interest paid on deposits	8741	30,882	11,979
Memberships	8761	28,871	48,244
Business taxes	8762	101,863	68,445
Office stationery and supplies	8811	58,549	58,419
Legal fees	8861	41,342	76,439
Accounting fees	8862	40,949	20,889
Consulting fees	8863	33,632	4,926
Training expense	8876	50,264	44,063
Equipment rental	8914	12,749	8,572
Repairs and maintenance - buildings	8961	19,219	70,998
Repairs and maintenance - vehicles	8962	64,268	116,002
Repairs and maintenance - machinery and equipment	8964	256,447	246,857
Garbage removal	9014	4,613	3,657
Directors fees	9064	43,585	
Management salaries	9065	873,184	861,197
Employee salaries	9066	1,556,483	1,358,527
Sub-contracts	9110	323,420	125,863
Small tools	9131	84,882	73,099
Uniforms	9133	13,116	16,298
Internet	9152		9,250
Property taxes	9180	88,842	82,927
Travel expenses	9200	6,566	3,205
Meetings and conventions	9201	42,901	38,667
Electricity	9221	72,676	84,104
Telephone and telecommunications	9225	90,572	74,206
Delivery, freight and express	9275	84,840	76,487
Vehicle expenses	9281	4,831	
General and administrative expenses	9284	12,675	12,664
Total operating expenses	9367	9,647,072	8,659,509
Total expenses *	9368	45,238,764	45,531,650

* Mandatory field

Net non-farming income

9369 1,895,292

1,317,155

Name of Corporation	Business Number	Tax year-end	Year	Month	Day
HALTON HILLS HYDRO INC.	867429623 RC 0001		2006	12	31

General Index of Financial Information (GIFI)

T2 SCH 125

Page 4 of 7

Farming Income Statement Information

Farming Revenue

Description	GIFI	Amount	Prior year
Grains and oilseeds	9370		
Wheat	9371		
Oats	9372		
Barley	9373		
Mixed grains	9374		
Corn	9375		
Canola	9376		
Flaxseed	9377		
Soya beans	9378		
Wheat board payments	9379		
Other crop revenues	9420		
Fruit	9421		
Potatoes	9422		
Vegetables	9423		
Tobacco	9424		
Greenhouse and nursery products	9425		
Forage crops	9426		
Livestock and animal products revenue	9470		
Cattle	9471		
Swine	9472		
Poultry	9473		
Sheep and lambs	9474		
Pregnant mare urine (PMU)	9475		
Milk and cream (excluding dairy subsidies)	9476		
Eggs for consumption	9477		
Hatching eggs	9478		
Aquaculture (hatching and raising)	9479		
Horses (breeding and meat)	9480		
Other commodities	9520		
Maple products	9521		
Artificial insemination	9522		
Semen production	9523		
Embryo production	9524		
Program payment revenues	9540		
Dairy subsidies	9541		
Crop insurance	9542		
NISA payments (CAIS)	9543		
Disaster Assistance Program payments	9544		
NISA benefit (CAIS)	9545		
Production insurance premium benefit	9546		

Name of Corporation	Business Number	Tax year-end	Year	Month	Day
HALTON HILLS HYDRO INC.	867429623 RC 0001		2006	12	31

General Index of Financial Information (GIFI)

T2 SCH 125

Page 5 of 7

Farming Income Statement Information

Farming Revenue (continued)

Description	GIFI	Amount	Prior year
Rebates	9570		
Rebates - fuel	9571		
Rebates - interest	9572		
Rebates - property taxes	9573		
Resales, rebates, GST for NISA eligible expenses (CAIS)	9574		
Rebates, GST for NISA non-eligible expenses (CAIS)	9575		
Other farm revenues/losses	9600		
Custom or contract work	9601		
Wood sales	9602		
Horse racing	9603		
Insurance proceeds	9604		
Patronage dividends	9605		
Rental income	9606		
Interest income	9607		
Dividend income	9608		
Gains/losses on disposal of assets	9609		
Gravel	9610		
Trucking	9611		
Resale of commodities purchased	9612		
Leases (gas, oil, well, surface, etc.)	9613		
Machine rentals	9614		
Farming partnership income/loss	9615		
Farming joint venture income/loss	9616		
Custom feeding	9617		
Non-farming income	9650		
Total farm revenue *	9659		

* Mandatory field

Name of Corporation	Business Number	Tax year-end	Year	Month	Day
HALTON HILLS HYDRO INC.	867429623 RC 0001		2006	12	31

General Index of Financial Information (GIFI)

T2 SCH 125

Page 6 of 7

Farming Income Statement Information

Farming Expenses

Description	GIFI	Amount	Prior year
Crop expenses	9660		
Containers, twine and baling wire	9661		
Fertilizers and lime	9662		
Pesticides	9663		
Seeds and plants	9664		
Insurance premiums (crop) NISA ACS (CAIS)	9665		
Livestock expenses	9710		
Feed, supplements, straw, and bedding	9711		
Livestock purchases	9712		
Veterinary fees, medicine, and breeding fees	9713		
Minerals and salts	9714		
Machinery expenses	9760		
Machinery insurance	9761		
Machinery licences	9762		
Machinery repairs	9763		
Machinery fuel	9764		
Machinery lease	9765		

Name of Corporation	Business Number	Tax year-end	Year	Month	Day
HALTON HILLS HYDRO INC.	867429623 RC 0001		2006	12	31

General Index of Financial Information (GIFI)

T2 SCH 125

Farming Income Statement Information

Page 7 of 7

Farming Expenses (continued)

Description	GIFI	Amount	Prior year
General farm expenses	9790		
Amortization of tangible assets	9791		
Advertising, marketing costs, and promotion	9792		
Bad debt	9793		
Benefits related to employee salaries	9794		
Building repairs and maintenance	9795		
Clearing, levelling, and draining land	9796		
Crop insurance, Revenue Protection Program, and stabilization premiums	9797		
Custom or contract work	9798		
Electricity	9799		
Fence repairs and maintenance	9800		
Freight and trucking	9801		
Heating fuel and curing fuel	9802		
Insurance program overpayment recapture	9803		
Other insurance premiums	9804		
Interest and bank charges	9805		
Marketing board fees	9806		
Memberships/subscription fees	9807		
Office expenses	9808		
Professional fees	9809		
Property taxes	9810		
Rent - land and buildings	9811		
Rent - machinery	9812		
Other rental expenses	9813		
Salaries and wages	9814		
Salaries and wages other than spouse or dependants	9815		
Salaries and wages paid to dependants	9816		
Selling costs	9817		
Supplies	9818		
Motor vehicle expenses	9819		
Small tools	9820		
Soil testing	9821		
Storage/drying	9822		
Licences/permits	9823		
Telephone	9824		
Quota rental (tobacco, dairy)	9825		
Gravel	9826		
Purchases of commodities resold	9827		
Salaries and wages paid to spouse	9828		
Motor vehicle interest and leasing costs	9829		
Prepared feed	9830		
Custom feed	9831		
Amortization of intangible assets	9832		
Amortization of milk quota	9833		
Travel expenses	9834		
Capital/business taxes	9835		
Commissions and levies	9836		
Non-farming expenses	9850		
Net inventory adjustment	9870		
Total farm expenses *	9898		
* Mandatory field			
Net farm income	9899		

Do not file with CRA. Submit the RSI forms only.

T2-RETURN AND SCHEDULE INFORMATION

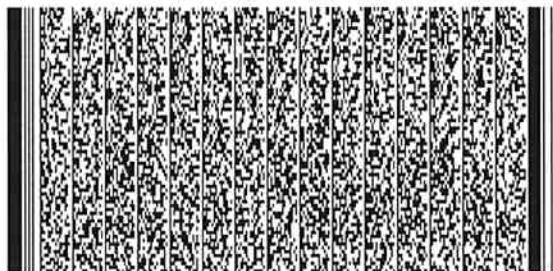
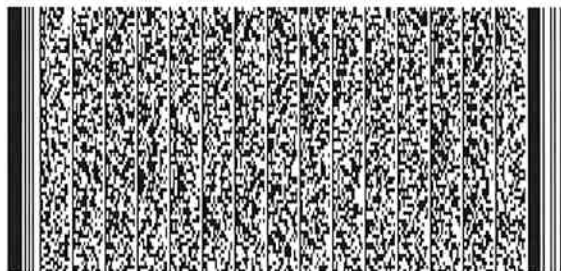
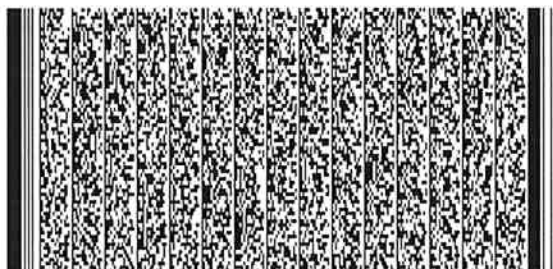
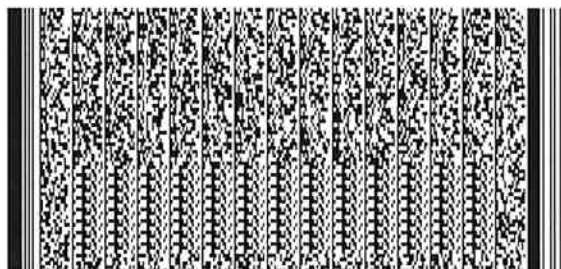
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BN: 86742 9623 RC 0001

Taxation Year End: 2006-12-31

For Agency Use

[055]



Name: HALTON HILLS HYDRO INC.

BN: 86742 9623 RC 0001

Taxation Year End: 2006-12-31

For Agency Use

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[002] HALTON HILLS HYDRO INC.

[003] 2

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For Agency Use

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For Agency Use

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[095] _____

[096] _____

[100] _____

Corporation's Legal Name HALTON HILLS HYDRO INC.	Ontario Corporations Tax Account No. (MOF) 1800262	Taxation Year End 2006/12/31

Part 2 - Amount to be included in income arising from disposition

Complete this part only if the amount at line M is negative.

Amount from line M above. <i>Show this as a positive amount; not negative.</i>	_____	R
Total cumulative eligible capital deductions from income for taxation years beginning after June 30, 1988	+ _____	1
Total of all amounts which reduced cumulative eligible capital in the current or prior years under subsection 80(7) of the ITA	+ _____	2
Total of cumulative eligible capital deductions claimed for taxation years beginning before July 1, 1988	+ _____	3
Negative balances in the cumulative eligible capital account that were included in income for taxation years beginning before July 1, 1988	- _____	4
Deduct line 4 from line 3 (if negative, enter zero)	= _____	5
Total lines 1 + 2 + 5	= _____	6
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 1	_____	7
Amounts at Line Z from Ontario Schedule 10 of previous taxation years ending after February 27, 2000 (This will be Line T in earlier versions of this schedule.)	+ _____	8
Total lines 7 + 8	= _____	9
Deduct line 9 from line 6 (if negative, enter zero)	= _____	S
R minus S (if negative, enter zero)	= _____	T
From Line 5	X 1/2	= _____
T minus U (if negative, enter zero)	= _____	U
From V	X 2/3	= _____
Lesser of R and S	= + _____	V
Amount to be included in income W + Z	= _____	W
		Z

Corporate Minimum Tax - Associated Corporations

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
HALTON HILLS HYDRO INC.	1800262	2006/12/31

Name of Associated Corporation (Canadian and Foreign)	Corporations Tax Number	Taxation Year End	Total Assets	Total Revenue
HALTON HILLS HYDRO INC.	1800262	2006/12/31	45,524,452	47,165,520
HALTON HILLS FIBRE OPTICS	1800329	2006/12/31	3,648,224	1,148,403
SOUTHWESTERN ENERGY INC.	1800261	2006/12/31	651,989	584,906
HALTON HILLS ENERGY INC.	6094233	2006/12/31	1,081	
HALTON HILLS ENERGY SERVIC	8238060	2006/12/31	1,440,335	682,919
Totals			51,266,081	49,581,748

Transfer to 249 of the CT23 Transfer to 250 of the CT23

Taxable Capital of Associated Corporations

(Applicable to an associated group that has a permanent establishment in Canada)

Schedule CT21

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
HALTON HILLS HYDRO INC.	1800262	2006/12/31

This schedule must be completed in determining the aggregate taxable capital of an associated group and/or partnership that has a permanent establishment (PE) in Canada.

Name of Associated Corporation (Must have a PE in Canada)	Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End	Taxable capital
HALTON HILLS HYDRO INC.	1800262	2006/12/31	37,121,698
HALTON HILLS FIBRE OPTICS	1800329	2006/12/31	2,563,531
SOUTHWESTERN ENERGY INC.	1800261	2006/12/31	319,844
HALTON HILLS ENERGY INC.	6094233	2006/12/31	1,081
HALTON HILLS ENERGY SERVIC	8238060	2006/12/31	549,364
Aggregate of taxable capital			40,555,518

Aggregate of taxable capital	40,555,518

Transfer to box 540 of the CT23



Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
HALTON HILLS HYDRO INC.	1800262	2006/12/31

This schedule is used to calculate Ontario Scientific Research and Experimental Development Expenditures (SR & ED). The rules used in the calculation of Ontario SR & ED follow the federal rules with the exception of the new Ontario measure introduced in the 2001 Ontario Budget and implemented in Bill 127 which received Royal Assent on December 5, 2001.

This schedule must be completed by all corporations performing qualified Ontario SR & ED in a "specified taxation year" or in the taxation year immediately preceding the first specified taxation year of the corporation and filed with the current CT23 or CT8. Other corporations may use this schedule, if they have claimed or are claiming a different SR & ED amount for Ontario than for federal income tax purposes.

• **"Specified Taxation Year" (STY)** is the taxation year of the corporation that begins after February 29, 2000 and ends after December 31, 2000.

• **"Investment Tax Credit Amount" (ITC)** means, in respect of a corporation for a taxation year, an amount deducted by the corporation for a preceding taxation year under subsection 127(5) or (6) of the *Income Tax Act* (Canada) (ITA).

• **"Qualified Ontario SR & ED Expenditure" (QORD)** means,

- A. A qualified expenditure within the meaning of subsection 12(1) of the *Corporations Tax Act* (CTA) that is made or incurred by a corporation in a STY or in the taxation year immediately preceding the first STY of corporation, or
- B. An expenditure made or incurred by a partnership in a fiscal period that ends in a STY of a corporation if,
 - the corporation is member of the partnership at any time in the STY, and
 - the expenditure would be a qualified expenditure within the meaning of subsection 12(1) of the CTA if it were made by a corporation.

• **"Ontario Allocation Factor" (OAF)** has the meaning given to that expression by subsection 12(1) of the CTA.

• If a corporation includes a federal ITC amount in determining the amount of the Ontario pool of deductible SR & ED expenditures for a STY, the following amounts are adjusted by the OAF:

- Amount of recaptured federal ITC relating to QORD for property disposed of in the preceding taxation year in on page 2.
- Amount of federal ITC relating to QORD claimed federally in the preceding taxation year(s) in on page 2.
- Amount of federal ITC relating to QORD allocated from partnerships in the current taxation year in on page 2.

• Federal ITCs earned on shared-use equipment (SUE) reduce the capital cost of the property acquired for federal and Ontario income tax purposes in the taxation year after the taxation year in which the ITC is claimed federally. The amount of the federal ITC that relates to QORD on SUE is added to the SR & ED pool for Ontario purposes in the taxation year after the taxation year in which the ITC is claimed federally.

**Ontario Scientific Research and
Experimental Development Expenditures
CT23 Schedule 161**

Page 2 of 5

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
HALTON HILLS HYDRO INC.	1800262	2006/12/31

Ontario Pool of Deductible SR & ED Expenditures for the current taxation year

Total allowable SR & ED expenditures (capital and current)

(From line 400 federal T661 (T2 SCH32)) - - - - - + 400

Less: Government and non-government assistance

(Form line 430 federal T661 (T2 SCH32)) - - - - - - 430

Preceding year's amount of federal ITC claimed for SR & ED

(From line 435 federal T661 (T2 SCH32)) - - - - - - 435 27,781

Sale of SR & ED capital assets and other deductions

(From line 440 federal T661 (T2 SCH32)) - - - - - - 440

Amount of recaptured federal ITC (From line 453 federal T661 (T2 SCH32))

relating to QORD for property disposed of in the preceding taxation year 442

Gross-up for Ontario allocation factor

From 442 $\div 100.0000\%$ = 444
(From 30 of the CT23 or CT8)

Subtotal: 400 - 430 - 435 - 440 - 444 - - - - - = 445 -27,781

Add: Repayments of government and non-government assistance

(From line 445 federal T661 (T2 SCH32)) - - - - - + 446

SR & ED expenditure pool transferred on amalgamation or wind-up

(From line 452 federal T661 (T2 SCH32)) - - - - - + 452

Amount of federal ITC recaptured in the preceding taxation year

(From line 453 federal T661 (T2 SCH32)) - - - - - + 453

Preceding year's balance in pool of deductible Ontario SR & ED expenditures

(From 480 of the preceding taxation year) - - - - - + 460

Federal ITC relating to QORD claimed federally in the preceding taxation year(s) + 462

(From 575 on Page 3)

Amount of federal ITC relating to QORD allocated from partnerships

in the current taxation year - - - - - + 465

Subtotal 462 + 465 - - - - - = 468

Gross-up for Ontario allocation factor

From 468 $\div 100.0000\%$ = 470
(From 30 of the CT23 or CT8)

Subtotal 445 + 446 + 452 + 453 + 460 + 470

(If the amount in 473 is negative, enter zero, in 475, 477 and add 473 to 615 of the 2002 CT23 or CT8,
or 616 of the 2003 or later CT23 or CT8.

If the amount in 473 is positive, enter the amount in 475.) - - - - - = 473 -27,781

Amount available for deduction - - - - - = 475

Deduction claimed in the taxation year for Ontario

(Enter the SR & ED expenditure pool deduction claimed in the taxation year in 679 of the CT23 or CT8) - - - - - - 477

Ontario current taxation year closing balance

in pool of deductible SR & ED expenditures 475 - 477 - - - - - = 480

(Transfer this amount to 460 as the carry forward amount for the next taxation year.)

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
HALTON HILLS HYDRO INC.	1800262	2006/12/31

Calculation of Preceding Taxation Year Amount and Account Balances - Federal ITC from SR & ED Expenditures relating to QORD.

- This page is used to calculate the amount of the federal ITC that relates to SR & ED performed in Ontario for certain taxation years and is used to increase the amount of the Ontario SR & ED pool on page 2.
- All amounts on this page are based on the preceding taxation year since the amount of the federal ITC that relates to QORD can only be used to increase the Ontario pool for SR & ED in the current taxation year if there was a federal ITC claimed for federal purposes in the preceding taxation year that related to QORD.
- **Do not include amounts** of federal ITCs that relate to QORD that were **allocated from a partnership**. These amounts are added to your SR & ED pool for Ontario in the taxation year that they are allocated from a partnership to a corporation, not in the year after they are claimed federally.

Opening Balance:

(Enter amount from Schedule 161 of the preceding taxation year, if any) - - - - - +

Add: Amount of federal ITC earned, relating to QORD
(QORD portion of line federal T2 SCH31 for the preceding taxation year) - - - - - +

Amount of federal ITC earned, relating to QORD, transferred on amalgamation or wind-up
(QORD portion of line federal T2 SCH31 for the preceding taxation year) - - - - - +

Subtotal: + + - - - - - =

Deduct: Amount of federal ITC, relating to QORD, claimed federally
(QORD portion of line federal T2 SCH31 for the preceding taxation year) - - - - - +

Amount of federal ITC, relating to QORD, carried back federally to a preceding taxation year(s)
(QORD portion of line P federal T2 SCH31 for the preceding taxation year) - - - - - +

A refund of federal ITC, relating to QORD, claimed federally
(QORD portion of line federal T2 SCH31 for the preceding taxation year) - - - - - +

Amount of federal ITC, relating to QORD, deemed as a remittance of co-op corporations
(QORD portion of line federal T2 SCH31 for the preceding taxation year) - - - - - +

Subtotal: + + + - - - - - =

(Transfer this amount to on Page 2)

Deduct: Amount of federal ITC, relating to QORD, expired per the ITA after 10 taxation years
(QORD portion of line federal T2 SCH31 for the preceding taxation year) - - - - - -

Closing Balance: - - - - - - - =

(Transfer this amount to as the opening balance for the next taxation year.)

**Ontario Scientific Research and
Experimental Development Expenditures
CT23 Schedule 161**

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Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
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Continuity Schedule for Federal ITC relating to SR & ED Expenditures for the Preceding Taxation Year

- All amounts on this page are based on the preceding taxation year.
- Amounts on this page should tie into Part 12 of federal T2 SCH31 completed for the preceding taxation year.

Yr. of Origin (Oldest yr. first) yyyy mm dd	Opening Balance	Additions	Deductions (other than amounts that were allocated from a partnership)	Deductions (only amounts that were allocated from a partnership)	Closing Balance
1996/12/31					
1997/12/31					
1998/12/31					
1999/12/31					
2000/12/31					
2001/12/31					
2002/12/31					
2003/12/31					
2004/12/31					
2005/12/31					
Totals (See note 1, 2 and 3)	725	740	755	770	785

Notes:

1. The amount in 725 should equal the amount of the investment tax credit at the end of the preceding taxation year less line 515 in Part 12 of the federal T2 SCH31 for the preceding taxation year.
2. The amount in 785 should equal the closing balance in line 620 in Part 12 of the federal T2 SCH31 for the preceding taxation year.
3. It is important that the amounts in the deductions columns on this page correctly reflect the year of origin of the federal ITC claimed because only amounts relating to QORD can be used to increase the Ontario SR & ED pool.

Corporation's Legal Name HALTON HILLS HYDRO INC.	Ontario Corporations Tax Account No. (MOF) 1800262	Taxation Year End 2006/12/31

Continuity Schedule for the Amount of Federal ITC from SR & ED Expenditures relating to QORD for the Preceding Taxation Year

- This page is required to record the amount of the ITC that relates to QORD by year of origin.
- All amounts on this page are based on the preceding taxation year.
- **Do not** include amounts of federal ITCs that relate to QORD that were **allocated from a partnership** (see text at the top of page 3).

Yr. of Origin (Oldest yr. first) yyyy mm dd	Opening Balance	Additions	Deductions	Closing Balance
1996/12/31				
1997/12/31				
1998/12/31				
1999/12/31				
2000/12/31				
2001/12/31				
2002/12/31				
2003/12/31				
2004/12/31				
2005/12/31				
Totals (See note 1 - 6)	825	840	855	870

Notes:

1. The amount in should equal on page 3.
2. The amount in should equal the total of and on page 3.
3. The amount in should equal on page 3.
4. The amount in should equal on page 3.
5. Any deductions that are recorded in the deduction column on this page must be taken out of the same year of origin as indicated in the deduction column on page 4. These deductions must be related to QORD and must not have been allocated from a partnership.
6. The amount of federal ITC relating to QORD will expire if the federal ITC it relates to expires before it is claimed federally.



Corporation's Legal Name HALTON HILLS HYDRO INC.	Ontario Corporations Tax Account No. (MOF) 1800262	Taxation Year End 2006/12/31

Instructions for completing the ATTC Claim Form

- Complete the section below, if claiming this credit.
- Enter the relevant details for each eligible apprentice, including the amount of tax credit.
- Your total tax credit for the taxation year is equal to the sum of the tax credits for each eligible apprentice.
- Enter the total tax credit claimed on line **203**, page 7 of the CT23 or page 4 of the CT8.
- Enter the total number of apprentice hired on line **202**, page 7 of the CT23 or page 4 of the CT8.

- Corporations are eligible for 25% (30% in the case of corporations with payroll not exceeding \$400,000) refundable tax credit on wages and salaries paid after May 18, 2004 to eligible apprentices during the first 36 months of an apprenticeship.
- The maximum amount of credit that can be claimed in respect of each eligible apprentice is \$5,000 per year to a maximum of \$15,000 over the first 36 months of the apprenticeship. The maximum annual tax credit of \$5,000 is pro-rated for the number of days the apprentice was employed during the taxation year.
- The credit is *considered government assistance* and is therefore *to be included in income* in the year the credit is claimed.

Summary of Apprenticeship Training Tax Credit Claimed

Complete a separate entry for each eligible apprentice that is in a qualifying skilled trade and hired before January 1, 2008. This credit applies to **salaries and wages paid after May 18, 2004 and before January 1, 2011** to eligible apprentices during the first 36 months of an apprenticeship.

Example: A taxpayer, with a December 31, 2004 taxation year end, hires an otherwise eligible apprentice on June 1, 2004 at a salary of \$3,500 per month. The taxpayer's salaries and wages in the preceding taxation year were \$700,000. The credit claimed is the lesser of **(1)** 25% of salaries paid to the apprentice during the period of employment ($25\% \times \$3,500 \times 7 = \$6,125$), and **(2)** \$5,000 multiplied by the number of days in the apprentice was employed during the taxation year, divided by the total number of days in the calendar year ($\$5,000 \times 214/366 = \$2,923$). Hence, the credit claimed in the 2004 taxation year is \$2,923.

Eligible Apprenticeship

Trade Code	Description of Apprenticeship Program	Apprentice Name and Social Insurance No.(SIN)	Registration Date of Apprenticeship Contract or Training Agreement year month day	Contract or Agreement No.	Employment Period year month day	Eligible Expenditures (EE)	* Credit Claimed (See notes below)
434a	Power Lin	Name GRAVES JASON SIN 507139400			From 2006/01/01 To 2006/12/31	5850 61,964	5876 5,000
434a	Power Lin	Name WOOD CHAD SIN 495139792			From 2006/01/01 To 2006/12/31	5851 54,498	5877 5,000
		Name SIN			From To	5852 5874	5878 5898
Totals						116,462	10,000

Corporation's salaries & wages paid in the preceding taxation year **A** \$

Transfer to **203** Page 7 of the CT23 or Page 4 of the CT8

- If **A** is \$600,000 or greater use 25%.
- If **A** is \$400,000 or less use 30%.
- If **A** is over \$400,000 but less than \$600,000 use the following formula to calculate the specified percentage:

$$\text{Specified percentage} = .30 - [.05 (\text{From } \mathbf{A} \text{ } - \$400,000) \div \$200,000]$$

Indicated specified percentage used **30.00** %

* Credit claimed equals lesser of:

- (1) EE multiplied by the specified percentage, and
- (2) \$5,000 x number of days the apprentice was employed in the taxation year
365 (366 if leap year)

Total number of Apprentice = **5896** 2
Transfer to **202** Page 7 of the CT23 or Page 4 of the CT8

Name: HALTON HILLS HYDRO INC.

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Taxation Year End: 2006-12-31

[030] @ 2

[031]

[032]

[035]

[036]

[037]

[038]

XXXXXXXXXXXX

[040]

1

[165]

[217]

[043]

[166]

[218]

[063]

2

[167]

[220]

[065]

[168]

[221]

[067]

2

[169]

[227]

[070]

2

[170]

[231]

[071]

2

[171]

[232]

1

[072]

2

[172]

[233]

1

[076]

2

[173]

1

[236]

1

[078]

2

[201]

1

[237]

[080]

1

[202]

[238]

[081]

[203]

[242]

[082]

2

[204]

[243]

[085]

[205]

[244]

[150]

1

[206]

[249]

[151]

[207]

[250]

[160]

1

[208]

1

[253]

[161]

[210]

1

[254]

[162]

1

[212]

[255]

[163]

[213]

[256]

[164]

[216]

Name: HALTON HILLS HYDRO INC.

BN: 86742 9623 RC 0001

Taxation Year End: 2006-12-31

[258]	_____	[284]	DISTRIBUTION OF ELECTRICITY
[259]	_____	[286]	_____
[260]	_____	[288]	_____
[261]	_____	[285]	100
[262]	_____	[287]	_____
[263]	_____	[289]	_____
[264]	_____	[950]	SKIDMORE
[291]	2	[951]	ARTHUR
[292]	2	[954]	CHIEF FINANCIAL OFFICER
[370]	_____	[955]	2007 06 30
[435]	_____	[956]	519 853 3700
[438]	_____	[957]	1
[624]	_____	[958]	_____
[646]	_____	[959]	_____
[750]	ON		XXXXXXXXXXXXX
[801]	_____		
[894]	_____		
[896]	2		
[898]	_____		
[910]	_____		
[914]	_____		
[918]	_____		
[990]	1		
	XXXXXXXXXXXXX		
[280]	2		
[281]	2		
[282]	_____		
[283]	_____		

Name: HALTON HILLS HYDRO INC.

BN: 86742 9623 RC 0001

Taxation Year End: 2006-12-31

[300]	1 921 918	[440]	_____	[652]	_____
[311]	_____	[445]	_____	[700]	425 128
[312]	_____	[450]	_____		XXXXXXXXXXXXX
[313]	_____	[600]	21 525		
[314]	_____	[632]	_____	[704]	_____
[320]	_____	[636]	_____	[708]	_____
[325]	_____	[780]	_____	[716]	_____
[331]	_____		XXXXXXXXXXXXX	[720]	_____
[332]	_____			[724]	_____
[333]	_____	[460]	5 528	[727]	_____
[334]	_____	[465]	_____	[728]	_____
[335]	_____	[480]	_____	[760]	_____
[340]	_____	[485]	5 528	[765]	_____
[350]	_____	[712]	_____	[770]	425 128
[355]	_____		XXXXXXXXXXXXX		XXXXXXXXXXXXX
[360]	1 921 918				
	XXXXXXXXXXXXX	[550]	730 329	[784]	_____
		[602]	_____	[788]	_____
[400]	1 921 918	[604]	_____	[792]	_____
[405]	1 921 918	[608]	192 192	[796]	_____
[410]	300 000	[616]	_____	[797]	_____
[425]	_____	[620]	_____	[800]	_____
[430]	_____	[628]	_____	[808]	_____
	XXXXXXXXXXXXX	[637]	_____	[812]	_____
		[638]	134 534	[840]	425 128
[415]	62 533	[639]	_____	[890]	425 128
	XXXXXXXXXXXXX	[640]	_____		XXXXXXXXXXXXX
		[644]	_____		
		[648]	_____		

Name: HALTON HILLS HYDRO INC.

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Taxation Year End: 2006-12-31

Certification

I, ARTHUR SKIDMORE am an authorized signing officer of the corporation.

I certify that the following amounts are, to the best of my knowledge, correct and complete, and fully disclose the corporation's income tax payable. These amounts also reflect the information given on the corporation's income tax return for the taxation year noted above.

Net income or (loss) for income tax purposes	
from Schedule 001, or GIF1 [line 200300]	1 921 918
Part I tax payable [line 200700]	425 128
Part I.3 tax payable [line 200704]	0
Part II surtax payable [line 200708]	0
Part IV tax payable [line 200712]	0
Part IV.1 tax payable [line 200716]	0
Part VI tax payable [line 200720]	0
Part VI.1 tax payable [line 200724]	0
Part XIV tax payable [line 200728]	0
Net provincial and territorial tax payable [line 200760]	0
Provincial tax on large corporations [line 200765]	0

I further certify that the method of calculating income for this taxation year is consistent with that of the previous year except as specifically disclosed in a statement attached to this return.

<u>2007 06 30</u>	<u>CHIEF FINANCIAL OFFICER</u>
Date	Signature of an authorized signing officer of the corporation Position, office or rank

Name: HALTON HILLS HYDRO INC.

BN: 86742 9623 RC 0001

Taxation Year End: 2006-12-31

[3640]	45 524 452	[1785]	29 114 871	[2961]	250 000
	XXXXXXXXXXXX	[1786]	# 7 684 749	[3139]	8 160 916
		[1787]	310 200	[3262]	16 141 970
[1000]	_____	[1788]	# 159 524	[3321]	828 788
[1001]	1 000	[2008]	37 361 277	[3450]	16 970 758
[1002]	1 599 010	[2009]	# 10 667 992	[3499]	25 131 674
[1062]	9 071 986	[2012]	359 705		XXXXXXXXXXXX
[1063]	# 89 550	[2013]	# 6 824		
[1064]	64 092	[2018]	336 911	[3500]	16 161 663
[1066]	3 075	[2019]	# 86 040	[3600]	4 231 115
[1067]	9 332	[2024]	4 739	[3620]	20 392 778
[1068]	1 710	[2178]	701 355		XXXXXXXXXXXX
[1071]	19 327	[2179]	# 92 864		
[1122]	1 087 028	[2243]	865 551	[3660]	3 065 624
[1403]	1 341 153	[2244]	865 552	[3680]	1 165 491
[1484]	248 551	[2311]	40 818	[3849]	4 231 115
[1599]	13 356 714	[2424]	3 094 041		XXXXXXXXXXXX
[1601]	354 871	[2589]	4 865 962		
[1682]	2 840 621	[2599]	45 524 452		
[1683]	# 342 582		XXXXXXXXXXXX		
[1742]	1 433 315				
[1743]	# 1 003 043	[2600]	_____		
[1744]	412 228	[2621]	7 053 024		
[1745]	# 213 689	[2622]	1 081		
[1770]	53 151	[2624]	81 906		
[1771]	# 33 237	[2626]	66 840		
[1772]	609 098	[2627]	31 098		
[1773]	# 171 709	[2628]	6 294		
[1774]	1 442 107	[2629]	171 754		
[1775]	# 1 059 459	[2680]	176 029		
[1782]	790 815	[2770]	322 890		

Name: HALTON HILLS HYDRO INC.

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Taxation Year End: 2006-12-31

[0001] _____

[0002] _____

XXXXXXXXXXXXX

[0003] _____

XXXXXXXXXXXXX

[8519]	11 256 896	[8300]	_____	[8876]	50 264
[9369]	1 895 292	[8320]	35 591 692	[8914]	12 749
[9899]	_____	[8518]	35 591 692	[8961]	19 219
[9970]	1 895 292	[8521]	18 254	[8962]	64 268
[9975]	_____	[8523]	12 237	[8964]	256 447
[9976]	_____	[8524]	16 085	[9014]	4 613
[9980]	_____	[8570]	13 204	[9064]	43 585
[9985]	_____	[8590]	42 000	[9065]	873 184
[9990]	729 801	[8621]	66 584	[9066]	1 556 483
[9995]	_____	[8622]	187 442	[9110]	323 420
[9999]	1 165 491	[8623]	206 651	[9131]	84 882
	XXXXXXXXXXXXX	[8670]	3 388 729	[9133]	13 116
		[8690]	104 159	[9180]	88 842
[8000]	46 461 104	[8711]	13 739	[9200]	6 566
[8020]	387 484	[8714]	1 478 097	[9201]	42 901
[8089]	46 848 588	[8715]	23 638	[9221]	72 676
[8094]	188 898	[8717]	34 032	[9225]	90 572
[8103]	81 599	[8741]	30 882	[9275]	84 840
[8141]	12 600	[8761]	28 871	[9281]	4 831
[8211]	774	[8762]	101 863	[9284]	12 675
[8235]	1 597	[8811]	58 549	[9367]	9 647 072
[8299]	47 134 056	[8861]	41 342	[9368]	45 238 764
	XXXXXXXXXXXXX	[8862]	40 949		XXXXXXXXXXXXX
		[8863]	33 632		

Name: HALTON HILLS HYDRO INC.

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[9370] _____

[9659] 0

XXXXXXXXXXXXX

[9660] _____

[9898] 0

XXXXXXXXXXXXX

Name: HALTON HILLS HYDRO INC.

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[095]	1
[097]	2
[198]	1
[099]	2
[101]	1
[102]	2
[103]	2
[104]	2
[105]	2
[106]	1
[107]	1
[108]	1
[109]	2

XXXXXXXXXXXX

Name: HALTON HILLS HYDRO INC.

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[600] Employee future benefit costs accrued
 [601] Provision for bad debts
 [602] _____
 [603] _____
 [604] _____
 [700] Employee future benefits expenses paid
 [701] Reg asset amort incl in tangible asset amort
 [702] _____
 [703] _____
 [704] _____

XXXXXXXXXXXX

[101]	729 801	[118]	_____	[203]	_____
[102]	_____	[119]	_____	[204]	_____
[103]	33 000	[120]	_____	[205]	_____
[104]	3 388 729	[121]	6 119	[206]	_____
[105]	_____	[122]	_____	[207]	_____
[106]	13 204	[123]	_____	[208]	_____
[107]	_____	[124]	_____	[209]	_____
[108]	_____	[125]	_____	[210]	_____
[109]	_____	[126]	_____	[211]	_____
[110]	_____	[127]	_____	[212]	_____
[111]	_____	[128]	_____	[213]	_____
[112]	_____	[199]	95 517	[214]	_____
[113]	_____	[500]	4 266 370	[215]	_____
[114]	_____		XXXXXXXXXXXX	[216]	_____
[115]	_____			[217]	_____
[116]	_____	[201]	_____	[218]	_____
[117]	_____	[202]	_____	[219]	_____

Name: HALTON HILLS HYDRO INC.

BN: 86742 9623 RC 0001

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[220]	_____	[300]	_____	[401]	774
[221]	_____	[301]	_____	[402]	_____
[222]	_____	[302]	_____	[403]	1 902 072
[223]	_____	[303]	_____	[404]	_____
[224]	_____	[304]	55 986	[405]	61 955
[225]	_____	[305]	1 597	[406]	_____
[226]	_____	[306]	_____	[407]	_____
[227]	_____	[307]	_____	[408]	_____
[228]	_____	[308]	_____	[409]	_____
[229]	_____	[309]	_____	[410]	_____
[230]	_____	[310]	_____	[411]	_____
[231]	27 781	[311]	_____	[413]	_____
[232]	_____	[312]	_____	[414]	_____
[233]	_____	[313]	_____	[416]	_____
[234]	_____	[314]	_____	[417]	_____
[235]	_____	[315]	_____	[499]	1 545 142
[236]	_____	[316]	_____	[510]	3 509 943
[237]	_____	[340]	_____		XXXXXXXXXXXXX
[238]	_____	[341]	_____		
[290]	25 736	[342]	_____		
[291]	42 000	[343]	_____		
[292]	_____	[344]	_____		
[293]	_____	[345]	_____		
[294]	_____	[346]	_____		
XXXXXXXXXXXXX		[390]	15 835		
		[391]	1 471 724		
		[392]	_____		
		[393]	_____		
		[394]	_____		

XXXXXXXXXXXXX

Name: HALTON HILLS HYDRO INC.

BN: 86742 9623 RC 0001

Taxation Year End: 2006-12-31

[101] 2

[200]

1. 1
2. 1
3. 8
4. 8
5. 8
6. 10
7. 10
8. 12
9. 8
10. 46
11. 45
12. 43.1
13. 49 *

[211]

1. _____
2. 14 900
3. 25 449
4. 22 017
5. 1 072
6. _____
7. 26 214
8. _____
9. _____
10. 48 744
11. 74 609
12. 306 310
13. 1 013 728 *

[212] 1. 4

2. 4
3. 20
4. 20
5. 20
6. 30
7. 30
8. 100
9. 20
10. 30
11. 45
12. 30
13. 8 *

XXXXXXXXXXXXX

[201] 1. 20 712 394

2. 2 290 038
3. 169 599
4. 160 398
5. 20 366
6. 158 266
7. 458 204
8. 13 650
9. 160 505
10. 25 773
11. 93 511
12. 65 464
13. 2 100 123 *

[203] 1. _____

Name: HALTON HILLS HYDRO INC.

BN: 86742 9623 RC 0001

Taxation Year End: 2006-12-31

2. 29 799

3. 50 897

4. 44 033

5. 2 144

6. _____

7. 52 428

8. 204 394

9. _____

10. 97 487

11. 149 217

12. 612 620

13. 2 027 456 *

4. _____

5. _____

6. _____

7. _____

8. _____

9. _____

10. _____

11. _____

12. _____

13. _____ *

[213]

1. _____

2. _____

3. _____

4. _____

5. _____

6. _____

7. _____

8. _____

9. _____

10. _____

11. _____

12. _____

13. _____ *

[205]

1. _____

2. _____

3. _____

4. _____

5. _____

6. _____

7. _____

8. _____

9. _____

10. _____

11. _____

12. _____

13. _____ *

[215]

1. _____

2. _____

3. _____

4. _____

5. _____

[207]

1. _____

2. _____

3. _____

Name: HALTON HILLS HYDRO INC.

BN: 86742 9623 RC 0001

Taxation Year End: 2006-12-31

6. _____
7. _____
8. _____
9. _____
10. _____
11. _____
12. _____
13. _____ *

8. _____
9. 128 404
10. 100 905
11. 167 074
12. 566 552
13. 3 878 471 *

XXXXXXXXXXXXX

[217] 1. 828 496
2. 92 197
3. 39 009
4. 36 483
5. 4 288
6. 47 480
7. 145 325
8. 218 044
9. 32 101
10. 22 355
11. 75 654
12. 111 532
13. 249 108 *

[220] 1. 19 883 898
2. 2 227 640
3. 181 487
4. 167 948
5. 18 222
6. 110 786
7. 365 307

Name: HALTON HILLS HYDRO INC.

BN: 86742 9623 RC 0001

Taxation Year End: 2006-12-31

- [300]
1. 88627 0727 RC 0001
 2. 87097 1181 RC 0001
 3. 87307 4876 RC 0001
 4. 86244 8453 RC 0001 *

- [400]
1. 2
 2. 2
 3. 2
 4. 3 *

XXXXXXXXXXXX

- [100]
1. HALTON HILLS FIBRE OPTICS INC.
 2. SOUTHWESTERN ENERGY INC.
 3. HALTON HILLS ENERGY INC.
 4. HALTON HILLS ENERGY SERVICES INC. *

- [200]
1. _____
 2. _____
 3. _____
 4. _____ *

- [500]
1. 956
 2. 603
 3. 100
 4. _____ *

- [550]
1. 100
 2. 100
 3. 100
 4. _____ *

Name: HALTON HILLS HYDRO INC.

BN: 86742 9623 RC 0001

Taxation Year End: 2006-12-31

[600] 1. _____
2. _____
3. _____
4. _____ *

[650] 1. _____
2. _____
3. _____
4. _____ *

[700] 1. 693 698
2. 171 853
3. 1
4. _____ *

XXXXXXXXXXXX

Name: HALTON HILLS HYDRO INC.

BN: 86742 9623 RC 0001

Taxation Year End: 2006-12-31

[200] 885 066

[222] _____

[224] _____

[226] _____

[228] _____

[230] 885 066

XXXXXXXXXXXXX

[242] _____

[244] _____

[246] _____

[248] _____

XXXXXXXXXXXXX

[249] _____

[250] 61 955

[300] 823 111

XXXXXXXXXXXXX

[400] _____

[401] _____

[402] _____

[408] _____

[409] _____

[410] _____

XXXXXXXXXXXXX

Name: HALTON HILLS HYDRO INC.

BN: 86742 9623 RC 0001

Taxation Year End: 2006-12-31

[100] 1. 1 *

[200] 1. _____ *

[300] 1. _____ *

[400] 1. 16 141 970 *

[500] 1. _____ *

[550] 1. _____ *

XXXXXXXXXXXX

Name: HALTON HILLS HYDRO INC.

BN: 86742 9623 RC 0001

Taxation Year End: 2006-12-31

[025] _____

[050] 2006

[075] 2

[200] 1. 86742 9623 RC 0001

2. 88627 0727 RC 0001

3. 87097 1181 RC 0001

4. 87307 4876 RC 0001

5. 86244 8453 RC 0001 *

[300] 1. 1

2. 1

3. 1

4. 1

5. 1 *

XXXXXXXXXXXXX

[350] 1. 100

2. _____

3. _____

4. _____

5. _____ *

XXXXXXXXXXXXX

[400] 1. 300 000

2. _____

3. _____

4. _____

5. _____ *

XXXXXXXXXXXXX

Name: HALTON HILLS HYDRO INC.

BN: 86742 9623 RC 0001

Taxation Year End: 2006-12-31

- [100]
1. HALTON HILLS HYDRO INC.
 2. HALTON HILLS FIBRE OPTICS
 3. SOUTHWESTERN ENERGY INC.
 4. HALTON HILLS ENERGY INC.
 5. HALTON HILLS ENERGY SERVIC *

XXXXXXXXXXXX

Name: HALTON HILLS HYDRO INC.

BN: 86742 9623 RC 0001

Taxation Year End: 2006-12-31

For Agency Use

[490] _____
[491] _____
[492] _____

XXXXXXXXXXXX

[100] ARTHUR SKIDMORE
[105] 519 853 3700
[110] 519 853 4148
[130] 2
[132] 2005
[142] 2
[145] _____
[150] _____
[155] HALTON HILLS HYDRO
[160] 1
[162] _____
[165] ARTHUR SKIDMORE
[170] 2007 06 30
[200] _____
[206] _____
[315] _____
[605] _____
[630] _____
[632] _____
[634] _____
[636] _____
[638] _____
[670] _____
[672] _____

Name: HALTON HILLS HYDRO INC.

BN: 86742 9623 RC 0001

Taxation Year End: 2006-12-31

[674] _____

XXXXXXXXXXXX

[701] _____

[702] @ _____

[704] _____

[711] _____

[712] _____

[714] _____

[716] _____

[718] _____

[721] _____

[731] _____

[732] _____

[734] _____

[736] _____

[738] _____

[740] _____

[900] _____

[920] _____

[210] 1. _____ *

[212] 1. _____ *

[214] 1. _____ *

Name: HALTON HILLS HYDRO INC.**BN: 86742 9623 RC 0001****Taxation Year End: 2006-12-31**

[216] 1. _____ *

[218] 1. _____ *

[220] 1. _____ *

[706] 1. _____ *

[850] 1. _____ *

[852] 1. _____ *

[854] 1. _____ *

[902] 1. _____ *

[904] 1. _____ *

[906] 1. _____ *

[908] 1. _____ *

[910] 1. _____ *

[912] 1. _____ *

[922] 1. _____ *

[924] 1. _____ *

Name: HALTON HILLS HYDRO INC.

BN: 86742 9623 RC 0001

Taxation Year End: 2006-12-31

[926] 1. _____ *

[928] 1. _____ *

[930] 1. _____ *

[932] 1. _____ *

XXXXXXXXXXXXX

Name: HALTON HILLS HYDRO INC.

BN: 86742 9623 RC 0001

Taxation Year End: 2006-12-31

[300]	_____	[460]	_____	[600]	_____
[305]	_____	[470]	_____	[602]	_____
[310]	_____		XXXXXXXXXXXXX	[604]	_____
[320]	_____			[606]	_____
[325]	_____	[500]	_____	[608]	_____
[340]	_____	[502]	_____	[610]	_____
[345]	_____	[504]	_____	[612]	_____
[350]	_____	[508]	_____	[614]	_____
[355]	_____	[510]	_____	[616]	_____
[360]	_____	[520]	_____	[618]	_____
[370]	_____	[522]	_____		XXXXXXXXXXXXX
[380]	_____	[524]	_____		
	XXXXXXXXXXXXX	[528]	_____	[650]	_____
		[530]	_____	[652]	_____
[390]	_____	[532]	_____	[654]	_____
	XXXXXXXXXXXXX	[534]	_____	[656]	_____
		[536]	_____	[658]	_____
[400]	_____	[538]	_____	[660]	_____
[430]	_____	[540]	_____	[662]	_____
[435]	27 781	[544]	_____	[664]	_____
[440]	_____	[546]	_____		XXXXXXXXXXXXX
[445]	_____	[548]	_____		
[450]	_____	[550]	_____	[812]	_____
[452]	_____	[560]	_____	[816]	_____
[453]	_____	[570]	_____	[818]	_____
[455]	_____		XXXXXXXXXXXXX		XXXXXXXXXXXXX
	XXXXXXXXXXXXX				

Name: HALTON HILLS HYDRO INC.

BN: 86742 9623 RC 0001

Taxation Year End: 2006-12-31

[856] 1. _____ *

[858] 1. _____ *

[860] 1. _____ *

XXXXXXXXXXXXX

Name: HALTON HILLS HYDRO INC.

BN: 86742 9623 RC 0001

Taxation Year End: 2006-12-31

[610]	1 921 918	[401]	865 552	[820]	_____
[821]	62 601	[402]	865 551	[861]	_____
[830]	21 525	[403]	_____	[862]	_____
[850]	_____	[404]	_____	[870]	_____
	XXXXXXXXXXXX	[405]	_____		XXXXXXXXXXXX
		[406]	_____		
[101]	456 900	[407]	_____		
[103]	16 161 663	[490]	1 731 103		
[104]	4 231 115		XXXXXXXXXXXX		
[105]	_____				
[106]	_____	[500]	36 821 447		
[107]	_____		XXXXXXXXXXXX		
[108]	17 024 242				
[109]	_____	[701]	_____		
[110]	_____	[711]	_____		
[111]	661 085	[712]	_____		
[112]	17 545	[713]	_____		
[121]	_____	[790]	_____		
[122]	_____		XXXXXXXXXXXX		
[123]	_____				
[124]	_____	[690]	36 821 447		
[190]	38 552 550	[801]	44 995 000		
	XXXXXXXXXXXX	[811]	_____		
			XXXXXXXXXXXX		

Name: HALTON HILLS HYDRO INC.

BN: 86742 9623 RC 0001

Taxation Year End: 2006-12-31

[010] _____

[020] 2

[030] 2006

- [300]
1. 86742 9623 RC 0001
 2. 88627 0727 RC 0001
 3. 87097 1181 RC 0001
 4. 87307 4876 RC 0001
 5. 86244 8453 RC 0001 *

- [500]
1. _____
 2. _____
 3. _____
 4. _____
 5. _____ *
- XXXXXXXXXXXXX

- [400]
1. 44 995 000
 2. 3 500 000
 3. 500 000
 4. 5 000
 5. 1 000 000 *
- XXXXXXXXXXXXX

- [200]
1. HALTON HILLS HYDRO INC.
 2. HALTON HILLS FIBRE OPTICS INC.
 3. SOUTHWESTERN ENERGY INC.
 4. HALTON HILLS ENERGY INC.
 5. HALTON HILLS ENERGY SERVICES INC. *
- XXXXXXXXXXXXX

Name: HALTON HILLS HYDRO INC.

BN: 86742 9623 RC 0001

Taxation Year End: 2006-12-31

[100] 1. TOWN OF HALTON HILLS *

[200] 1. 10812 6897 RC 0001 *

[300] 1. _____ *

[350] 1. _____ *

[400] 1. 100 *

[500] 1. _____ *

XXXXXXXXXXXX

Name: HALTON HILLS HYDRO INC.

BN: 86742 9623 RC 0001

Taxation Year End: 2006-12-31

[500] _____

[050] 852 946

[520] _____

[100] _____

[540] _____

[190] 1 306 904

[941] _____

[200] _____

[942] _____

[210] _____

[943] _____

[300] _____

[944] _____

[310] _____

[945] _____

[490] 2 159 851

[951] _____

XXXXXXXXXXXX

[952] _____

[953] _____

[560] _____

[954] _____

[590] 2 159 851

[955] 852 946

XXXXXXXXXXXX

XXXXXXXXXXXX

[110] 1 921 918

[120] _____

[130] _____

[140] _____

[150] 1 921 918

XXXXXXXXXXXX

[220] _____

[230] _____

[240] _____

[290] _____

XXXXXXXXXXXX

Name of Corporation	Business Number	Tax year-end	Year	Month	Day
HALTON HILLS HYDRO INC.	867429623 RC 0001		2006	12	31

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.

Schedules - Answer the following questions. For each Yes response, attach to the T2 return the schedule that applies.

	Yes	Schedule
Is the corporation related to any other corporations?	150 ☒	9
Is the corporation an associated Canadian-controlled private corporation?	160 ☒	23
Is the corporation an associated Canadian-controlled private corporation that is claiming the expenditure limit?	161 ☐	49
Does the corporation have any non-resident shareholders?	151 ☐	19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162 ☒	11
If you answered Yes to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163 ☐	44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164 ☐	14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165 ☐	15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166 ☐	T5004
Is the corporation a member of a partnership for which a partnership identification number has been assigned?	167 ☐	T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust?	168 ☐	22
Did the corporation have any foreign affiliates during the year?	169 ☐	25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal <i>Income Tax Regulations</i> ?	170 ☐	29
Has the corporation had any non-arm's length transactions with a non-resident?	171 ☐	T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173 ☒	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172 ☐	—
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201 ☒	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; or gifts of cultural or ecological property?	202 ☐	2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203 ☐	3
Is the corporation claiming any type of losses?	204 ☐	4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205 ☐	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206 ☐	6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) is the corporation claiming the refundable portion of Part I tax?	207 ☐	7
Does the corporation have any property that is eligible for capital cost allowance?	208 ☒	8
Does the corporation have any property that is eligible capital property?	210 ☒	10
Does the corporation have any resource-related deductions?	212 ☐	12
Is the corporation claiming reserves of any kind?	213 ☐	13
Is the corporation claiming a patronage dividend deduction?	216 ☐	16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217 ☐	17
Is the corporation an investment corporation or a mutual fund corporation?	218 ☐	18
Was the corporation carrying on business in Canada as a non-resident corporation?	220 ☐	20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221 ☐	21
Does the corporation have any Canadian manufacturing and processing profits?	227 ☐	27
Is the corporation claiming an investment tax credit?	231 ☐	31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232 ☒	T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over \$10,000,000?	233 ☒	33/34/35
Is the corporation a member of a related group with one or more members subject to gross Part I.3 tax?	236 ☒	36
Is the corporation claiming a surtax credit?	237 ☐	37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238 ☐	38
Is the corporation claiming a Part I tax credit?	242 ☐	42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243 ☐	43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244 ☐	45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249 ☐	46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250 ☐	39
Is the corporation claiming a Canadian film or video production tax credit refund?	253 ☐	T1131
Is the corporation claiming a film or video production services tax credit refund?	254 ☐	T1177
Is the corporation subject to Part XIII.1 tax?	255 ☐	92*

* We do not print this schedule.

Name of Corporation HALTON HILLS HYDRO INC.	Business Number 867429623 RC 0001	Tax year-end	Year Month Day 2006/12/31

Attachments - continued from page 2

	Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	☐	T1134-A
Did the corporation have any controlled foreign affiliates?	☐	T1134-B
Did the corporation own specified foreign property in the year with a cost amount over \$100,000?	☐	T1135
Did the corporation transfer or loan property to a non-resident trust?	☐	T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	☐	T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	☐	T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	☐	T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	☐	T1174

Additional information

Is the corporation inactive?	280	1 Yes ☐	2 No ☒
Has the major business activity changed since the last return was filed? (enter Yes for first-time filers)	281	1 Yes ☐	2 No ☒
What is the corporation's major business activity? (Only complete if Yes was entered at line 281.)	282	DISTRIBUTION OF ELECTRICITY	
If the major business activity involves the resale of goods, show whether it is wholesale or retail	283	1 Wholesale ☐	2 Retail ☐
Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.	284	DISTRIBUTION OF ELECTRICITY	285 100.00%
	286		287 %
	288		289 %
Did the corporation immigrate to Canada during the tax year?	291	1 Yes ☐	2 No ☒
Did the corporation emigrate from Canada during the tax year?	292	1 Yes ☐	2 No ☒

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFL	300	1,921,918	A
Deduct: Charitable donations from Schedule 2	311		
Gifts to Canada, a province, or a territory from Schedule 2	312		
Cultural gifts from Schedule 2	313		
Ecological gifts from Schedule 2	314		
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320		
Part VI.1 tax deduction from Schedule 43*	325		
Non-capital losses of preceding tax years from Schedule 4	331		
Net capital losses of preceding tax years from Schedule 4	332		
Restricted farm losses of preceding tax years from Schedule 4	333		
Farm losses of preceding tax years from Schedule 4	334		
Limited partnership losses of preceding tax years from Schedule 4	335		
Taxable capital gains or taxable dividends allocated from a central credit union	340		
Prospector's and grubstaker's shares	350		
Subtotal			B
Subtotal (amount A minus amount B)(if negative, enter "0")		1,921,918	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355		D
Taxable income (amount C plus amount D)	360	1,921,918	
Income exempt under paragraph 149(1)(t)	370		
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 minus line 370)		1,921,918	Z

* This amount is equal to 3 times the Part VI.1 tax payable at line 724.

Name of Corporation	Business Number	Tax year-end	Year	Month	Day
HALTON HILLS HYDRO INC.	867429623 RC 0001		2006	12	31

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7 **400** 1,921,918 **A**

Taxable income from line 360, minus 10/3 of the amount on line 632*, minus 3 times the amount on line 636**, and minus any amount that, because of federal law, is exempt from Part I tax **405** 1,921,918 **B**

Calculation of the business limit:

For all CCPCs, calculate the amount at line 4 below.

250,000	x	Number of days in the tax year in 2004	=		1
		Number of days in the tax year		365	
300,000	x	Number of days in the tax year in 2005 and 2006	=	365	2
		Number of days in the tax year		365	
400,000	x	Number of days in the tax year after 2006	=		3
		Number of days in the tax year		365	

Add amounts at lines 1, 2, and 3 300,000 **4**

Business limit (see notes 1 and 2 below) **410** 300,000 **C**

Notes: 1. For CCPCs that are not associated, enter the amount from line 4 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate the amount from line 4 by the number of days in the tax year divided by 365, and enter the result on line 410.

2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C 300,000 x **415 ***** 62,533 **D** = 11,250 **E**

Reduced business limit (amount C minus amount E) (if negative, enter "0") **425** **F**

Small business deduction - Whichever amount is the least: A, B, C, or F

Amount G1	x	Number of days in the tax year before 2008	365	x 16.00%	=	G1
		Number of days in the tax year	365			G2
Amount G1	x	Number of days in the tax year in 2008		x 16.50%	=	G3
		Number of days in the tax year	365			G4
Amount G1	x	Number of days in the tax year after 2008		x 17.00%	=	G4
		Number of days in the tax year	365			

Small business deduction - total of amounts G2, G3, and G4 (enter amount G on line 9) **430** <NIL> **G**

* Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporate tax reductions under section 123.4.

*** Large corporations

- If the corporation is not associated with any corporations in both the current and the preceding tax years, the amount to be entered at line 415 is: (Total taxable capital employed in Canada for the **prior year** minus \$10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the preceding tax year, the amount to be entered at line 415 is: (Total taxable capital employed in Canada for the **current year** minus \$10,000,000) x 0.225%
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

Resource deduction

Taxable resource income [as defined in subsection 125.11(1)] **435** **H**

Amount H	x	Number of days in the tax year in 2004		x 2%	=	I
		Number of days in the tax year	365			
Amount H	x	Number of days in the tax year in 2005		x 3%	=	J
		Number of days in the tax year	365			
Amount H	x	Number of days in the tax year in 2006		x 5%	=	K
		Number of days in the tax year	365			
Amount H	x	Number of days in the tax year after 2006		x 7%	=	L
		Number of days in the tax year	365			

Resource deduction - total of amounts I, J, K, and L (enter amount M on line 10) **438** **M**

Name of Corporation	Business Number	Tax year-end	Year	Month	Day
HALTON HILLS HYDRO INC.	867429623 RC 0001		2006	12	31

General tax reduction for Canadian-controlled private corporations
Canadian-controlled private corporations throughout the tax year

Taxable income from line 360						1,921,918	A	
Amount Z1 from Part 9 of Schedule 27							B	
Amount QQ from Part 13 of Schedule 27							C	
Taxable resource income from line 435							D	
Amount used to calculate the credit union deduction (amount E in Part 3 of Schedule 17)							E	
Amount on line 400, 405, 410, or 425, whichever is the least							F	
Aggregate investment income from line 440							G	
Total of amounts B, C, D, E, F, and G							H	
Amount A minus amount H (if negative, enter "0")						1,921,918	I	
Amount I	1,921,918	x	Number of days in the tax year before 2008	365	X 7%	=	134,534	J1
			Number of days in the tax year	365				
Amount I	1,921,918	x	Number of days in the tax year in 2008		X 7.5%	=		J2
			Number of days in the tax year	365				
Amount I	1,921,918	x	Number of days in the tax year in 2009		X 8%	=		J3
			Number of days in the tax year	365				
Amount I	1,921,918	x	Number of days in the tax year after 2009		X 9%	=		J4
			Number of days in the tax year	365				
General tax reduction for Canadian-controlled private corporations - total of amounts J1, J2, J3, and J4							134,534	J
(enter amount J on line 638)								

General tax reduction
Corporations other than a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, or a mutual fund corporation. For tax years starting after May 1, 2006, any corporation with taxable income that is not subject to the full tax rate.

Taxable income from line 360							M	
Amount Z1 from Part 9 of Schedule 27							N	
Amount QQ from Part 13 of Schedule 27							O	
Taxable resource income from line 435							P	
Amount used to calculate the credit union deduction (amount E in Part 3 of Schedule 17)							Q	
Total of amounts N, O, P, and Q							R	
Amount M minus amount R (if negative, enter "0")							S	
Amount S		x	Number of days in the tax year before 2008	365	X 7%	=		T1
			Number of days in the tax year	365				
Amount S		x	Number of days in the tax year in 2008		X 7.5%	=		T2
			Number of days in the tax year	365				
Amount S		x	Number of days in the tax year in 2009		X 8%	=		T3
			Number of days in the tax year	365				
Amount S		x	Number of days in the tax year after 2009		X 9%	=		T4
			Number of days in the tax year	365				
General tax reduction - total of amounts T1, T2, T3, and T4								T
(enter amount T on line 639)								

Name of Corporation HALTON HILLS HYDRO INC.	Business Number 867429623 RC 0001	Tax year-end	Year 2006	Month 12	Day 31

Refundable portion of Part I tax
Canadian-controlled private corporations throughout the tax year

Aggregate investment income **440** X 26 2/3 % = ... **A**
(amount O from Part 1 of Schedule 7)

Foreign non-business income tax credit from line 632

Deduct:

Foreign investment income **445** X 9 1/3 % = ... **B**
(amount L from Part 2 of Schedule 7) (if negative, enter "0")

Amount A minus amount B (if negative, enter "0") **C**

Taxable income from line 360 **1,921,918**

Deduct:

Amount on line 400, 405, 410, or 425,
whichever is the least

Foreign non-business income tax
credit from line 632 X 25/9 = ...

Foreign business income tax
credit from line 636 X 3 = ...

1,921,918 X 26 2/3 % = 512,511 **D**

Part I tax payable minus investment tax credit refund (line 700 minus line 780) 425,128

Deduct: Corporate surtax from line 600 21,525

Net amount 403,603 **E**

Refundable portion of Part I tax - Amount C, D, or E, whichever is the least **450** <NIL> **F**

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the preceding tax year **460** 5,528

Deduct: Dividend refund for the previous tax year **465**

5,528 **G**

Add the total of:

Refundable portion of Part I tax from line 450 above

Total Part IV tax payable from line 360 on page 3 of Schedule 3

Net refundable dividend tax on hand transferred from a predecessor
corporation on amalgamation, or from a wound-up subsidiary corporation **480**

5,528 **H**

Refundable dividend tax on hand at the end of the tax year - Amount G plus amount H **485** 5,528

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 on page 3 of Schedule 3 X 1/3 **I**

Refundable dividend tax on hand at the end of the tax year from line 485 above 5,528 **J**

Dividend refund - Amount I or J, whichever is less (enter this amount on line 784)

Name of Corporation HALTON HILLS HYDRO INC.	Business Number 867429623 RC 0001	Tax year-end	Year 2006	Month 12	Day 31

Part I tax

Base amount of Part I tax - 38% of taxable income (line 360 or amount Z, whichever applies) **550** 730,329 **A**

Corporate surtax calculation

Base amount from line A above 730,329 **1**

Deduct:

10% of taxable income (line 360 or amount Z, whichever applies) 192,192 **2**

Investment corporation deduction from line 620 below **3**

Federal logging tax credit from line 640 below **4**

Federal qualifying environmental trust tax credit from line 648 below **5**

For a mutual fund corporation or an investment corporation throughout the tax year, enter amount a, b, or c below on line 6, whichever is the least:

28% of taxable income from line 360 538,137 **a**

28% of taxed capital gains **b**

Part I tax otherwise payable
(line A plus lines C and D minus line F) 403,603 **c**

Total of lines 2 to 6 192,192 **7**

Net amount (line 1 minus line 7) 538,137 **8**

Corporate surtax

Line 8 538,137 X 4% X Number of days in the tax year before 2008 365 = **600** 21,525 **B**
Number of days in the tax year 365

Recapture of investment tax credit from line OO in Part 17 of Schedule 31 **602** **C**

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income (if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 **i**

Taxable income from line 360 1,921,918

Deduct:

Amount on line 400, 405, 410, or 425, whichever is the least

Net amount 1,921,918 **ii**

Refundable tax on CCPC's investment income - 6 2/3 % of whichever is less: amount i or ii **604** **D**

Subtotal (add lines A, B, C, and D) 751,854 **E**

Deduct:

Small business deduction from line 430 **9**

Federal tax abatement 608 192,192

Manufacturing and processing profits deduction
from amount BB or amount RR of Schedule 27 616

Investment corporation deduction 620

(taxed capital gains 624)

Additional deduction - credit unions from Schedule 17 628

Federal foreign non-business income tax credit from Schedule 21 632

Federal foreign business income tax credit from Schedule 21 636

Resource deduction from line 438 **10**

General tax reduction for CCPCs from amount J 638 134,534

General tax reduction from amount T 639

Federal logging tax credit from Schedule 21 640

Federal political contribution tax credit 644

Federal political contributions 646

Federal qualifying environmental trust tax credit 648

Investment tax credit from Schedule 31 652

Subtotal 326,726 **F**

Part I tax payable - Line E minus line F (enter amount G on line 700) 425,128 **G**

Summary of tax and credits

Federal tax

Part I tax payable	700	425,128
Part I.3 tax payable from Schedule 33, 34, or 35	704	
Part II surtax payable from Schedule 46	708	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		425,128

Add provincial or territorial tax:

Provincial or territorial jurisdiction **750 Ontario**

(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec, Ontario, and Alberta) **760**

Provincial tax on large corporations (New Brunswick and Nova Scotia) **765**

Total tax payable 770 425,128 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780	
Dividend refund	784	
Federal capital gains refund from Schedule 18	788	
Federal qualifying environmental trust tax credit refund	792	
Canadian film or video production tax credit refund (Form T1131)	796	
Film or video production services tax credit refund (Form T1177)	797	
Tax withheld at source	800	
Total payments on which tax has been withheld	801	
Provincial and territorial capital gains refund from Schedule 18	808	
Provincial and territorial refundable tax credits from Schedule 5	812	
Tax instalments paid	840	425,128
Total credits	890	425,128

Balance (line A minus line B) <NIL>

Refund code **894**

Overpayment

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information **910**

914 **918** Branch number

Institution number Account number

If the result is negative, you have an **overpayment**.
If the result is positive, you have a **balance unpaid**.
Enter the amount on whichever line applies.
Generally, we do not charge or refund a difference of \$2 or less.
Balance unpaid

Enclosed payment **898**

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due?

896 1 Yes ☐ 2 No ☒

Certification

I, **950 SKIDMORE**

Last name in block letters

951 ARTHUR

First name in block letters

954 CHIEF FINANCIAL OFFICER

Position, office, or rank

I am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I further certify that the method of calculating income for this tax year is consistent with that of the previous year except as specifically disclosed in a statement attached to this return.

955 2007/06/30

Date (yyyy/mm/dd)

Signature of the authorized signing officer of the corporation

956 (519) 853-3700

Telephone number

Is the contact person the same as the authorized signing officer? If No, complete the information below

957 1 Yes ☒ **2 No** ☐

958

Name in block letters

959

Telephone number

Language of correspondence - Langue de correspondance

990 Indicate your language of correspondence by entering 1 for English or 2 for French.

Indiquez votre langue de correspondance en inscrivant 1 pour anglais ou 2 pour français.

1 English/Anglais ☒ 2 Francais/French ☐

NET INCOME (LOSS) FOR INCOME TAX PURPOSES

SCHEDULE 1

Name of Corporation	Business Number	Tax year-end	Year	Month	Day
HALTON HILLS HYDRO INC.	867429623 RC 0001		2006	12	31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the *T2 Corporation Income Tax Guide*.
- Please provide us with the applicable details in the identification area, and complete the applicable lines that contain a numbered black box. You should report amounts in accordance with the Generally Accepted Accounting Principles (GAAP).
- Sections, subsections, and paragraphs referred to on this schedule are from the *Income Tax Act*.

Net income (loss) after taxes and extraordinary items per financial statements 1,165,491 A

Add:

Provision for income taxes - current	101	729,801	
Provision for income taxes - deferred	102		
Interest and penalties on taxes	103	33,000	
Amortization of tangible assets	104	3,388,729	
Amortization of natural resource assets	105		
Amortization of intangible assets	106	13,204	
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 from Schedule 2	112		
Taxable capital gains from Schedule 6	113		
Political donations	114		
Holdbacks	115		
Deferred and prepaid expenses	116		
Depreciation in inventory - end of year	117		
Scientific research expenditures deducted per financial statements	118		
Capitalized interest	119		
Non-deductible club dues and fees	120		
Non-deductible meals and entertainment expenses	121	6,119	
Non-deductible automobile expenses	122		
Non-deductible life insurance premiums	123		
Non-deductible company pension plans	124		
Tax reserves deducted in prior year from Schedule 13	125		
Reserves from financial statements - balance at the end of the year	126		
Soft costs on construction and renovation of buildings	127		
Non-deductible fines and penalties under section 67.6	128		
Total of fields 201 to 294 on page 2	199	95,517	
Total of fields 101 to 199	500	4,266,370	▶ 4,266,370

Deduct:

Gain on disposal of assets per financial statements	401	774	
Dividends not taxable under section 83 from Schedule 3	402		
Capital cost allowance from Schedule 8	403	1,902,072	
Terminal loss from Schedule 8	404		
Cumulative eligible capital deduction from Schedule 10	405	61,955	
Allowable business investment loss - Schedule 6	406		
Foreign non-business tax deduction under subsection 20(12)	407		
Holdbacks	408		
Deferred and prepaid expenses	409		
Depreciation in inventory - end of prior year	410		
Scientific research expenses claimed in year from Form T661	411		
Tax reserves claimed in current year from Schedule 13	413		
Reserves from financial statements - balance at the beginning of the year	414		
Patronage dividends from Schedule 16	416		
Contributions to deferred income plans from Schedule 15	417		
Total of fields 300 to 394 on page 3	499	1,545,142	
Total of fields 401 to 499	510	3,509,943	▶ 3,509,943

Net income (loss) for income tax purposes - enter on line 300 on page 3 of the T2 return 1,921,918

Name of Corporation HALTON HILLS HYDRO INC.	Business Number 867429623 RC 0001	Tax year-end	Year 2006	Month 12	Day 31

Add:

Accounts payable and accruals for cash basis - closing	201	
Accounts receivable and prepaid for cash basis - opening	202	
Accrual inventory - opening	203	
Accrued dividends - prior year	204	
Book loss on joint ventures or partnerships	205	
Capital items expensed	206	
All crown charges, royalties, rental, etc.		
- Non-deductible crown payments		
- Taxable portion of Alberta royalty tax credit and other rebates 12(1)(x.2)		
- Other		
Total	207	
Debt issue expense	208	
Deemed dividend income	209	
Deemed interest on loans to non-residents	210	
Deemed interest received	211	
Development expenses claimed in current year	212	
Dividend stop-loss adjustment	213	
Dividends credited to the investment account	214	
Exploration expenses claimed in current year	215	
Financing fees deducted in books	216	
Foreign accrual property income	217	
Foreign affiliate property income	218	
Foreign exchange included in retained earnings	219	
Gain on settlement of debt	220	
Interest paid on income debentures	221	
Limited partnership losses from Schedule 4	222	
Loss from international banking centres	223	
Mandatory inventory adjustment - included in current year	224	
Mining royalties (provincial mining taxes)	225	
Non-deductible advertising	226	
Non-deductible interest	227	
Non-deductible legal and accounting fees	228	
Optional value of inventory - included in current year	229	
Other expenses from financial statements		
- for resource loss		
- others		
Total	230	
Recapture of SR&ED expenditures - Form T661	231	27,781
Resource amounts deducted	232	
Restricted farm losses - current year - Schedule 4	233	
Sales tax assessments	234	
Share issue expense	235	
Write-down of capital property	236	
Amounts received in respect of qualifying environmental trust		
per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	
Contractors' completion method adjustment: revenue net of costs on contracts under 2 years - previous year	238	
Other additions:		
600 Employee future benefit costs accrued	290	25,736
601 Provision for bad debts	291	42,000
602	292	
603	293	
604a		
604b	294	
Total of fields 201 to 294 (enter this amount at line 199 on page 1)		95,517

Name of Corporation	Business Number	Tax year-end	Year	Month	Day
HALTON HILLS HYDRO INC.	867429623 RC 0001		2006	12	31

Deduct:

Accounts payable and accruals for cash basis - opening	300	
Accounts receivable and prepaid for cash basis - closing	301	
Accrual inventory - closing	302	
Accrued dividends - current year	303	
Bad debt	304	55,986
Book income of joint venture or partnership	305	1,597
Equity in income from subsidiaries or affiliates	306	
Exempt income under section 81	307	
Income from international banking centres	308	
Mandatory inventory adjustment - included in prior year	309	
Contributions to a qualifying environmental trust	310	
Non-Canadian advertising expenses - broadcasting	311	
Non-Canadian advertising expenses - printed materials	312	
Optional value of inventory - included in prior year	313	
Other income from financial statements	314	
Payments made for allocations in proportion to borrowing and bonus interest payment from Schedule 17	315	
Contractors' completion method adjustment: revenue net of costs on contracts under 2 years - current year	316	

Resource deductions:

Canadian development expenses from Schedule 12	340	
Canadian exploration expenses from Schedule 12	341	
Canadian oil and gas property expenses from Schedule 12	342	
Deductible crown charges	343	
Depletion from Schedule 12	344	
Foreign exploration and development expenses from Schedule 12	345	
Resource allowance	346	

Other deductions:

700 Employee future benefits expenses paid	390	15,835
701 Reg asset amort incl in tangible asset amort	391	1,471,724
702	392	
703	393	
704	394	
Total of fields 300 to 394 (enter this amount at line 499 on page 1)		1,545,142

CAPITAL COST ALLOWANCE (CCA)

SCHEDULE 8 - Federal

Name of Corporation HALTON HILLS HYDRO INC.	Business Number 867429623 RC 0001	Tax year-end	Year Month Day 2006/12/31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under regulation 1101(5q)? **101** 1 Yes ☐ 2 No ☒

1 Class no.	Description	2 Undepreciated capital cost at the beginning of the year (column 11 from last year's T2S(8))	3 Cost of acquisitions during the year (new property must be available for use) See note 1 below	4 Adjustments (show negative amounts in brackets)	5 Proceeds of dispositions during the year (amount not to exceed the capital cost)	6 Undepreciated capital cost (column 2 plus column 3 plus or minus column 4 minus column 5)	7 50% rule (deduct 1/2 the amount, if any, by which the net cost of acquisitions exceeds col. 5) See note 2 below	8 Reduced undepreciated capital cost (column 6 minus column 7)	9 CCA rate %	10 Capital cost allowance (column 8 multiplied by column 9; or a lower amount) See note 3 below	11 Undepreciated capital cost at the end of the year (column 6 minus column 10)
200		201	203	205	207		211		212	217	220
1.0	Dist'n System	20,712,394				20,712,394		20,712,394	4.0	828,496	19,883,898
1.0	Buildings & fixtures	2,290,038	29,799			2,319,837	14,900	2,304,937	4.0	92,197	2,227,640
8.0	Major Tools	169,599	50,897			220,496	25,449	195,047	20.0	39,009	181,487
8.0	Office Equipment	160,398	44,033			204,431	22,017	182,414	20.0	36,483	167,948
8.0	Stores Equipment	20,366	2,144			22,510	1,072	21,438	20.0	4,288	18,222
10.0	Computer Hardware	158,266				158,266		158,266	30.0	47,480	110,786
10.0	Fleet	458,204	52,428			510,632	26,214	484,418	30.0	145,325	365,307
12.0	Computer Software	13,650	204,394			218,044		218,044	100.	218,044	<NIL>
8.0	Scada comm equipment	160,505				160,505		160,505	20.0	32,101	128,404
46.0	Scada comm equipment	25,773	97,487			123,260	48,744	74,516	30.0	22,355	100,905
45.0	Computer hardware	93,511	149,217			242,728	74,609	168,119	45.0	75,654	167,074
43.1	Conservatn Demand Mg	65,464	612,620			678,084	306,310	371,774	30.0	111,532	566,552
49.0	Electricity Distn Eqp	2,100,123	2,027,456			4,127,579	1,013,728	3,113,851	8.0	249,108	3,878,471
	Totals	26,428,291	3,270,475			29,698,766	1,533,043	28,165,723		1,902,072	27,796,694

Note 1. Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule. See Regulation 1100(2) and (2.2).

Note 2. The net cost of acquisitions is the cost of acquisitions plus or minus certain adjustments from column 4.

Note 3. If the taxation year is shorter than 365 days, prorate the CCA claim. See the T2 Guide for more information.

Note 4. Ontario recapture should be included in net income after deducting the federal recapture and the Ontario terminal loss is deducted from net income after including the federal terminal loss.

CAPITAL COST ALLOWANCE (CCA)

SCHEDULE 8SUM - Federal

Name of Corporation	Business Number	Tax year-end	Year	Month	Day
HALTON HILLS HYDRO INC.	867429623 RC 0001		2006	12	31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*

Is the corporation electing under regulation 1101(5q)?

1 Yes ☐

2 No ☒

1 Class number	2 UCC start of year (UCC at end of year of last year)	3 Cost of acquisitions during the year (new property must be available for use) *	4 Net adjustments **	5 Proceeds of dispositions (amount not to exceed the capital cost) 207	6 Adjusted UCC	7 50% rule on net acquisitions ***	8 Reduced UCC
200	201	203	205			211	
reg	26428.291	3.270.475			29698.766	1.533.043	28165.723
10.1							
13							
14							
	10 Recapture of CCA (line 107 of Schedule 1) 213	11 Terminal loss (line 404 of Schedule 1) 215	12 CCA (line 403 of Schedule 1) **** 217	13 UCC at end of year 220			
reg			1.902.072	27796.694			
10.1							
13							
14							
Totals			1.902.072				

1 Class number	2 UCC start of year (UCC at end of year of last year)	3 Cost of acquisitions during the year (new property must be available for use) *	4 Net adjustments **	5 Proceeds of dispositions (amount not to exceed the capital cost) 207	6 Adjusted UCC	7 50% rule on net acquisitions ***	8 Reduced UCC
200	201	203	205			211	
24							
27							
29							
34							
43.3							
Rental							
	10 Recapture of CCA (line 107 of Schedule 1) 213	11 Terminal loss (line 404 of Schedule 1) 215	12 CCA (line 403 of Schedule 1) **** 217	13 UCC at end of year 220			
24							
27							
29							
34							
43.3							
Rental							
Totals							

Totals: Recapture (Schedule 1 Line 107)

Terminal loss (Schedule 1 Line 404)

CCA Claimed 1.902.072 (Schedule 1 Line 403)

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see Regulation 1100(2) and (2.2).

** Include amounts transferred under section 85, or on amalgamation and winding-up of a subsidiary. See the *T2 Corporation Income Tax Guide* for other examples of adjustments to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) plus or minus certain adjustments from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance - General Comments*.

**** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

Name of Corporation		Business Number		Tax	Year	Month	Day
HALTON HILLS HYDRO INC.		867429623 RC 0001		year-end	2006	12	31

This schedule is to be completed by a corporation having one or more of the following:

- related corporation(s)
- associated corporation(s)

[illegible]

Note 1: Enter "NR" if a corporation is not registered.

Note 2: Enter the code number of the relationship that applies from the following order: 1- Parent 2 - Subsidiary 3 - Associated 4 - Related, but not associated.

Name of Corporation HALTON HILLS HYDRO INC.	Business Number 867429623 RC 0001	Tax year-end	Year 2006	Month 12	Day 31

- For use by a corporation that has eligible capital property. For more information, see the T2 Corporation Income Tax Guide.
- A separate cumulative eligible capital account must be kept for each business.

Part 1 - Calculation of current year deduction and carry-forward

Cumulative eligible capital - Balance at end of preceding taxation year (if negative, enter "0")	200	885,066	A
Add: Cost of eligible capital property acquired during the taxation year	222		
Other adjustments	226		
Subtotal (line 222 plus line 226)		x 0.75 =	B
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002.	228	x 0.50 =	C
amount B minus amount C (if negative, enter "0")			D
Amount transferred on amalgamation or wind-up subsidiary	224		E
Subtotal (add amounts A, D, and E)	230		885,066 F
Deduct:			
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year	242		G
The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7)	244		H
Other adjustments	246		I
(add amounts G, H, and I)		x 0.75 =	248 J
Cumulative eligible capital balance (amount F minus amount J) (if amount K is negative, enter "0" at line M and proceed to Part 2)			885,066 K
Cumulative eligible capital for a property no longer owned after ceasing to carry on that business	249		
amount K	885,066		
less amount from line 249			
Current year deduction	885,066	x 7.00 =	250 61,955
(line 249 plus line 250) (enter this amount at line 405 of Schedule 1)			61,955 L
Cumulative eligible capital - Closing balance (amount K minus amount L) (if negative, enter "0")	300		823,111 M

Note: You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

Part 2 - Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

Amount from line K (show as a positive amount)			N
Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988	400	1	
Total of all amounts which reduced CEC in the current or prior years under subsection 80(7)	401	2	
Total of CEC deductions claimed for taxation years beginning before July 1, 1988	402	3	
Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988	408	4	
Line 3 minus line 4 (if negative, enter "0")		5	
Total of lines 1, 2, and 5		6	
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400		7	
Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000		8	
Subtotal (line 7 plus line 8)	409	9	
Line 6 minus line 9 (if negative, enter "0")			O
Line N minus line O (if negative, enter "0")			P
Line 5		x 50.0000 % =	Q
Line P minus line Q (if negative, enter "0")			R
Amount R		x 66.6667 % =	S
Amount N or amount O, whichever is less			T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)	410		



TRANSACTIONS WITH SHAREHOLDERS, OFFICERS OR EMPLOYEES

Name of Corporation	Business Number	Tax year-end	Year	Month	Day
HALTON HILLS HYDRO INC.	867429623 RC 0001		2006	12	31

Provide the details of any transactions with shareholders, officers or employees that involve:

- payments the corporation made or amounts credited to the account of shareholders, officers, or employees, that were not part of their remuneration or reimbursement of expenses;
- assets the corporation sold to or purchased from shareholders, officers, or employees, including those for which an election was made under section 85; or
- loans or indebtedness to shareholders, officers, or employees, or persons connected with a shareholder that were not repaid by the end of the taxation year.

	Relationship code (see note 1) 100	Payments \$ 200	Reimbursement \$ 300	Loans \$ 400	Assets sold or purchased \$ 500	Does section 85 apply to assets sold or purchased? 550
1.	1			16,141,970		Yes ☐ No ☐
2.						Yes ☐ No ☐
3.						Yes ☐ No ☐
4.						Yes ☐ No ☐
5.						Yes ☐ No ☐
6.						Yes ☐ No ☐
7.						Yes ☐ No ☐
8.						Yes ☐ No ☐
9.						Yes ☐ No ☐
10.						Yes ☐ No ☐
11.						Yes ☐ No ☐
12.						Yes ☐ No ☐
13.						Yes ☐ No ☐

Note: Enter the code number of the relationship that applies: 1 - Shareholder
2 - Officer
3 - Employee

**SCHEDULE 23**

• For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.

Allocating the business limit

		Year Month Day		
Date filed (do not use this area)	025			
Enter the calendar year to which the agreement applies	050	Year		
Is this an amended agreement for the above-noted calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below?	075	Yes ☐	No ☒	

[illegible]

CLAIM FOR SCIENTIFIC RESEARCH AND EXPERIMENTAL DEVELOPMENT (SR&ED) CARRIED OUT IN CANADA

- Use this form to claim SR&ED carried out in Canada during the year. File it with your return of income.
- If you are filing a T2 corporation return of income, place this form on top of the return so that we can identify your SR&ED claim quickly.
- Use a separate form to support SR&ED expenditures incurred by each partnership of which you are a partner.
- Use Guide T4088, *Claiming Scientific Research and Experimental Development Expenditures*, to help you fill out this form. You can also consult our Web site at www.cra.gc.ca/sred for an online help guide.
- If the SR&ED was performed in the province of Newfoundland and Labrador, Nova Scotia, New Brunswick, Québec, Ontario, Manitoba, Saskatchewan, or British Columbia, or in the Yukon Territory, you may be entitled to a provincial or territorial tax credit.
- Complete schedules A, B, C, D, E, and F, if they apply to your situation.
- Prepare and retain schedules to support the breakdown for each expenditure claimed in this form and on the required attachments.
- On this form, references to the Act are to the *Income Tax Act*. References to the Regulations are to the *Income Tax Act Regulations*.
- All the information requested in this form including the attachments, schedules and any other document supporting your expenditures is prescribed information. You have to file the information that applies to your claim, along with Schedule T2 SCH 31 or Form T2038(IND), within 12 months of the filing-due date of your return of income for the year you incurred the expenditures. If you do not meet this reporting deadline, we may reject your claim.

Part 1 - General Information (please print)

Name of claimant HALTON HILLS HYDRO INC.		Claimant's business address and postal code Claimant's Web site (if available) http://www.	
Business Number, social insurance number, or partnership identification number 867429623 RC 0001		Return for tax year from: 2006/01/01 to: 2006/12/31	
100 Name of contact person ARTHUR SKIDMORE		142 Is the claim filed for a partnership? 1 Yes ☐ 2 No ☒	
105 Telephone number/extension (519) 853-3700	110 Fax number (519) 853-4148	145 If yes, what is the name of the partnership? _____ _____ _____	
130 Is this the first time you are claiming for SR&ED? 1 Yes ☐ 2 No ☒		150 Percentage of SR&ED investment tax credits allocated from the partnership _____ %	
132 If not, when was the last claim? Year 2005		155 Name of the person or firm who prepared this claim HALTON HILLS HYDRO	

Certification and Election

I certify that I have examined the information provided on this form, and on the related schedules and attachments and it is true, correct, and complete.

I elect (choose) to use the following method to calculate my SR&ED expenditures and related investment tax credits (ITC) for the year.

I understand that my election (choice) is irrevocable for this year.

160 I elect to use the proxy method under clause 37(8)(a)(ii)(B) 1 Yes ☒

162 I choose to use the traditional method 1 Yes ☐

165 ARTHUR SKIDMORE 170 2007/06/30

Name of authorized signing officer of the corporation, authorized partner, or individual

Signature

Date

For Canada Revenue Agency use only

490 _____

491 _____

492 _____

Name of Corporation	Business Number	Tax year-end	Year	Month	Day
HALTON HILLS HYDRO INC.	867429623 RC 0001		2006	12	31

Part 2 - Scientific or Technological Project Information

Provide the information requested in Step 1 on separate sheets of paper for each project, and attach them to this form. If you have more than 20 projects, you only need to provide project descriptions for the 20 that are largest in term of dollar value. For step 2, provide the information requested on this form and complete Schedule E. For more information, see Guide T4088, *Claiming Scientific Research and Experimental Development*.

Step 1 - Detailed project description

Identify each of the projects you are claiming and use questions A to E below to help you provide the information we need to process your claim. If the project is continuing from last year and the objective has not changed or been achieved, you can use the same information that you provided last year for questions A, B and C. Include sufficient information to show how your project work meets the requirements of the SR&ED Program.

We recommend that you read Guide T4088 before you answer questions A to E. This will help you understand the type of information the Canada Revenue Agency needs to process your claim and will reduce or eliminate the need for you to submit more information. It will also help you avoid preparing unnecessary information. Most projects can be described in four pages or less. It would be helpful to take into account whether your project involved experimental development work or scientific research work, because the eligibility requirements for these are different. In general, **experimental development** work is done either in or outside a laboratory in order to achieve a technological advancement for creating new, or improving existing materials, devices, products, or processes. Scientific research work is done mostly in a laboratory setting to obtain new scientific knowledge.

- A. Scientific or technological objectives** - What is the scientific or technological objective of your project? Does this project involve scientific research or experimental development?
- B. Technology or knowledge base or level** - If your project work is mostly experimental development, what were the technological limitations of the products or processes before you started your project? If your project work is mostly scientific research, what was the extent of existing scientific knowledge in this area?
- C. Scientific or technological advancement** - What advancement in technology is being sought? What were the problems or challenges that could not be solved using commonly available techniques requiring you to seek an advance in the underlying technology to achieve the objective in A above, or what was the new scientific knowledge sought in your work? To what field of science or technology would the advance contribute?
- D. Description of work in the tax year** - Describe the work, including experiments and analyses, that you did in this tax year to achieve the technological or scientific objectives above. If all or part of the work that you are claiming was performed by contractors, include a description of the work performed on your behalf by the contractors or a copy of the statement of work from the contract.
- E. Supporting information** - What technical records or documents generated over the course of the work, such as records of trials, test results, progress and final reports, minutes of meetings, employee activity records, prototypes and new products, are available to support your claim?

Step 2 - Project summary information

Total number of projects you are claiming in this tax year. **200** _____

If you received an amount under the Industrial Research Assistance Program (IRAP) for SR&ED type work, please indicate the amount you received. **206** _____

Complete Schedule E to provide a list of all SR&ED projects for which you are claiming expenditures this year.

Name of Corporation	Business Number	Tax year-end	Year	Month	Day
HALTON HILLS HYDRO INC.	867429623 RC 0001		2006	12	31

Part 3 - Summary of SR&ED Expenditures (nearest dollar)

Step 1 - Allowable SR&ED expenditures for SR&ED carried out in Canada

SR&ED portion of salary or wages of employees directly engaged in SR&ED:

- employees other than specified employees 300
- specified employees (do not include bonuses or remuneration based on profits)(see guide) 305

Amounts deemed incurred in the year under subsection 78(4) (salary or wages) 310

Unpaid amounts deemed not incurred in the year under subsection 78(4) 315

Cost of materials consumed in the prosecution of SR&ED 320

Cost of materials transformed in the prosecution of SR&ED 325

SR&ED contracts performed on your behalf (complete Schedule F):

- arm's length contracts 340
- non-arm's length contracts 345

Lease costs of equipment used:

- all or substantially all (90% of the time or more) for SR&ED 350
- primarily (more than 50% but less than 90% of the time) for SR&ED. Enter only 50% of the lease costs if you use the proxy method. If you use the traditional method, enter "0". 355

Overhead or other expenditures (enter "0" if you use the proxy method) 360

Subtotal (add lines 300 to 360; do not add line 315) 365

Third-party payments (complete Schedule A) 370

Total current SR&ED expenditures (add lines 365 and 370) 380

Capital expenditures (for ASA equipment, see guide) 390

Total allowable SR&ED expenditures (add lines 380 and 390) 400

Step 2 - Pool of deductible SR&ED expenditures

Amount from line 400

less

- government and non-government assistance for expenditures included on line 400 430
- SR&ED ITC claimed last year (other than ITC on shared-use equipment) 435
- sale of SR&ED capital assets (see guide) and other deductions 440

add

- previous year's ending balance in the pool of deductible SR&ED expenditures 450
- amount of ITC recaptured in the preceding tax year 453
- adjustments to the pool of deductible expenditures (complete Schedule B, Section 1) 454

Amount available for deduction (If the amount is negative, enter "0" and add to income in the year) 455

Deduction claimed in the year 460

Current year's balance of deductible SR&ED expenditures applicable to future years (line 455 minus line 460) 470

Step 3 - Qualified SR&ED expenditures for ITC purposes

Enter the breakdown between current and capital expenditures for ITC purposes.

	Current Expenditures	Capital Expenditures
Total expenditures for SR&ED (from lines 380 and 390)	492	496

add

- unpaid amounts (other than salary or wages) from previous years that were paid in the year under subsection 127(26) 500
- prescribed proxy amount (complete Schedule D); enter "0" if you use the traditional method 502
- expenditures on shared-use equipment (See Note 1) 504
- qualified expenditures transferred to you (from Form T1146) 508

less

- government and non-government assistance, and contract payments 534
- amounts from lines 552 and 554 of Schedule B, Section 2 552
- amounts from lines 555 and 556 of Schedule C 555

Subtotal 557

SR&ED qualified expenditure pool (add lines 557 and 558) 559

add

- Repayments of assistance and contract payments made in the year 560

Total SR&ED expenditures that qualify for ITC purposes (add lines 559 and 560)* 570

* To claim an ITC on this amount, you must complete Schedule T2 SCH 31 - Investment Tax Credit - Corporation, or Form T2038(IND), Investment Tax Credit (Individuals), whichever applies.

Note 1 The expenditure is deemed to be 1/4 of the capital cost of the equipment. Certain adjustments may be required if the equipment was purchased from a non-arm's length supplier (see explanations for lines 522 and 524 in the guide).

Name of Corporation	Business Number	Tax year-end	Year	Month	Day
HALTON HILLS HYDRO INC.	867429623 RC 0001		2006	12	31

Part 4 - Background information

This information is used to administer the SR&ED program.

Expenditures for SR&ED performed by you (line 400 minus line 340, 345, and 370)	605	
A. Sources of funds for SR&ED		
From the total you entered on line 605, estimate the percentage of distribution of the sources of funds for SR&ED performed within your organization.		
	Canadian (%)	Foreign (%)
Internal	600	
Parent companies, subsidiaries, and affiliated companies	602	604
Federal grants (do not include funds or tax credits from SR&ED tax incentives)	606	
Federal contracts	608	
Provincial funding	610	
SR&ED contract work performed for other companies on their behalf	612	614
Other funding (e.g. universities, foreign governments)	616	618
B. Business personnel		
Total number of employees	630	
SR&ED personnel (full time SR&ED staff, plus full-time equivalent for staff engaged part-time in this activity):		
Scientists and engineers	632	Technologists and technicians 634
Managers and administrators	636	Other technical supporting staff 638
C. Nature of SR&ED work		
From the total you entered on line 605, estimate the approximate distribution of your SR&ED effort:		
Basic research (no specific application in view) 650	Applied research (specific practical application in view) 652	
Development of new: product 654	process 656	technical services 658
Improvement to existing: product 660	process 662	technical services 664
D. Specialized field of research		
Indicate, if applicable, the percentage of the amount on line 605 attributed to the following fields of research:		
Software development 670	Biotechnology 672	Environmental protection 674

Complete Claim Checklist

To speed up the processing of your claim, make sure you have:

1. Used the current version of Form T661 if you are filing a current-year claim ☐
2. Signed the "Certification and Election" section in Part 1 of Form T661 ☐
3. Indicated the method you have chosen for reporting your SR&ED expenditures in fields 160 or 162 in Part 1 ☒
4. Provided a summary of information for each project, with a breakdown of expenditures (labour, materials, and contracts) as per Schedule E. ☐
5. Submitted a detailed project description of your 20 largest projects in terms of their dollar value ☐
6. Retained documents prepared to support the SR&ED expenditures claimed in Part 3. If you forget to claim an expenditure, you have up to 12 months after the filing-due date of your tax return for the year to submit an amended Form T661 ☐
7. Completed Part 4 - Background Information ☐
8. Completed schedules A, B, C, D, E and F, if they apply to your situation, and attached to form T661 ☐
9. Filed a completed Schedule T2 SCH 31, *Investment Tax Credit - Corporations*, or Form T2038(IND), *Investment Tax Credit (Individuals)*, to claim ITCs on your qualified SR&ED expenditures ☐

All the information requested in this form including the attachments, schedules and any other document to support your expenditures is prescribed information. You have to file the information that applies to your claim, along with Schedule T2 SCH 31 or Form T2038(IND), within 12 months of the filing-due date of your income tax return for the year you incurred the expenditures. If you do not meet this reporting deadline, your claim may be rejected.

OEB STAFF INTERROGATORIES

APPENDIX B

Halton Hills Hydro Inc. Economic Evaluation Model

Guide to MEA Model on Economic Evaluation of Expansion Projects

1. Introduction

This spreadsheet provides a model for economic evaluation of proposed expansion projects in a service area of a electricity distributor. The Distribution System Code issued by the Ontario Energy Board (OEB) requires that a distributor perform such an evaluation to determine if the future revenue from the customer(s) will pay for the capital cost and on-going maintenance costs of the expansion project. If a shortfall between the present value of the projected costs and revenues is calculated, the distributor may propose to collect all or a portion of that amount from the customer(s). The evaluation is basically a discounted cash flow calculation that brings all costs and revenues to their net present values. This model, in general, follows the methodology, the set of common elements and related assumptions provided in Appendix B of the Distribution System Code.

Some cells include explanatory comments and are indicated by way of  triangle in the upper right-hand corner of those cells.

2. Licence Agreement and Disclaimer

See tab **Agreement** in this model.

3. System Requirements

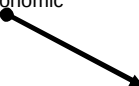
Microsoft Excel 2000 (or similar spreadsheet program capable of translating an Excel workbook). The model includes a circular calculation in cell D83 of the NPV Calculation Worksheet. To ensure an appropriate result the calculation settings must be changed. In Microsoft Excel select the menu item Tools, Options and select "Iterations" in the dialogue box under the tab "Calculation".

4. Methodology

This model follows the requirements of chapter 3 and the suggested formula from Appendix "B" of the OEB's Distribution System Code. The calculation depends on two worksheets called "Data Inputs" and "NPV Calculation". The worksheet "Data Inputs" is used for all variables required by the model. This sheet allows data to be entered for each of the first five years and for a fixed annual amount for the years six through twenty-five. The worksheet "NPV Calculation" performs all of the calculations required to determine the amount of contributed capital that may be required for a particular project.

5. Reference

The MEA examined issues relating to the economic evaluation of expansion projects and produced a List of Issues on Economic Evaluation of Expansions and Responses. The document provides different examples and options to address the issues. Column E (on the right-hand side) of this sheet provides cross-references between the input data/calculations and the issues addressed in the document. It is strongly recommended that users of this model refer to that document when carrying out the economic evaluation.

 **Reference to MEA List of Issues on Economic Evaluation of Expansions and Response**

6. Input Data Worksheet

The model includes sample data which should be overwritten with your utility specific data.

General information about the expansion project is entered into the first four lines of column E:

- The first line is where the Project Name is input;
- The Developer Name is entered into the second line;
- The number of years in the Customer Connection Horizon is entered into the third line; and
- The Customer Revenue Horizon is entered into the fourth line.

There are twelve colour coded data input tables.

- Yellow tables are used to enter constants which do not normally change in the year.
- Blue tables are used for project specific data.

Yellow
Blue

All costs and revenues should be in today's dollars, no inflation needs to apply to any of them.

Table 1: Forecasted customer additions (non-cumulative)

Blue

Enter customer additions by class that will be added in the year. The model assumes that customer additions are made evenly throughout the year. The model creates cumulative data to automatically calculate revenues.

Table 2: Estimate of average energy per added customer (monthly kWh)

Blue

Enter average customer monthly energy consumption per additional customer by class. These figures can vary for year 1 to 5 and are to be a fixed number for each class for year 6 to 25.

Table 3: Estimate of average demand per added customer (kW)

Blue

Enter average customer demand (per customer) for classes that a demand charge applies. These figures can vary for year 1 to 5 and are to be a fixed number for each class for year 6 through 25.

Table 4: Approved wires only rates per rate schedule - fixed monthly charg

Yellow Issues # 2a & 2b

The approved rates for the relevant rate classes should be input in this table. No discount rates should be applied to rates for future years. The sample rates in this table are constant. For rates to be used in the First Generation PBR period, refer to Issues # 2a and 2b in the MEA Issues List and Responses. The OEB has indicated that rates for the first three years can be ramped to include approved rate increases.

Table 5: Approved wires only rates per rate schedule - variable charge (per kWh)

Yellow Issues # 2a & 2b

See comment under table 4.

Table 6: Approved wires only rates per rate schedule - demand charge (per kW)

Yellow Issues # 2a & 2b

See comment under table 4.

Table 7: New facilities and/or reinforcement investments

Blue Issues # 5a, 5b & 9c

Enter costs for new facilities in this table. For a facility that is to be put in the future, its cost is to be entered in the year when, according to the LDC's forecast, it will be substantially complete. The treatment of upstream costs is addressed in the MEA List of Issues and Responses; users should consider the options/examples on the list.

Table 8: Customer specific capital

Blue Issue # 16b

In general, most customer specific capital (e.g. for power quality purposes) should be paid for by the customer and should not be included in the evaluation. If a user can justify including certain customer specific capital in the evaluation, Table 8 is to be used to enter the data.

Table 9: Incremental overheads at project level applicable to distribution expansion

Blue Issue # 18c

A LDC may classify certain capital costs as overheads and use this table to enter the figures; another utility may classify all capital costs as direct and put them in Table 7 leaving Table 9 blank. It is important that, in using this model, users should make sure their classification of capital costs are consistent with their utilities' accounting practices.

Table 10: Attributable incremental annual operating, maintenance and administration (OM&A) expenditures (per customer addition)

Blue Issues # 6a, 6b 6c & 6d

It should be noted that incremental administration cost should also be included in entries in this table. After considering all the different options determining incremental OM&A costs, perhaps the simplest way is to average costs as a suitable surrogate.

Table 11: Discount rate data

Yellow

- Borrowing Rate: Enter utility's prospective (forward outlook) borrowing rate
- Rate of rate on Common Equity: Enter the rate of return allowed by the OEB. Currently, the rate is 9.88%.
- Total debt and Common Equity: actual debt and equity ratio should be used (not deemed ratio).
- Marginal Tax rates: The current marginal tax rate is 43.5%

Table 12: Tax rate data

Yellow

The Taxable Capital Employed in Canada (TCEC) is specific to each corporation and is allocable among affiliates. The Federal capital tax (LCT) does not apply where TCEC is less than \$10.0 million.

7. NPV Calculation Worksheet

All figures for the years in the revenue horizon are shown in these tables.

The Following tables are included in this sheet

- Customer Revenue Table

Customer additions are assumed to be added evenly throughout the year, therefore, current year additions are divided by two.

- Capital Costs Table

Capital costs are calculated and summarized.

Issue # 16a

- Incremental Operating, Maintenance & Administration Table

- Tax Calculation Table

Payments in lieu of income taxes are not applicable until Section 93 of the *Electricity Act, 1998* comes in to force (i.e. Market Opening).

Issue # 16d, 16e & 16f

- Net Present Value Summary Table

If the net present value of the project is negative, the utility may collect up to that amount of contributed capital from the customer/developer.

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Table No.	Project name	Acme Homes Phase 2(Signed Aug 12/05 wo#99520)				
	Developer name	Acme Homes				
	Customer connection horizon (max 5)	5	YELLOW CELLS ONLY ARE FOR DATA INPUT OF ANNUAL CONSTANTS.			
	Customer revenue horizon (max 25)	25	BLUE CELLS ARE USED FOR PROJECT SPECIFIC DATA			
1	Forecasted customer additions (non-cumulative)					
	Customer Class	Aug-06	Aug-07	Aug-08	Aug-09	Aug-10
	Residential	162			0	0
	General Service < 50kW					
	General Service > 50kW					
	General Service > 1000kW					
	Large User					
	Other class - non-demand					
	Other class - non-demand					
	Other class - demand					
	Street Lights	150				
2	Estimate of average energy per added customer (monthly kWh)					
	Customer Class	Year 1	Year 2	Year 3	Year 4	Year 5
	Residential	262	262	262	262	262
	General Service < 50kW					
	General Service > 50kW					
	General Service > 1000kW					
	Large User					
	Other class - non-demand					
	Other class - non-demand					
	Other class - demand					
	Street Lights	0.1634	0.1634	0.1634	0.1634	0.1634
3	Estimate of average demand per added customer kW					
	Customer Class	Year 1	Year 2	Year 3	Year 4	Year 5
	General Service > 50kW	0	0	0	0	0
	General Service > 1000kW	0	0	0	0	0
	Large User	0	0	0	0	0
	Other class - demand	0	0	0	0	0
	Street Lights	0.1634	0.1634	0.1634	0.1634	0.1634
4	Approved wires only rates per rate schedule - monthly fixed charge					
	Customer Class	Year 1	Year 2	Year 3	Year 4	Year 5
	Residential	\$ 13.23	\$ 13.23	\$ 13.23	\$ 13.23	\$ 13.23
	General Service < 50kW	\$ 14.16	\$ 14.16	\$ 14.16	\$ 14.16	\$ 14.16
	General Service > 50kW	\$ 67.24	\$ 67.24	\$ 67.24	\$ 67.24	\$ 67.24
	General Service > 1000kW	\$ 875.25	\$ 875.25	\$ 875.25	\$ 875.25	\$ 875.25
	Large User	\$ 3,897.80	\$ 3,897.80	\$ 3,897.80	\$ 3,897.80	\$ 3,897.80
	Other class - non-demand					
	Other class - non-demand					
	Street Lights (100 W) - demand	\$ 0.150	\$ 0.150	\$ 0.150	\$ 0.150	\$ 0.150
	Street Lights (150 W) - demand	\$ 0.150	\$ 0.150	\$ 0.150	\$ 0.150	\$ 0.150
5	Approved wires only rates per rate schedule - variable charge (per kWh)					
	Customer Class	Year 1	Year 2	Year 3	Year 4	Year 5
	Residential	0.0125	0.0125	0.0125	0.0125	0.0125
	General Service < 50kW	0.0150	0.0150	0.0150	0.0150	0.0150
	General Service > 50kW					
	General Service > 1000kW					
	Large User					
	Other class - non-demand					
	Other class - non-demand					
	Street Lights (100 W) - demand					
	Street Lights (150 W) - demand					
6	Approved wires only rates per rate schedule - demand charge (per kW)					
	Customer Class	Year 1	Year 2	Year 3	Year 4	Year 5
	General Service > 50kW	2.3443	2.3443	2.3443	2.3443	2.3443
	General Service > 1000kW	2.8761	2.8761	2.8761	2.8761	2.8761
	Large User	2.4571	2.4571	2.4571	2.4571	2.4571
	Street Lights (100 W) - demand	0.7365	0.7365	0.7365	0.7365	0.7365
	Street Lights (150 W) - demand	0.7365	0.7365	0.7365	0.7365	0.7365
7	New facilities and/or reinforcement investments					
	Capital elements	Year 1	Year 2	Year 3	Year 4	Year 5
	Distribution stations					
	Distribution lines	600,000				
	Distribution transformers	185,000				
	Secondary busses	35,000				
	Services (Metering)	70,141				
	External (paid by developer)					
	External (paid by MH)					
	Total	890,141	-	-	-	-
	Assessed value of land					
8	Customer specific capital					
	Customer Class	Year 1	Year 2	Year 3	Year 4	Year 5
	Residential	0	0	0	0	0
	General Service < 50kW	0	0	0	0	0
	General Service > 50kW	0	0	0	0	0
	General Service > 1000kW	0	0	0	0	0
	Large User	0	0	0	0	0
	Other class - non-demand	0	0	0	0	0
	Other class - non-demand	0	0	0	0	0
	Other class - demand	0	0	0	0	0
	Other class - demand	0	0	0	0	0
	Total	0	0	0	0	0
9	Incremental overheads (capital) at project level applicable to distribution system expansion					
	Customer Class	Year 1	Year 2	Year 3	Year 4	Year 5
	Residential	\$ 50,000	0	0	0	0
	General Service < 50kW	0	0	0	0	0
	General Service > 50kW	0	0	0	0	0
	General Service > 1000kW	0	0	0	0	0
	Large User	0	0	0	0	0
	Developer Design	-	0	0	0	0
	Other class - non-demand	0	0	0	0	0
	Other class - non-demand	0	0	0	0	0
	Other class - demand	0	0	0	0	0
	Other class - demand	0	0	0	0	0
10	Attributable incremental annual operating, maintenance and administration expenditures (per customer addition)					
	Customer Class	Year 1	Year 2	Year 3	Year 4	Year 5
	Residential	138	138	138	138	138
	General Service < 50kW					
	General Service > 50kW					
	General Service > 1000kW					
	Large User					
	Other class - non-demand					
	Other class - non-demand					
	Other class - demand					
	Other class - demand					
11	Discount rate data					
	Incremental after-tax cost of capita	Year 1	Year 2	Year 3	Year 4	Year 5
	Borrowing rate	6.25%	6.25%	6.25%	6.25%	6.25%
	Rate of return on common equity	9.00%	9.00%	9.00%	9.00%	9.00%
	Total debt outstanding (%)	50.00%	50.00%	50.00%	50.00%	50.00%
	Total common equity (%)	50.00%	50.00%	50.00%	50.00%	50.00%
	Marginal income tax rate	36.12%	36.12%	36.12%	36.12%	36.12%
	Incremental after-tax weighted average cost of capital	6.4963%	6.4963%	6.4963%	6.4963%	6.4963%
12	Tax rate data	Aug-06	Aug-07	Aug-08	Aug-09	Aug-10

Forecasted customer additions (non-cumulative)

Weighted Avg Conn Months

Type of tax	Year 1	Year 2	Year 3	Year 4	Year 5	Years 6-25
Municipal tax rate	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Marginal income tax rate	36.12%	36.12%	36.12%	36.12%	36.12%	36.12%
Federal capital tax rate	0.125%	0.125%	0.125%	0.125%	0.125%	0.125%
Provincial capital tax rate	0.300%	0.300%	0.300%	0.300%	0.300%	0.300%
Capital cost allowance rate	8.000%	8.000%	8.000%	8.000%	8.000%	8.000%
Taxable capital employed in Canada	38,406,768	38,406,768	38,406,768	38,406,768	38,406,768	38,406,768
Capital Deduction (Federal purposes)	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000
Base for Federal capital tax	(11,593,232)	(11,593,232)	(11,593,232)	(11,593,232)	(11,593,232)	(11,593,232)

Discount rate		0.06496	0.06496	0.06496	0.06496	0.06496	0.06496	0.06496	0.06496	0.06496	0.06496	0.06496
Present value factor - end of year		0.93900	0.88172	0.82794	0.77743	0.73001	0.68548	0.64366	0.60440	0.56753	0.53291	0.20732
Present value factor - mid-year		0.96902	0.90991	0.85441	0.80229	0.75335	0.70739	0.66424	0.62372	0.58568	0.54995	0.21395
	Total	1	2	3	4	5	6	7	8	9	10	25

OPERATIONS

Customer revenue - fixed charge rate

Residential	624,549	7,290	25,719	25,719	25,719	25,719	25,719	25,719	25,719	25,719	25,719	25,719
General Service < 50kW	0	0	0	0	0	0	0	0	0	0	0	0
General Service > 50kW	0	0	0	0	0	0	0	0	0	0	0	0
General Service > 1000kW	0	0	0	0	0	0	0	0	0	0	0	0
Large User	0	0	0	0	0	0	0	0	0	0	0	0
Other class - non-demand	0	0	0	0	0	0	0	0	0	0	0	0
Other class - non-demand	0	0	0	0	0	0	0	0	0	0	0	0
Other class - demand	0	0	0	0	0	0	0	0	0	0	0	0
Street Lights	6,615	135	270	270	270	270	270	270	270	270	270	270
Total fixed charge revenue	631,164	7,425	25,989	25,989	25,989	25,989	25,989	25,989	25,989	25,989	25,989	25,989

Customer revenue - variable charge rate

Residential	154,635	1,805	6,368	6,368	6,368	6,368	6,368	6,368	6,368	6,368	6,368	6,368
General Service < 50kW	0	0	0	0	0	0	0	0	0	0	0	0
General Service > 50kW	0	0	0	0	0	0	0	0	0	0	0	0
General Service > 1000kW	0	0	0	0	0	0	0	0	0	0	0	0
Large User	0	0	0	0	0	0	0	0	0	0	0	0
Other class - non-demand	0	0	0	0	0	0	0	0	0	0	0	0
Other class - non-demand	0	0	0	0	0	0	0	0	0	0	0	0
Other class - demand	0	0	0	0	0	0	0	0	0	0	0	0
Street Lights	5,306	108	217	217	217	217	217	217	217	217	217	217
Total variable charge revenue	159,941	1,913	6,584	6,584	6,584	6,584	6,584	6,584	6,584	6,584	6,584	6,584

Customer revenue - total

	791,105	9,338	32,574	32,574	32,574	32,574	32,574	32,574	32,574	32,574	32,574	32,574

Revenue received for each of the years 6 - 25 are the same as year 5

Incremental OM&A

Residential	542,881	6,337	22,356	22,356	22,356	22,356	22,356	22,356	22,356	22,356	22,356	22,356
General Service < 50kW	0	0	0	0	0	0	0	0	0	0	0	0
General Service > 50kW	0	0	0	0	0	0	0	0	0	0	0	0
General Service > 1000kW	0	0	0	0	0	0	0	0	0	0	0	0
Large User	0	0	0	0	0	0	0	0	0	0	0	0
Other class - non-demand	0	0	0	0	0	0	0	0	0	0	0	0
Other class - non-demand	0	0	0	0	0	0	0	0	0	0	0	0
Other class - demand	0	0	0	0	0	0	0	0	0	0	0	0
Other class - demand	0	0	0	0	0	0	0	0	0	0	0	0
Total Incremental OM&A	542,881	6,337	22,356	22,356	22,356	22,356	22,356	22,356	22,356	22,356	22,356	22,356

Current year customer additions are divided by two in order to recognize level activities throughout the year.

CAPITAL COSTS

New facilities and/or reinforcement investments

	890,141	890,141	0	0	0	0	0	0	0	0	0	0

Customer specific capital

Residential	0	0	0	0	0	0	0	0	0	0	0	0
General Service < 50kW	0	0	0	0	0	0	0	0	0	0	0	0
General Service > 50kW	0	0	0	0	0	0	0	0	0	0	0	0
General Service > 1000kW	0	0	0	0	0	0	0	0	0	0	0	0
Large User	0	0	0	0	0	0	0	0	0	0	0	0
Other class - non-demand	0	0	0	0	0	0	0	0	0	0	0	0
Other class - non-demand	0	0	0	0	0	0	0	0	0	0	0	0
Other class - demand	0	0	0	0	0	0	0	0	0	0	0	0
Other class - demand	0	0	0	0	0	0	0	0	0	0	0	0
Total customer specific capital (exclude land)	0	0	0	0	0	0	0	0	0	0	0	0

Incremental Overheads at project level

Residential	50,000	50,000	0	0	0	0	0	0	0	0	0	0
General Service < 50kW	0	0	0	0	0	0	0	0	0	0	0	0
General Service > 50kW	0	0	0	0	0	0	0	0	0	0	0	0
General Service > 1000kW	0	0	0	0	0	0	0	0	0	0	0	0
Large User	0	0	0	0	0	0	0	0	0	0	0	0
Other class - non-demand	0	0	0	0	0	0	0	0	0	0	0	0
Other class - non-demand	0	0	0	0	0	0	0	0	0	0	0	0
Other class - demand	0	0	0	0	0	0	0	0	0	0	0	0
Other class - demand	0	0	0	0	0	0	0	0	0	0	0	0
Total incremental overheads	50,000	50,000	0	0	0	0	0	0	0	0	0	0

Land and land rights

	0	0	0	0	0	0	0	0	0	0	0	0

Annual Total Capital Costs

	940,141	940,141	0	0	0	0	0	0	0	0	0	0

Annual Capital Costs excluding land

	940,141	940,141	0	0	0	0	0	0	0	0	0	0

There is assumption made here that there are no up front capital costs in the first year, that Costs in the first year are incurred evenly during the year.

Present Value Of Annual Capital Costs

	911,016	911,016	0	0	0	0	0	0	0	0	0	0

Present Value Of CCA Tax Shield

Opening undepreciated capital cost		940,141	125,265	115,243	106,024	97,542	89,739	82,560	75,955	69,878	64,288	18,406
Less: Contributed Capital		(809,657)										
Less: Capital cost allowance	113,551		10,021	9,219	8,482	7,803	7,179	6,605	6,076	5,590	5,143	1,472
Closing undepreciated capital cost		125,265	115,243	106,024	97,542	89,739	82,560	75,955	69,878	64,288	59,145	16,933
CCA Annual Income Tax Savings		1,885	3,620	3,330	3,064	2,819	2,593	2,386	2,195	2,019	1,858	532
Present Value of CCA Tax Shield	25,301	1,827	3,294	2,845	2,458	2,123	1,834	1,585	1,369	1,183	1,022	114

Present Value of Operating Cash Flow

Present Value of Net Operating Cash

Customer revenue - total	791,105	9,338	32,574	32,574	32,574	32,574	32,574	32,574	32,574	32,574	32,574	32,574
Less Total Incremental OM&A	(542,881)	(6,337)	(22,356)	(22,356)	(22,356)	(22,356)	(22,356)	(22,356)	(22,356)	(22,356)	(22,356)	(22,356)
Net (Wires) Operating Cash before Income Tax	248,224	3,001	10,218	10,218	10,218	10,218	10,218	10,218	10,218	10,218	10,218	10,218

Forecasted customer additions (non-cumulative)

Forecasted Customer Additions (Non-Cumulative)												
Present value of Net Operating Cash	121,670	2,908	9,297	8,730	8,197	7,697	7,228	6,787	6,373	5,984	5,619	2,186
Present Value of Taxes												
Income Taxes	88,173	948	3,566	3,576	3,585	3,593	3,601	3,608	3,615	3,621	3,627	3,672
Provincial Capital Taxes	4,113	376	346	318	293	269	248	228	210	193	177	51
Federal Capital Taxes	0	0	0	0	0	0	0	0	0	0	0	0
Annual Municipal Taxes	0	0	0	0	0	0	0	0	0	0	0	0
Total Taxes	92,286	1,324	3,911	3,894	3,878	3,863	3,849	3,836	3,825	3,814	3,804	3,723
PV of Taxes	45,612	1,283	3,559	3,327	3,111	2,910	2,723	2,548	2,385	2,234	2,092	797
PV of Municipal TaxesTaxes	0	0	0	0	0	0	0	0	0	0	0	0

Net Present Value Summary

	With taxes	Without Federal and Provincial taxes
1. PV of Operating Cash Flow		
a) PV of Net Operating Cash Flow	121,670	121,670
b) PV of Taxes	(45,612)	0
PV of Operating Cash Flow	76,058	121,670
2. PV of Capital	(911,016)	(911,016)
3. PV of CCA Tax Shield	25,301	
NET PRESENT VALUE	(\$809,657)	(\$789,346)

Halton Hills Hydro's Contribution	101,358
Less:	
Amount paid by HH for incremental overheads	-50000
Amount paid by HH for Capital	-70141
Addback: Cash deposit received from developer	97060
Net Halton Hills Hydro Contribution -YR 1	78,277

Actual	FORECAST	FORECAST	FORECAST	FORECAST			
Aug-06	Aug-07	Aug-08	Aug-09	Aug-10	TOTAL MH Contr.	TOTAL CAP	%
\$101,358.42					\$101,358.42	\$911,015.88	11%
Net Payment to Developer before GST	\$78,276.96	\$0.00				\$78,276.96	
GST on incremental costs	(\$7,208.49)	\$0.00	\$0.00	\$0.00	\$0.00	(\$7,208.49)	
Net Payment to Developer	\$71,068.47	\$0.00	\$0.00	\$0.00	\$0.00	\$71,068.47	

Reconciliation Summary:	HHH	Developer	PV Capital
cash outlays	\$ 120,141	\$ 790,874	
refunds given (received/due)	\$ 78,277	\$ (78,277)	
deposits given (received)	\$ (97,060)	\$ 97,060	
Total share per party	\$ 101,358	\$ 809,657	\$ 911,016
	11%	89%	
		variance	\$ -

Year 1 - Developer Costs are estimated. Any adjustments will be made in the Year 2 review.

Table
No.

Project name Developer name Customer connection horizon (max 5) Customer revenue horizon (max 25)	Acme Homes Phase 2(Signed Aug 12/05 wo#99520)					
	Acme Homes					
	5	YELLOW CELLS ONLY ARE FOR DATA INPUT OF ANNUAL CONSTANTS.				
	25	BLUE CELLS ARE USED FOR PROJECT SPECIFIC DATA				
Forecasted customer additions (non-cumulative)						Weighted Avg Conn Months
Customer Class	Aug-06	Aug-07	Aug-08	Aug-09	Aug-10	year 1
Residential	162	260	0	0	0	3.401234568
General Service < 50kW	0					
General Service > 50kW	0					
General Service > 1000kW	0					
Large User	0					
Other class - non-demand	0					
Other class - non-demand	0					
Other class - demand	0					
Street Lights	150					
Estimate of average energy per added customer (monthly kWh)						
Customer Class	Year 1	Year 2	Year 3	Year 4	Year 5	
Residential	262	550	550	550	550	
General Service < 50kW	0					
Other class - non-demand	0					
Other class - non-demand	0					
Estimate of average demand per added customer kW						
Customer Class	Year 1	Year 2	Year 3	Year 4	Year 5	
General Service > 50kW	0.0	0	0	0	0	
General Service > 1000kW	0.0	0	0	0	0	
Large User	0.0	0	0	0	0	
Other class - demand	0.0	0	0	0	0	
Street Lights	0.1634	0.1634	0.1634	0.1634	0.1634	
Approved wires only rates per rate schedule - monthly fixed charge						
Customer Class	Year 1	Year 2	Year 3	Year 4	Year 5	
Residential	\$ 13.23	\$ 13.23	\$ 13.23	\$ 13.23	\$ 13.23	
General Service < 50kW	\$ 14.16	\$ 14.16	\$ 14.16	\$ 14.16	\$ 14.16	
General Service > 50kW	\$ 67.24	\$ 67.24	\$ 67.24	\$ 67.24	\$ 67.24	
General Service > 1000kW	\$ 875.25	\$ 875.25	\$ 875.25	\$ 875.25	\$ 875.25	
Large User	\$ 3,897.80	\$ 3,897.80	\$ 3,897.80	\$ 3,897.80	\$ 3,897.80	
Other class - non-demand	\$ -	\$ -	\$ -	\$ -	\$ -	
Other class - non-demand	\$ -	\$ -	\$ -	\$ -	\$ -	
Street Lights (100 W) - demand	\$ 0.150	\$ 0.150	\$ 0.150	\$ 0.150	\$ 0.150	
Street Lights (150 W) - demand	\$ 0.150	\$ 0.150	\$ 0.150	\$ 0.150	\$ 0.150	
Approved wires only rates per rate schedule - variable charge (per kWh)						
Customer Class	Year 1	Year 2	Year 3	Year 4	Year 5	
Residential	\$ 0.0125	\$ 0.0125	\$ 0.0125	\$ 0.0125	\$ 0.0125	
General Service < 50kW	\$ 0.0150	\$ 0.0150	\$ 0.0150	\$ 0.0150	\$ 0.0150	
Other class - non-demand	\$ -	\$ -	\$ -	\$ -	\$ -	
Other class - non-demand	\$ -	\$ -	\$ -	\$ -	\$ -	
Approved wires only rates per rate schedule - demand charge (per kW)						
Customer Class	Year 1	Year 1	Year 3	Year 4	Year 5	
General Service > 50kW	\$ 2.34	\$ 2.34	\$ 2.34	\$ 2.34	\$ 2.34	
General Service > 1000kW	\$ 2.88	\$ 2.88	\$ 2.88	\$ 2.88	\$ 2.88	
Large User	\$ 2.46	\$ 2.46	\$ 2.46	\$ 2.46	\$ 2.46	
Street Lights (100 W) - demand	\$ 0.7365	\$ 0.7365	\$ 0.7365	\$ 0.7365	\$ 0.7365	
Street Lights (150 W) - demand	\$ 0.7365	\$ 0.7365	\$ 0.7365	\$ 0.7365	\$ 0.7365	
New facilities and/or reinforcement investments						
Capital elements	Year 1	Year 2	Year 3	Year 4	Year 5	
Distribution stations	-					
Distribution lines	600,000					
Distribution transformers	185,000					
Secondary busses	\$ 35,000	50,000				
Services (Metering)	70,141	-				
External (paid by developer)	\$ -					
External (paid by MH)	-					
Total	\$890,141	\$50,000	\$0	\$0	\$0	
Assessed value of land						
Customer specific capital						
Customer Class	Year 1	Year 2	Year 3	Year 4	Year 5	
Residential	0	0	0	0	0	
General Service < 50kW	0	0	0	0	0	
General Service > 50kW	0	0	0	0	0	
General Service > 1000kW	0	0	0	0	0	
Large User	0	0	0	0	0	
Other class - non-demand	0	0	0	0	0	
Other class - non-demand	0	0	0	0	0	
Other class - demand	0	0	0	0	0	
Other class - demand	0	0	0	0	0	
Total	0	0	0	0	0	
Incremental overheads (capital) at project level applicable to distribution system expansion						
Customer Class	Year 1	Year 2	Year 3	Year 4	Year 5	Years 6-25
Residential	\$ 50,000	\$ 60,000	0	0	0	0
General Service < 50kW	0	0	0	0	0	0
General Service > 50kW	0	0	0	0	0	0
General Service > 1000kW	0	0	0	0	0	0
Large User	0	0	0	0	0	0
Other class - non-demand	0	0	0	0	0	0
Other class - non-demand	0	0	0	0	0	0
Other class - demand	0	0	0	0	0	0
Other class - demand	0	0	0	0	0	0
Attributable incremental annual operating, maintenance and administration expenditures (per customer addition)						
Customer Class	Year 1	Year 2	Year 3	Year 4	Year 5	Years 6-25
Residential	138	138	138	138	138	138
General Service < 50kW	0	0				
General Service > 50kW	0	0				
General Service > 1000kW	0	0				
Large User	0	0				
Other class - non-demand	0	0				
Other class - non-demand	0	0				
Other class - demand	0	0				
Other class - demand	0	0				
Discount rate data						
Incremental after-tax cost of capital	Year 1	Year 2	Year 3	Year 4	Year 5	Years 6-25
Borrowing rate	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%
Rate of return on common equity	9.00%	9.00%	9.00%	9.00%	9.00%	9.00%

Total debt outstanding (%)	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%
Total common equity (%)	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%
Marginal income tax rate	36.12%	36.12%	36.12%	36.12%	36.12%	36.12%
Incremental after-tax weighted average cost of capital	6.4963%	6.4963%	6.4963%	6.4963%	6.4963%	6.4963%
	Aug-06	Aug-07	Aug-08	Aug-09	Aug-10	

Tax rate data

Type of tax	Year 1	Year 2	Year 3	Year 4	Year 5	Years 6-25
Municipal tax rate	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Marginal income tax rate	36.12%	36.12%	36.12%	36.12%	36.12%	36.12%
Federal capital tax rate	0.125%	0.125%	0.125%	0.125%	0.125%	0.125%
Provincial capital tax rate	0.300%	0.300%	0.300%	0.300%	0.300%	0.300%
Capital cost allowance rate	5.000%	8.000%	8.000%	8.000%	8.000%	8.000%
Taxable capital employed in Canada	38,406,768	38,406,768	38,406,768	38,406,768	38,406,768	38,406,768
Capital Deduction (Federal purposes)	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000
Base for Federal capital tax	(11,593,232)	(11,593,232)	(11,593,232)	(11,593,232)	(11,593,232)	(11,593,232)

Discount rate		0.06496	0.06496	0.06496	0.06496	0.06496	0.06496	0.06496	0.06496	0.06496	0.06496	0.06496
Present value factor - end of year		0.93900	0.88172	0.82794	0.77743	0.73001	0.68548	0.64366	0.60440	0.56753	0.53291	0.20732
Present value factor - mid-year		0.96902	0.90991	0.85441	0.80229	0.75335	0.70739	0.66424	0.62372	0.58568	0.54995	0.21395
	Total	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	YEAR 6	YEAR 7	YEAR 8	YEAR 9	YEAR 10	YEAR 25

OPERATIONS**Customer revenue - fixed charge rate**

Residential	1,604,045	7,290	55,831	66,997	66,997	66,997	66,997	66,997	66,997	66,997	66,997	66,997
General Service < 50kW	0	0	0	0	0	0	0	0	0	0	0	0
General Service > 50kW	0	0	0	0	0	0	0	0	0	0	0	0
General Service > 1000kW	0	0	0	0	0	0	0	0	0	0	0	0
Large User	0	0	0	0	0	0	0	0	0	0	0	0
Other class - non-demand	0	0	0	0	0	0	0	0	0	0	0	0
Other class - non-demand	0	0	0	0	0	0	0	0	0	0	0	0
Other class - demand	0	0	0	0	0	0	0	0	0	0	0	0
Street Lights	6,615	135	270	270	270	270	270	270	270	270	270	270
Total fixed charge revenue	1,610,660	7,425	56,101	67,267	67,267	67,267	67,267	67,267	67,267	67,267	67,267	67,267

Customer revenue - variable charge rate

Residential	831,562	1,805	29,013	34,815	34,815	34,815	34,815	34,815	34,815	34,815	34,815	34,815
General Service < 50kW	0	0	0	0	0	0	0	0	0	0	0	0
General Service > 50kW	0	0	0	0	0	0	0	0	0	0	0	0
General Service > 1000kW	0	0	0	0	0	0	0	0	0	0	0	0
Large User	0	0	0	0	0	0	0	0	0	0	0	0
Other class - non-demand	0	0	0	0	0	0	0	0	0	0	0	0
Other class - non-demand	0	0	0	0	0	0	0	0	0	0	0	0
Other class - demand	0	0	0	0	0	0	0	0	0	0	0	0
Street Lights	5,306	108	217	217	217	217	217	217	217	217	217	217
Total variable charge revenue	836,868	1,913	29,229	35,032	35,032	35,032	35,032	35,032	35,032	35,032	35,032	35,032

Customer revenue - total

	2,447,528	9,338	85,330	102,298	102,298	102,298	102,298	102,298	102,298	102,298	102,298	102,298

Revenue received for each of the years 6 - 25 are the same as year 5

Incremental OM&A

Residential	1,394,295	6,337	48,530	58,236	58,236	58,236	58,236	58,236	58,236	58,236	58,236	58,236
General Service < 50kW	0	0	0	0	0	0	0	0	0	0	0	0
General Service > 50kW	0	0	0	0	0	0	0	0	0	0	0	0
General Service > 1000kW	0	0	0	0	0	0	0	0	0	0	0	0
Large User	0	0	0	0	0	0	0	0	0	0	0	0
Other class - non-demand	0	0	0	0	0	0	0	0	0	0	0	0
Other class - non-demand	0	0	0	0	0	0	0	0	0	0	0	0
Other class - demand	0	0	0	0	0	0	0	0	0	0	0	0
Other class - demand	0	0	0	0	0	0	0	0	0	0	0	0
Total Incremental OM&A	1,394,295	6,337	48,530	58,236	58,236	58,236	58,236	58,236	58,236	58,236	58,236	58,236

Current year customer additions are divided by two in order to recognize level activities throughout the year.

CAPITAL COSTS**New facilities and/or reinforcement investments**

	940,141	890,141	50,000	0	0	0

Customer specific capital

Residential	0	0	0	0	0	0
General Service < 50kW	0	0	0	0	0	0
General Service > 50kW	0	0	0	0	0	0
General Service > 1000kW	0	0	0	0	0	0
Large User	0	0	0	0	0	0
Other class - non-demand	0	0	0	0	0	0
Other class - non-demand	0	0	0	0	0	0
Other class - demand	0	0	0	0	0	0
Other class - demand	0	0	0	0	0	0
Total customer specific capital (exclude land)	0	0	0	0	0	0

Incremental Overheads at project level

Residential	110,000	50,000	60,000	0	0	0
General Service < 50kW	0	0	0	0	0	0
General Service > 50kW	0	0	0	0	0	0
General Service > 1000kW	0	0	0	0	0	0
Large User	0	0	0	0	0	0
Other class - non-demand	0	0	0	0	0	0
Other class - non-demand	0	0	0	0	0	0
Other class - demand	0	0	0	0	0	0
Other class - demand	0	0	0	0	0	0
Total incremental overheads	110,000	50,000	60,000	0	0	0

Land and land rights

	0	0	0	0	0	0

Annual Total Capital Costs

	1,050,141	940,141	110,000	0	0	0

Annual Capital Costs excluding land

	1,050,141	940,141	110,000	0	0	0

There is assumption made here that there are no up front capital costs in the first year, that Costs in the first year are incurred evenly during the year.

Present Value Of Annual Capital Costs

	1,011,106	911,016	100,090	0	0	0

Present Value Of CCA Tax Shield

Opening undepreciated capital cost	940,141	323,365	403,095	370,848	341,180	313,886	288,775	265,673	244,419	224,865	64,378
Less: Contributed Capital	(608,485)										
Less: Capital cost allowance	382,428	8,291	30,269	32,248	29,668	27,294	25,111	23,102	21,254	19,554	5,150
Closing undepreciated capital cost	323,365	403,095	370,848	341,180	313,886	288,775	265,673	244,419	224,865	206,876	59,228
CCA Annual Income Tax Savings	2,995	10,933	11,648	10,716	9,859	9,070	8,344	7,677	7,063	6,498	1,860
Present Value of CCA Tax Shield	83,436	2,902	9,948	9,952	8,597	7,427	6,416	5,543	4,788	4,136	398

Present Value of Operating Cash Flow

Present Value of Net Operating Cash

Customer revenue - total	2,447,528	9,338	85,330	102,298	102,298	102,298	102,298	102,298	102,298	102,298	102,298
Less Total Incremental OM&A	(1,394,295)	(6,337)	(48,530)	(58,236)	(58,236)	(58,236)	(58,236)	(58,236)	(58,236)	(58,236)	(58,236)
Net (Wires) Operating Cash before Income Tax	1,053,234	3,001	36,800	44,062	44,062	44,062	44,062	44,062	44,062	44,062	44,062
Present value of Net Operating Cash	508,445	2,908	33,484	37,647	35,351	33,194	31,169	29,268	27,483	25,806	24,232

Present Value of Taxes

Income Taxes	375,356	734	12,855	15,513	15,546	15,575	15,602	15,627	15,650	15,672	15,691
Provincial Capital Taxes	14,043	970	1,209	1,113	1,024	942	866	797	733	675	621
Federal Capital Taxes	0	0	0	0	0	0	0	0	0	0	0
Annual Municipal Taxes	0	0	0	0	0	0	0	0	0	0	0
Total Taxes	389,399	1,704	14,065	16,626	16,569	16,517	16,469	16,424	16,384	16,346	16,312
PV of Taxes	189,260	1,651	12,797	14,205	13,293	12,443	11,650	10,910	10,219	9,574	8,971
PV of Municipal Taxes	0	0	0	0	0	0	0	0	0	0	0

Net Present Value Summary

	With taxes	Without Federal and Provincial taxes
1. PV of Operating Cash Flow		
a) PV of Net Operating Cash Flow	508,445	508,445
b) PV of Taxes	(189,260)	0
PV of Operating Cash Flow	319,184	508,445
2. PV of Capital	(1,011,106)	(1,011,106)
3. PV of CCA Tax Shield	83,436	
NET PRESENT VALUE	(\$608,485)	(\$502,661)

Halton Hills Hydro's Contribution	402,621
Less:	
Amount paid by HH for incremental overheads	-110,000
Amount paid by HH for Capital	-70,141
Addback: Cash deposit received from developer	97,060
Net Halton Hills Hydro Contribution -YR 2	319,539

Actual	Actual	FORECAST	FORECAST	FORECAST			
Aug-06	Aug-07	Aug-08	Aug-09	Aug-10	TOTAL MH Contr.	TOTAL CAP	%
\$101,358.42	\$301,262.09	\$0.00	\$0.00	\$0.00	\$402,620.51	\$1,011,105.98	40%

Net Payment to Developer before GST	\$78,276.96	\$241,262.09	\$0.00	\$0.00	\$0.00	\$319,539.05
GST on incremental costs	(\$7,208.49)	(\$3,600.00)	\$0.00	\$0.00	\$0.00	(\$10,808.49)
Net Payment to Developer	\$71,068.47	\$237,662.09	\$0.00	\$0.00	\$0.00	\$308,730.56

Reconciliation Summary:	HHH	Developer	PV Capital
cash outlays	\$ 180,141	\$ 830,965	
refunds given (received/due)	\$ 319,539	\$ (319,539)	
deposits given (received)	\$ (97,060)	\$ 97,060	
Total share per party	\$ 402,621	\$ 608,485	\$ 1,011,106
	40%	60%	
		variance	\$ -

Table
No.

Project name Developer name Customer connection horizon (max 5) Customer revenue horizon (max 25)	Acme Homes Phase 2(Signed Aug 12/05 wo#99520)					Weighted Avg Conn Months year 1year 2year 3			
	Acme Homes								
	5	YELLOW CELLS ONLY ARE FOR DATA INPUT OF ANNUAL CONSTANTS.							
	25	BLUE CELLS ARE USED FOR PROJECT SPECIFIC DATA							
Forecasted customer additions (non-cumulative)									
Customer Class	Aug-06	Aug-07	Aug-08	Aug-09	Aug-10	Maximum Units422			
Residential	162	260	0	0	0		3.401234568	10	12
General Service < 50kW	0	0							
General Service > 50kW	0	0							
General Service > 1000kW	0	0							
Large User	0	0							
Other class - non-demand	0	0							
Other class - non-demand	0	0							
Other class - demand	0	0							
Street Lights	150	0							
Estimate of average energy per added customer (monthly kWh)									
Customer Class	Year 1	Year 2	Year 3	Year 4	Year 5				
Residential	262	550	600	600	600				
General Service < 50kW	0	0							
Other class - non-demand	0	0							
Other class - non-demand	0	0							
Estimate of average demand per added customer kW									
Customer Class	Year 1	Year 2	Year 3	Year 4	Year 5				
General Service > 50kW	0	0	0	0	0				
General Service > 1000kW	0	0	0	0	0				
Large User	0	0	0	0	0				
Other class - demand	0	0	0	0	0				
Street Lights	0.1634	0.1634	0.1634	0.1634	0.1634				
Approved wires only rates per rate schedule - monthly fixed charge									
Customer Class	Year 1	Year 2	Year 3	Year 4	Year 5				
Residential	\$ 13.23	\$ 13.23	\$ 13.23	\$ 13.23	\$ 13.23				
General Service < 50kW	\$ 14.16	\$ 14.16	\$ 14.16	\$ 14.16	\$ 14.16				
General Service > 50kW	\$ 67.24	\$ 67.24	\$ 67.24	\$ 67.24	\$ 67.24				
General Service > 1000kW	\$ 875.25	\$ 875.25	\$ 875.25	\$ 875.25	\$ 875.25				
Large User	\$ 3,897.80	\$ 3,897.80	\$ 3,897.80	\$ 3,897.80	\$ 3,897.80				
Other class - non-demand	\$ -	\$ -	\$ -	\$ -	\$ -				
Other class - non-demand	\$ -	\$ -	\$ -	\$ -	\$ -				
Street Lights (100 W) - demand	\$ 0.150	\$ 0.150	\$ 0.150	\$ 0.150	\$ 0.150				
Street Lights (150 W) - demand	\$ 0.150	\$ 0.150	\$ 0.150	\$ 0.150	\$ 0.150				
Approved wires only rates per rate schedule - variable charge (per kWh)									
Customer Class	Year 1	Year 2	Year 3	Year 4	Year 5				
Residential	0.0125	0.0125	0.0125	0.0125	0.0125				
General Service < 50kW	0.0150	0.0150	0.0150	0.0150	0.0150				
Other class - non-demand	0.0000	0.0000	0.0000	0.0000	0.0000				
Other class - non-demand	0.0000	0.0000	0.0000	0.0000	0.0000				
Approved wires only rates per rate schedule - demand charge (per kW)									
Customer Class	Year 1	Year 1	Year 3	Year 4	Year 5				
General Service > 50kW	2.34	2.34	2.34	2.34	2.34				
General Service > 1000kW	2.88	2.88	2.88	2.88	2.88				
Large User	2.46	2.46	2.46	2.46	2.46				
Street Lights (100 W) - demand	0.7365	0.7365	0.7365	0.7365	0.7365				
Street Lights (150 W) - demand	0.7365	0.7365	0.7365	0.7365	0.7365				
New facilities and/or reinforcement investments									
Capital elements	Year 1	Year 2	Year 3	Year 4	Year 5				
Distribution stations	\$0	\$0							
Distribution lines	\$600,000	\$0							
Distribution transformers	\$185,000	\$0							
Secondary busses	\$35,000	\$50,000	-						
Services (Metering)	\$70,141	\$0	-						
External (paid by developer)	\$0	\$0							
External (paid by MH)	\$0	\$0							
Total	\$890,141	\$50,000	\$0	\$0	\$0				
Assessed value of land		-							
Customer specific capital									
Customer Class	Year 1	Year 2	Year 3	Year 4	Year 5				
Residential	0	0	0	0	0				
General Service < 50kW	0	0	0	0	0				
General Service > 50kW	0	0	0	0	0				
General Service > 1000kW	0	0	0	0	0				
Large User	0	0	0	0	0				
Other class - non-demand	0	0	0	0	0				
Other class - non-demand	0	0	0	0	0				
Other class - demand	0	0	0	0	0				
Other class - demand	0	0	0	0	0				
Total	0	0	0	0	0				
Incremental overheads (capital) at project level applicable to distribution system expansion									
Customer Class	Year 1	Year 2	Year 3	Year 4	Year 5	Years 6-25			
Residential	50,000	60,000	2,000	0	0	0			
General Service < 50kW	0	0	0	0	0	0			
General Service > 50kW	0	0	0	0	0	0			
General Service > 1000kW	0	0	0	0	0	0			
Large User	0	0	0	0	0	0			
Other class - non-demand	0	0	0	0	0	0			
Other class - non-demand	0	0	0	0	0	0			
Other class - demand	0	0	0	0	0	0			
Other class - demand	0	0	0	0	0	0			
Attributable incremental annual operating, maintenance and administration expenditures (per customer addition)									
Customer Class	Year 1	Year 2	Year 3	Year 4	Year 5	Years 6-25			
Residential	138	138	138	138	138	138			
General Service < 50kW	0	0							
General Service > 50kW	0	0							
General Service > 1000kW	0	0							
Large User	0	0							
Other class - non-demand	0	0							
Other class - non-demand	0	0							
Other class - demand	0	0							

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Other class - demand	0	0				
Discount rate data						
Incremental after-tax cost of capital	Year 1	Year 2	Year 3	Year 4	Year 5	Years 6-25
Borrowing rate	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%
Rate of return on common equity	9.00%	9.00%	9.00%	9.00%	9.00%	9.00%
Total debt outstanding (%)	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%
Total common equity (%)	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%
Marginal income tax rate	36.12%	36.12%	36.12%	36.12%	36.12%	36.12%
Incremental after-tax weighted average cost of capital	6.4963%	6.4963%	6.4963%	6.4963%	6.4963%	6.4963%
	Aug-06	Aug-07	Aug-08	Aug-09	Aug-10	

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Tax rate data						
Type of tax	Year 1	Year 2	Year 3	Year 4	Year 5	Years 6-25
Municipal tax rate	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Marginal income tax rate	36.12%	36.12%	36.12%	36.12%	36.12%	36.12%
Federal capital tax rate	0.125%	0.125%	0.125%	0.125%	0.125%	0.125%
Provincial capital tax rate	0.300%	0.300%	0.300%	0.300%	0.300%	0.300%
Capital cost allowance rate	5.000%	8.000%	8.000%	8.000%	8.000%	8.000%
Taxable capital employed in Canada	38,406,768	38,406,768	38,406,768	38,406,768	38,406,768	38,406,768
Capital Deduction (Federal purposes)	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000
Base for Federal capital tax	(11,593,232)	(11,593,232)	(11,593,232)	(11,593,232)	(11,593,232)	(11,593,232)

Discount rate	0.06496	0.06496	0.06496	0.06496	0.06496	0.06496	0.06496	0.06496	0.06496	0.06496	0.06496	0.06496
Present value factor - end of year	0.93900	0.88172	0.82794	0.77743	0.73001	0.68548	0.64366	0.60440	0.56753	0.53291	0.20732	
Present value factor - mid-year	0.96902	0.90991	0.85441	0.80229	0.75335	0.70739	0.66424	0.62372	0.58568	0.54995	0.21395	
	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	YEAR 6	YEAR 7	YEAR 8	YEAR 9	YEAR 10	YEAR 25	
Total	1	2	3	4	5	6	7	8	9	10	25	

OPERATIONS

Customer revenue - fixed charge rate

Residential	1,604,045	7,290	55,831	66,997	66,997	66,997	66,997	66,997	66,997	66,997	66,997	66,997
General Service < 50kW	0	0	0	0	0	0	0	0	0	0	0	0
General Service > 50kW	0	0	0	0	0	0	0	0	0	0	0	0
General Service > 1000kW	0	0	0	0	0	0	0	0	0	0	0	0
Large User	0	0	0	0	0	0	0	0	0	0	0	0
Other class - non-demand	0	0	0	0	0	0	0	0	0	0	0	0
Other class - non-demand	0	0	0	0	0	0	0	0	0	0	0	0
Other class - demand	0	0	0	0	0	0	0	0	0	0	0	0
Street Lights	6,615	135	270	270	270	270	270	270	270	270	270	270
Total fixed charge revenue	1,610,660	7,425	56,101	67,267	67,267	67,267	67,267	67,267	67,267	67,267	67,267	67,267

Customer revenue - variable charge rate

Residential	904,357	1,805	29,013	37,980	37,980	37,980	37,980	37,980	37,980	37,980	37,980	37,980
General Service < 50kW	0	0	0	0	0	0	0	0	0	0	0	0
General Service > 50kW	0	0	0	0	0	0	0	0	0	0	0	0
General Service > 1000kW	0	0	0	0	0	0	0	0	0	0	0	0
Large User	0	0	0	0	0	0	0	0	0	0	0	0
Other class - non-demand	0	0	0	0	0	0	0	0	0	0	0	0
Other class - non-demand	0	0	0	0	0	0	0	0	0	0	0	0
Other class - demand	0	0	0	0	0	0	0	0	0	0	0	0
Street Lights	5,306	108	217	217	217	217	217	217	217	217	217	217
Total variable charge revenue	909,663	1,913	29,229	38,197	38,197	38,197	38,197	38,197	38,197	38,197	38,197	38,197
Customer revenue - total	2,520,323	9,338	85,330	105,463	105,463	105,463	105,463	105,463	105,463	105,463	105,463	105,463

Revenue received for each of the years 6 - 25 are the same as year 5

Incremental OM&A

Residential	1,394,295	6,337	48,530	58,236	58,236	58,236	58,236	58,236	58,236	58,236	58,236	58,236
General Service < 50kW	0	0	0	0	0	0	0	0	0	0	0	0
General Service > 50kW	0	0	0	0	0	0	0	0	0	0	0	0
General Service > 1000kW	0	0	0	0	0	0	0	0	0	0	0	0
Large User	0	0	0	0	0	0	0	0	0	0	0	0
Other class - non-demand	0	0	0	0	0	0	0	0	0	0	0	0
Other class - non-demand	0	0	0	0	0	0	0	0	0	0	0	0
Other class - demand	0	0	0	0	0	0	0	0	0	0	0	0
Other class - demand	0	0	0	0	0	0	0	0	0	0	0	0
Total Incremental OM&A	1,394,295	6,337	48,530	58,236	58,236	58,236	58,236	58,236	58,236	58,236	58,236	58,236

Current year customer additions are divided by two in order to recognize level activities throughout the year.

CAPITAL COSTS

New facilities and/or reinforcement investments

Customer specific capital	940,141	890,141	50,000	0	0	0
Residential	0	0	0	0	0	0
General Service < 50kW	0	0	0	0	0	0
General Service > 50kW	0	0	0	0	0	0
General Service > 1000kW	0	0	0	0	0	0
Large User	0	0	0	0	0	0
Other class - non-demand	0	0	0	0	0	0
Other class - non-demand	0	0	0	0	0	0
Other class - demand	0	0	0	0	0	0
Other class - demand	0	0	0	0	0	0
Total customer specific capital (exclude land)	0	0	0	0	0	0

Incremental Overheads at project level

Residential	112,000	50,000	60,000	2,000	0	0
General Service < 50kW	0	0	0	0	0	0
General Service > 50kW	0	0	0	0	0	0
General Service > 1000kW	0	0	0	0	0	0
Large User	0	0	0	0	0	0
Other class - non-demand	0	0	0	0	0	0
Other class - non-demand	0	0	0	0	0	0
Other class - demand	0	0	0	0	0	0
Other class - demand	0	0	0	0	0	0
Total incremental overheads	112,000	50,000	60,000	2,000	0	0

Land and land rights	0	0	0	0	0	0	0	0	0	0	0	0
Annual Total Capital Costs	1,052,141	940,141	110,000	2,000	0	0	0	0	0	0	0	0
Annual Capital Costs excluding land	1,052,141	940,141	110,000	2,000	0	0	0	0	0	0	0	0
There is assumption made here that there are no up front capital costs in the first year, that Costs in the first year are incurred evenly during the year.												
Present Value Of Annual Capital Costs	1,012,815	911,016	100,090	1,709	0	0	0	0	0	0	0	0

Present Value Of CCA Tax Shield												
Opening undepreciated capital cost		940,141	347,419	425,226	393,128	361,677	332,743	306,124	281,634	259,103	238,375	68,246
Less: Contributed Capital		(583,814)										
Less: Capital cost allowance	405,541	8,908	32,194	34,098	31,450	28,934	26,619	24,490	22,531	20,728	19,070	5,460
Closing undepreciated capital cost		347,419	425,226	393,128	361,677	332,743	306,124	281,634	259,103	238,375	219,305	62,786
CCA Annual Income Tax Savings		3,218	11,628	12,316	11,360	10,451	9,615	8,846	8,138	7,487	6,888	1,972
Present Value of CCA Tax Shield	88,499	3,118	10,581	10,523	9,114	7,873	6,802	5,876	5,076	4,385	3,788	422

Present Value of Operating Cash Flow												
Present Value of Net Operating Cash												
Customer revenue - total	2,520,323	9,338	85,330	105,463	105,463	105,463	105,463	105,463	105,463	105,463	105,463	105,463
Less Total Incremental OM&A	(1,394,295)	(6,337)	(48,530)	(58,236)	(58,236)	(58,236)	(58,236)	(58,236)	(58,236)	(58,236)	(58,236)	(58,236)
Net (Wires) Operating Cash before Income Tax	1,126,029	3,001	36,800	47,227	47,227	47,227	47,227	47,227	47,227	47,227	47,227	47,227
Present value of Net Operating Cash	542,352	2,908	33,484	40,351	37,890	35,579	33,408	31,370	29,457	27,660	25,973	10,104

Present Value of Taxes												
Income Taxes	401,342	708	12,831	16,633	16,667	16,698	16,727	16,753	16,778	16,800	16,821	16,990
Provincial Capital Taxes	14,894	1,042	1,276	1,179	1,085	998	918	845	777	715	658	188
Federal Capital Taxes	0	0	0	0	0	0	0	0	0	0	0	0
Annual Municipal Taxes	0	0	0	0	0	0	0	0	0	0	0	0
Total Taxes	416,236	1,750	14,107	17,812	17,752	17,696	17,645	17,598	17,555	17,515	17,479	17,179
PV of Taxes	201,850	1,696	12,836	15,219	14,242	13,331	12,482	11,689	10,949	10,258	9,612	3,675
PV of Municipal TaxesTaxes	0	0	0	0	0	0	0	0	0	0	0	0

Net Present Value Summary

	With taxes	Without Federal and Provincial taxes
1. PV of Operating Cash Flow		
a) PV of Net Operating Cash Flow	542,352	542,352
b) PV of Taxes	(201,850)	0
PV of Operating Cash Flow	340,502	542,352
2. PV of Capital	(1,012,815)	(1,012,815)
3. PV of CCA Tax Shield	88,499	
NET PRESENT VALUE	(\$583,814)	(\$470,463)

Halton Hills Hydro's Contribution	429,001
Less:	
Amount paid by HH for incremental overheads	-112000
Amount paid by HH for Capital	-70141
Addback: Cash deposit received from developer	97060
Net Halton Hills Hydro Contribution -YR 3	343,919

	Actual Aug-06	Actual Aug-07	Actual Aug-08	FORECAST Aug-09	FORECAST Aug-10	TOTAL MH Contr.	TOTAL CAP	%
	\$101,358.42	\$301,262.09	\$26,380.33	\$0.00	\$0.00	\$429,000.84	\$1,012,814.80	42%
Net Payment to Developer before GST	\$78,276.96	\$241,262.09	\$24,380.33	\$0.00	\$0.00		\$343,919.37	
GST on incremental costs	(\$7,208.49)	(\$3,600.00)	(\$120.00)	\$0.00	\$0.00		(\$10,928.49)	
Net Payment to Developer	\$71,068.47	\$237,662.09	\$24,260.33	\$0.00	\$0.00		\$332,990.88	

Reconciliation Summary:	HHHI	Developer	PV Capital
cash outlays	\$ 182,141	\$ 830,673	
refunds given (received/due)	\$ 343,919	\$ (343,919)	
deposits given (received)	\$ (97,060)	\$ 97,060	
Total share per party	\$ 429,001	\$ 583,814	\$ 1,012,815
	42%	58%	
		variance	\$ -

Table
No.

Project name		Acme Homes Phase 2(Signed Aug 12/05 wor99520)				
Developer name		Acme Homes				
Customer connection horizon (max 5)		5	YELLOW CELLS ONLY ARE FOR DATA INPUT OF ANNUAL CONSTANTS.			
Customer revenue horizon (max 25)		25	BLUE CELLS ARE USED FOR PROJECT SPECIFIC DATA			
Forecasted customer additions (non-cumulative)						
Customer Class	Aug-06	Aug-07	Aug-08	Aug-09	Aug-10	Maximum Units
Residential	162	260	0	0	0	422
General Service < 50kW	0	0	0			
General Service > 50kW	0	0	0			
General Service > 1000kW	0	0	0			
Large User	0	0	0			
Other class - non-demand	0	0	0			
Other class - non-demand	0	0	0			
Other class - demand	0	0	0			
Street Lights	150	0	0			
Estimate of average energy per added customer (monthly kWh)						
Customer Class	Year 1	Year 2	Year 3	Year 4	Year 5	
Residential	262	550	600	650	650	
General Service < 50kW	0	0	0			
Other class - non-demand	0	0	0			
Other class - non-demand	0	0	0			
Estimate of average demand per added customer kW						
Customer Class	Year 1	Year 2	Year 3	Year 4	Year 5	
General Service > 50kW	0	0	0	0	0	
General Service > 1000kW	0	0	0	0	0	
Large User	0	0	0	0	0	
Other class - demand	0	0	0	0	0	
Street Lights	0.1634	0.1634	0.1634	0.1634	0.1634	
Approved wires only rates per rate schedule - monthly fixed charge						
Customer Class	Year 1	Year 2	Year 3	Year 4	Year 5	
Residential	\$ 13.23	\$ 13.23	\$ 13.23	\$ 13.23	\$ 13.23	
General Service < 50kW	\$ 14.16	\$ 14.16	\$ 14.16	\$ 14.16	\$ 14.16	
General Service > 50kW	\$ 67.24	\$ 67.24	\$ 67.24	\$ 67.24	\$ 67.24	
General Service > 1000kW	\$ 875.25	\$ 875.25	\$ 875.25	\$ 875.25	\$ 875.25	
Large User	\$ 3,897.80	\$ 3,897.80	\$ 3,897.80	\$ 3,897.80	\$ 3,897.80	
Other class - non-demand	\$ -	\$ -	\$ -	\$ -	\$ -	
Other class - non-demand	\$ -	\$ -	\$ -	\$ -	\$ -	
Street Lights (100 W) - demand	\$ 0.150	\$ 0.150	\$ 0.150	\$ 0.150	\$ 0.150	
Street Lights (150 W) - demand	\$ 0.150	\$ 0.150	\$ 0.150	\$ 0.150	\$ 0.150	
Approved wires only rates per rate schedule - variable charge (per kWh)						
Customer Class	Year 1	Year 2	Year 3	Year 4	Year 5	
Residential	0.0125	0.0125	0.0125	0.0125	0.0125	
General Service < 50kW	0.0150	0.0150	0.0150	0.0150	0.0150	
Other class - non-demand	\$ -	\$ -	\$ -	\$ -	\$ -	
Other class - non-demand	\$ -	\$ -	\$ -	\$ -	\$ -	
Approved wires only rates per rate schedule - demand charge (per kW)						
Customer Class	Year 1	Year 1	Year 3	Year 4	Year 5	
General Service > 50kW	2.34	2.34	2.34	2.34	2.34	
General Service > 1000kW	2.88	2.88	2.88	2.88	2.88	
Large User	2.46	2.46	2.46	2.46	2.46	
Street Lights (100 W) - demand	0.7365	0.7365	0.7365	0.7365	0.7365	
Street Lights (150 W) - demand	0.7365	0.7365	0.7365	0.7365	0.7365	
New facilities and/or reinforcement investments						
Capital elements	Year 1	Year 2	Year 3	Year 4	Year 5	
Distribution stations	\$0	\$0	\$0			
Distribution lines	\$600,000	\$0	\$0			
Distribution transformers	\$185,000	\$0	\$0			
Secondary busses	\$35,000	\$50,000	\$0	-		
Services (Metering)	\$70,141	\$0	\$0	-		
External (paid by developer)	\$0	\$0	\$0			
External (paid by MH)	\$0	\$0	\$0			
Total	\$890,141	\$50,000	\$0	\$0	\$0	
Assessed value of land		-	\$0			
Customer specific capital						
Customer Class	Year 1	Year 2	Year 3	Year 4	Year 5	
Residential	\$0	\$0	\$0	0	0	
General Service < 50kW	\$0	\$0	\$0	0	0	
General Service > 50kW	\$0	\$0	\$0	0	0	
General Service > 1000kW	\$0	\$0	\$0	0	0	
Large User	\$0	\$0	\$0	0	0	
Other class - non-demand	\$0	\$0	\$0	0	0	
Other class - non-demand	\$0	\$0	\$0	0	0	
Other class - demand	\$0	\$0	\$0	0	0	
Other class - demand	\$0	\$0	\$0	0	0	
Total	0	0	0	0	0	
Incremental overheads (capital) at project level applicable to distribution system expansion						
Customer Class	Year 1	Year 2	Year 3	Year 4	Year 5	Years 6-25
Residential	\$50,000	\$60,000	\$2,000	0	0	0
General Service < 50kW	\$0	\$0	\$0	0	0	0
General Service > 50kW	\$0	\$0	\$0	0	0	0
General Service > 1000kW	\$0	\$0	\$0	0	0	0
Large User	\$0	\$0	\$0	0	0	0
Other class - non-demand	\$0	\$0	\$0	0	0	0
Other class - non-demand	\$0	\$0	\$0	0	0	0
Other class - demand	\$0	\$0	\$0	0	0	0
Other class - demand	\$0	\$0	\$0	0	0	0
Attributable incremental annual operating, maintenance and administration expenditures (per customer addition)						
Customer Class	Year 1	Year 2	Year 3	Year 4	Year 5	Years 6-25
Residential	\$138	\$138	\$138	138	138	138
General Service < 50kW	\$0	\$0	\$0			
General Service > 50kW	\$0	\$0	\$0			
General Service > 1000kW	\$0	\$0	\$0			
Large User	\$0	\$0	\$0			
Other class - non-demand	\$0	\$0	\$0			
Other class - non-demand	\$0	\$0	\$0			
Other class - demand	\$0	\$0	\$0			
Other class - demand	\$0	\$0	\$0			
Discount rate data						
Incremental after-tax cost of capital	Year 1	Year 2	Year 3	Year 4	Year 5	Years 6-25
Borrowing rate	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%
Rate of return on common equity	9.00%	9.00%	9.00%	9.00%	9.00%	9.00%

Total debt outstanding (%)	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%
Total common equity (%)	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%
Marginal income tax rate	36.12%	36.12%	36.12%	36.12%	36.12%	36.12%

Incremental after-tax weighted average cost of capital

	6.4963%	6.4963%	6.4963%	6.4963%	6.4963%	6.4963%
	Aug-06	Aug-07	Aug-08	Aug-09	Aug-10	

Tax rate data

Type of tax	Year 1	Year 2	Year 3	Year 4	Year 5	Years 6-25
Municipal tax rate	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Marginal income tax rate	36.12%	36.12%	36.12%	36.12%	36.12%	36.12%
Federal capital tax rate	0.125%	0.125%	0.125%	0.125%	0.125%	0.125%
Provincial capital tax rate	0.300%	0.300%	0.300%	0.300%	0.300%	0.300%
Capital cost allowance rate	5.000%	8.000%	8.000%	8.000%	8.000%	8.000%
Taxable capital employed in Canada	38,406,768	38,406,768	38,406,768	38,406,768	38,406,768	38,406,768
Capital Deduction (Federal purposes)	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000
Base for Federal capital tax	(11,593,232)	(11,593,232)	(11,593,232)	(11,593,232)	(11,593,232)	(11,593,232)

Discount rate		0.06496	0.06496	0.06496	0.06496	0.06496	0.06496	0.06496	0.06496	0.06496	0.06496	0.06496
Present value factor - end of year		0.93900	0.88172	0.82794	0.77743	0.73001	0.68548	0.64366	0.60440	0.56753	0.53291	0.20732
Present value factor - mid-year		0.96902	0.90991	0.85441	0.80229	0.75335	0.70739	0.66424	0.62372	0.58568	0.54995	0.21395
	Total	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	YEAR 6	YEAR 7	YEAR 8	YEAR 9	YEAR 10	YEAR 25
		1	2	3	4	5	6	7	8	9	10	25

OPERATIONS
Customer revenue - fixed charge rate

Residential	1,604,045	7,290	55,831	66,997	66,997	66,997	66,997	66,997	66,997	66,997	66,997	66,997
General Service < 50kW	0	0	0	0	0	0	0	0	0	0	0	0
General Service > 50kW	0	0	0	0	0	0	0	0	0	0	0	0
General Service > 1000kW	0	0	0	0	0	0	0	0	0	0	0	0
Large User	0	0	0	0	0	0	0	0	0	0	0	0
Other class - non-demand	0	0	0	0	0	0	0	0	0	0	0	0
Other class - non-demand	0	0	0	0	0	0	0	0	0	0	0	0
Other class - demand	0	0	0	0	0	0	0	0	0	0	0	0
Street Lights	6,615	135	270	270	270	270	270	270	270	270	270	270
Total fixed charge revenue	1,610,660	7,425	56,101	67,267	67,267	67,267	67,267	67,267	67,267	67,267	67,267	67,267

Customer revenue - variable charge rate

Residential	952,887	1,805	29,013	37,980	41,145	41,145	40,090	40,090	40,090	40,090	40,090	40,090
General Service < 50kW	0	0	0	0	0	0	0	0	0	0	0	0
General Service > 50kW	0	0	0	0	0	0	0	0	0	0	0	0
General Service > 1000kW	0	0	0	0	0	0	0	0	0	0	0	0
Large User	0	0	0	0	0	0	0	0	0	0	0	0
Other class - non-demand	0	0	0	0	0	0	0	0	0	0	0	0
Other class - non-demand	0	0	0	0	0	0	0	0	0	0	0	0
Other class - demand	0	0	0	0	0	0	0	0	0	0	0	0
Street Lights	5,306	108	217	217	217	217	217	217	217	217	217	217
Total variable charge revenue	958,193	1,913	29,229	38,197	41,362	41,362	40,307	40,307	40,307	40,307	40,307	40,307
Customer revenue - total	2,568,853	9,338	85,330	105,463	108,628	108,628	107,573	107,573	107,573	107,573	107,573	107,573

Revenue received for each of the years 6 - 25 are the same as year 5

Incremental OM&A

Residential	1,394,295	6,337	48,530	58,236	58,236	58,236	58,236	58,236	58,236	58,236	58,236	58,236
General Service < 50kW	0	0	0	0	0	0	0	0	0	0	0	0
General Service > 50kW	0	0	0	0	0	0	0	0	0	0	0	0
General Service > 1000kW	0	0	0	0	0	0	0	0	0	0	0	0
Large User	0	0	0	0	0	0	0	0	0	0	0	0
Other class - non-demand	0	0	0	0	0	0	0	0	0	0	0	0
Other class - non-demand	0	0	0	0	0	0	0	0	0	0	0	0
Other class - demand	0	0	0	0	0	0	0	0	0	0	0	0
Other class - demand	0	0	0	0	0	0	0	0	0	0	0	0
Total Incremental OM&A	1,394,295	6,337	48,530	58,236	58,236	58,236	58,236	58,236	58,236	58,236	58,236	58,236

Current year customer additions are divided by two in order to recognize level activities throughout the year.

CAPITAL COSTS

New facilities and/or reinforcement investments	940,141	890,141	50,000	0	0	0						
Customer specific capital												
Residential	0	0	0	0	0	0						
General Service < 50kW	0	0	0	0	0	0						
General Service > 50kW	0	0	0	0	0	0						
General Service > 1000kW	0	0	0	0	0	0						
Large User	0	0	0	0	0	0						
Other class - non-demand	0	0	0	0	0	0						
Other class - non-demand	0	0	0	0	0	0						
Other class - demand	0	0	0	0	0	0						
Other class - demand	0	0	0	0	0	0						
Total customer specific capital (exclude land)	0	0	0	0	0	0						
Incremental Overheads at project level												
Residential	112,000	50,000	60,000	2,000	0	0						
General Service < 50kW	0	0	0	0	0	0						
General Service > 50kW	0	0	0	0	0	0						
General Service > 1000kW	0	0	0	0	0	0						
Large User	0	0	0	0	0	0						
Other class - non-demand	0	0	0	0	0	0						
Other class - non-demand	0	0	0	0	0	0						
Other class - demand	0	0	0	0	0	0						
Other class - demand	0	0	0	0	0	0						
Total incremental overheads	112,000	50,000	60,000	2,000	0	0						
Land and land rights	0	0	0	0	0	0						
Annual Total Capital Costs	1,052,141	940,141	110,000	2,000	0	0						
Annual Capital Costs excluding land	1,052,141	940,141	110,000	2,000	0	0						
There is assumption made here that there are no up front capital costs in the first year, that Costs in the first year are incurred evenly during the year.												
Present Value Of Annual Capital Costs	1,012,815	911,016	100,090	1,709	0	0						

Present Value Of CCA Tax Shield

Opening undepreciated capital cost	940,141	364,435	440,880	407,530	374,927	344,933	317,339	291,952	268,595	247,108	70,746
Less: Contributed Capital	(566,362)										
Less: Capital cost allowance	420,693	9,344	33,555	35,350	32,602	29,994	27,595	25,387	23,356	21,488	5,660
Closing undepreciated capital cost		364,435	440,880	407,530	374,927	344,933	317,339	291,952	268,595	247,108	65,087
CCA Annual Income Tax Savings		3,375	12,120	12,769	11,776	10,834	9,967	9,170	8,436	7,761	2,044
Present Value of CCA Tax Shield	91,840	3,271	11,028	10,910	9,448	8,162	7,051	6,091	5,262	4,546	437

Present Value of Operating Cash Flow

Present Value of Net Operating Cash

Customer revenue - total	2,568,853	9,338	85,330	105,463	108,628	108,628	107,573	107,573	107,573	107,573	107,573
Less Total Incremental OM&A	(1,394,295)	(6,337)	(48,530)	(58,236)	(58,236)	(58,236)	(58,236)	(58,236)	(58,236)	(58,236)	(58,236)
Net (Wires) Operating Cash before Income Tax	1,174,559	3,001	36,800	47,227	50,392	50,392	49,337	49,337	49,337	49,337	49,337
Present value of Net Operating Cash	564,795	2,908	33,484	40,351	40,429	37,963	34,901	32,772	30,773	28,896	10,556

Present Value of Taxes

Income Taxes	418,669	689	12,814	16,617	17,795	17,828	17,477	17,504	17,530	17,553	17,574
Provincial Capital Taxes	15,453	1,093	1,323	1,223	1,125	1,035	952	876	806	741	682
Federal Capital Taxes	0	0	0	0	0	0	0	0	0	0	0
Annual Municipal Taxes	0	0	0	0	0	0	0	0	0	0	0
Total Taxes	434,122	1,783	14,137	17,839	18,920	18,863	18,429	18,380	18,335	18,294	18,256
PV of Taxes	210,182	1,727	12,863	15,242	15,179	14,210	13,036	12,209	11,436	10,715	10,040
PV of Municipal Taxes	0	0	0	0	0	0	0	0	0	0	0

Net Present Value Summary

	With taxes	Without Federal and Provincial taxes
1. PV of Operating Cash Flow		
a) PV of Net Operating Cash Flow	564,795	564,795
b) PV of Taxes	(210,182)	0
PV of Operating Cash Flow	354,613	564,795
2. PV of Capital	(1,012,815)	(1,012,815)
3. PV of CCA Tax Shield	91,840	
NET PRESENT VALUE	(\$566,362)	(\$448,019)

Halton Hills Hydro's Contribution	446,453
Less:	
Amount paid by HH for incremental overheads	-112,000
Amount paid by HH for Capital	-70,141
Addback: Cash deposit received from developer	97,060
Net Halton Hills Hydro Contribution -YR 4	361,371

Actual	Actual	Actual	Actual	FORECAST			
Aug-06	Aug-07	Aug-08	Aug-09	Aug-10	TOTAL MH Contr.	TOTAL CAP	%
\$101,358.42	\$301,262.09	\$26,380.33	\$17,452.06	\$0.00	\$446,452.90	\$1,012,814.80	44%

Net Payment to Developer before GST	\$78,276.96	\$241,262.09	\$24,380.33	\$17,452.06	\$0.00	\$361,371.43
GST on incremental costs	(\$7,208.49)	(\$3,600.00)	(\$120.00)	\$0.00	\$0.00	(\$10,928.49)
Net Payment to Developer	\$71,068.47	\$237,662.09	\$24,260.33	\$17,452.06	\$0.00	\$350,442.94

Reconciliation Summary:	HHH	Developer	PV Capital
cash outlays	\$ 182,141	\$ 830,673	
refunds given (received/due)	\$ 361,371	\$ (361,371)	
deposits given (received)	\$ (97,060)	\$ 97,060	
Total share per party	\$ 446,453	\$ 566,362	\$ 1,012,815
	44%	56%	
		variance	\$ -

Table
No.

Project name
Developer name

Acme Homes Phase 2(Signed Aug 12/05 wor99520)	
Acme Homes	
5	YELLOW CELLS ONLY ARE FOR DATA INPUT OF ANNUAL CONSTANTS.
25	BLUE CELLS ARE USED FOR PROJECT SPECIFIC DATA

Customer connection horizon (max 5)

Customer revenue horizon (max 25)

1 Forecasted customer additions (non-cumulative)

Customer Class	Aug-06	Aug-07	Aug-08	Aug-09	Aug-10	Maximum Units	Weighted Avg Conn Months		
							year 1	year 2	year 3
Residential	162	260	0	0	0	422	3.401234568	10	12
General Service < 50kW	0	0	0	0	0				
General Service > 50kW	0	0	0	0	0				
General Service > 1000kW	0	0	0	0	0				
Large User	0	0	0	0	0				
Other class - non-demand	0	0	0	0	0				
Other class - non-demand	0	0	0	0	0				
Other class - demand	0	0	0	0	0				
Street Lights	150	0	0	0	0				

2 Estimate of average energy per added customer (monthly kWh)

Customer Class	Year 1	Year 2	Year 3	Year 4	Year 5
Residential	262	550	600	650	675
General Service < 50kW	0	0	0	0	0
General Service > 1000kW	0	0	0	0	0
Other class - non-demand	0	0	0	0	0
Other class - demand	0	0	0	0	0

3 Estimate of average demand per added customer kW

Customer Class	Year 1	Year 2	Year 3	Year 4	Year 5
General Service > 50kW	0	0	0	0	0
General Service > 1000kW	0	0	0	0	0
Large User	0	0	0	0	0
Other class - demand	0	0	0	0	0
Street Lights	0.1634	0.1634	0.1634	0.1634	0.1634

4 Approved wires only rates per rate schedule - monthly fixed charge

Customer Class	Year 1	Year 2	Year 3	Year 4	Year 5
Residential	\$ 13.23	\$ 13.23	\$ 13.23	\$ 13.23	\$ 13.23
General Service < 50kW	\$ 14.16	\$ 14.16	\$ 14.16	\$ 14.16	\$ 14.16
General Service > 50kW	\$ 67.24	\$ 67.24	\$ 67.24	\$ 67.24	\$ 67.24
General Service > 1000kW	\$ 875.25	\$ 875.25	\$ 875.25	\$ 875.25	\$ 875.25
Large User	\$ 3,897.80	\$ 3,897.80	\$ 3,897.80	\$ 3,897.80	\$ 3,897.80
Other class - non-demand	\$ -	\$ -	\$ -	\$ -	\$ -
Other class - non-demand	\$ -	\$ -	\$ -	\$ -	\$ -
Street Lights (100 W) - demand	\$ 0.150	\$ 0.150	\$ 0.150	\$ 0.150	\$ 0.150
Street Lights (150 W) - demand	\$ 0.150	\$ 0.150	\$ 0.150	\$ 0.150	\$ 0.150

5 Approved wires only rates per rate schedule - variable charge (per kWh)

Customer Class	Year 1	Year 2	Year 3	Year 4	Year 5
Residential	\$ 0.0125	\$ 0.0125	\$ 0.0125	\$ 0.0125	\$ 0.0125
General Service < 50kW	\$ 0.0150	\$ 0.0150	\$ 0.0150	\$ 0.0150	\$ 0.0150
Other class - non-demand	\$ -	\$ -	\$ -	\$ -	\$ -
Other class - demand	\$ -	\$ -	\$ -	\$ -	\$ -

6 Approved wires only rates per rate schedule - demand charge (per kW)

Customer Class	Year 1	Year 2	Year 3	Year 4	Year 5
General Service > 50kW	\$ 2.34	\$ 2.34	\$ 2.34	\$ 2.34	\$ 2.34
General Service > 1000kW	\$ 2.88	\$ 2.88	\$ 2.88	\$ 2.88	\$ 2.88
Large User	\$ 2.46	\$ 2.46	\$ 2.46	\$ 2.46	\$ 2.46
Street Lights (100 W) - demand	\$ 0.7365	\$ 0.7365	\$ 0.7365	\$ 0.7365	\$ 0.7365
Street Lights (150 W) - demand	\$ 0.7365	\$ 0.7365	\$ 0.7365	\$ 0.7365	\$ 0.7365

7 New facilities and/or reinforcement investments

Capital elements	Year 1	Year 2	Year 3	Year 4	Year 5
Distribution stations	\$0	\$0	\$0	\$0	\$0
Distribution lines	\$600,000	\$0	\$0	\$0	\$0
Distribution transformers	\$185,000	\$0	\$0	\$0	\$0
Secondary busses	\$35,000	\$50,000	\$0	\$0	-
Services (Metering)	\$70,141	\$0	\$0	\$0	-
External (paid by developer)	\$0	\$0	\$0	\$0	\$0
External (paid by MH)	\$0	\$0	\$0	\$0	\$0
Total	\$890,141	\$50,000	\$0	\$0	\$0
Assessed value of land		-	\$0	\$0	\$0

8 Customer specific capital

Customer Class	Year 1	Year 2	Year 3	Year 4	Year 5
Residential	\$0	\$0	\$0	\$0	0
General Service < 50kW	\$0	\$0	\$0	\$0	0
General Service > 50kW	\$0	\$0	\$0	\$0	0
General Service > 1000kW	\$0	\$0	\$0	\$0	0
Large User	\$0	\$0	\$0	\$0	0
Other class - non-demand	\$0	\$0	\$0	\$0	0
Other class - non-demand	\$0	\$0	\$0	\$0	0
Other class - demand	\$0	\$0	\$0	\$0	0
Other class - demand	\$0	\$0	\$0	\$0	0
Total	0	0	0	0	0

9 Incremental overheads (capital) at project level applicable to distribution system expansion

Customer Class	Year 1	Year 2	Year 3	Year 4	Year 5	Years 6-25
Residential	\$50,000	\$60,000	\$2,000	\$0	0	0
General Service < 50kW	\$0	\$0	\$0	\$0	0	0
General Service > 50kW	\$0	\$0	\$0	\$0	0	0
General Service > 1000kW	\$0	\$0	\$0	\$0	0	0
Large User	\$0	\$0	\$0	\$0	0	0
Developer Design	\$0	\$0	\$0	\$0	0	0
Other class - non-demand	\$0	\$0	\$0	\$0	0	0
Other class - demand	\$0	\$0	\$0	\$0	0	0
Other class - demand	0	0	\$0	\$0	0	0

10 Attributable incremental annual operating, maintenance and administration expenditures (per customer addition)

Customer Class	Year 1	Year 2	Year 3	Year 4	Year 5	Years 6-25
Residential	\$138	\$138	\$138	\$138	138	138
General Service < 50kW	\$0	\$0	\$0	\$0		
General Service > 50kW	\$0	\$0	\$0	\$0		
General Service > 1000kW	\$0	\$0	\$0	\$0		
Large User	\$0	\$0	\$0	\$0		
Other class - non-demand	\$0	\$0	\$0	\$0		
Other class - non-demand	\$0	\$0	\$0	\$0		
Other class - demand	\$0	\$0	\$0	\$0		
Other class - demand	0	0	\$0	\$0		

11 Discount rate data

Incremental after-tax cost of capital	Year 1	Year 2	Year 3	Year 4	Year 5	Years 6-25

Borrowing rate	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%
Rate of return on common equity	9.00%	9.00%	9.00%	9.00%	9.00%	9.00%
Total debt outstanding (%)	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%
Total common equity (%)	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%
Marginal income tax rate	36.12%	36.12%	36.12%	36.12%	36.12%	36.12%

Incremental after-tax weighted average cost of capital

6.4963%	6.4963%	6.4963%	6.4963%	6.4963%	6.4963%
Aug-06	Aug-07	Aug-08	Aug-09	Aug-10	

12

Tax rate data

Type of tax	Year 1	Year 2	Year 3	Year 4	Year 5	Years 6-25
Municipal tax rate	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Marginal income tax rate	36.12%	36.12%	36.12%	36.12%	36.12%	36.12%
Federal capital tax rate	0.125%	0.125%	0.125%	0.125%	0.125%	0.125%
Provincial capital tax rate	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%
Capital cost allowance rate	5.00%	8.00%	8.00%	8.00%	8.00%	8.00%
Taxable capital employed in Canada	38,406,768	38,406,768	38,406,768	38,406,768	38,406,768	38,406,768
Capital Deduction (Federal purposes)	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000
Base for Federal capital tax	(11,593,232)	(11,593,232)	(11,593,232)	(11,593,232)	(11,593,232)	(11,593,232)

Discount rate	0.06496	0.06496	0.06496	0.06496	0.06496	0.06496	0.06496	0.06496	0.06496	0.06496	0.06496	0.06496
Present value factor - end of year	0.93900	0.88172	0.82794	0.77743	0.73001	0.68548	0.64366	0.60440	0.56753	0.53291	0.20732	
Present value factor - mid-year	0.96902	0.90991	0.85441	0.80229	0.75335	0.70739	0.66424	0.62372	0.58568	0.54995	0.21395	
Total	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	YEAR 6	YEAR 7	YEAR 8	YEAR 9	YEAR 10	YEAR 25	

OPERATIONS

Customer revenue - fixed charge rate

Residential	1,604,045	7,290	55,831	66,997	66,997	66,997	66,997	66,997	66,997	66,997	66,997	66,997
General Service < 50kW	0	0	0	0	0	0	0	0	0	0	0	0
General Service > 50kW	0	0	0	0	0	0	0	0	0	0	0	0
General Service > 1000kW	0	0	0	0	0	0	0	0	0	0	0	0
Large User	0	0	0	0	0	0	0	0	0	0	0	0
Other class - non-demand	0	0	0	0	0	0	0	0	0	0	0	0
Other class - non-demand	0	0	0	0	0	0	0	0	0	0	0	0
Other class - demand	0	0	0	0	0	0	0	0	0	0	0	0
Street Lights	6,615	135	270	270	270	270	270	270	270	270	270	270
Total fixed charge revenue	1,610,660	7,425	56,101	67,267	67,267	67,267	67,267	67,267	67,267	67,267	67,267	67,267

Customer revenue - variable charge rate

Residential	965,020	1,805	29,013	37,980	41,145	42,728	40,618	40,618	40,618	40,618	40,618	40,618
General Service < 50kW	0	0	0	0	0	0	0	0	0	0	0	0
General Service > 50kW	0	0	0	0	0	0	0	0	0	0	0	0
General Service > 1000kW	0	0	0	0	0	0	0	0	0	0	0	0
Large User	0	0	0	0	0	0	0	0	0	0	0	0
Other class - non-demand	0	0	0	0	0	0	0	0	0	0	0	0
Other class - non-demand	0	0	0	0	0	0	0	0	0	0	0	0
Other class - demand	0	0	0	0	0	0	0	0	0	0	0	0
Street Lights	5,306	108	217	217	217	217	217	217	217	217	217	217
Total variable charge revenue	970,326	1,913	29,229	38,197	41,362	42,944	40,834	40,834	40,834	40,834	40,834	40,834
Customer revenue - total	2,580,986	9,338	85,330	105,463	108,628	110,211	108,101	108,101	108,101	108,101	108,101	108,101

Revenue received for each of the years 6 - 25 are the same as year 5

Incremental OM&A

Residential	1,394,295	6,337	48,530	58,236	58,236	58,236	58,236	58,236	58,236	58,236	58,236	58,236
General Service < 50kW	0	0	0	0	0	0	0	0	0	0	0	0
General Service > 50kW	0	0	0	0	0	0	0	0	0	0	0	0
General Service > 1000kW	0	0	0	0	0	0	0	0	0	0	0	0
Large User	0	0	0	0	0	0	0	0	0	0	0	0
Other class - non-demand	0	0	0	0	0	0	0	0	0	0	0	0
Other class - non-demand	0	0	0	0	0	0	0	0	0	0	0	0
Other class - demand	0	0	0	0	0	0	0	0	0	0	0	0
Other class - demand	0	0	0	0	0	0	0	0	0	0	0	0
Total Incremental OM&A	1,394,295	6,337	48,530	58,236	58,236	58,236	58,236	58,236	58,236	58,236	58,236	58,236

Current year customer additions are divided by two in order to recognize level activities throughout the year.

CAPITAL COSTS

New facilities and/or reinforcement investments

Customer specific capital

Residential	0	0	0	0	0	0
General Service < 50kW	0	0	0	0	0	0
General Service > 50kW	0	0	0	0	0	0
General Service > 1000kW	0	0	0	0	0	0
Large User	0	0	0	0	0	0
Other class - non-demand	0	0	0	0	0	0
Other class - non-demand	0	0	0	0	0	0
Other class - demand	0	0	0	0	0	0
Other class - demand	0	0	0	0	0	0
Total customer specific capital (exclude land)	0	0	0	0	0	0

Incremental Overheads at project level

Residential	112,000	50,000	60,000	2,000	0	0
General Service < 50kW	0	0	0	0	0	0
General Service > 50kW	0	0	0	0	0	0
General Service > 1000kW	0	0	0	0	0	0
Large User	0	0	0	0	0	0
Other class - non-demand	0	0	0	0	0	0
Other class - non-demand	0	0	0	0	0	0
Other class - demand	0	0	0	0	0	0
Other class - demand	0	0	0	0	0	0
Total incremental overheads	112,000	50,000	60,000	2,000	0	0

Land and land rights

0	0	0	0	0	0	0
Annual Total Capital Costs	1,052,141	940,141	110,000	2,000	0	0
Annual Capital Costs excluding land	1,052,141	940,141	110,000	2,000	0	0

There is assumption made here that there are no up front capital costs in the first year, that Costs in the first year are incurred evenly during the year.

Present Value Of Annual Capital Costs	1,012,815	911,016	100,090	1,709	0	0

Present Value Of CCA Tax Shield												
Opening undepreciated capital cost		940,141	368,660	444,767	411,106	378,217	347,960	320,123	294,513	270,952	249,276	71,367
Less: Contributed Capital		(562,029)										
Less: Capital cost allowance	424,455	9,453	33,893	35,661	32,888	30,257	27,837	25,610	23,561	21,676	19,942	5,709
Closing undepreciated capital cost		368,660	444,767	411,106	378,217	347,960	320,123	294,513	270,952	249,276	229,334	65,658
CCA Annual Income Tax Savings		3,414	12,242	12,881	11,879	10,929	10,055	9,250	8,510	7,829	7,203	2,062
Present Value of CCA Tax Shield	92,669	3,309	11,139	11,006	9,531	8,233	7,113	6,144	5,308	4,586	3,961	441

Present Value of Operating Cash Flow

Present Value of Net Operating Cash

Customer revenue - total	2,580,986	9,338	85,330	105,463	108,628	110,211	108,101	108,101	108,101	108,101	108,101	108,101
Less Total Incremental OM&A	(1,394,295)	(6,337)	(48,530)	(58,236)	(58,236)	(58,236)	(58,236)	(58,236)	(58,236)	(58,236)	(58,236)	(58,236)
Net (Wires) Operating Cash before Income Tax	1,186,691	3,001	36,800	47,227	50,392	51,975	49,865	49,865	49,865	49,865	49,865	49,865
Present value of Net Operating Cash	570,368	2,908	33,484	40,351	40,429	39,155	35,274	33,122	31,102	29,205	27,423	10,669

Present Value of Taxes

Income Taxes	423,001	685	12,810	16,613	17,792	18,396	17,664	17,692	17,718	17,741	17,763	17,940
Provincial Capital Taxes	15,592	1,106	1,334	1,233	1,135	1,044	960	884	813	748	688	197
Federal Capital Taxes	0	0	0	0	0	0	0	0	0	0	0	0
Annual Municipal Taxes	0	0	0	0	0	0	0	0	0	0	0	0
Total Taxes	438,593	1,791	14,144	17,846	18,927	19,440	18,625	18,576	18,530	18,489	18,451	18,137
PV of Taxes	212,251	1,735	12,870	15,248	15,185	14,645	13,175	12,339	11,558	10,829	10,147	3,880
PV of Municipal TaxesTaxes	0	0	0	0	0	0	0	0	0	0	0	0

Net Present Value Summary

	With taxes	Without Federal and Provincial taxes
1. PV of Operating Cash Flow		
a) PV of Net Operating Cash Flow	570,368	570,368
b) PV of Taxes	(212,251)	0
PV of Operating Cash Flow	358,116	570,368
2. PV of Capital	(1,012,815)	(1,012,815)
3. PV of CCA Tax Shield	92,669	
NET PRESENT VALUE	(\$562,029)	(\$442,447)

Halton Hills Hydro's Contribution	450,786
Less:	
Amount paid by HH for incremental overheads	-112000
Amount paid by HH for Capital	-70141
Addback: Cash deposit received from developer	97060
Net Halton Hills Hydro Contribution -YR 5	365,704

	Actual Aug-06	Actual Aug-07	Actual Aug-08	Actual Aug-09	Actual Aug-10	TOTAL MH Contr.	TOTAL CAP	%
	\$101,358.42	\$301,262.09	\$26,380.33	\$17,452.06	\$4,332.90	\$450,785.80	\$1,012,814.80	45%

Net Payment to Developer before GST	\$78,276.96	\$241,262.09	\$24,380.33	\$17,452.06	\$4,332.90	\$365,704.33
GST on incremental costs	(\$7,208.49)	(\$3,600.00)	(\$120.00)	\$0.00	\$0.00	(\$10,928.49)
Net Payment to Developer	\$71,068.47	\$237,662.09	\$24,260.33	\$17,452.06	\$4,332.90	\$354,775.85

Reconciliation Summary:	HHHI	Developer	PV Capital
cash outlays	\$ 182,141	\$ 830,673	
refunds given (received/due)	\$ 365,704	\$ (365,704)	
deposits given (received)	\$ (97,060)	\$ 97,060	
Total share per party	\$ 450,786	\$ 562,029	\$ 1,012,815
	45%	55%	
		variance	\$ -

OEB STAFF INTERROGATORIES

APPENDIX C

GTA West Supply Study



GTA West Supply Study

Adequacy of Transmission Facilities

And

Transmission Supply Plan 2005 – 2015

February 16, 2006

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Foreword

This report is the result of a joint study by Enersource Hydro Mississauga, Halton Hills Hydro Inc., Hydro One Brampton, Hydro One Networks Inc. Distribution, Milton Hydro and Hydro One Networks Inc. Transmission. The study team members were:

Paul Cook, Hydro One Networks
Gary Ebersberger, Halton Hills Hydro Inc.
Dave Haddock, Hydro One Brampton
Charlie Lee, Hydro One Networks Distribution

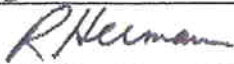
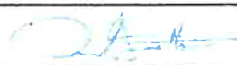
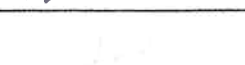
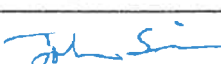
Richard Murray, Milton Hydro Distribution Inc.
Eva Ping, Hydro One Networks
Vaffi Poonja, Enersource Hydro Mississauga
Christine Spears, Hydro One Networks

The load forecast is based on information available to Enersource Hydro Mississauga, Hydro One Brampton, Toronto Hydro Electric System, Halton Hills Hydro, Milton Hydro and Hydro One-Distribution.

The preferred plans have been selected and endorsed based primarily on technical considerations. Where applicable, these plans will be subject to Environmental Assessment approval and / or Ontario Energy Board (OEB) approval. The issue of cost allocation between utilities was not addressed.

Signatures

We have reviewed this report and concur with its recommendations. This endorsement shall not operate as a waiver of any participant's rights due to material changes in load forecasts or economic considerations.

Utility	Signature	Title
Enersource Hydro Mississauga		Roland Herman Executive VP & Chief Operating Officer
Halton Hills Hydro Inc.		Dan Guatto President
Hydro One Brampton		Roger Albert President
Hydro One Networks Inc. - Distribution		Ron Salt Manager, Distribution Development
Hydro One Networks Inc. - Transmission		John Sabiston Team Leader/ Senior Advisor
Milton Hydro Distribution Inc.		Don Thorne President & CEO

Date: February 16, 2006

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Date: February 16, 2006

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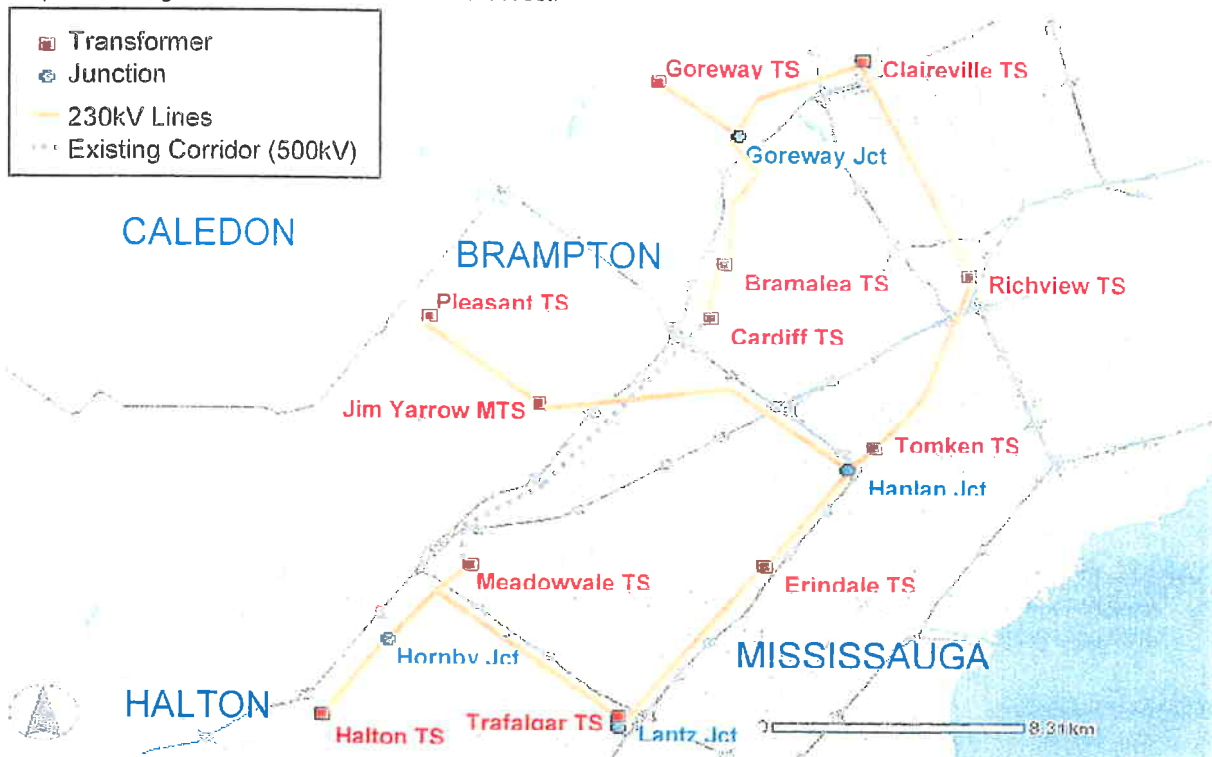
EXECUTIVE SUMMARY

Background

For the purpose of this study, Greater Toronto Area (GTA) West includes the area roughly bordered geographically by Highway 27 to the east, King Street to the north, Regional Road 25 to the west and Highway 403/407 to the south. Much of the study area is Peel Region, with a small section of both Halton Region and Toronto.

The electrical supply in this area is provided through 500 kV and 230 kV transmission lines and step down transformation facilities as shown in Map 1. The distribution system within this area is at two different voltage levels, 44 kV and 27.6 kV. Load forecasts provided by the Local Distribution Companies (LDCs) in GTA West indicate that electrical load growth is expected to continue at a summer average rate of 2.6% per year at the 27.6 kV sub-transmission level and 1.5% per year at the 44 kV sub-transmission level, for the next ten years.

Map 1: Existing Transmission Facilities in GTA West.



In June of 2004, a joint utility planning study was initiated between five of the six LDCs in GTA West and Hydro One Networks Inc. - Transmission. The LDC participants in this joint study were:

- ◆ Enersource Hydro Mississauga (EHM)
- ◆ Halton Hills Hydro Inc. (HHH)
- ◆ Hydro One Brampton (HOB)
- ◆ Hydro One Networks Inc. - Distribution (HONI - Dx)
- ◆ Milton Hydro Distribution Inc. (MHD)

This study identified the need for transmission capacity and voltage stability in GTA West, and assessed the capability of the transmission system to meet the load requirements for the 10 year study period (from 2005 to 2015). An additional assessment for expected 2024 conditions was also undertaken to evaluate the proposed plans with respect to the long-term system requirements and identify potential gaps. Several transmission alternatives were investigated to address the needs and deficiencies as soon as practical.

Need

The needs assessed in this study were evaluated and identified based on the occurrence of a single contingency.

Station Overloads (230/27.6 kV)

- ◆ Transformers T1/T2 at Bramalea Transmission Station (TS) are currently exceeding their summer capacity limit¹ (2005)
- ◆ Transformers T1/T2 at Erindale TS are currently exceeding their summer capacity limit (2005)
- ◆ Transformers T5/T6 at Pleasant TS are currently loaded to their summer capacity limit (2005)
- ◆ Transformers T1/T2 at Jim Yarrow Municipal Transmission Station (MTS) are expected to exceed their summer capacity limit by summer 2009²
- ◆ Transformers T5/T6 at Goreway TS are expected to reach their summer capacity limit by summer 2011³
- ◆ Transformers T3/T4 at Halton TS are expected to reach their summer capacity limit by summer 2011

Station Overloads (230/44 kV)

- ◆ Transformers T1/T2 at Meadowvale TS are currently exceeding their summer capacity limits (2005)
- ◆ Transformers T3/T4 and T5/T6 at Erindale TS are expected to exceed their summer capacity limit by summer 2006⁴
- ◆ Transformers T1/T2 at Pleasant TS are expected to exceed their summer capacity limits by summer 2011

Voltage Deficiencies

- ◆ Meadowvale TS is currently experiencing voltage deficiencies during periods of high summer loading and is below Operating and Planning Standards⁵

Circuit Overloads

- ◆ Segments of circuits R19T/R21T are expected to reach thermal capacity limits as per Operating and Planning Standards by summer 2009
- ◆ Segments of circuits T38B/T39B are expected to be nearing thermal capacity limits as per Operating and Planning Standards by summer 2015

¹ "summer capacity limit" is discussed in Section 2.

² Jim Yarrow MTS forecast includes load transfers from Bramalea TS (transformers T1/T2) and Pleasant TS (transformers T5/T6).

³ Goreway TS (transformers T5/T6) forecast includes load transfers from Bramalea TS (transformers T1/T2).

⁴ Erindale TS (T3/T4, 230/44 kV) will experience unacceptable voltage decline before transformers reach capacity, while transformers T5/T6 will be at the transformer capacity limit.

⁵ Please refer to Section 5 for details on Operating and Planning Standards.

Forced Load Transfers

Due to the rapid load growth in this area, and the lack of local transmission resources, several stations have been and/or will be forced to designate cascading load transfers to other stations in order to mitigate operating risks until further capacity can be supplied.

This study was conducted under the assumption that by 2005 additional station capacity would be provided by a new TS (Cardiff TS coming into service in May 2005). Some immediate load relief is possible via load transfers between stations operating at the same sub-transmission voltage levels, however the load growth in this area is such that new step down facilities will be required before 2007. Load transfers between different sub-transmission voltage levels are either not technically possible or economically prohibitive.

Recommended Transmission Reinforcements

A number of options were considered to address the needs as indicated above, and after a thorough technical analysis and review, the following recommendations were made:

- ◆ Install by summer 2007 Low Voltage (LV) capacitors at Meadowvale TS (2 capacitor banks, 32.4 MVAR at 46 kV)
- ◆ For short-term relief and as they become necessary, perform load transfers:
 - From Bramalea TS (T1/T2, 230/27.6 kV) to Goreway TS (T5/T6, 230/27.6 kV) and Jim Yarrow MTS (T1/T2, 230/27.6 kV)
 - From Pleasant TS (T5/T6, 230/27.6 kV) to Jim Yarrow MTS (T1/T2, 230/27.6 kV)
 - From Erindale TS (T1/T2, 230/27.6 kV) to Cardiff TS (T1/T2, 230/27.6 kV)
 - From Meadowvale TS (T1/T2, 230/44 kV) to Erindale TS (T3/T4, 230/44 kV)
- ◆ Construct by summer 2008 Winston TS with two 230/44 kV, 75/125 MVA transformers in the vicinity of Winston Churchill Blvd. and Highway 403
- ◆ Extend by summer 2009 circuits V72R and V73R from Cardiff TS to the Pleasant TS tap and construct Hurontario Switching Station (SS). Radially re-supply Jim Yarrow MTS from this SS
- ◆ Construct by summer 2009 Pleasant TS #3 with two 230/27.6 kV, 75/125 MVA transformers on the existing Pleasant TS site
- ◆ Construct by summer 2011 Goreway TS #2 with two 230/27.6 kV, 75/125 MVA transformers on the existing Goreway TS site
- ◆ Install by summer 2011 a second 230/44 kV, 50/83 MVA transformer at Goreway TS
- ◆ Construct by summer 2011 either Steeles TS or James Snow TS with two 230/27.6 kV, 50/83 MVA transformers. The Steeles TS location would be in the vicinity of Steeles Avenue and Trafalgar Road while the James Snow TS location would be in the vicinity of Steeles Avenue and James Snow Parkway

Recommendations

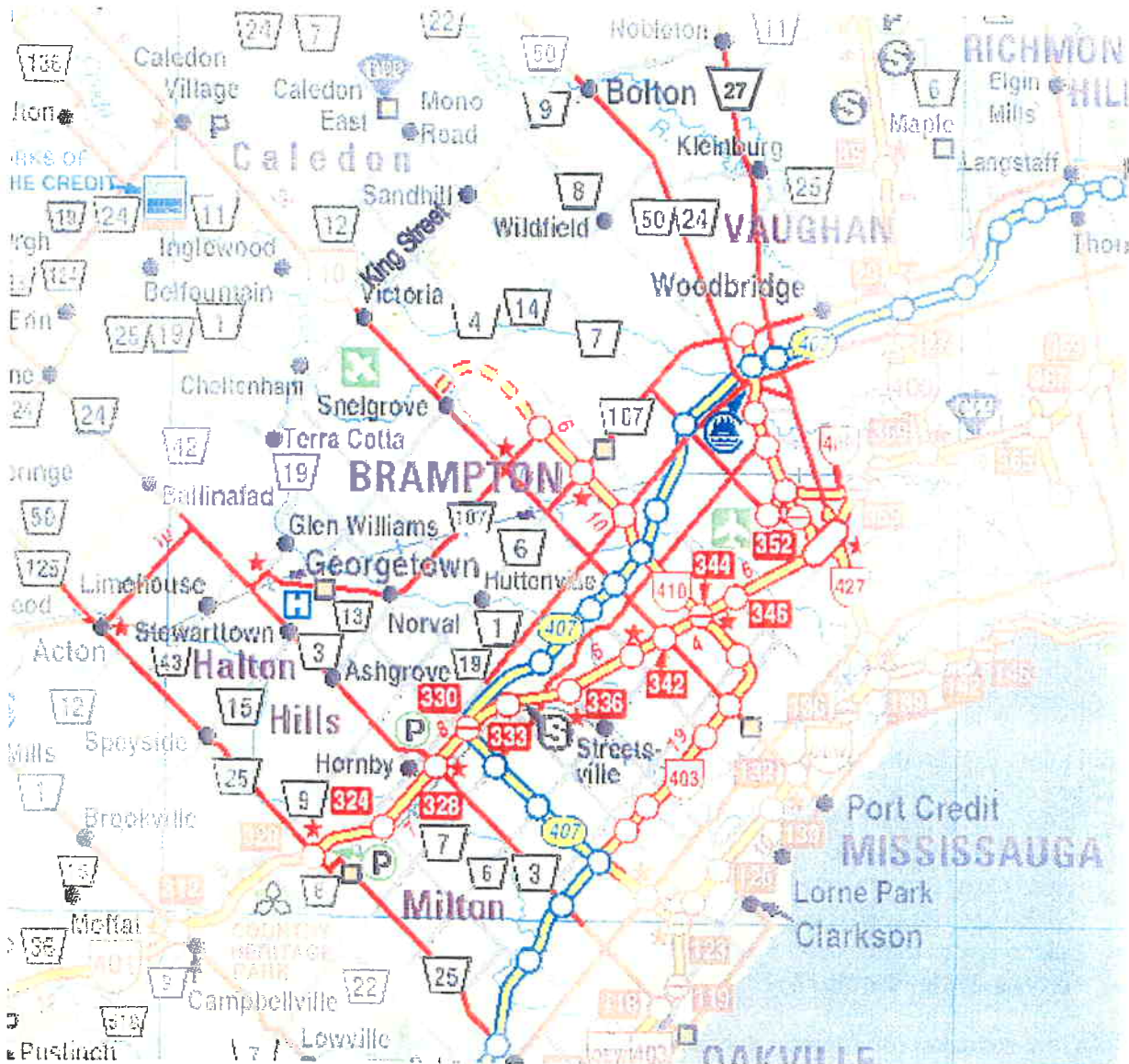
Several recommendations can be drawn from this study to address the current system deficiencies and provide system capacity to meet forecasted load growth. These recommendations are:

1. Subject to the Ontario Power Authority's integrative review (Integrated Power System Plan) Hydro One Networks Inc. to initiate the approval processes required for the extension of circuits V72R and V73R and the construction of Hurontario SS.
2. Hydro One Networks Inc. to commence the detailed specification and engineering of the LV capacitors at Meadowvale TS.
3. Hydro One Networks Inc. to commence the preliminary engineering and consultation with the LDCs, and to initiate the approval processes on the construction of a new TS , Winston TS, in the vicinity of Winston Churchill Blvd. and Highway 403 in Mississauga.
4. The LDCs to continue to transfer loads as necessary to mitigate potential operating risks until transmission capacity is established.
5. The LDCs to continue to monitor load growth in the GTA West area and to review options for long-term growth based on the location of new developments and load forecasts.

1. INTRODUCTION

For the purpose of this study, Greater Toronto Area (GTA) West includes the area roughly bordered by Highway 27 to the east, King Street to the north, Regional Road 25 to the west and Highways 403/407 to the south (refer to Map 2). Much of the study area is Peel Region, with a small section of both Halton Region and Toronto.

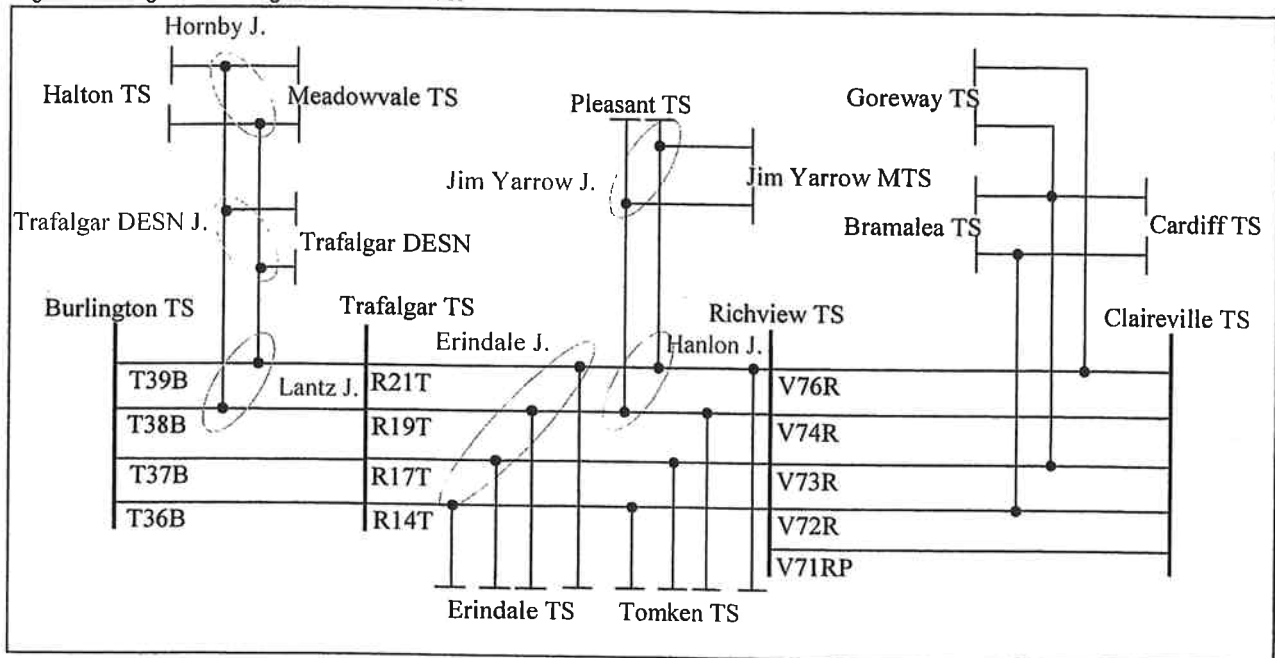
Map 2: Study Geographical Area⁶



Electrical supply in this area is provided through 500 kV and 230 kV transmission lines and step down transformation facilities (Transmission Station, TS; Municipal Transmission Station, MTS) as shown in Map 1 and Figure 1.

⁶ Map clip from <http://www.mto.gov.on.ca/english/traveller/map/images/pdf/southont/sheets/Map3.pdf>

Figure 1: Single Line Diagram of GTA West



The northern Mississauga and Brampton area is expected to have a large rate of load growth for the upcoming years as a result of population growth and development projects taking place in this area. Load growth trends in this area indicate that recent transmission upgrades and newly built or planned stations, including the construction of Jim Yarrow MTS and Cardiff TS, will not be able to provide the required transformation capacity. For this reason, in June 2004, five of the six Local Distribution Companies (LDCs) in GTA West and Hydro One initiated a joint study.

The purpose of this joint study was to assess the load growth in GTA West and ensure that adequate transmission and connection facilities will be available to meet the electrical demand requirements over the upcoming decade, 2005 to 2015.

Six Local Distribution Companies (LDCs) own and operate assets in the specified study area. These companies are:

- ◆ Enersource Hydro Mississauga (EHM)
- ◆ Halton Hills Hydro Inc. (HHH)
- ◆ Hydro One Brampton (HOB)
- ◆ Hydro One Networks Inc. – Distribution (HONI – Dx)
- ◆ Milton Hydro Distribution Inc. (MHD)
- ◆ Toronto Hydro Electric System (THES)

With the exclusion of Toronto Hydro Electric System⁷, the above listed LDCs participated in this joint study.

⁷ Toronto Hydro Electric System did not participate in this study beyond providing load forecasts, as their asset locations and circumstances are such that they are able to resolve capacity issues via load transfers between various transmission facilities within their jurisdiction.

2. EXISTING TRANSMISSION SYSTEM AND NEEDS

GTA West is supported by two main 500/230 kV TSs (Claireville TS and Trafalgar TS) transforming electricity from 500 kV to 230 kV, and one 230 kV electrical system hub (Richview TS).

There are ten step-down transmission facilities that were analyzed in this study. These stations step the transmission voltage of 230 kV down to a sub-transmission level, either 27.6 kV or 44 kV, for distribution of electricity to the end-use customer. Table 1 lists the stations and their associated step-down transformer voltage capability. Four of the ten existing TSs (Bramalea TS, Erindale TS, Goreway TS and Pleasant TS) in the study area have the ability to step-down to both sub-transmission voltages. The remaining stations are only able to step-down to one sub-transmission voltage.

Table 1: Transmission Step-down Facilities Within GTA West

Station	230 / 27.6 kV	230 / 44 kV
Bramalea TS	Transformers T1/T2	Transformers T3/T4 and T5/T6
Cardiff TS	Transformers T1/T2	
Erindale TS	Transformers T1/T2	Transformers T3/T4 and T5/T6
Goreway TS	Transformers T5/T6	Transformer T4
Halton TS	Transformers T1/T2	
Jim Yarrow MTS	Transformers T1/T2	
Meadowvale TS		Transformers T1/T2
Pleasant TS	Transformers T5/T6	Transformers T1/T2
Richview TS	Transformers T1/T2, T5/T6 and T7/T8	
Tomken TS		Transformers T1/T2 and T3/T4

The above mentioned TSs are connected as follows (refer to Figure 1 and Map 1):

1. Trafalgar TS and Richview TS are connected via four 230 kV circuits (R14T, R17T, R19T and R21T). Erindale TS and Tomken TS are tapped off of these circuits. Two radial extensions from R19T and R21T at Hanlon Junction supply Pleasant TS and Jim Yarrow MTS.
2. Richview TS and Claireville TS are connected via five 230 kV circuits (V71RP, V72R, V73R, V74R, V76R). Goreway TS, Bramalea TS and Cardiff TS are tapped off of these circuits.
3. Meadowvale TS and Halton TS are supplied via two radial extensions from two 230 kV circuits (T38B and T39B) connecting Trafalgar TS and Burlington TS.

The study area was identified as summer critical⁸. Load forecasts provided by the LDCs indicate that electrical load growth is expected to continue at a summer average rate of 2.6% per year at the 27.6 kV sub-transmission level and 1.5 % per year at the 44 kV sub-transmission level, for the next ten years.

⁸ Summer critical means less available margin between loading and applicable equipment ratings during this particular season.

Some stations in the study area are already peaking above their summer capacity limit (Limited Time Rating, LTR)⁹, as well as experiencing voltage deficiencies related to high loading. The particular needs of this system were identified using a single contingency analysis. Those needs and the associated need dates are detailed below. Refer to Table 2 for a summary.

Station Overloads (230/27.6 kV)

- ◆ Transformers T1/T2 at Bramalea TS are currently exceeding their summer 10-day LTR (2005)
- ◆ Transformers T1/T2 at Erindale TS are currently exceeding their summer 10-day LTR (2005)
- ◆ Transformers T5/T6 at Pleasant TS are currently loaded to their summer 10-day LTR (2005)
- ◆ Transformers T1/T2 at Jim Yarrow MTS are expected to exceed their station summer 10-day LTR by summer 2009¹⁰
- ◆ Transformers T5/T6 at Goreway TS are expected to reach their summer 10-day LTR by summer 2011¹¹
- ◆ Transformers T3/T4 at Halton TS are expected to reach their summer 10-day LTR by summer 2011

Station Overloads (230/44 kV)

- ◆ Transformers T1/T2 at Meadowvale TS are currently exceeding their summer 10-day LTR (2005)
- ◆ Transformers T3/T4 and T5/T6 at Erindale TS are expected to exceed their summer 10-day LTR by summer 2006
- ◆ Transformers T1/T2 at Pleasant TS are expected to exceed their summer 10-day LTR by summer 2011

Voltage Deficiencies

- ◆ Meadowvale TS is currently experiencing voltage deficiencies during periods of high summer loading and is below Operating and Planning Standards (refer to Section 5 for definition of Operating and Planning Standards)

Circuit Overloads¹²

- ◆ Segments of circuits R19T/R21T are expected to reach summer thermal capacity limits as per Operating and Planning Standards (refer to section 5) by 2009
- ◆ Segments of circuits T38B/T39B are expected to be nearing summer thermal capacity limits as per Operating and Planning Standards by 2015

⁹ For planning purposes, the LTRs, or thermal capacity limits, referred to in this study are emergency ratings for electrical equipment to acknowledge that equipment ratings can be exceeded for a certain length of time without causing undue stress on the equipment. For transformers, this is a 10-day LTR and for circuits or lines this is a 15-minute LTR immediate post fault, and continuous rating for steady state post fault.

¹⁰ Jim Yarrow MTS load growth forecast includes load transfers from Bramalea TS (T1/T2, 230/27.6 kV) and Pleasant TS (T5/T6, 230/27.6 kV).

¹¹ Goreway TS (T5/T6) load growth forecast includes load transfers from Bramalea TS (T1/T2).

¹² These circuit overloads were observed in a basecase loadflow with a Flow East Towards Toronto (FETT) transfer of approximately 3600 MW.

Table 2: Summary of Transmission Needs and Need Dates

Year	27.6 kV Stations	44 kV Stations	Circuits
2005 (Present)	Bramalea TS (T1/T2) Erindale TS (T1/T2) Pleasant TS (T5/T6)	Meadowvale TS (T1/T2)	
2006		Erindale TS (T3/T4 and T5/T6)	
2009	Jim Yarrow MTS (T1/T2)		R19T/R21T
2011	Goreway TS (T5/T6) Halton TS (T3/T4)	Pleasant TS (T1/T2)	

3. LOAD GROWTH

Load forecasts provided by LDCs in GTA West indicate that electrical load growth is expected to continue at a summer average rate of 2.6% per year for the next ten years at the 27.6 kV level and at 1.5% per year at the 44 kV level (refer to Table 3). More detailed load forecasts, including station capacity data, can be found in Appendix A.

Table 3: Forecast – Summer Peak Load (MW)

	Forecast Load in MW											
230/27.6 kV Stations	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	
1. Bramalea TS ^{1,2,3}	193	174	175	177	179	181	183	183	184	184	184	
2. Cardiff TS ¹	0	101	103	105	107	110	112	112	112	113	113	
3. Erindale TS ^{1,4}	233	167	170	174	177	181	185	185	186	187	187	
4. Goreway TS ³	148	155	163	170	177	184	192	200	208	216	224	
5. Halton TS	97	114	131	149	162	166	170	175	179	183	188	
6. Jim Yarrow MTS ²	95	100	113	125	138	152	166	180	196	211	225	
7. Pleasant TS ²	198	198	198	198	198	198	198	198	198	198	198	
8. Richview TS	354	362	364	368	371	374	377	380	385	388	392	
Total:	1318	1371	1418	1466	1509	1546	1582	1614	1647	1680	1710	Avg.
Growth Rate:		4.0%	3.4%	3.4%	3.0%	2.4%	2.4%	2.0%	2.1%	2.0%	1.8%	2.6%
230/44 kV Stations	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	
1. Bramalea TS ^{1,2,3}	179	184	188	192	196	201	205	210	215	220	224	
2. Goreway TS ³	28	29	30	31	32	34	35	36	37	39	40	
3. Erindale TS ^{1,4}	360	374	384	394	405	415	425	427	429	431	433	
4. Meadowvale TS ⁴	181	181	181	181	181	181	181	181	181	181	181	
5. Pleasant TS ²	131	136	140	144	148	152	156	161	164	170	174	
6. Tomken TS	312	314	316	317	319	321	322	323	324	325	326	
Total:	1191	1217	1239	1260	1281	1303	1324	1337	1350	1364	1377	Avg.
Growth Rate:		2.3%	1.8%	1.7%	1.7%	1.7%	1.7%	1.0%	0.9%	1.1%	0.9%	1.5%
1 Net load; includes load transfers from Bramalea TS and Erindale TS to Cardiff TS.												
2 Net load; includes load transfers from Pleasant TS and Bramalea TS.												
3 Net load; Includes load transfers from Bramalea TS.												
4 Net load; Includes load transfers from Meadowvale TS to Erindale TS												

The major load centres during the ten-year study period exist in the north and westerly parts of the city of Mississauga at the 44 kV sub-transmission level. As well, major load centres exist in the west and northeasterly parts of Brampton at both 44 and 27.6 kV sub-transmission levels. The study area is considered summer critical.

4. SYSTEM ASSUMPTIONS

Certain assumptions were made in order to assess the effects of different contingencies to verify the system capacity. The assumptions used in the study were:

1. If a coincident peak load forecast was not provided by the LDC, the coincident peaks were calculated using the factors in Table 4.

Table 4: Coincidence Factors

LDC	Coincidence Factor
Enersource Hydro Mississauga	Coincident peak forecast provided
Halton Hills Hydro Inc.	Coincident peak forecast provided
Hydro One Brampton	Coincident peak forecast provided
HONI Dx	Coincident peak forecast provided
Milton Hydro Distribution Inc.	0.95
Toronto Hydro Electric System	0.95

2. Power factors were provided by each LDC and used in this study as listed in Table 5.

Table 5: Power Factors

LDC	Power Factor	
Enersource Hydro Mississauga	0.9	
Halton Hills Hydro Inc.	0.9	
Hydro One Brampton	Bramalea TS (27.6 kV) – 0.88 ¹³ Goreway TS (27.6 kV) – 0.92 Jim Yarrow MTS (27.6 kV) – 0.92 Pleasant TS (27.6 kV) – 0.93	Bramalea TS (44 kV) – 0.88 ¹⁴ Goreway TS (44 kV) – 0.85 Pleasant TS (44 kV) – 0.88 ¹⁵
Hydro One Networks Inc. – Distribution	0.88	
Milton Hydro Distribution Inc.	0.9	
Toronto Hydro Electric System	0.9	

3. A study period of 10 years, from 2005 to 2015, was used to assess the transmission requirements.
4. Equipment summer continuous ratings and LTRs were based on a daytime ambient temperature of 30°C with a wind speed of 4 km/hour.
5. Hydro One Brampton shifts 60% of Bramalea TS (T1/T2, 27.6 kV) load growth to Jim Yarrow MTS (T1/T2, 27.6 kV) and 40% of Bramalea TS (T1/T2, 27.6 kV) load growth to Goreway TS (T5/T6, 27.6 kV).
6. Hydro One Brampton shifts all future load growth at Pleasant TS (T5/T6, 27.6 kV) to Jim Yarrow MTS (T1/T2, 27.6 kV)

¹³ Low voltage (LV) capacitors have been installed at Bramalea TS to compensate for the power factor.

¹⁴ LV capacitors have been installed at Bramalea TS to compensate for the power factor.

¹⁵ LV capacitors have been installed at Pleasant TS to compensate for the power factor.

-
7. Toronto Hydro Electric System transfers load amongst the Richview TS step-down facilities (27.6 kV) so that they remain under the station capacity limit (10-day LTR).
 8. Enersource Hydro Mississauga is unable to create more 44 kV ties between Tomken TS and Erindale TS due to the geography of the region and the lack of sub-transmission corridors. Thus, extra load from Erindale TS (T5/T6, 44 kV) and Meadowvale TS (T1/T2, 44 kV) are to be shifted to Erindale TS (T3/T4, 44 kV).
 9. Powerflow simulation analysis was based on the July 2004 load flow basecase with loads increased to represent the year under study. LDCs provided load forecasts from 2004 to 2024.

5. OPERATING AND PLANNING STANDARDS

The following Operating and Planning Standards were followed throughout this assessment.

The Independent Electricity System Operator's (IESO) Planning and Operating Standards indicate that¹⁶:

- The minimum voltage on the 230 kV transmission system under normal conditions is 220 kV, with a maximum allowable decline of 10% for a single element contingency;
- A maximum allowable voltage decline of 10% at all buses before tap changer action takes place;
- A maximum allowable voltage decline of 10% at high voltage and a maximum decline of 5% at low voltage (sub-transmission level) buses after tap changer action takes place; and,
- Voltage rises to be within 4% upon capacitor switching.

All transmission circuits and stations must be loaded to within their applicable ratings. When assessing thermal constraints at TSs, loading must not exceed the 10-day LTR in the event of a single contingency, both immediate post fault (before tap changer action takes place) and steady state post fault (after tap changer action takes place). Thermal constraints on transmission circuits are such that they must not exceed the 15-minute LTR for immediate post fault and must not exceed the continuous rating for steady state post fault for a single contingency.

For area supply planning purposes, the IESO stipulates the following guideline for loads greater than 500 MW in the IESO Supply Deliverability Guidelines:

*"With all transmission elements in service, any single element or double circuit contingency should not result in an interruption of supply to a load level of 500MW or more."*¹⁷

¹⁶ IESO Transmission Assessment Criteria, IMO_REQ_0041

http://www.ieso.ca/imoweb/pubs/marketAdmin/IMO_REQ_0041_TransmissionAssessmentCriteria.pdf

¹⁷ IESO Supply Deliverability Guidelines, IMO_GDL_0021

www.ieso.ca/imoweb/pubs/marketAdmin/IMO_GDL_0021_IMOSupplyAvailabilityGuidelines.pdf

6. ADEQUACY OF EXISTING FACILITIES

This section reviews the adequacy of the existing 500 kV and 230 kV transmission facilities to supply the load in GTA West to step-down transformation facilities Bramalea TS, Cardiff TS, Erindale TS, Goreway TS, Halton TS, Jim Yarrow MTS, Meadowvale TS, Pleasant TS, Richview TS, and Tomken TS. The transformation capacity at these load stations is also reviewed.

6.1 230 kV Transmission System

Four circuits (R14T, R17T, R19T and R21T) extend between Richview TS and Trafalgar TS to supply electricity to Erindale TS, Tomken TS, Pleasant TS and Jim Yarrow MTS as well as carry power to Richview and transmission facilities further east. Circuits R14T and R17T have the capability to supply the forecasted load growth for the study period without any observable thermal or voltage limitations. Circuits R19T and R21T reach thermal limits by 2009. Circuits R19T and R21T supply electricity to more than 500 MW of load and are thus operating beyond the adequate system reliability and security guidelines as outlined in the IESO Supply Deliverability Guidelines.

Four circuits (T36B, T37B, T38B and T39B) extend between Trafalgar TS and Burlington TS. Step-down transformation facilities tapped off of circuits T38B and T39B within the defined GTA West geographic area were included in this study. Circuits T36B and T37B were only assessed in those situations where a contingency redistributed significant amounts of electricity along those lines. Step-down facilities tapped off of these lines were not included in this study. Under all contingencies, circuits T36B and T37B did not display any thermal loading or voltage deficiency limitations during the study period. The loss of either circuits T38B or T39B caused voltage deficiencies starting in 2005 at Meadowvale TS and in 2012 at Halton TS LV buses. By 2015, the segment of circuits T38B and T39B between Lantz Junction and Trafalgar TS DESN¹⁹ (approximately the distance of one tower span) is loaded to approximately 80% of its continuous rating, steady state post contingency.²⁰

Five circuits (V71RP, V72R, V73R, V74R and V76R) extend from Claireville TS to Richview TS. Bramalea TS and Cardiff TS are tapped off of a radial extension of V72R and V73R. Goreway TS is tapped off of a radial extension of V73R and V76R. By 2008, circuits V72R, V73R and V76R will be loaded up to 50% of their continuous rating pre-contingency on the segments between Claireville TS and Richview TS. In the same year, under steady state post contingency, these three circuits are not loaded beyond 60% of their continuous rating. On the radial tap extending from circuit V72R, the loading does not exceed 21% of its continuous rating and likewise for V73R. For circuit V76R, the loading does not exceed 14%. At the end of the study period, 2015, the loading on the three radial segments of circuits V72R, V73R and V76R does not exceed 32% of their continuous rating.

¹⁸ IESO Supply Deliverability Guidelines, IMO_GDL_0021

www.ieso.ca/imoweb/pubs/marketAdmin/IMO_GDL_0021_IMOSupplyAvailabilityGuidelines.pdf

¹⁹ DESN – Dual Element Spot Network; a step down facility who has the same name as a Transformer Station (TS) whose purpose is to transform electricity from one high voltage to another. The term DESN is used to identify the load connection TS.

²⁰ Where the contingency is the loss of the parallel circuit.

6.2 Step Down Transformation Facilities

Of imminent concern in this assessment is the step-down transformer capacity in GTA West. Several stations were found, at the very early stages of the study period, to be operating beyond Operating and Planning Standards (please refer to Section 5). A total of seven TSs require either additional capacity or voltage correction by the end of the study period; some of these at two separate sub-transmission levels. Further load forecast information can be found in Appendix A.

- ◆ Bramalea TS has step-down transformation capability to both 44 kV and 27.6 kV. Transformers T1 and T2 step-down voltage from 230 kV to 27.6 kV, and are already exceeding capacity. At this time, additional load growth in the Bramalea TS area at voltage level 27.6 kV is being transferred to Jim Yarrow MTS (60%) and Goreway TS (40%). This station has no additional capacity to supply the increasing load in the area. Due to the influx of local generation²¹ in the Bramalea TS area connected to the 44 kV sub-transmission system, the transformation facilities connected to the 44 kV system were not found to be near thermal limits, nor were any voltage deficiencies identified during the study period.
- ◆ Erindale TS has step-down transformation capability to both 44 kV and 27.6 kV. Transformers T1 and T2 step-down voltage from 230 kV to the 27.6 kV level. These transformers are currently loaded beyond their summer 10-day LTR. Load is being transferred to Cardiff TS and will continue to be transferred until transformers T1 and T2 at Erindale TS are within their summer 10-day LTR. Transformers T5 and T6 (44 kV) are also currently loaded beyond their summer 10-day LTR. However, there is some available capacity on transformers T3 and T4 (44 kV) to which load is being transferred from transformers T5 and T6. With these and other 44 kV load transfers from Meadowvale TS, transformers T5 and T6 at Erindale TS are expected to be loaded to capacity by 2005, and transformers T3 and T4 at Erindale TS (44 kV) are expected to be loaded beyond capacity by 2006. There is additional capacity at Tomken TS (44 kV) for load transfers, however, there are insufficient sub-transmission right-of-ways on which to build distribution lines between these two stations. Thus 44 kV Erindale TS load cannot be transferred to Tomken TS.
- ◆ Pleasant TS has step-down transformation capability to both 44 kV and 27.6 kV. Transformers T5 and T6 transform electricity from 230 kV to the 27.6 kV level. These transformers are currently loaded to their summer 10-day LTR and all additional load is being transferred to Jim Yarrow MTS. Transformers T1 and T2 transform electricity from 230 kV to the 44 kV level. These transformers are expected to reach their summer 10-day LTR by summer 2011.
- ◆ Meadowvale TS has step-down transformation capability to 44 kV. This station is currently loaded to its summer 10-day LTR and all additional load is being transferred to Erindale TS.
- ◆ Halton TS has step-down transformation capability to 27.6 kV. This station is expected to be loaded to its summer 10-day LTR by 2011.

²¹ Local generation on the Bramalea TS 44 kV system: Greater Toronto Airport Authority, McDonnell Douglas CGS and Algonquin Power Energy from Waste.

- ♦ Jim Yarrow MTS has step-down transformation capability to 27.6 kV. Jim Yarrow MTS is currently receiving load transfers from Pleasant TS and Bramalea TS. The load at this station is expected to exceed its summer 10-day LTR by 2009.
- ♦ Goreway TS has step-down transformation capability to both 44 kV and 27.6 kV. Load forecasts suggest that transformers T5 and T6 at Goreway TS, which transform from 230 kV to 27.6 kV, will be loaded to their summer 10-day LTR by 2011. This is assuming that the low voltage buses have balanced loads and taking into consideration the load transfers from Bramalea TS. Transformer T4 (44 kV) at Goreway TS, does not display any problems during the study period.
- ♦ Cardiff TS was placed in-service in 2005. This station transforms from 230 kV to 27.6 kV. Load forecasts suggest that this station will be exceeding its summer 10-day LTR by the end of the study period, 2015.

6.3 Load Transfer Capability

Load transfer capability within the sub-transmission systems has enabled some of the immediate concerns at several stations to be temporarily addressed. Due to the rapid load growth in several areas of GTA West, and the lack of local transmission resources, several stations have been and/or will be forced to designate cascading load transfers to other stations in order to mitigate operating risks until further capacity can be supplied. These load transfers are from:

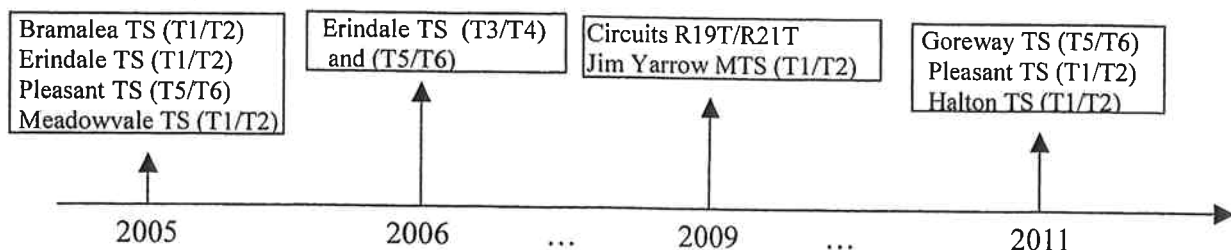
- ♦ Transformers T1/T2 at Bramalea TS (27.6 kV) to transformers T5/T6 at Goreway TS (27.6 kV), transformers T1/T2 at Jim Yarrow MTS (27.6 kV) and transformers T1/T2 at Cardiff TS (27.6 kV);
- ♦ Transformers T1/T2 at Erindale TS (27.6 kV) to transformers T1/T2 at Cardiff TS (27.6 kV);
- ♦ Transformers T5/T6 at Pleasant TS (27.6 kV) to transformers T1/T2 at Jim Yarrow MTS (27.6 kV); and,
- ♦ Transformers T1/T2 at Meadowvale TS (44 kV) to transformers T3/T4 at Erindale TS (44 kV).

These load transfers have already been or are in the process of being initiated by the LDCs. However, the load transfers do not address the overall load growth requirements, transmission capacity and voltage deficiencies, and in fact will accelerate transmission capacity needs at other stations.

6.4 Summary of Needs

A summary of the needs to be addressed via transmission, step-down transformation, and voltage correction facilities as proposed in this study are shown in Figure 2. The need dates for the study area indicate that several new TSs are required immediately.

Figure 2: Summary of Needs, 2005 – 2015



In order to identify potential solutions that would address more than one need, the needs identified in this study were combined into different groups taking into account the load transfer activities outlined in Section 6.3, the voltage transformation capabilities at the stations and the geographic load growth. These groups of needs, shown in Table 6, may have slightly different need dates than the dates shown in Figure 2.

Table 6: Geographic / Voltage Level Grouping of Needs

Group	Voltage Level	Need Date
Erindale TS / Meadowvale TS	44 kV	2006
Pleasant TS / Jim Yarrow MTS	27.6 kV	2009
Circuits R19T / R21T	230 kV	2009
Bramalea TS / Goreway TS	27.6 kV	2011
Pleasant TS	44 kV	2011
Halton TS	27.6 kV	2012

7. POSSIBLE OPTIONS TO ADDRESS SUPPLY CAPACITY & VOLTAGE STABILITY

This section outlines all possible options considered in the study in order to address the identified needs in GTA West. Table 7 itemizes the options that are rejected and those that are further analyzed. These options address the overall transmission concerns that arise, despite the load transfers that are in progress. In some cases, options were proposed to address issues at two voltage levels. For this reason, some options may occur twice in the following table under different needs.

Table 7: Summary of Options

Option	Description	Status
"Do Nothing"	"Do Nothing"	Rejected
Meadowvale TS Voltage Decline		
LVC	Install Low Voltage (LV) Capacitors – 2, 32.4 MVAR at 46 kV	Further Analyzed
Relief for Erindale TS and Meadowvale TS (44 kV)		
EM1	New DESN at Meadowvale TS (Meadowvale TS #2); two 230/44/27.6 kV, 75/125 MVA transformers	Rejected
EM2	New DESN at Meadowvale TS (Meadowvale TS #2); two 230/44 kV, 75/125 MVA transformers	Further Analyzed
EM3	New DESN, Winston TS, in the vicinity of Winston Churchill Blvd and Highway 403; two 230/44 kV, 75/125 MVA transformers	Further Analyzed
Relief for Goreway TS and Bramalea TS (27.6 kV)		
GB1	New DESN, North Central Brampton TS, in the vicinity of Bovaird Drive and Heart Lake Road; two 230/27.6 kV, 75/125 MVA transformers	Rejected
GB2	New DESN at Cardiff TS (Cardiff TS #2); two 230/27.6 kV, 75/125 MVA transformers	Rejected
GB3	New DESN at Goreway TS (Goreway TS #2); two 230/27.6 kV, 75/125 MVA transformers	Further Analyzed
Relief for Pleasant TS (44 kV)		
EM2	New DESN at Meadowvale TS (Meadowvale TS #2); two 230/44 kV, 75/125 MVA transformers and cascading load transfers from Pleasant TS	Rejected
EM3	New DESN, Winston TS, in the vicinity of Winston Churchill Blvd and Highway 403; two 230/44 kV, 75/125 MVA transformers and cascading load transfers from Pleasant TS (44 kV).	Rejected
P1	New DESN at Pleasant TS (Pleasant TS #3); two 230/44/27.6 kV, 75/125 MVA transformers	Rejected
P2	2 nd 230/44 kV, 50/83 MVA transformer at Goreway TS; cascading load transfers from Pleasant TS	Further Analyzed
Relief for Pleasant TS and Jim Yarrow MTS (27.6 kV)		
EM1	New DESN at Meadowvale TS (Meadowvale TS #2); two 230/44/27.6 kV, 75/125 MVA transformers	Rejected

GB1	New DESN, North Central Brampton TS, in the vicinity of Bovaird Drive and Heart Lake Road; two 230/27.6 kV, 75/125 MVA transformers	Rejected
P1	New DESN at Pleasant TS (Pleasant TS #3); two 230/44/27.6 kV, 75/125 MVA transformers	Rejected
PJ1	New DESN at Pleasant TS (Pleasant TS #3); two 230/27.6 kV, 75/125 MVA transformers	Further Analyzed
PJ2	New DESN, Orlando TS, in the vicinity of Mississauga Rd and Highway 407; two 230/27.6 kV, 75/125 MVA transformers	Rejected
Relief for Halton TS (27.6 kV)		
EM1	New DESN at Meadowvale TS (Meadowvale TS #2); two 230/44/27.6 kV, 75/125 MVA transformers	Rejected
H1	New DESN at Halton TS (Halton TS #2); two 230/27.6 kV, 50/83 MVA transformers	Rejected
H2	New DESN, Steeles TS, in the vicinity of Steeles Ave. and Trafalgar Rd; two 230/27.6 kV, 50/83 MVA transformers	Further Analyzed
H3	New DESN, James Snow TS, in the vicinity of Steeles Ave. and James Snow Parkway; two 230/27.6 kV, 50/83 MVA transformers	Further Analyzed
Relief for circuits R19T/R21T and 500 MW IESO Guideline Restriction (230 kV)		
T1	Extend circuits V72R/V73R from Cardiff TS to the Pleasant TS tap and construct a new Switching Station (SS), Hurontario SS, west of Hurontario Street	Further Analyzed
T2	Extend circuits V72R/V73R from Cardiff TS to Jim Yarrow MTS and re-supply Jim Yarrow MTS	Rejected
T3	Extend circuits T38B/T39B from Meadowvale TS to the Pleasant TS tap and construct a new SS, Hurontario SS, west of Hurontario Street	Further Analyzed
T4	Extend circuits T38B/T39B from Meadowvale TS to Jim Yarrow MTS and re-supply Jim Yarrow MTS	Rejected
T5	Reconductor circuits R19T/R21T from Trafalgar TS to Erindale Junction and from Hanlon Junction to Jim Yarrow Junction	Rejected
T6	Extend circuits V73R/V76R from Goreway TS to the Pleasant TS tap and construct a new SS, Pleasant SS	Rejected

7.1 "Do Nothing"

The "Do Nothing" approach will aggravate the existing load supply and transmission capacity problems and accelerate capacity problems with circuits R19T/R21T.

For circuits R19T/R21T, this approach does not satisfy the IESO requirements stipulated in the guideline for loads greater than 500 MW.

This alternative is not an acceptable approach and is not considered further.

7.2 Meadowvale TS Voltage Decline

LVC: Install Low Voltage Capacitors

Installation of LV capacitors at Meadowvale TS will allow the station to meet minimum voltage requirements in the event of a single contingency.

7.3 Relief of Erindale TS and Meadowvale TS (44 kV)

EM1: Meadowvale TS #2

A new 230/44/27.6 kV, 75/125 MVA DESN at Meadowvale TS would provide capacity for the Erindale TS and Meadowvale TS areas. The use of a three winding transformer to transform voltages to two sub-transmission levels (44 kV and 27.6 kV) would mean that Jim Yarrow MTS and Pleasant TS and/or Halton TS may also take advantage of the capacity offered by this proposed new DESN. This option was considered and rejected on the basis that a single DESN would not be able to supply the necessary capacity for both the 44 kV and 27.6 kV needs in the surrounding area over the next ten years.

EM2: Meadowvale TS #2

A new 230/44 kV, 75/125 MVA DESN at Meadowvale TS would provide capacity for Erindale TS and Meadowvale TS at the 44 kV sub-transmission level. This option was further evaluated.

EM3: Winston TS

A new 230/44 kV, 75/125 MVA DESN in the vicinity of Winston Churchill Boulevard (or Erin Mills Parkway) and Highway 403 would provide additional capacity off-loading Erindale TS and Meadowvale TS. This option was further evaluated.

7.4 Relief for Goreway TS and Bramalea TS (27.6 kV)

GB1: North Central Brampton TS

A new 230/27.6 kV, 75/125 MVA DESN in North Central Brampton in the vicinity of Bovaird Drive and Heart Lake Road would provide transmission capacity to relieve Goreway TS and Bramalea TS. This option does not completely satisfy the needs of the LDC and therefore was considered and rejected.

GB2: Cardiff TS #2

A new 230/27.6 kV, 75/125 MVA DESN at Cardiff TS would provide additional transmission capacity relieving Goreway TS and Bramalea TS. There is insufficient room for the required facilities on the existing site and this option does not completely satisfy the needs of the LDC and therefore was considered and rejected.

GB3: Goreway TS #2

A new 230/27.6 kV, 75/125 MVA DESN at Goreway TS would provide transmission capacity to relieve both Goreway TS and Bramalea TS. The location of this DESN is closer to the load centre and would be in an overall more ideal location than the other two proposals (GB1 and GB2). Thus, this option was considered further.

7.5 Relief for Pleasant TS (44 kV)

EM2: Meadowvale TS #2

Same as above (EM2, Section 7.3), with the addition of cascading load transfers from Pleasant TS to the new DESN at Meadowvale TS. However, cascading load transfers from Pleasant TS to Meadowvale TS would be complex and costly for the LDC, thus this option was considered and rejected.

EM3: Winston TS

Same as above (EM3, Section 7.3), with the addition of cascading load transfers from Pleasant TS to the new DESN at Winston TS. However, cascading load transfers from Pleasant TS to the proposed station in the vicinity of Winston Churchill Blvd and Highway 403 would be complex and costly for the LDC, thus this option was considered and rejected.

P1: Pleasant TS #3

A new 230/44/27.6 kV, 75/125 MVA DESN at Pleasant TS would provide additional transmission capacity to Pleasant TS at the 44 kV sub-transmission level, as well as address needed capacity at the 27.6 kV sub-transmission level for Pleasant TS and Jim Yarrow MTS. However, the capacity requirements for 27.6 kV are large enough to require a whole DESN while the capacity requirements at the 44 kV level are small enough to make this transformer size uneconomic. Thus, this option was considered and rejected.

P2: Goreway TS 44 kV DESN

Install a second 230/44 kV, 50/83 MVA transformer at Goreway TS. This would provide the required transmission capacity for Pleasant TS at the 44 kV sub-transmission level, as well as complete the DESN at Goreway TS, providing redundancy and thereby reducing operating risks to the load already established there. This option was considered further.

7.6 Relief for Pleasant TS and Jim Yarrow MTS (27.6 kV)

EM1: Meadowvale TS #2

Same as above (EM1, Section 7.3) with the addition of cascading load transfers at the 27.6 kV level from Pleasant TS and Jim Yarrow MTS to the new DESN at Meadowvale TS. The load requirements for Pleasant TS and Jim Yarrow MTS are such that they would require an entire 75/125 MVA DESN. Thus, this option of sharing between the two sub-transmission levels was considered and rejected.

GB1: North Central Brampton TS

Same as above (GB1, Section 7.4) with the addition of cascading load transfers from Pleasant TS and Jim Yarrow MTS (27.6 kV) to this new DESN. However, the load requirements at the 27.6 kV sub-transmission level do not permit the sharing of a single DESN as it would not provide enough capacity to the 27.6 kV level. Thus, this option was considered and rejected.

PJ1: Pleasant TS #3

A new 230/27.6 kV, 75/125 MVA DESN at Pleasant TS would provide the needed capacity at the 27.6 kV sub-transmission level. This option was considered further.

PJ2: Orlando TS

A new 230/27.6 kV, 75/125 MVA DESN in the vicinity of Mississauga Road and Highway 407 would provide the needed transmission capacity. However, the location of this proposed DESN is too far away from the load centre. Thus, this option was considered and rejected.

7.7 Relief for Halton TS (27.6 kV)

EM1: Meadowvale TS #2

Same as above (EM1, Section 7.3), with the addition of load transfers from Halton TS to Meadowvale TS #2. This option would not provide enough capacity at the 44 kV level for the requirements of Meadowvale TS and Erindale TS. This option was therefore considered and rejected.

H1: Halton TS #2

A new 230/27.6 kV, 50/83 MVA DESN at Halton TS would provide transmission capacity for the load growth near Halton TS at the 27.6 kV level. However, this option does not completely satisfy the needs of the LDC. Thus, this option was considered and rejected.

H2: Steeles TS

A new 230/27.6 kV, 50/83 MVA DESN in the vicinity of Steeles Avenue and Trafalgar Road would provide transmission capacity for the load growth near Halton TS at the 27.6 kV level. This option was preferred by the LDCs and was considered further.

H3: James Snow TS

A new 230/27.6 kV, 50/83 MVA DESN in the vicinity of James Snow Parkway and Steeles Avenue would provide transmission capacity for the load growth near Halton TS at the 27.6 kV level. This option was preferred by the LDCs and was considered further.

7.8 Relief for Circuits R19T/R21T and IESO 500 MW Guideline Restriction (230 kV)

T1: Circuits V72R/V73R Extension and Hurontario SS

Circuits V72R and V73R are extended from Cardiff TS west to the Pleasant TS tap (approximately 4 km in length). A new SS is constructed at this junction, Hurontario SS. Jim Yarrow MTS is radially re-supplied from the new SS. This effectively provides a second source of power for the Pleasant TS tap, off-loading circuits R19T and R21T from Erindale Junction to Hanlon Junction and from Hanlon Junction to Jim Yarrow Junction. The new SS satisfies the IESO requirements stipulated in the guideline for loads greater than 500 MW by creating an isolation point on circuits R19T and R21T.

T2: Circuits V72R/V73R Extension and Re-supply Jim Yarrow MTS

Circuits V72R and V73R are extended from Cardiff TS west to Jim Yarrow MTS. Jim Yarrow MTS is re-supplied from this extension. This option would place too much load on circuits V72R/V73R and was thus considered and rejected.

T3: Circuits T38B/T39B Extension and Hurontario SS

Circuits T38B and T39B are extended from Meadowvale TS east to the Pleasant tap (approximately 9 km). A new SS is constructed at this junction, Hurontario SS, and Jim Yarrow MTS is radially re-supplied from the new SS.

T4: Circuits T38B/T39B Extension and Re-supply Jim Yarrow MTS

Circuits T38B and T39B are extended from Meadowvale TS east to Jim Yarrow MTS. Jim Yarrow MTS is re-supplied from this extension. This option would place too much load on circuits T38B/T39B and was thus considered and rejected.

T5: Reconductor Circuits R19T/R21T

Circuits R19T and R21T are reconducted between Erindale Junction and Hanlon Junction (5.1 km in length) and between Hanlon Junction and Jim Yarrow Junction (11.6 km in length). For circuits R19T and R21T, this option does not satisfy the IESO requirements stipulated in the guideline for loads greater than 500 MW and was therefore considered and rejected.

T6: Circuits V73R/V76R Extension and Pleasant SS

Circuits V73R and V76R are extended from Goreway TS to the Pleasant TS tap and a new SS (Pleasant SS) is constructed at this junction. However, there is insufficient space at Pleasant

TS to economically incorporate both a third DESN as well as a new SS. Moreover, this option would require at least 13 km of double circuit underground cable at a cost of \$5-10 Million/km as there is no available transmission right-of-way. This option was considered cost prohibitive. It was therefore considered and rejected.

7.9 Consideration of Local Generation

Several local power generating stations (GS) in the Brampton area are currently in-service and/or are expected to be in-service within the next 12-24 months. Despite rapid load growth, the 44 kV DESN at Bramalea TS was not a concern throughout the study period as the local generation is connected to the system at the 44 kV sub-transmission level. This local generation has sufficiently off-loaded the transformers of the 44 kV DESN at Bramalea TS such that new transmission capacity was not an identified requirement throughout the study period. However, this local generation does not affect the loading of the 27.6 kV DESN at Bramalea TS. As such, this DESN still poses a problem, requiring immediate load transfers to various other TSs in the Brampton area, in addition to future planned transmission capacity.

A large GS in the vicinity of Goreway TS area is also proposed. A qualitative analysis shows that this GS, even at a 900 MW capacity, will not resolve any of the needs identified in this study. The transmission capacity needed in the Bramalea TS, Goreway TS and Cardiff TS areas would be unresolved by connecting a GS at the 230 kV high voltage level. However, this proposed GS could potentially increase the usability of an extension of circuits V72R/V73R to the Pleasant TS tap, with the establishment of Hurontario SS as outlined in option T1.

8. PLANS: OPTION COMBINATIONS

The options listed in the previous section that were considered worth further analysis were combined into several combinations and evolved into four plans as shown in Table 8. These plans effectively resolve all transmission capacity problems throughout the study period from 2005 to 2015.

Table 8: Plans: Option Combinations

Need	Year	Plan			
		A	B	C	D
Pleasant TS/Jim Yarrow MTS (27.6 kV)	2009	PJ1	PJ1	PJ1	PJ1
Bramalea TS/Goreway TS (27.6 kV)	2011	GB3	GB3	GB3	GB3
Erindale TS/Meadowvale TS (44 kV)	2006	EM3	EM3	EM2	EM2
Pleasant TS (44 kV)	2011	P2	P2	P2	P2
Halton TS (27.6 kV)*	2012	H2	H2	H2	H2
R19T/R21T and IESO 500 MW Guideline	2009	T1	T3	T1	T3

* Option H3 would be supplied from the same tap as H2, thus results from H2 were considered to satisfactorily represent option H3 for the purposes of this study.

Please refer to Figures 3, 4, 5 and 6 for schematic diagrams of the above plans.

Figure 3: Plan A

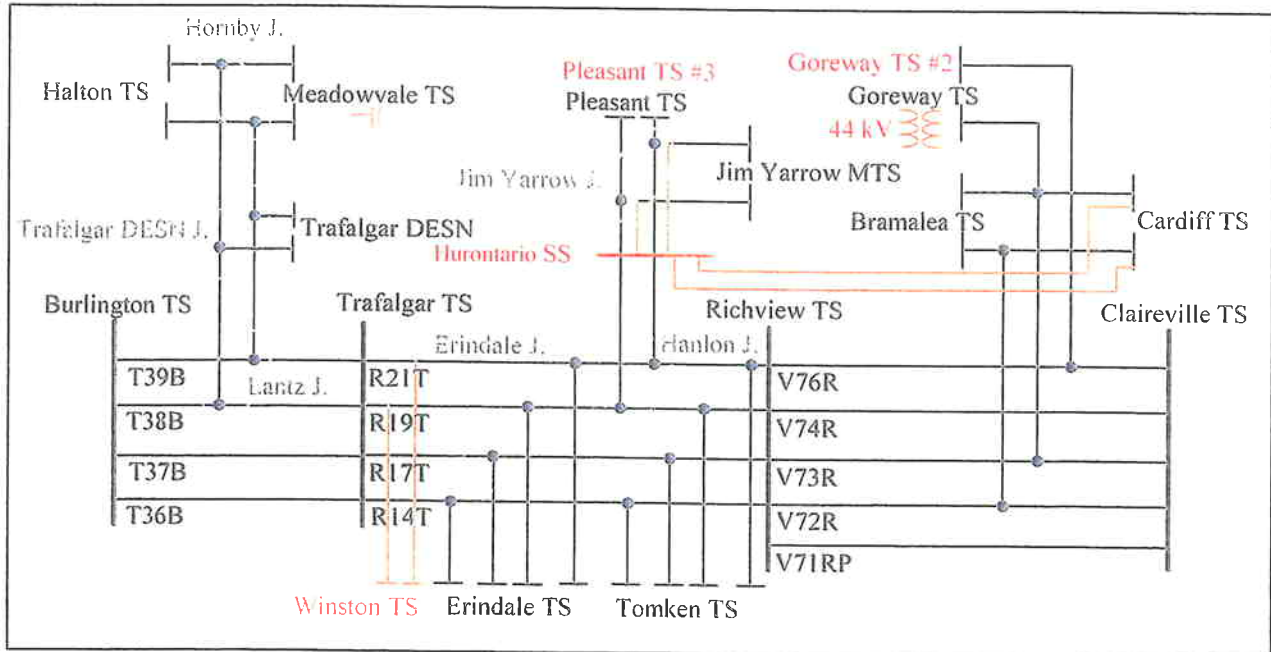


Figure 4: Plan B

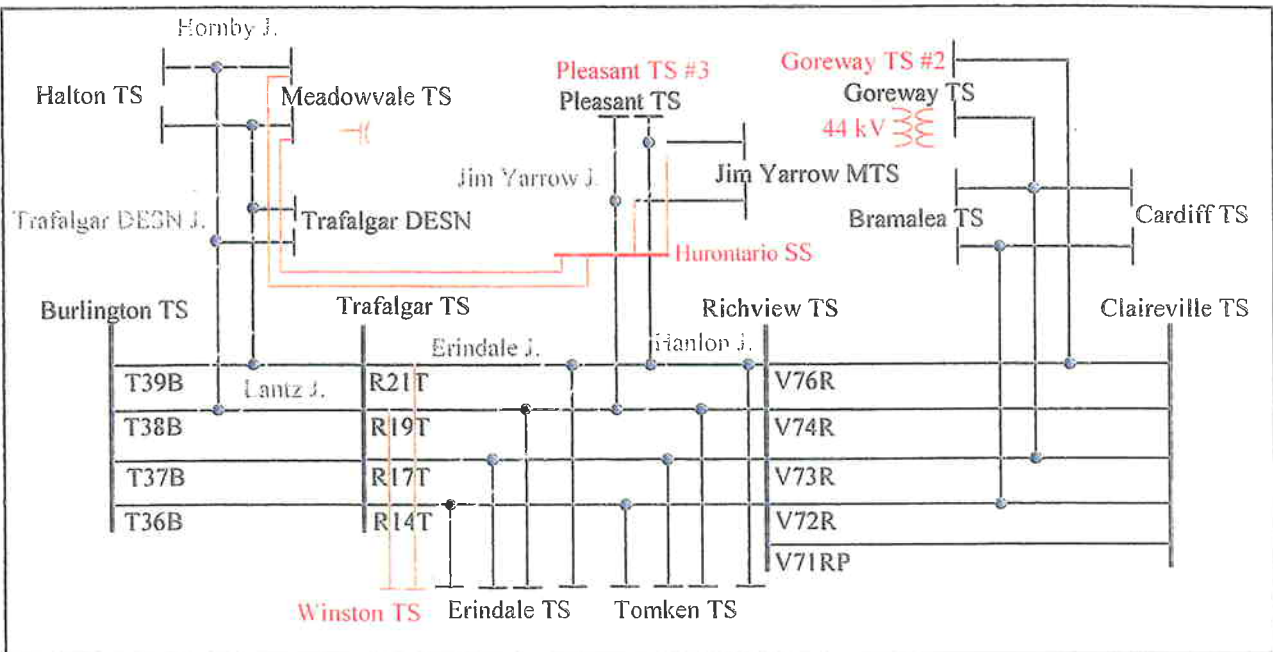


Figure 5: Plan C

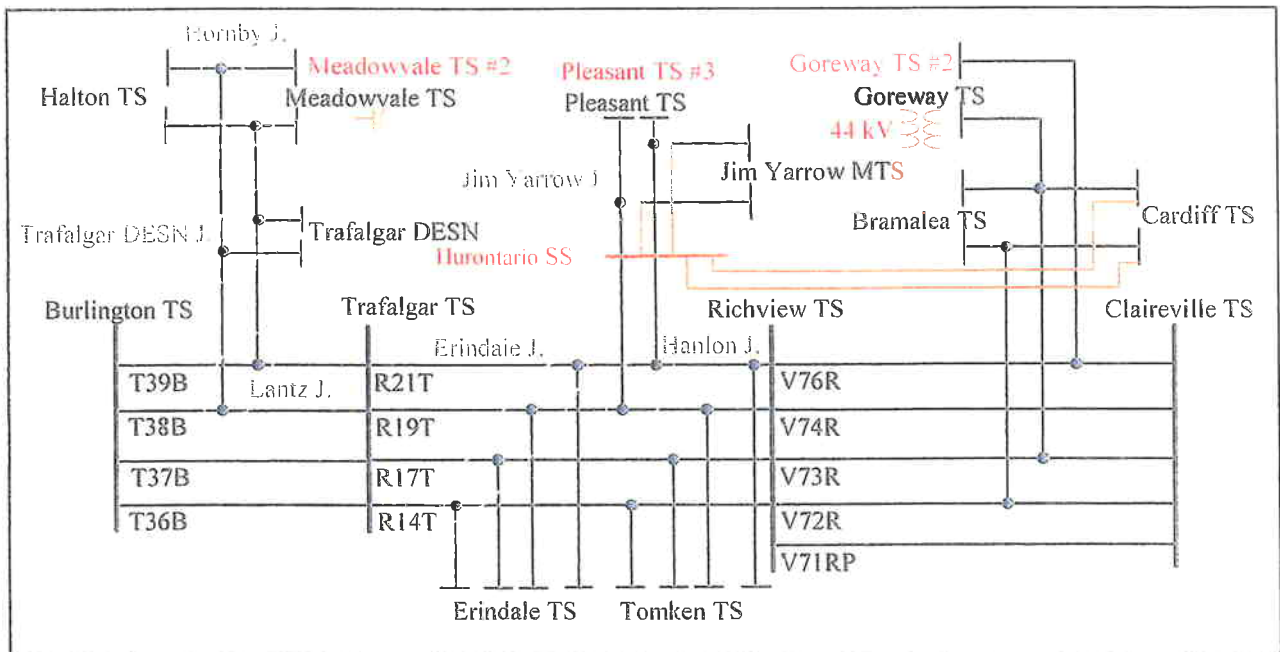
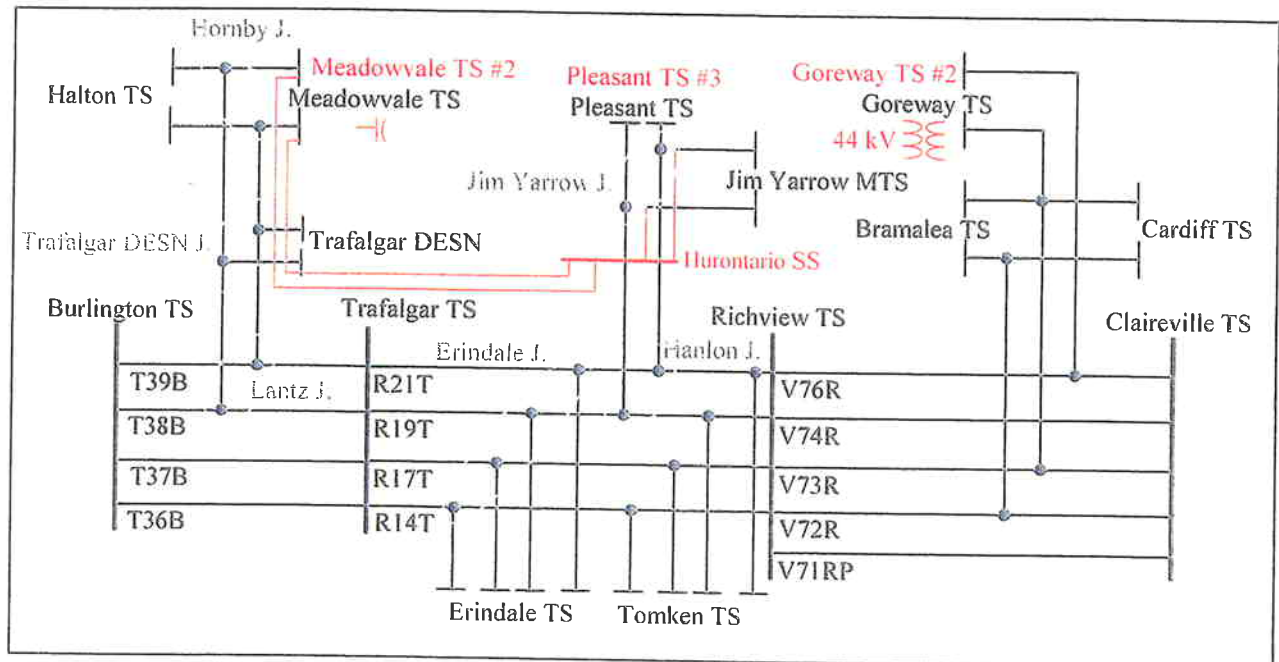


Figure 6: Plan D



9. SELECTION OF PREFERRED PLAN

The Shaw Power Technologies Inc. PSS/E software²² was used to assess the transmission capacity for the existing facilities and for the proposed plans in GTA West. All plans address the needs identified during the 10-year study period. Specific loadflow results can be found in Appendix C.

9.1 2015 Technical Evaluation

9.1.1 *Plan A: Extension of Circuits V72R/V73R, Winston TS*

Plan A addresses all of the identified needs in this study. This Plan includes the extension of circuits V72R and V73R from Cardiff TS across to the proposed new SS, Hurontario SS, located on the Pleasant TS tap. Jim Yarrow MTS is radially re-supplied from Hurontario SS. The proposed new TS, Winston TS, tapped from circuits R19T and R21T will support the growing 44 kV load, off-loading Meadowvale TS and Erindale TS. New 230/27.6 kV transformation capacity is provided at Pleasant TS and Goreway TS and new 230/44 kV transformation capacity is provided at Goreway TS.

Technically, Plan A performed well. The majority of the high voltage buses were within an acceptable voltage range of between 240 and 243 kV pre-contingency. The following contingencies were observed: loss of circuit V72R, loss of circuit T38B, loss of circuit R19T Upper²³, loss of circuit R19T Lower²⁴, and loss of circuit R14T. Since the ratings on the double circuits²⁵ were consistent, it is a good assumption that the loss of the other circuit in the double circuit pair would warrant the same technical results. These contingencies revealed that Erindale TS and Meadowvale TS may need to transfer further load to the new TS, Winston TS, in order to maintain transformer operation below the summer 10-day LTR. The load at Cardiff TS exceeds the station capacity, steady state post fault (107%). The voltage at Hurontario SS was 240.5 kV and the voltage at Cardiff TS was 240.7 kV. The loading on the extension of circuits V72R and V73R was approximately 280 MW total and each line was loaded to 18% of its continuous rating, under pre-fault conditions. Winston TS placed additional load on circuits R19T and R21T, however this load is tapped off prior to the line sections of concern (Erindale Junction to Hanlon Junction and Hanlon Junction to Hurontario SS).

9.1.2 *Plan B: Extension of Circuits T38B/T39B, Winston TS*

Plan B involved the extension of circuits T38B and T39B from Meadowvale TS across to the proposed new SS, Hurontario SS, located along the Pleasant TS tap. The new proposed TS, Winston TS, is tapped from circuits R19T and R21T. New 230/27.6 kV transformation capacity is provided at Pleasant TS and Goreway TS and new 230/44 kV transformation capacity is provided at Goreway TS. Plan B performed adequately, though the voltages were not quite as high as for Plan A. Again, Cardiff TS exceeded capacity, steady state post fault (107%). The voltage at Hurontario SS was 239.2 kV and the voltage at Meadowvale TS was 239.3 kV. Meadowvale TS, Halton TS and Erindale TS exceeded capacity steady state post fault. The voltages on the Pleasant TS tap were low, and Pleasant TS 230/44 kV transformers were nearly loaded to capacity steady state post fault (~96%). The loading on the extension of circuits T38B and T39B was approximately 250 MW total and each line was loaded to 20% of its continuous rating under pre-fault conditions.

²² Copyright © 1976 – 2004 Siemens Power

²³ R19T Upper is the portion of circuit R19T north of Hurontario SS.

²⁴ R19T Lower is the portion of circuit R19T between Richview TS and Trafalgar TS and from Hanlon Junction to Hurontario SS.

²⁵ A line of supporting structures that carries two power circuits.

9.1.3 Plan C: Extension of Circuits V72R/V73R, Meadowvale TS #2

Plan C performed similarly to Plan A. The only difference between these two plans is the addition of Meadowvale TS #2 in place of the new TS, Winston TS. New 230/27.6 kV transformation capacity is provided at Pleasant TS and Goreway TS and new 230/44 kV transformation capacity is provided at Goreway TS. These similarities were reflected in the results of the technical analysis. Again, Cardiff TS exceeded capacity, steady state post fault (107%). Meadowvale TS may need to transfer additional load onto Meadowvale TS #2. The voltage at Hurontario SS was 240.4 kV pre-fault. The voltage at Cardiff TS is 240.6 and the voltage at Meadowvale TS was 239.9 kV. The loading on the extension of circuits V72R and V73R was approximately 290 MW total and each line was loaded to 19% of its continuous rating, under pre-fault conditions.

9.1.4 Plan D: Extension of Circuits T38B/T39B, Meadowvale TS #2

Plan D performed similarly to Plan B. Again the only difference between these two plans is the addition of Meadowvale TS #2 in place of the new TS, Winston TS. New 230/27.6 kV transformation capacity is provided at Pleasant TS and Goreway TS and new 230/44 kV transformation capacity is provided at Goreway TS. The overall system voltages were slightly lower especially on the Meadowvale TS tap. Again, Cardiff TS exceeded capacity, steady state post fault (107%). Erindale TS may need to transfer more load onto Meadowvale TS #2. The voltage at Hurontario SS was 238.5 kV. The voltage at Meadowvale TS was 238.6 kV. The total load on the extension of circuits T38B and T39B was approximately 240 MW, with each line loaded to approximately 19% of its continuous rating, under pre-fault conditions. On the loss of circuit R19T, the line section between Erindale Junction and Hanlon Junction on circuit R21T is loaded to 43% of continuous, steady state post fault. On the loss of circuit T38B, the line section between Lantz Junction and Trafalgar DESN Junction on T39B is loaded to 86% and the line section between Trafalgar DESN Junction and Hornby Junction on the same line is loaded to 78%.

9.1.5 Plans A and C Versus Plans B and D: Circuit Extension V72R/V73R Versus T38B/T39B

The intent of extending either circuits V72R/V73R or T38B/T39B is to off-load circuits R19T/R21T between Hanlon Junction and the proposed new Hurontario SS. Table 9 shows that the extension of circuits V72R/V73R (Plans A and C) allows circuits R19T/R21T to be off-loaded more than the extension of circuits T38B/T39B (Plans B and D). In Plans A and C, circuit R21T is loaded to 37% and 35% respectively, of its continuous current loading capacity. While for Plans B and D, circuit R21T is loaded to 41% and 43% respectively. Approximately 60% of the reactive support for the Pleasant tap comes from the Richview/Claireville area and 40% from the Trafalgar area. The extension of T38B/T39B causes all of the reactive support from Richview/Claireville to flow along R21T. This increases the flow along the line segment between Hanlon Junction and Hurontario SS, causing it to be loaded higher in Plans B and D than in Plans A and C.

Table 9: Impact on Circuit R21T, With Loss of Circuit R19T Lower

Loss of R19T Lower, 2015 Steady State Post Contingency	Plan			
	V72R/ V73R	T38B/ T39B	V72R/ V73R	T38B/ T39B
	A	B	C	D
From Hanlon J. to Hurontario SS	37%	41%	35%	43%
From Erindale J. to Hanlon J.	62%	48%	55%	43%
Note: All % values are a percentage of current loading, continuous rating				

Another line segment of concern on circuits R19T/R21T was between Erindale Junction and Hanlon Junction. Table 9 shows that Plans B and D (48% and 43%) actually allow this section of the circuits to be off-loaded more than Plans A and C (62% and 55%). The extension of circuits T38B/T39B changes the flow on circuit R21T such that Tomken TS is mainly supplied from Richview TS whereas the extension of circuits V72R/V73R causes Tomken TS to be mainly supplied from Trafalgar TS. Supplying Tomken from the Trafalgar side of R21T increases the loading on the line segment between Erindale Junction and Hanlon Junction, causing it to be loaded higher in Plans A and C than in Plans B and D.

9.1.6 Plans A and B Versus Plans C and D: Winston TS Versus Meadowvale TS #2

Circuits T38B/T39B are affected by the options of whether to construct the new TS, Winston TS or add Meadowvale TS #2. Increased load on circuits T38B/T39B could precipitate the need for reconductoring sections of these lines sooner than anticipated. Table 10 shows the impact.

Table 10: Impact on Circuit T39B With Loss of Circuit T38B

Loss of T38B, 2015 Steady State Post Contingency	Plan			
	Winston TS		Meadowvale TS #2	
	A	B	C	D
Lantz J. to Trafalgar DESN J.	71%	77%	86%	86%
Trafalgar DESN J. to Hornby J.	63%	69%	78%	78%
Note: All % values are a percentage of current loading, continuous rating				

Plans A and B represent the Winston TS option while Plans C and D represent the Meadowvale TS #2 option. Line segments Lantz Junction to Trafalgar DESN Junction and Trafalgar DESN Junction to Hornby Junction were identified as being most susceptible to over-loading on circuits T38B/T39B. As shown in Table 10, the current loading on circuit T39B, between Lantz Junction and Trafalgar DESN Junction, is considerably less for Winston TS (71% and 77%) than for Meadowvale TS #2 (86% and 86%). Similarly, on the line segment between Trafalgar DESN Junction and Hornby Junction the current loading is less for Winston TS (63% and 69%) versus Meadowvale TS #2 (78% and 78%).

9.1.7 Plan A Versus Plans B, C and D: Trafalgar TS and Claireville TS Autotransformers

The loads flowing on the Trafalgar TS and Claireville TS autotransformers were observed and compared amongst the four plans to determine their impact. The Trafalgar TS autotransformers were within their capacity limits for the duration of the study period. The Claireville TS autotransformers were at their capacity limits by the end of the study period. Resolving issues with the loading on the autotransformers at Claireville TS requires further investigation beyond the GTA West study, and is therefore considered outside of the scope of this study. It is assumed that measures, independent of this study, are being taken to resolve this issue²⁶. However, none of the options being considered will change the recommendations of this study.

The basecase conditions relevant to the loading on the Trafalgar TS and Claireville TS autotransformers were:

- Summer peak load of 26,000 MW
- Flow East Towards Toronto (FETT) transfers of approximately 3600 MW
- Queenston Flow West (QFW) transfers of approximately 500 MW
- 6 Pickering GS units, 4 Darlington GS units, 6 Bruce GS units and 0 Lakeview GS units modelled

²⁶ Some of the options being considered include Goreway GS and other generation in GTA West as well as additional autotransformers at Parkway TS.

- Local 44 kV generation connected to Bramalea TS in-service
- Proposed Goreway GS not in-service

Table 11 shows the impact each plan had on the autotransformers,. Plan A was used as a base for the comparison, and Plans B, C and D were compared to Plan A to show the difference in the megawatt (MW) flow. The flows were normalized by the number of autotransformers at each of the stations (2 at Trafalgar TS, 4 at Claireville TS).

Table 11: Autotransformer Impact		Plan Comparison			
Stations / Plans		A	B	C	D
Trafalgar TS	--	22	-7	22	
Claireville TS	--	-20	4	-17	

Note: Numbers are in Δ MW/Autotransformer

There is no material effect on the flows on the autotransformers at either Trafalgar TS or Claireville TS when comparing the construction of Winston TS (Plans A and B) to the construction of Meadowvale TS #2 (Plans C and D). The following conclusions can be drawn when comparing the extension of circuits V72R/V73R (Plans A and C) to the extension of circuits T38B/T39B (Plans B and D):

- the extension of V72R/V73R will increase the flow on the Claireville TS autotransformers.
- the extension of T38B/T39B will increase the flow on the Trafalgar TS autotransformers.

Overall, the flow differential between the four plans is minimal and not considered material.

9.1.8 Preferred Plan

HV Voltages in Plan A were within a very acceptable range, and slightly higher than in Plans B, C or D. Winston TS (Plans A and B) is a better technical choice than Meadowvale TS #2 (Plans C and D) as there are indications that the addition of Meadowvale TS #2 could lead to transmission problems well into the future. When comparing the extension of circuits V72R/V73R (Plan A) to the extension of circuits T38B/T39B (Plan B), Table 10 clearly shows that the current loading percentages for Plan A are less than for Plan B. Specifically, the extension of circuits T38B/T39B places additional stress on certain line segments which may advance the need for reconductoring these line sections on circuits T38B/T39B. The flows on the autotransformers at Trafalgar TS and Claireville TS were marginally different between the four plans, with the new 44 kV TS (Winston TS/Meadowvale TS #2) having no material effect whatsoever. In consideration of the technical analysis for the year 2015, the best choice is Plan A, which includes the extension of circuits V72R/V73R and the construction of a new TS, Winston TS.

9.1.9 2024 Technical Assessment

All plans met the needs identified in the 10-year study period. These plans were further technically evaluated with respect to the long-term system planning requirements by assessing them for the expected 2024 conditions. This method provides a snapshot of the long-term viability of each of the plans, and how each would perform under the increasing load growth that is expected in the GTA West. The study participants provided load forecasts up to the year 2024. Overall, with respect to long-term system planning requirements in GTA West, Plan A performed technically better than the other plans. Refer to Appendix B for results of the 2024 Technical Assessment.

9.2 Cost Comparison

Table 12 shows representative costs comparing potential total cost for each of the proposed options. These estimated costs are preliminary and are used for comparison only. The most economic plan is Plan C and the second most economic is Plan A. Both of these plans encompass the extension of circuits V72R/V73R, and differ only in regards to the construction of Winston TS (Plan A, \$15M) versus Meadowvale TS #2 (Plan C, \$10M). However, considering the degree of accuracy of the preliminary costs, the differential between the plans is nominal.

Table 12: Cost Comparison of Option Combinations

Plan	A	B	C	D
LVC	1	1	1	1
PJ1	10	10	10	10
GB3	10	10	10	10
EM2	--	--	10	10
EM3	15	15	--	--
P2	3	3	3	3
H2	15	15	15	15
T1	32	--	32	--
T3	--	42	--	42
Total:	86	96	81	91

Note: all numbers are listed as \$ Million

10. DISCUSSION

Overall, Plan A performed technically better than Plans B, C or D. Generally, the HV system voltages were slightly higher for Plan A. The specific sections of circuits R19T/R21T were off-loaded sufficiently to eliminate the need for reconductoring. The four plans displayed relatively minimal change to the flow distribution on the Trafalgar TS and Claireville TS autotransformers.

In the long-term, Plan A did not advance further transmission problems along circuits T38B/T39B or cause problems along any other circuits. Placing additional reactive power on the HV system for voltage support could enhance Plan A. All of the new deficiencies observed in the 2024 outlook (refer to Appendix B) could be resolved via load transfers between stations and/or addition of LV capacitors and HV reactive support.

Discussion with the LDCs determined that Winston TS is the preferred option to Meadowvale TS #2 as there are indications that the addition of Meadowvale TS #2 could lead to transmission problems well into the future. This eliminates Plans C and D. Between the remaining two plans (Plans A and B), Plan A is more economic as shown in Table 12. The reason for this is that the extension of circuits V72R and V73R is 5 km shorter than the extension of circuits T38B and T39B. Thus, Plan A is the preferred alternative.

11. CONCLUSIONS

The following conclusions can be reached from the analysis performed for this study:

- ◆ Bramalea TS (27.6 kV), Pleasant TS (27.6 kV) and Erindale TS (27.6 kV) are currently loaded to or beyond their capability and are being forced to transfer load to other stations to mitigate operating risks.
- ◆ Meadowvale TS (44 kV) and Erindale TS (44 kV) are expected to be at capacity by 2006. The earliest possible option to relieve the loading at Meadowvale TS and Erindale TS (44 kV) is 2008 with the addition of the proposed TS, Winston TS.
- ◆ Meadowvale TS will currently suffer voltage declines greater than 10% under immediate post fault conditions. This voltage stability problem can be rectified with a LV capacitor. The earliest that a LV capacitor could be installed at Meadowvale TS is summer 2007.
- ◆ Circuits R19T/R21T are currently (2005) beyond the IESO requirements stipulated in the guideline for loads greater than 500 MW. Segments of these lines are expected to be at capacity by 2009. The earliest possible option to address this problem can be implemented by 2009.
- ◆ Pleasant TS T1/T2 (44 kV) is expected to be at capacity by 2011. Option P2 (Goreway TS 44 kV DESN) can address this issue as early as 2011.
- ◆ Pleasant TS and Jim Yarrow MTS (27.6 kV) are expected to exceed capacity by 2009. Option PJ1 (Pleasant TS #3) can address this issue as early as 2009.
- ◆ Bramalea TS and Goreway TS (27.6 kV) are expected to be at capacity by 2011. Option GB3 (Goreway TS #2) can address these issues as early as 2011.
- ◆ Halton TS (27.6 kV) is expected to be at capacity by 2011. Options H2 (Steeles TS) or H3 (James Snow TS) can address this issue as early as 2011.
- ◆ The preferred Plan to meet all of these needs is Plan A, consisting of the following:
 1. Install LV capacitors at Meadowvale TS;
 2. Build Winston TS;
 3. Extend circuits V72R/V73R from Cardiff TS to the Pleasant TS tap, build Hurontario SS, and radially re-supply Jim Yarrow MTS;
 4. Add a 2nd 230/44 kV transformer at Goreway TS (44 kV DESN);
 5. Build Pleasant TS #3; and,
 6. Build Goreway TS #2.

12. RECOMMENDATIONS

Several recommendations can be drawn from this study to address the current system deficiencies and provide system capacity to meet forecasted load growth. These recommendations are:

1. Subject to the Ontario Power Authority's integrative review (Integrated Power System Plan) Hydro One Networks Inc. to initiate the approval processes required for the extension of circuits V72R and V73R and the construction of Hurontario SS.
2. Hydro One Networks Inc. to commence the detailed specification and engineering of the LV capacitors for Meadowvale TS.
3. Hydro One Networks Inc. to commence the preliminary engineering and consultation with the LDCs, and to initiate the approval processes on the construction of a new TS, Winston TS, in the vicinity of Winston Churchill Blvd. and Highway 403.
4. The LDCs to continue to transfer loads as necessary to mitigate potential operating risks until additional transmission capacity becomes available.
5. The LDCs and Hydro One to continue to monitor load growth in the GTA West area and to review options for long-term growth based on the location of new developments and load forecasts.

APPENDIX A:

LOAD FORECASTING DATA

Table A1 below shows the coincident load forecast from 2005 to 2015 for all stations in MVA. It includes the station or DESN LTR (limited time rating). The data in this table does not include load transfers to new stations proposed in this study, however it does include load transfers to existing stations as proposed by the LDCs. Please note, Richview DESN load was neglected as it was assumed that Toronto Hydro Electric System would manage their load between DESNs to reduce operating risks when necessary.

Table A1: Coincident Load Forecast in MVA

Forecast Load in MVA													
	Station - 27.6 kV	LTR (MVA)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
1.	Bramalea T1/T2	172.6	217	195	197	199	201	203	205	206	206	206	207
2.	Cardiff TS	126.1	0	112	115	117	119	122	124	125	125	125	126
3.	Erindale T1/T2	190.8	259	186	189	193	197	201	205	206	207	207	208
4.	Goreway T5/T6	191.8	161	169	177	184	192	200	209	217	226	235	243
5.	Halton TS	206.6	108	127	146	165	180	184	189	194	199	204	208
6.	Jim Yarrow MTS	174.0	104	109	122	136	150	165	180	196	213	229	244
7.	Pleasant T5/T6	198.6	213	213	213	213	213	213	213	213	213	213	213
8.	Richview T1/T2	172.6	152	154	155	157	158	160	161	163	165	167	168
9.	Richview T5/T6	198.4	116	119	121	122	123	124	125	126	127	128	129
10.	Richview T7/T8	88.1	137	141	142	143	144	145	146	147	149	150	151
	Total:		1466	1524	1576	1629	1677	1717	1758	1792	1829	1865	1898
	Growth Rate			4.0%	3.4%	3.3%	2.9%	2.4%	2.3%	2.0%	2.0%	2.0%	1.8%
													2.6%

	Station - 44 kV	LTR (MVA)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
1.	Bramalea T3/T4 ¹	117.4	118	118	118	118	118	118	118	118	118	118	118
2.	Bramalea T5/T6	176.8	83	89	94	98	103	108	112	118	123	129	134
3.	Goreway T4	95.4	33	34	36	37	38	40	41	42	44	45	47
4.	Erindale T5/T6	171.9	184	184	184	184	184	184	184	184	184	184	184
5.	Erindale T3/T4 ²	209.1	216	231	243	254	266	277	289	291	293	295	297
6.	Meadowvale TS	200.7	201	201	201	201	201	201	201	201	201	201	201
7.	Pleasant T1/T2	164.5	148	153	157	162	166	171	176	181	185	191	196
8.	Tomken T1/T2	183.0	166	168	169	170	171	172	173	173	174	175	175
9.	Tomken T3/T4	202.9	180	181	182	183	183	184	185	185	186	187	187
	Total:		1329	1359	1383	1407	1431	1455	1479	1494	1508	1525	1539
	Growth Rate			2.3%	1.8%	1.7%	1.7%	1.7%	1.7%	1.0%	0.9%	1.1%	0.9%
													1.5%

The numbers in bold indicate those that are at or above the station LTR. In some cases, there are LV capacitors at the stations which indirectly provide additional capacity at the station and effectively raises the LTR at the station. The numbers in bolded red indicate where the loading at the station has

¹ Bramalea T3/T4 (44 kV) appears to be loaded beyond its summer 10-day LTR, however, this problem is addressed by local generation.

² Includes load transfers from Meadowvale TS and from Erindale T5/T6.

become larger than this inflated LTR value provided by the LV capacitors. In other cases, a voltage decline issue arose while the study was being conducted which indicated that the voltage decline at a particular station reached an unacceptable level prior to the station load being at capacity. These numbers were indicated in red, non-bolded font. All of the red numbers (bolded and non-bolded) indicate where load must be transferred to another station (new or existing) to mitigate operating risks.

For some stations where there was a single customer, it was necessary to review the non-coincident load forecast information in order to determine when the station peak would surpass the station LTR and further capacity or LV capacitors would be required to mitigate operating risks. These stations and/or DESNS are shown in Table A2. At stations where there were multiple customers reporting load forecasting information, coincident data was utilized to provide the need dates for additional transformation capacity.

Table A2: Non-Coincident Load Forecast

	Forecast Load in MVA											
	LTR	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Jim Yarrow MTS	174.0	120.6	138.2	154.6	169.5	184.9	200.8	217.4	234.5	252.1	270.5	286.7

APPENDIX B:

2024 Technical Assessment

All plans address the needs identified during the 10-year study period. These plans were further technically evaluated with respect to the long-term system planning requirements by assessing them for the expected year 2024 conditions. This method provides a snapshot of the long-term viability of each of the plans, and how each would perform under the increasing load growth that is expected in GTA West. The study participants provided load forecasts up to the year 2024. Specific loadflow results can be found in Appendix D.

All plans met the needs identified in the 10 year study period.

Plan A: V72R/V73R Extension, "Winston TS"

The assessment of Plan A through the years 2015 to 2024 identified the development of several future deficiencies in GTA West.

The overall system voltages in the study area were quite low, ranging from 232 kV at Pleasant TS. The loading at Pleasant TS is very high, and LV capacitors on the proposed Pleasant TS #3 LV buses would assist in supporting the voltage at this station. Additional reactive support may also be of benefit on the high voltage (HV) system at the proposed Hurontario SS.

Upon the loss of circuits R19T between Hurontario SS and Pleasant TS, the low voltages decline nearly 10% at Pleasant TS and decline more than 10% on the Pleasant TS #3 LV bus, under immediate post fault conditions. The loading at Pleasant TS #3 (27.6 kV) is beyond capacity (103% of the summer 10-day LTR) using the voltage varying load method. Under steady state post fault conditions, a voltage collapse occurs at Pleasant TS #3 by 2024, due to the high loading combined with the depressed voltage at both the transmission and sub-transmission levels. This problem could be addressed with the addition of LV capacitors at Pleasant TS #3, or by transferring load from Pleasant TS #3 to another station. Of additional note is the overloading of circuit R21T between Hurontario SS and Pleasant TS. This was noticeable under steady state post fault conditions with the use of a pair of LV capacitors at Pleasant TS #3. Under this scenario, this circuit was loaded to 110% of its continuous rating, steady state post fault.

For the loss of the lower portion of circuit R19T, the low transmission system voltages contribute to the overload of Erindale T5 (106%) under steady state post fault conditions. There is plenty of capacity at Winston TS to transfer any excess load from Erindale TS (T5/T6). However, it is advisable that if the transmission system voltages can be well supported with reactive power, then the load will not have to be transferred.

The loss of circuit V73R identified that the 44 kV DESN at Goreway TS was loaded beyond its summer 10-day LTR. This significantly depresses the voltage levels at Goreway TS during a single contingency. The 44 kV DESN at Goreway TS is loaded to 131% under immediate post fault conditions (using the voltage varying load method) and to 167% under steady state post fault conditions. The 27.6 kV load at Goreway TS is also over the summer 10-day LTR (101%). However, there is spare capacity at Goreway TS #2 to transfer any excess load from Goreway TS.

The loss of circuit T38B identified that Meadowvale TS and Halton TS were above their summer 10-day LTRs (loaded to 102% and 100% respectively, under steady state post fault conditions). This is due to the overall depressed transmission system voltage. There is spare capacity at Winston TS and Steeles TS to transfer load from Meadowvale TS and Halton TS, respectively.

However, if the transmission system voltages can be improved with reactive support, load would not have to be transferred.

Plan B: T38B/T39B Extension, "Winston TS"

Plan B also meets all of the needs identified in the study period. The same deficiencies arose at Pleasant TS #3 and Goreway TS as well as on circuits R19T and R21T between Hurontario SS and Pleasant TS. The problems at Erindale TS and Meadowvale TS were also present as well.

With the extension of circuits T38B and T39B (Plan B), circuits R19T/R21T was offloaded more in Plan B in comparison to Plan A, as previously identified in section 8.1. The HV system voltages are approximately 2 to 3 kV lower for Plan B than for Plan A.

Plan C: V72R/V73R Extension, Meadowvale TS #2

Plan C performed slightly worse than Plan A. Meadowvale TS #2 had lower voltages than Winston TS (234.9 kV versus 237.8 kV). Overall, the voltages on the Meadowvale TS/Halton TS tap are lower for Plan C compared to Plan A.

The contingency where circuit T38B or T39B was forced from service is of concern for Plan C. Under immediate post fault conditions, the LV buses at Halton TS declined nearly 10% using the voltage varying load method. Under steady state post fault conditions, the system voltages for Plan C were generally lower than for Plan A. As well, the following segments of the in-service circuit (T39B) was loaded over 95% of its continuous rating (the same results would be expected on T38B with T39B removed from service). Hornby Junction by Trafalgar DESN Junction was 95.5% of its continuous rating, and Lantz Junction by Trafalgar DESN Junction was 103.4% of its continuous rating. Under the implementation of Plan C, these line sections would require reconductoring sometime between 2015 and 2024. Halton TS and Meadowvale TS are overloaded sometime before 2024 under steady state post fault conditions.

Overall, Plan C did not perform, technically, as well as Plan A. There are indications that the addition of Meadowvale TS #2 could lead to transmission problems on circuits T38B/T39B as well as voltage problems on the Meadowvale TS/Halton TS tap well into the future.

Plan D: T38B/T39B Extension, Meadowvale TS #2

Due to the fact that the LDCs preferred the option of Winston TS over Meadowvale TS #2, and the extension of circuits V72R/V73R was more cost effective than the extension of circuits T38B/T39B, this option was not reviewed further.

OEB STAFF INTERROGATORIES

APPENDIX D

Gross Asset Continuity Statements

GROSS ASSETS TABLE

BREAKOUT OF OVERHEADS & INTEREST

ACCOUNT: 1805 1805-Land

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	354,871	354,871	354,871	354,871			
Additions	0	0	0	0			
Overheads	0	0	0	0			
Interest	0	0	0	0			
Retirements & Sales	0	0	0	0			
Other (specify) ARO							
Closing Balance	354,871	354,871	354,871	354,871	0	0	0
Average Balance	354,871	354,871	354,871	354,871			
Change in Year	0	0	0	0			

GROSS ASSETS TABLE

BREAKOUT OF OVERHEADS & INTEREST

ACCOUNT: 1806 1806-Land Rights

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	4,738	4,738	4,738	4,738			
Additions	0	0	0	0			
Overheads	0	0	0	0			
Interest	0	0	0	0			
Retirements & Sales	0	0	0	0			
Other (specify) ARO							
Closing Balance	4,738	4,738	4,738	4,738	0	0	0
Average Balance	354,871	4,738	4,738	4,738			
Change in Year	0	0	0	0			

GROSS ASSETS TABLE

BREAKOUT OF OVERHEADS & INTEREST

ACCOUNT: 1808 1808-Buildings and Fixtures

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	2,567,902	2,810,822	2,840,621	2,840,621			
Additions		29,799	0	285,000			
Overheads	0	0	0	0			
Interest	0	0	0	0			
Retirements & Sales	0	0	0	0			
Other (specify) ARO							
Closing Balance	2,567,902	2,840,621	2,840,621	3,125,621	272,719	0	285,000
Average Balance	2,567,902	2,825,722	2,840,621	2,983,121			
Change in Year	0	29,799	0	285,000			

GROSS ASSETS TABLE

BREAKOUT OF OVERHEADS & INTEREST

ACCOUNT: Land & Buildings total

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	2,927,511	3,170,431	3,200,230	3,200,230			
Additions	0	29,799	0	285,000			
Overheads	0	0	0	0			
Interest	0	0	0	0			
Retirements & Sales	0	0	0	0			
Other (specify) ARO							
Closing Balance	2,927,511	3,200,230	3,200,230	3,485,230	272,719	0	285,000
Average Balance	2,927,511	3,185,331	3,200,230	3,342,730			
Change in Year	0	29,799	0	285,000			

GROSS ASSETS TABLE

BREAKOUT OF OVERHEADS & INTEREST

ACCOUNT: 1820 1820-Distribution Station Equipment - Normally Primary below 50 kV

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	1,811,709	2,052,096	2,182,511	3,758,775			
Additions		109,587	1,607,514	1,091,460			
Overheads		20,828	86,090	221,780			
Interest		0	33,660	0			
Retirements & Sales			-151,000	-1,000			
Other (specify) ARO							
Closing Balance	1,811,709	2,182,511	3,758,775	5,071,015	370,802	1,576,264	1,312,240
Average Balance	1,811,709	2,117,304	2,970,643	4,414,895			
Change in Year	0	130,415	1,576,264	1,312,240			

GROSS ASSETS TABLE

BREAKOUT OF OVERHEADS & INTEREST

ACCOUNT: 1830 1830-Poles, Towers and Fixtures

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	12,377,413	12,557,459	13,229,914	14,477,914			
Additions		574,411	1,001,520	1,069,860			
Overheads		98,044	246,480	250,140			
Interest		0	0	0			
Retirements & Sales	0	0	0	0			
Other (specify) ARO							
Reclass 1995 applied	1,094,055						
Reclass reporting adj	-2,153,995						
Closing Balance	11,317,473	13,229,914	14,477,914	15,797,914	1,912,441	1,248,000	1,320,000
Average Balance	11,847,443	12,893,687	13,853,914	15,137,914			
Change in Year	0	672,455	1,248,000	1,320,000			

GROSS ASSETS TABLE

BREAKOUT OF OVERHEADS & INTEREST

ACCOUNT: 1835 1835-Overhead Conductors and Devices

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	481,764	3,076,374	3,519,573	3,851,573			
Additions		378,581	266,430	273,138			
Overheads		64,618	65,570	63,862			
Interest		0	0	0			
Retirements & Sales	0	0	0	0			
Other (specify) ARO							
Reclass 1995 applied	116,479						
Reclass reporting adj	2,153,995						
Closing Balance	2,752,238	3,519,573	3,851,573	4,188,573	767,335	332,000	337,000
Average Balance	1,617,001	3,297,974	3,685,573	4,020,073			
Change in Year	0	443,199	332,000	337,000			

GROSS ASSETS TABLE

BREAKOUT OF OVERHEADS & INTEREST

ACCOUNT: 1840 1840-Underground Conduit

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	2,882,475	734,213	772,105	845,105			
Additions		32,367	58,582	68,082			
Overheads		5,525	14,418	15,918			
Interest		0	0	0			
Retirements & Sales	0	0	0	0			
Other (specify) ARO							
Reclass 1995 applied	298,076						
Reclass reporting adj	-2,625,228						
Closing Balance	555,323	772,105	845,105	929,105	216,782	73,000	84,000
Average Balance	808,605	753,159	808,605	887,105			
Change in Year	73,000	37,892	73,000	84,000			

GROSS ASSETS TABLE

BREAKOUT OF OVERHEADS & INTEREST

ACCOUNT: 1845 1845-Underground Conductors and Devices

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	408,573	3,398,991	3,547,331	3,881,831			
Additions		126,712	268,436	273,138			
Overheads		21,628	66,064	63,862			
Interest		0	0	0			
Retirements & Sales	0	0	0	0			
Other (specify) ARO							
Reclass 1995 applied	32,854						
Reclass reporting adj	2,625,228						
Closing Balance	3,066,655	3,547,331	3,881,831	4,218,831	480,676	334,500	337,000
Average Balance	1,737,614	3,473,161	3,714,581	4,050,331			
Change in Year	0	148,340	334,500	337,000			

GROSS ASSETS TABLE
BREAKOUT OF OVERHEADS & INTEREST
ACCOUNT: Poles & Wires totals

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	16,150,225	19,767,037	21,068,923	23,056,423			
Additions	0	1,112,071	1,594,968	1,684,218			
Overheads		189,815	392,532	393,782			
Interest		0	0	0			
Retirements & Sales	0	0	0	0			
Other (specify) ARO							
Reclass 1995 applied	1,541,464						
Reclass reporting adj	0						
Closing Balance	17,691,689	21,068,923	23,056,423	25,134,423	3,377,234	1,987,500	2,078,000
Average Balance	16,920,957	20,417,980	22,062,673	24,095,423			
Change in Year	0	1,301,886	1,987,500	2,078,000			

GROSS ASSETS TABLE

BREAKOUT OF OVERHEADS & INTEREST

ACCOUNT: 1850 1850-Line Transformers

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	5,094,734	5,781,540	6,101,044	6,676,544			
Additions		272,920	461,839	478,195			
Overheads		46,584	113,661	111,805			
Interest		0	0	0			
Retirements & Sales	0	0	0	0			
Other (specify) ARO							
Reclass 1995 applied	455,656						
Closing Balance	5,550,390	6,101,044	6,676,544	7,266,544	550,654	575,500	590,000
Average Balance	5,322,562	5,941,292	6,388,794	6,971,544			
Change in Year	0	319,504	575,500	590,000			

GROSS ASSETS TABLE

BREAKOUT OF OVERHEADS & INTEREST

ACCOUNT: 1855 1855-Services

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	363,501	928,161	1,476,214	1,615,144			
Additions		468,119	111,620	113,946			
Overheads		79,934	27,310	26,554			
Interest		0	0	0			
Retirements & Sales	0	0	0	0			
Other (specify) ARO							
Reclass 1995 applied	92,620						
Closing Balance	456,121	1,476,214	1,615,144	1,755,644	1,020,093	138,930	140,500
Average Balance	409,811	1,202,188	1,545,679	1,685,394			
Change in Year	0	548,053	138,930	140,500			

GROSS ASSETS TABLE

BREAKOUT OF OVERHEADS & INTEREST

ACCOUNT: 1860 1860-Meters

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	1,331,726	1,810,406	2,081,193	2,673,193			
Additions		216,587	472,203	117,053			
Overheads		54,200	119,797	22,347			
Interest		0	0	0			
Retirements & Sales	0	0	0	0			
Other (specify) ARO							
Reclass 1995 applied	195,959						
Closing Balance	1,527,685	2,081,193	2,673,193	2,812,593	553,508	592,000	139,400
Average Balance	1,429,706	1,945,800	2,377,193	2,742,893			
Change in Year	0	270,787	592,000	139,400			

GROSS ASSETS TABLE

BREAKOUT OF OVERHEADS & INTEREST

ACCOUNT: Services & meters totals

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	1,695,227	2,738,567	3,557,407	4,288,337			
Additions	0	684,706	583,823	230,999			
Overheads		134,134	147,107	48,901			
Interest		0	0	0			
Retirements & Sales	0	0	0	0			
Other (specify) ARO							
Reclass 1995 applied	288,579						
Closing Balance	1,983,806	3,557,407	4,288,337	4,568,237	1,573,601	730,930	279,900
Average Balance	1,839,517	3,147,987	3,922,872	4,428,287			
Change in Year	0	818,840	730,930	279,900			

GROSS ASSETS TABLE

BREAKOUT OF OVERHEADS & INTEREST

ACCOUNT: 1920 1920-Computer Equipment - Hardware

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	531,584	622,493	771,710	411,410			
Additions		149,217	141,200	337,000			
Overheads		0	0	0			
Interest		0	0	0			
Retirements & Sales			-501,500	-81,500			
Other (specify) ARO							
Closing Balance	531,584	771,710	411,410	666,910	240,126	-360,300	255,500
Average Balance	531,584	697,102	591,560	539,160			
Change in Year	0	149,217	-360,300	255,500			

GROSS ASSETS TABLE

BREAKOUT OF OVERHEADS & INTEREST

ACCOUNT: 1925 1925-Computer Software

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	438,703	466,003	670,397	772,197			
Additions		204,394	101,800	83,700			
Overheads		0	0	0			
Interest		0	0	0			
Retirements & Sales	0	0	0	0			
Other (specify) ARO							
Closing Balance	438,703	670,397	772,197	855,897	231,694	101,800	83,700
Average Balance	438,703	568,200	721,297	814,047			
Change in Year	0	204,394	101,800	83,700			

GROSS ASSETS TABLE

BREAKOUT OF OVERHEADS & INTEREST

ACCOUNT: IT assets totals

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	970,287	1,088,496	1,442,107	1,183,607			
Additions	0	353,611	243,000	420,700			
Overheads		0	0	0			
Interest		0	0	0			
Retirements & Sales	0	0	-501,500	-81,500			
Other (specify) ARO							
Closing Balance	970,287	1,442,107	1,183,607	1,522,807	471,820	-258,500	339,200
Average Balance	970,287	1,265,302	1,312,857	1,353,207			
Change in Year	0	353,611	-258,500	339,200			

GROSS ASSETS TABLE

BREAKOUT OF OVERHEADS & INTEREST

ACCOUNT: 1915 1915-Office Furniture and Equipment

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	261,818	284,724	328,757	267,257			
Additions		50,915	27,500	82,000			
Overheads		0	0	0			
Interest		0	0	0			
Retirements & Sales		-6,882	-89,000	-15,500			
Other (specify) ARO							
Closing Balance	261,818	328,757	267,257	333,757	66,939	-61,500	66,500
Average Balance	261,818	306,741	298,007	300,507			
Change in Year	0	44,033	-61,500	66,500			

GROSS ASSETS TABLE

BREAKOUT OF OVERHEADS & INTEREST

ACCOUNT: 1930 1930-Transportation Equipment

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	1,317,735	1,380,887	1,433,315	1,579,952			
Additions		52,428	303,940	280,000			
Overheads		0	0	0			
Interest		0	3,697	0			
Retirements & Sales			-161,000	-135,000			
Other (specify) ARO							
Closing Balance	1,317,735	1,433,315	1,579,952	1,724,952	115,580	146,637	145,000
Average Balance	1,317,735	1,407,101	1,506,634	1,652,452			
Change in Year	0	52,428	146,637	145,000			

GROSS ASSETS TABLE

BREAKOUT OF OVERHEADS & INTEREST

ACCOUNT: 1935 1935-Stores Equipment

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	51,006	51,007	53,152	45,152			
Additions		2,145	0	0			
Overheads		0	0	0			
Interest		0	0	0			
Retirements & Sales			-8,000	-500			
Other (specify) ARO							
Closing Balance	51,006	53,152	45,152	44,652	2,146	-8,000	-500
Average Balance	51,006	52,080	49,152	44,902			
Change in Year	0	2,145	-8,000	-500			

GROSS ASSETS TABLE

BREAKOUT OF OVERHEADS & INTEREST

ACCOUNT: 1940 1940-Tools, Shop and Garage Equipment

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	351,513	361,332	412,229	380,729			
Additions		50,897	57,000	49,700			
Overheads		0	0	0			
Interest		0	0	0			
Retirements & Sales			-88,500	-44,500			
Other (specify) ARO							
Closing Balance	351,513	412,229	380,729	385,929	60,716	-31,500	5,200
Average Balance	351,513	386,781	396,479	383,329			
Change in Year	0	50,897	-31,500	5,200			

GROSS ASSETS TABLE
BREAKOUT OF OVERHEADS & INTEREST
ACCOUNT: Equipment totals

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	1,982,072	2,077,950	2,227,453	2,273,090			
Additions	0	156,385	388,440	411,700			
Overheads		0	0	0			
Interest		0	3,697	0			
Retirements & Sales	0	-6,882	-346,500	-195,500			
Other (specify) ARO							
Closing Balance	1,982,072	2,227,453	2,273,090	2,489,290	245,381	45,637	216,200
Average Balance	1,982,072	2,152,702	2,250,272	2,381,190			
Change in Year	0	149,503	41,940	216,200			

GROSS ASSETS TABLE

BREAKOUT OF OVERHEADS & INTEREST

ACCOUNT: 1970 1970-Load Management Controls - Customer Premises

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	0	77,016	689,636	859,156			
Additions		612,620	169,520	0			
Overheads		0	0	0			
Interest		0	0	0			
Retirements & Sales	0	0	0	0			
Other (specify) ARO							
Closing Balance	0	689,636	859,156	859,156	689,636	169,520	0
Average Balance	0	383,326	774,396	859,156			
Change in Year	0	612,620	169,520	0			

GROSS ASSETS TABLE

BREAKOUT OF OVERHEADS & INTEREST

ACCOUNT: 1980 1980-System Supervisory Equipment

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	511,611	511,611	609,098	636,598			
Additions		97,487	27,500	140,200			
Overheads		0	0	12,600			
Interest		0	0	0			
Retirements & Sales	0	0	0	0			
Other (specify) ARO							
Closing Balance	511,611	609,098	636,598	789,398	97,487	27,500	152,800
Average Balance	511,611	560,355	622,848	712,998			
Change in Year	0	97,487	27,500	152,800			

GROSS ASSETS TABLE

BREAKOUT OF OVERHEADS & INTEREST

ACCOUNT: 1995 1995-Contributions and Grants - Credit

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	0	-3,329,331	-3,872,520	-4,299,655			
Additions		-543,189	-427,135	-700,330			
Overheads		0	0	0			
Interest		0	0	0			
Retirements & Sales	0	0	0	0			
Other (specify) ARO							
Reclass 1995 allocated to assets	-2,285,699						
Closing Balance	-2,285,699	-3,872,520	-4,299,655	-4,999,985	-1,586,821	-427,135	-700,330
Average Balance	-1,142,850	-3,600,926	-4,086,088	-4,649,820			
Change in Year	0	-543,189	-427,135	-700,330			

GROSS ASSETS TABLE

BREAKOUT OF OVERHEADS & INTEREST

ACCOUNT: 1610 1610-Miscellaneous Intangible Plant

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	336,911	336,911	336,911	336,911			
Additions	0	0	0	0			
Overheads		0	0	0			
Interest		0	0	0			
Retirements & Sales	0	0	0	0			
Other (specify) ARO							
Closing Balance	336,911	336,911	336,911	336,911	0	0	0
Average Balance	336,911	336,911	336,911	336,911			
Change in Year	0	0	0	0			

GROSS ASSETS TABLE

BREAKOUT OF OVERHEADS & INTEREST

ACCOUNT: Other distribution assets total

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	848,522	-2,403,793	-2,236,875	-2,466,990			
Additions	0	166,918	-230,115	-560,130			
Overheads		0	0	12,600			
Interest		0	0	0			
Retirements & Sales							
Other (specify) ARO							
Reclass 1995 allocated	-2,285,699						
Closing Balance	-1,437,177	-2,236,875	-2,466,990	-3,014,520	-799,698	-230,115	-547,530
Average Balance	-294,328	-2,320,334	-2,351,933	-2,740,755			
Change in Year	0	166,918	-230,115	-547,530			

GROSS ASSETS TABLE
BREAKOUT OF OVERHEADS & INTEREST
ACCOUNT: Overall totals

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	31,480,287	34,272,324	37,542,800	41,970,016			
Additions	0	2,885,997	4,649,469	4,042,142			
Overheads		391,361	739,390	788,868			
Interest		0	37,357	0			
Retirements & Sales	0	-6,882	-999,000	-278,000			
Other (specify) ARO							
Reclass 1995	0						
Reclass reporting adj	0						
Closing Balance	31,480,287	37,542,800	41,970,016	46,523,026	6,062,513	4,427,216	4,553,010
Average Balance	31,480,287	35,907,562	39,756,408	44,246,521			
Change in Year	0	3,270,476	4,389,859	4,553,010			

GROSS ASSETS TABLE
FUNCTIONAL BREAKDOWN
ACCOUNT: 1805 1805-Land

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	354,871	354,871	354,871	354,871			
Additions	0	0	0	0			
Depreciation 0.0%							
Retirements & Sales	0	0	0	0			
Other (specify) ARO							
Closing Balance	354,871	354,871	354,871	354,871	0	0	0
Average Balance	354,871	354,871	354,871	354,871			
Change in Year	0	0	0	0			

Capital Function:

Sustaining	-	-	-
Development	-	-	-
Total adds	-	-	-

**GROSS ASSETS TABLE
FUNCTIONAL BREAKDOWN**

ACCOUNT: 1806 1806-Land Rights

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	4,738	4,738	4,738	4,738			
Additions	0	0	0	0			
Depreciation 0.0%							
Retirements & Sales	0	0	0	0			
Other (specify) ARO							
Closing Balance	4,738	4,738	4,738	4,738	0	0	0
Average Balance	354,871	4,738	4,738	4,738			
Change in Year	0	0	0	0			

Capital Function:

Sustaining	-	-	-
Development	-	-	-
Total adds	-	-	-

GROSS ASSETS TABLE
FUNCTIONAL BREAKDOWN

ACCOUNT: 1808 1808-Buildings and Fixtures

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	2,567,902	2,810,822	2,840,621	2,840,621			
Additions		29,799	0	285,000			
Depreciation 4.0%							
Retirements & Sales	0	0	0	0			
Other (specify) ARO							
Closing Balance	2,567,902	2,840,621	2,840,621	3,125,621	272,719	0	285,000
Average Balance	2,567,902	2,825,722	2,840,621	2,983,121			
Change in Year	0	29,799	0	285,000			

Capital Function:

Sustaining	29,799	-	285,000
Development	-	-	
Total adds	29,799	-	285,000

GROSS ASSETS TABLE

FUNCTIONAL BREAKDOWN

ACCOUNT: Land & Buildings total

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	2,927,511	3,170,431	3,200,230	3,200,230			
Additions	0	29,799	0	285,000			
Depreciation 0.0%							
Retirements & Sales	0	0	0	0			
Other (specify) ARO							
Closing Balance	2,927,511	3,200,230	3,200,230	3,485,230	272,719	0	285,000
Average Balance	2,927,511	3,185,331	3,200,230	3,342,730			
Change in Year	0	29,799	0	285,000			

Capital Function:

Sustaining	29,799	-	285,000
Development	-	-	-
Total adds	29,799	-	285,000

GROSS ASSETS TABLE
FUNCTIONAL BREAKDOWN

ACCOUNT: 1820 1820-Distribution Station Equipment - Normally Primary below 50 kV

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	1,811,709	2,052,096	2,182,511	3,758,775			
Additions		130,415	1,727,264	1,313,240			
Depreciation 4.0%							
Retirements & Sales			-151,000	-1,000			
Other (specify) ARO							
Closing Balance	1,811,709	2,182,511	3,758,775	5,071,015	370,802	1,576,264	1,312,240
Average Balance	1,811,709	2,117,304	2,970,643	4,414,895			
Change in Year	0	130,415	1,576,264	1,312,240			

Capital Function:

Sustaining	130,415	1,727,264	1,030,240
Development	-	-	283,000
Total adds	130,415	1,727,264	1,313,240

GROSS ASSETS TABLE
FUNCTIONAL BREAKDOWN

ACCOUNT: 1830 1830-Poles, Towers and Fixtures

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	12,377,413	12,557,459	13,229,914	14,477,914			
Additions		672,455	1,248,000	1,320,000			
Depreciation 4.0%							
Retirements & Sales	0	0	0	0			
Other (specify) ARO							
Reclass 1995 applied	1,094,055						
Reclass reporting adj	-2,153,995						
Closing Balance	11,317,473	13,229,914	14,477,914	15,797,914	1,912,441	1,248,000	1,320,000
Average Balance	11,847,443	12,893,687	13,853,914	15,137,914			
Change in Year	0	672,455	1,248,000	1,320,000			

Capital Function:

Sustaining	330,713	524,778	638,352
Development	341,742	723,222	681,648
Total adds	672,455	1,248,000	1,320,000

GROSS ASSETS TABLE
FUNCTIONAL BREAKDOWN

ACCOUNT: 1835 1835-Overhead Conductors and Devices

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	481,764	3,076,374	3,519,573	3,851,573			
Additions		443,199	332,000	337,000			
Depreciation 4.0%							
Retirements & Sales	0	0	0	0			
Other (specify) ARO							
Reclass 1995 applied	116,479						
Reclass reporting adj	2,153,995						
Closing Balance	2,752,238	3,519,573	3,851,573	4,188,573	767,335	332,000	337,000
Average Balance	1,617,001	3,297,974	3,685,573	4,020,073			
Change in Year	0	443,199	332,000	337,000			

Capital Function:

Sustaining	217,965	139,595	162,973
Development	225,234	192,405	174,027
Total adds	443,199	332,000	337,000

GROSS ASSETS TABLE
FUNCTIONAL BREAKDOWN

ACCOUNT: 1840 1840-Underground Conduit

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	2,882,475	734,213	772,105	845,105			
Additions		37,892	73,000	84,000			
Depreciation 4.0%							
Retirements & Sales	0	0	0	0			
Other (specify) ARO							
Reclass 1995 applied	298,076						
Reclass reporting adj	-2,625,228						
Closing Balance	555,323	772,105	845,105	929,105	216,782	73,000	84,000
Average Balance	808,605	753,159	808,605	887,105			
Change in Year	73,000	37,892	73,000	84,000			

Capital Function:

Sustaining	18,635	31,288	40,622
Development	19,257	41,712	43,378
Total adds	37,892	73,000	84,000

GROSS ASSETS TABLE
FUNCTIONAL BREAKDOWN

ACCOUNT: 1845 1845-Underground Conductors and Devices

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	408,573	3,398,991	3,547,331	3,881,831			
Additions		148,340	334,500	337,000			
Depreciation 4.0%							
Retirements & Sales	0	0	0	0			
Other (specify) ARO							
Reclass 1995 applied	32,854						
Reclass reporting adj	2,625,228						
Closing Balance	3,066,655	3,547,331	3,881,831	4,218,831	480,676	334,500	337,000
Average Balance	1,737,614	3,473,161	3,714,581	4,050,331			
Change in Year	0	148,340	334,500	337,000			

Capital Function:

Sustaining	65,051	143,367	162,973
Development	83,289	191,133	174,027
Total adds	148,340	334,500	337,000

GROSS ASSETS TABLE
FUNCTIONAL BREAKDOWN
ACCOUNT: Poles & Wires totals

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	16,150,225	19,767,037	21,068,923	23,056,423			
Additions	0	1,301,886	1,987,500	2,078,000			
Depreciation 0.0%							
Retirements & Sales	0	0	0	0			
Other (specify) ARO							
Reclass 1995 applied	1,541,464						
Reclass reporting adj	0						
Closing Balance	17,691,689	21,068,923	23,056,423	25,134,423	3,377,234	1,987,500	2,078,000
Average Balance	16,920,957	20,417,980	22,062,673	24,095,423			
Change in Year	0	1,301,886	1,987,500	2,078,000			

Capital Function:

Sustaining	632,364	839,028	1,004,920
Development	669,522	1,148,472	1,073,080
Total adds	1,301,886	1,987,500	2,078,000

GROSS ASSETS TABLE
FUNCTIONAL BREAKDOWN

ACCOUNT: 1850 1850-Line Transformers

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	5,094,734	5,781,540	6,101,044	6,676,544			
Additions		319,504	575,500	590,000			
Depreciation 4.0%							
Retirements & Sales	0	0	0	0			
Other (specify) ARO							
Reclass 1995 applied	455,656						
Closing Balance	5,550,390	6,101,044	6,676,544	7,266,544	550,654	575,500	590,000
Average Balance	5,322,562	5,941,292	6,388,794	6,971,544			
Change in Year	0	319,504	575,500	590,000			

Capital Function:

Sustaining	157,132	246,659	285,324
Development	162,372	328,841	304,676
Total adds	319,504	575,500	590,000

GROSS ASSETS TABLE
FUNCTIONAL BREAKDOWN

ACCOUNT: 1855 1855-Services

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	363,501	928,161	1,476,214	1,615,144			
Additions		548,053	138,930	140,500			
Depreciation 4.0%							
Retirements & Sales	0	0	0	0			
Other (specify) ARO							
Reclass 1995 applied	92,620						
Closing Balance	456,121	1,476,214	1,615,144	1,755,644	1,020,093	138,930	140,500
Average Balance	409,811	1,202,188	1,545,679	1,685,394			
Change in Year	0	548,053	138,930	140,500			

Capital Function:

Sustaining	269,532	59,545	67,946
Development	278,521	79,385	72,554
Total adds	548,053	138,930	140,500

GROSS ASSETS TABLE
FUNCTIONAL BREAKDOWN

ACCOUNT: 1860 1860-Meters

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	1,331,726	1,810,406	2,081,193	2,673,193			
Additions		270,787	592,000	139,400			
Depreciation 4.0%							
Retirements & Sales	0	0	0	0			
Other (specify) ARO							
Reclass 1995 applied	195,959						
Closing Balance	1,527,685	2,081,193	2,673,193	2,812,593	553,508	592,000	139,400
Average Balance	1,429,706	1,945,800	2,377,193	2,742,893			
Change in Year	0	270,787	592,000	139,400			

Capital Function:

Sustaining	270,787	592,000	139,400
Development	-	-	-
Total adds	270,787	592,000	139,400

GROSS ASSETS TABLE
FUNCTIONAL BREAKDOWN
ACCOUNT: Services & meters totals

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	1,695,227	2,738,567	3,557,407	4,288,337			
Additions	0	818,840	730,930	279,900			
Depreciation 0.0%							
Retirements & Sales	0	0	0	0			
Other (specify) ARO							
Reclass 1995 applied	288,579						
Closing Balance	1,983,806	3,557,407	4,288,337	4,568,237	1,573,601	730,930	279,900
Average Balance	1,839,517	3,147,987	3,922,872	4,428,287			
Change in Year	0	818,840	730,930	279,900			

Capital Function:

Sustaining	540,319	651,545	207,346
Development	278,521	79,385	72,554
Total adds	818,840	730,930	279,900

GROSS ASSETS TABLE
FUNCTIONAL BREAKDOWN

ACCOUNT: 1920 1920-Computer Equipment - Hardware

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	531,584	622,493	771,710	411,410			
Additions		149,217	141,200	337,000			
Depreciation 20.0%							
Retirements & Sales			-501,500	-81,500			
Other (specify) ARO							
Closing Balance	531,584	771,710	411,410	666,910	240,126	-360,300	255,500
Average Balance	531,584	697,102	591,560	539,160			
Change in Year	0	149,217	-360,300	255,500			

Capital Function:

Sustaining	139,918	131,200	317,000
Development	9,299	10,000	20,000
Total adds	149,217	141,200	337,000

GROSS ASSETS TABLE
FUNCTIONAL BREAKDOWN

ACCOUNT: 1925 1925-Computer Software

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	438,703	466,003	670,397	772,197			
Additions		204,394	101,800	83,700			
Depreciation 100.0%							
Retirements & Sales	0	0	0	0			
Other (specify) ARO							
Closing Balance	438,703	670,397	772,197	855,897	231,694	101,800	83,700
Average Balance	438,703	568,200	721,297	814,047			
Change in Year	0	204,394	101,800	83,700			

Capital Function:

Sustaining	183,458	101,800	83,700
Development	20,936	-	-
Total adds	204,394	101,800	83,700

GROSS ASSETS TABLE
FUNCTIONAL BREAKDOWN
ACCOUNT: IT assets totals

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	970,287	1,088,496	1,442,107	1,183,607			
Additions	0	353,611	243,000	420,700			
Depreciation 0.0%							
Retirements & Sales	0	0	-501,500	-81,500			
Other (specify) ARO							
Closing Balance	970,287	1,442,107	1,183,607	1,522,807	471,820	-258,500	339,200
Average Balance	970,287	1,265,302	1,312,857	1,353,207			
Change in Year	0	353,611	-258,500	339,200			

Capital Function:

Sustaining	323,376	233,000	400,700
Development	30,235	10,000	20,000
Total adds	353,611	243,000	420,700

GROSS ASSETS TABLE
FUNCTIONAL BREAKDOWN

ACCOUNT: 1915 1915-Office Furniture and Equipment

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	261,818	284,724	328,757	267,257			
Additions		50,915	27,500	82,000			
Depreciation 15.0%							
Retirements & Sales		-6,882	-89,000	-15,500			
Other (specify) ARO							
Closing Balance	261,818	328,757	267,257	333,757	66,939	-61,500	66,500
Average Balance	261,818	306,741	298,007	300,507			
Change in Year	0	44,033	-61,500	66,500			

Capital Function:

Sustaining	50,915	27,500	82,000
Development	-	-	-
Total adds	50,915	27,500	82,000

GROSS ASSETS TABLE
FUNCTIONAL BREAKDOWN

ACCOUNT: 1930 1930-Transportation Equipment

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	1,317,735	1,380,887	1,433,315	1,579,952			
Additions		52,428	307,637	280,000			
Depreciation 15.0%							
Retirements & Sales			-161,000	-135,000			
Other (specify) ARO							
Closing Balance	1,317,735	1,433,315	1,579,952	1,724,952	115,580	146,637	145,000
Average Balance	1,317,735	1,407,101	1,506,634	1,652,452			
Change in Year	0	52,428	146,637	145,000			

Capital Function:

Sustaining	52,428	307,637	280,000
Development	-	-	-
Total adds	52,428	307,637	280,000

GROSS ASSETS TABLE

FUNCTIONAL BREAKDOWN

ACCOUNT: 1935 1935-Stores Equipment

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	51,006	51,007	53,152	45,152			
Additions		2,145	0	0			
Depreciation 10.0%							
Retirements & Sales			-8,000	-500			
Other (specify) ARO							
Closing Balance	51,006	53,152	45,152	44,652	2,146	-8,000	-500
Average Balance	51,006	52,080	49,152	44,902			
Change in Year	0	2,145	-8,000	-500			

Capital Function:

Sustaining	2,145	-	-
Development	-	-	-
Total adds	2,145	-	-

GROSS ASSETS TABLE
FUNCTIONAL BREAKDOWN

ACCOUNT: 1940 1940-Tools, Shop and Garage Equipment

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	351,513	361,332	412,229	380,729			
Additions		50,897	57,000	49,700			
Depreciation 10.0%							
Retirements & Sales			-88,500	-44,500			
Other (specify) ARO							
Closing Balance	351,513	412,229	380,729	385,929	60,716	-31,500	5,200
Average Balance	351,513	386,781	396,479	383,329			
Change in Year	0	50,897	-31,500	5,200			

Capital Function:

Sustaining	50,897	57,000	49,700
Development	-	-	-
Total adds	50,897	57,000	49,700

GROSS ASSETS TABLE
FUNCTIONAL BREAKDOWN
ACCOUNT: Equipment totals

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	1,982,072	2,077,950	2,227,453	2,273,090			
Additions	0	156,385	392,137	411,700			
Depreciation 0.0%							
Retirements & Sales	0	-6,882	-346,500	-195,500			
Other (specify) ARO							
Closing Balance	1,982,072	2,227,453	2,273,090	2,489,290	245,381	45,637	216,200
Average Balance	1,982,072	2,152,702	2,250,272	2,381,190			
Change in Year	0	149,503	45,637	216,200			

Capital Function:

Sustaining	156,385	392,137	411,700
Development	-	-	-
Total adds	156,385	392,137	411,700

GROSS ASSETS TABLE
FUNCTIONAL BREAKDOWN

ACCOUNT: 1970 1970-Load Management Controls - Customer Premises

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	0	77,016	689,636	859,156			
Additions		612,620	169,520	0			
Depreciation 10.0%							
Retirements & Sales	0	0	0	0			
Other (specify) ARO							
Closing Balance	0	689,636	859,156	859,156	689,636	169,520	0
Average Balance	0	383,326	774,396	859,156			
Change in Year	0	612,620	169,520	0			

Capital Function:

Sustaining	-	-	-
Development	612,620	169,520	-
Total adds	612,620	169,520	-

GROSS ASSETS TABLE
FUNCTIONAL BREAKDOWN

ACCOUNT: 1980 1980-System Supervisory Equipment

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	511,611	511,611	609,098	636,598			
Additions		97,487	27,500	152,800			
Depreciation 6.7%							
Retirements & Sales	0	0	0	0			
Other (specify) ARO							
Closing Balance	511,611	609,098	636,598	789,398	97,487	27,500	152,800
Average Balance	511,611	560,355	622,848	712,998			
Change in Year	0	97,487	27,500	152,800			

Capital Function:

Sustaining	-	-	-
Development	97,487	27,500	152,800
Total adds	97,487	27,500	152,800

GROSS ASSETS TABLE
FUNCTIONAL BREAKDOWN

ACCOUNT: 1995 1995-Contributions and Grants - Credit

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	0	-3,329,331	-3,872,520	-4,299,655			
Additions		-543,189	-427,135	-700,330			
Depreciation 4.0%							
Retirements & Sales	0	0	0	0			
Other (specify) ARO							
Reclass 1995 allocated to assets	-2,285,699						
Closing Balance	-2,285,699	-3,872,520	-4,299,655	-4,999,985	-1,586,821	-427,135	-700,330
Average Balance	-1,142,850	-3,600,926	-4,086,088	-4,649,820			
Change in Year	0	-543,189	-427,135	-700,330			

Capital Function:

Sustaining	(268,518)	(427,135)	(700,330)
Development	(274,671)	-	-
Total adds	(543,189)	(427,135)	(700,330)

GROSS ASSETS TABLE

FUNCTIONAL BREAKDOWN

ACCOUNT: 1610 1610-Miscellaneous Intangible Plant

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	336,911	336,911	336,911	336,911			
Additions	0	0	0	0			
Depreciation 0.0%							
Retirements & Sales	0	0	0	0			
Other (specify) ARO							
Closing Balance	336,911	336,911	336,911	336,911	0	0	0
Average Balance	336,911	336,911	336,911	336,911			
Change in Year	0	0	0	0			

Capital Function:

Sustaining	-	-	-
Development	-	-	-
Total adds	-	-	-

GROSS ASSETS TABLE
FUNCTIONAL BREAKDOWN

ACCOUNT: Other distribution assets total

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	848,522	-2,403,793	-2,236,875	-2,466,990			
Additions	0	166,918	-230,115	-547,530			
Depreciation 0.0%							
Retirements & Sales							
Other (specify) ARO							
Reclass 1995 allocated	-2,285,699						
Closing Balance	-1,437,177	-2,236,875	-2,466,990	-3,014,520	-799,698	-230,115	-547,530
Average Balance	-294,328	-2,320,334	-2,351,933	-2,740,755			
Change in Year	0	166,918	-230,115	-547,530			

Capital Function:

Sustaining	(268,518)	(427,135)	(700,330)
Development	435,436	197,020	152,800
Total adds	166,918	(230,115)	(547,530)

GROSS ASSETS TABLE
FUNCTIONAL BREAKDOWN
ACCOUNT: Overall totals

	2006 APPROVED	2006 ACTUAL	BRIDGE YEAR	TEST YEAR	VARIANCES		
	Gross Cost	Gross Cost	Gross Cost	Gross Cost	2006 ACTUAL FROM BOARD APPROVED	2007 BRIDGE FROM 2006 ACTUAL	2008 TEST FROM 2007 BRIDGE
Opening Balance	31,480,287	34,272,324	37,542,800	41,970,016			
Additions	0	3,277,358	5,426,216	4,831,010			
Depreciation 0.0%							
Retirements & Sales	0	-6,882	-999,000	-278,000			
Other (specify) ARO							
Reclass 1995	0						
Reclass reporting adj	0						
Closing Balance	31,480,287	37,542,800	41,970,016	46,523,026	6,062,513	4,427,216	4,553,010
Average Balance	31,480,287	35,907,562	39,756,408	44,246,521			
Change in Year	0	3,270,476	4,427,216	4,553,010			

Capital Function:

Sustaining	1,701,272	3,662,498	2,924,900
Development	1,576,086	1,763,718	1,906,110
Total adds	3,277,358	5,426,216	4,831,010

OEB STAFF INTERROGATORIES

APPENDIX E

Cost Allocation Run 2 Filing

E3	PLCC	Backup documentation for calculating Peak Load Carrying Capability.
E4	Trial Balance Index	Exhibit showing 1. how accounts are grouped for reporting, how accounts are categorized and how accounts are allocated
E5	Reconciliation	Exhibit showing reconciliation of accounts included and excluded from the allocation study to TB balance



2006 Cost Allocation Information Filing

Halton Hills Hydro Inc.

EB-2005-0374 EB-2007-0001

Monday, January 15, 2007

Sheet I2 Class Selection -

Second Run

Instructions:

Step 1: Please input your existing classes

Step 2: If this is your first run, select "First Run" in the drop-down menu below

Step 3: After all classes have been entered, Click the "Update" button in row E41.

Click for Drop-Down
Menu



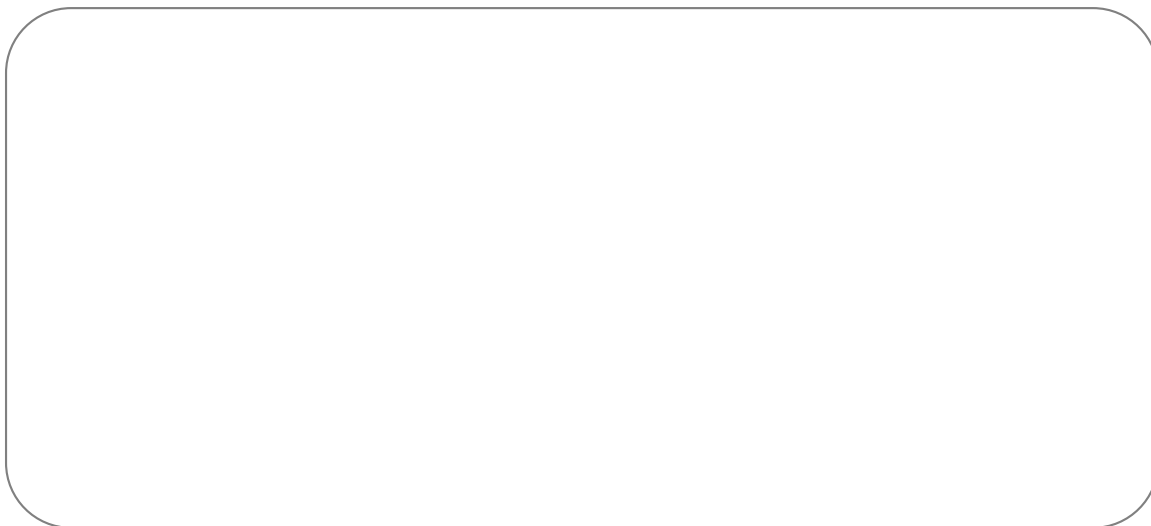
Second Run

If desired, provide a summary of this run
(40 characters max.)

		Utility's Class Definition	Current
1	Residential	Residential	YES
2	GS <50	GS<50kW	YES
3	GS>50-Regular	GS 50-999 kW	YES
4	GS> 50-TOU	GS 1000-4999	YES
5	GS >50-Intermediate		YES
6	Large Use >5MW		YES
7	Street Light	Street Light	YES
8	Sentinel	Sentinel	YES
9	Unmetered Scattered Load	Unmetered Scattered Load	YES
10	Embedded Distributor		YES
11	Back-up/Standby Power		YES
12	Rate Class 1		YES
13	Rate class 2		YES
14	Rate class 3		YES
15	Rate class 4		YES
16	Rate class 5		YES
17	Rate class 6		YES
18	Rate class 7		YES
19	Rate class 8		YES
20	Rate class 9		YES

Update

**** Space available for additional information about this run**

A large, empty rounded rectangular box with a thin black border, intended for additional information about the run.



2006 Cost Allocation Information Filing

Halton Hills Hydro Inc.

EB-2005-0374 EB-2007-0001

Monday, January 15, 2007

Sheet I3 Trial Balance Data - Second Run

Instructions:

Step 1: Copy 2006 EDR Trial Balance values (Sheet 2-4, Column P17 to P446) to Column D21 of this worksheet. Use the Edit - Paste *Special - Values* function.

Step 2: Enter the amounts needed to be reclassified to column F.

Step 3: Enter Target Net Income from approved EDR (Sheet 4-1, cell F23)

Step 4: Enter PILs from approved EDR (Sheet 4-2, cell E15)

Step 5: Enter Interest from approved EDR (Sheet 4-1, cell F21)

Step 6: Enter specific service charges offset from approved EDR (Sheet 5-5, cell D19)

Step 7: Enter Transformation Ownership Allowance Credit from approved EDR (Sheet 6-3, cell R120)

Step 8: Enter Low Voltage Wheeling Adjustment Credit from approved EDR (Sheet ADJ 3, cell F46)

Step 9: Enter Revenue Requirement from approved EDR (Sheet 5-1, cell F22)

Approved Target Net Income (\$)	\$1,329,336
Approved PILs (\$)	\$938,649
Approved Interest (\$)	\$923,150
Approved Specific Service Charges (\$)	\$319,620
Approved Transformer Ownership Allowance (\$)	\$165,383
Approved Low Voltage Wheeling Adjustment (\$)	\$613,744
Approved Revenue Requirement (\$)	\$9,663,351

From this Sheet

Differences?

Step 10: Enter Total Rate Base from approved EDR (Sheet 3-1, cell F21)

Step 11: Enter Directly Allocated amounts into column G.

Revenue Requirement to be Used in this model (\$)	\$9,214,990
Approved Rate Base (\$)	\$29,540,791
Rate Base to be Used in this model (\$)	\$29,473,537

\$9,214,991

Rev Req Matches

\$29,473,536

Rate Base Matches

Uniform System of Accounts - Detail Accounts

USoA Account #	Accounts	Financial Statement (EDR Sheet 2.4, Column P)	Model Adjustments	Reclassify accounts	Direct Allocation	Reclassified Balance
1005	Cash					\$0
1010	Cash Advances and Working Funds					\$0
1020	Interest Special Deposits					\$0
1030	Dividend Special Deposits					\$0
1040	Other Special Deposits					\$0
1060	Term Deposits					\$0
1070	Current Investments					\$0
1100	Customer Accounts Receivable					\$0
1102	Accounts Receivable - Services					\$0
1104	Accounts Receivable - Recoverable Work					\$0
1105	Accounts Receivable - Merchandise, Jobbing, etc.					\$0
1110	Other Accounts Receivable					\$0
1120	Accrued Utility Revenues					\$0
1130	Accumulated Provision for Uncollectible Accounts-- Credit					\$0
1140	Interest and Dividends Receivable					\$0
1150	Rents Receivable					\$0
1170	Notes Receivable					\$0
1180	Prepayments					\$0
1190	Miscellaneous Current and Accrued Assets					\$0
1200	Accounts Receivable from Associated Companies					\$0
1210	Notes Receivable from Associated Companies					\$0
1305	Fuel Stock					\$0
1330	Plant Materials and Operating Supplies					\$0
1340	Merchandise					\$0
1350	Other Materials and Supplies					\$0
1405	Long Term Investments in Non-Associated Companies					\$0
1408	Long Term Receivable - Street Lighting Transfer					\$0
1410	Other Special or Collateral Funds					\$0
1415	Sinking Funds					\$0
1425	Unamortized Debt Expense					\$0
1445	Unamortized Discount on Long-Term Debt--Debit					\$0
1455	Unamortized Deferred Foreign Currency Translation Gains and Losses					\$0
1460	Other Non-Current Assets					\$0
1465	O.M.E.R.S. Past Service Costs					\$0
1470	Past Service Costs - Employee Future Benefits					\$0
1475	Past Service Costs - Other Pension Plans					\$0

1675	Generators	
1680	Accessory Electric Equipment	
1685	Miscellaneous Power Plant Equipment	
1705	Land	
1706	Land Rights	
1708	Buildings and Fixtures	
1710	Leasehold Improvements	
1715	Station Equipment	
1720	Towers and Fixtures	
1725	Poles and Fixtures	
1730	Overhead Conductors and Devices	
1735	Underground Conduit	
1740	Underground Conductors and Devices	
1745	Roads and Trails	
1805	Land	
1806	Land Rights	
1808	Buildings and Fixtures	
1810	Leasehold Improvements	
1815	Transformer Station Equipment - Normally Primary above 50 kV	
1820	Distribution Station Equipment - Normally Primary below 50 kV	
1825	Storage Battery Equipment	
1830	Poles, Towers and Fixtures	
1835	Overhead Conductors and Devices	
1840	Underground Conduit	
1845	Underground Conductors and Devices	
1850	Line Transformers	
1855	Services	
1860	Meters	
1865	Other Installations on Customer's Premises	
1870	Leased Property on Customer Premises	
1875	Street Lighting and Signal Systems	
1905	Land	
1906	Land Rights	
1908	Buildings and Fixtures	
1910	Leasehold Improvements	
1915	Office Furniture and Equipment	
1920	Computer Equipment - Hardware	
1925	Computer Software	
1930	Transportation Equipment	
1935	Stores Equipment	
1940	Tools, Shop and Garage Equipment	
1945	Measurement and Testing Equipment	
1950	Power Operated Equipment	
1955	Communication Equipment	
1960	Miscellaneous Equipment	

		\$0
		\$0
		\$0
		\$0
		\$0
		\$0
		\$0
		\$0
		\$0
		\$0
		\$0
		\$0
		\$0
		\$0
		\$0
		\$0
		\$354,871
		\$4,739
		\$2,563,489
		\$0
		\$0
		\$1,677,812
		\$0
	(\$2,153,995)	\$8,864,448
	\$2,153,995	\$3,604,201
		\$1,550,461
		\$1,688,629
		\$5,040,858
		\$271,718
		\$1,181,487
		\$0
		\$0
		\$0
		\$0
		\$0
		\$0
		\$212,753
		\$494,378
		\$377,719
		\$1,186,706
		\$51,007
		\$323,377
		\$0
		\$0
		\$0
		\$0

4840	Transmission of Electricity by Others	
4845	Miscellaneous Transmission Expense	
4850	Rents	
4905	Maintenance Supervision and Engineering	
4910	Maintenance of Transformer Station Buildings and Fixtures	
4916	Maintenance of Transformer Station Equipment	
4930	Maintenance of Towers, Poles and Fixtures	
4935	Maintenance of Overhead Conductors and Devices	
4940	Maintenance of Overhead Lines - Right of Way	
4945	Maintenance of Overhead Lines - Roads and Trails Repairs	
4950	Maintenance of Overhead Lines - Snow Removal from Roads and Trails	
4960	Maintenance of Underground Lines	
4965	Maintenance of Miscellaneous Transmission Plant	
5005	Operation Supervision and Engineering	
5010	Load Dispatching	
5012	Station Buildings and Fixtures Expense	
5014	Transformer Station Equipment - Operation Labour	
5015	Transformer Station Equipment - Operation Supplies and Expenses	
5016	Distribution Station Equipment - Operation Labour	
5017	Distribution Station Equipment - Operation Supplies and Expenses	
5020	Overhead Distribution Lines and Feeders - Operation Labour	
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	
5030	Overhead Subtransmission Feeders - Operation	
5035	Overhead Distribution Transformers- Operation	
5040	Underground Distribution Lines and Feeders - Operation Labour	
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	
5050	Underground Subtransmission Feeders - Operation	
5055	Underground Distribution Transformers - Operation	
5060	Street Lighting and Signal System Expense	
5065	Meter Expense	
5070	Customer Premises - Operation Labour	
5075	Customer Premises - Materials and Expenses	
5085	Miscellaneous Distribution Expense	
5090	Underground Distribution Lines and Feeders - Rental Paid	
5095	Overhead Distribution Lines and Feeders - Rental Paid	
5096	Other Rent	

		\$0
		\$0
		\$0
		\$0
		\$0
		\$0
		\$0
		\$0
		\$0
		\$0
		\$0
		\$0
		\$0
		\$161,630
		\$0
		\$2,329
		\$0
		\$0
		\$15,961
		\$5,858
		\$58,678
		\$0
		\$0
\$0		\$0
		\$0
		\$9,916
		\$91,927
\$91,162		\$136,149
		\$0
		\$87,804
		\$11,268
		\$409
		\$4,331
		\$0
		\$0
		\$0

6305	Extraordinary Income				\$0
6310	Extraordinary Deductions				\$0
6315	Income Taxes, Extraordinary Items				\$0
6405	Discontinues Operations - Income/ Gains				\$0
6410	Discontinued Operations - Deductions/ Losses				\$0
6415	Income Taxes, Discontinued Operations				\$0

22,504,604

\$0



Reclassification Equals to Zero.
O.K. to Proceed.

Asset Accounts Directly Allocated \$0



2006 Cost Allocation Information Filing

Halton Hills Hydro Inc.

EB-2005-0374 EB-2007-0001

Monday, January 15, 2007

Sheet I4 Break Out Worksheet - Second Run

Instructions:

This is an input sheet for the Break Out of Distribution Assets, Contributed Capital, Amortization, and Amortization Expenses.

****Please see Handbook for detailed instructions****

Enter Net Fixed Assets from <u>approved</u> EDR, Sheet 3-1, cell F12	\$24,244,338

RATE BASE AND DISTRIBUTION ASSETS		BALANCE SHEET ITEMS						
Account	Description	Break out Functions	BREAK OUT (%)	BREAK OUT (\$)	After BO	Contributed Capital - 1995	Accumulated Depreciation - 2105 Capital Contribution	Accumulated Depreciation - 2105 Fixed Assets Only
1565	Conservation and Demand Management	\$355,490		-	355,490			
1805	Land	\$354,871		(\$354,871)	-			
1805-1	Land Station >50 kV			\$0	-			
1805-2	Land Station <50 kV		100.00%	\$354,871	354,871			
1806	Land Rights	\$4,739		(\$4,739)	-			
1806-1	Land Rights Station >50 kV			\$0	-			
1806-2	Land Rights Station <50 kV		100.00%	\$4,739	4,739			
1808	Buildings and Fixtures	\$2,563,489		(\$2,563,489)	-			
1808-1	Buildings and Fixtures > 50 kV			\$0	-			
1808-2	Buildings and Fixtures < 50 kV		100.00%	\$2,563,489	2,563,489			\$ (226,703)
1810	Leasehold Improvements	\$0		\$0	-			
1810-1	Leasehold Improvements >50 kV			\$0	-			
1810-2	Leasehold Improvements <50 kV		100.00%	\$0	-			
1815	Transformer Station Equipment - Normally Primary above 50 kV	\$0		\$0	-			
1820	Distribution Station Equipment - Normally Primary below 50 kV	\$1,677,812		(\$1,677,812)				



2006 Cost Allocation Information Filing

Halton Hills Hydro Inc.

EB-2005-0374 EB-2007-0001

Monday, January 15, 2007

Sheet I4 Break Out Worksheet - Second Run

Instructions:

This is an input sheet for the Break Out of Distribution Assets, Contributed Capital, Amortization, and Amortization Expenses.

****Please see Handbook for detailed instructions****

Enter Net Fixed Assets from <u>approved</u> EDR, Sheet 3-1, cell F12	\$24,244,338

RATE BASE AND DISTRIBUTION ASSETS		BALANCE SHEET ITEMS						
Account	Description	Break out Functions	BREAK OUT (%)	BREAK OUT (\$)	After BO	Contributed Capital - 1995	Accumulated Depreciation - 2105 Capital Contribution	Accumulated Depreciation - 2105 Fixed Assets Only
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)			\$0	-			
1820-2	Distribution Station Equipment - Normally Primary below 50 kV Primary)		100.00%	\$1,677,812	1,677,812			\$ (358,811)
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)		0.00%	\$0	-			
1825	Storage Battery Equipment	\$0		\$0	-			
1825-1	Storage Battery Equipment > 50 kV			\$0	-			
1825-2	Storage Battery Equipment <50 kV		100.00%	\$0	-			
1830	Poles, Towers and Fixtures	\$8,864,448		(\$8,864,448)	-			
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery			\$0	-			
1830-4	Poles, Towers and Fixtures - Primary		72.00%	\$6,382,403	6,382,403			\$ (1,001,215)



2006 Cost Allocation Information Filing

Halton Hills Hydro Inc.

EB-2005-0374 EB-2007-0001

Monday, January 15, 2007

Sheet I4 Break Out Worksheet - Second Run

Instructions:

This is an input sheet for the Break Out of Distribution Assets, Contributed Capital, Amortization, and Amortization Expenses.

****Please see Handbook for detailed instructions****

Enter Net Fixed Assets from <u>approved</u> EDR, Sheet 3-1, cell F12	\$24,244,338

RATE BASE AND DISTRIBUTION ASSETS		BALANCE SHEET ITEMS						
Account	Description	Break out Functions	BREAK OUT (%)	BREAK OUT (\$)	After BO	Contributed Capital - 1995	Accumulated Depreciation - 2105 Capital Contribution	Accumulated Depreciation - 2105 Fixed Assets Only
1830-5	Poles, Towers and Fixtures - Secondary		28.00%	\$2,482,045	2,482,045			\$ (389,362)
1835	Overhead Conductors and Devices	\$3,604,201		(\$3,604,201)	-			
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery			\$0	-			
1835-4	Overhead Conductors and Devices - Primary		65.00%	\$2,342,731	2,342,731			\$ (666,403)
1835-5	Overhead Conductors and Devices - Secondary		35.00%	\$1,261,470	1,261,470			\$ (358,832)
1840	Underground Conduit	\$1,550,461		(\$1,550,461)	-			
1840-3	Underground Conduit - Bulk Delivery		65.00%	\$1,007,800	1,007,800			\$ (243,602)
1840-4	Underground Conduit - Primary		35.00%	\$542,661	542,661			\$ (131,170)
1840-5	Underground Conduit - Secondary		0.00%	\$0	-			
1845	Underground Conductors and Devices	\$1,688,629		(\$1,688,629)	-			
1845-3	Underground Conductors and Devices - Bulk Delivery			\$0	-			



2006 Cost Allocation Information Filing

Halton Hills Hydro Inc.

EB-2005-0374 EB-2007-0001

Monday, January 15, 2007

Sheet I4 Break Out Worksheet - Second Run

Instructions:

This is an input sheet for the Break Out of Distribution Assets, Contributed Capital, Amortization, and Amortization Expenses.

****Please see Handbook for detailed instructions****

Enter Net Fixed Assets from <u>approved</u> EDR, Sheet 3-1, cell F12	\$24,244,338

RATE BASE AND DISTRIBUTION ASSETS		BALANCE SHEET ITEMS						
Account	Description	Break out Functions	BREAK OUT (%)	BREAK OUT (\$)	After BO	Contributed Capital - 1995	Accumulated Depreciation - 2105 Capital Contribution	Accumulated Depreciation - 2105 Fixed Assets Only
1845-4	Underground Conductors and Devices - Primary		65.00%	\$1,097,609	1,097,609			\$ (38,911)
1845-5	Underground Conductors and Devices - Secondary		35.00%	\$591,020	591,020			\$ (20,952)
1850	Line Transformers	\$5,040,858		\$0	5,040,858			\$ (684,850)
1855	Services	\$271,718		\$0	271,718			\$ (59,594)
1860	Meters	\$1,181,487		\$0	1,181,487			\$ (168,041)
	Total	\$27,158,201		(\$0)	\$27,158,201	\$0	\$0	(\$4,348,446)



2006 Cost Allocation Information Filing

Halton Hills Hydro Inc.

EB-2005-0374 EB-2007-0001

Monday, January 15, 2007

Sheet I4 Break Out Worksheet - Second Run

Instructions:

This is an input sheet for the Break Out of Distribution Assets, Contributed Capital, Amortization, and Amortization Expenses.

****Please see Handbook for detailed instructions****

Enter Net Fixed Assets from <u>approved</u> EDR, Sheet 3-1, cell F12	\$24,244,338

RATE BASE AND DISTRIBUTION ASSETS		BALANCE SHEET ITEMS						
Account	Description	Break out Functions	BREAK OUT (%)	BREAK OUT (\$)	After BO	Contributed Capital - 1995	Accumulated Depreciation - 2105 Capital Contribution	Accumulated Depreciation - 2105 Fixed Assets Only
	SUB TOTAL from I3	\$27,158,201						

General Plant		Break out Functions				Contributed Capital - 1995	Accumulated Depreciation - 2105 Capital Contribution	Accumulated Depreciation - 2105 Fixed Assets Only
1905	Land	\$0			-			
1906	Land Rights	\$0			-			
1908	Buildings and Fixtures	\$0			-			
1910	Leasehold Improvements	\$0			-			
1915	Office Furniture and Equipment	\$212,753			212,753			\$ (99,894)
1920	Computer Equipment - Hardware	\$494,378			494,378			\$ (333,390)
1925	Computer Software	\$377,719			377,719			\$ (286,078)
1930	Transportation Equipment	\$1,186,706			1,186,706			\$ (650,256)
1935	Stores Equipment	\$51,007			51,007			\$ (22,663)
1940	Tools, Shop and Garage Equipment	\$323,377			323,377			\$ (149,184)



2006 Cost Allocation Information Filing

Halton Hills Hydro Inc.

EB-2005-0374 EB-2007-0001

Monday, January 15, 2007

Sheet I4 Break Out Worksheet - Second Run

Instructions:

This is an input sheet for the Break Out of Distribution Assets, Contributed Capital, Amortization, and Amortization Expenses.

****Please see Handbook for detailed instructions****

Enter Net Fixed Assets from <u>approved</u> EDR, Sheet 3-1, cell F12	\$24,244,338

RATE BASE AND DISTRIBUTION ASSETS		BALANCE SHEET ITEMS						
Account	Description	Break out Functions	BREAK OUT (%)	BREAK OUT (\$)	After BO	Contributed Capital - 1995	Accumulated Depreciation - 2105 Capital Contribution	Accumulated Depreciation - 2105 Fixed Assets Only
1945	Measurement and Testing Equipment	\$0			-			
1950	Power Operated Equipment	\$0			-			
1955	Communication Equipment	\$0			-			
1960	Miscellaneous Equipment	\$0			-			
1970	Load Management Controls - Customer Premises	\$0			-			
1975	Load Management Controls - Utility Premises	\$0			-			
1980	System Supervisory Equipment	\$485,269			485,269			\$ (95,303)
1990	Other Tangible Property	\$0			-			
2005	Property Under Capital Leases	\$0			-			
2010	Electric Plant Purchased or Sold	\$0			-			
Total		\$3,131,206		\$0	\$3,131,206	\$0	\$0	(\$1,636,768)
SUB TOTAL from I3		\$3,131,206						
I3 Directly Allocated		\$0						
Grand Total		\$30,289,407		(\$0)	\$30,289,407	\$0	\$0	(\$5,985,214)

2006 Cost Allocation Information Filing

Halton Hills Hydro Inc.

EB-2005-0374 EB-2007-0001

Monday, January 15, 2007

Sheet I4 Break Out Worksheet - Second Run

Instructions:

This is an input sheet for the Break Out of Distribution Assets, Contributed Capital, Amortization, and Amortization Expenses.

****Please see Handbook for detailed instructions****

Enter Net Fixed Assets from <u>approved</u> EDR, Sheet 3-1, cell F12	\$24,244,338

RATE BASE AND DISTRIBUTION ASSETS		BALANCE SHEET ITEMS						
Account	Description	Break out Functions	BREAK OUT (%)	BREAK OUT (\$)	After BO	Contributed Capital - 1995	Accumulated Depreciation - 2105 Capital Contribution	Accumulated Depreciation - 2105 Fixed Assets Only
<u>To be Prorated</u>								
1995	Contributed Capital - 1995					\$0	Balanced	
2105	Accumulated Depreciation - 2105							\$5,985,214

To be Prorated

1995	Contributed Capital - 1995	\$0	
2105	Accumulated Depreciation - 2105	(\$5,985,214)	
2120	Accumulated Depreciation - 2120	(\$59,855)	
	Total	(\$6,045,069)	
	Net Assets	\$24,244,338	Net Fixed Assets Match EDR

Amortization Expenses

5705	Amortization Expense - Property, Plant, and Equipment	\$1,833,134
5710	Amortization of Limited Term Electric Plant	\$0
5715	Amortization of Intangibles and Other Electric Plant	\$13,204



2006 Cost Allocation Information Filing

Halton Hills Hydro Inc.

EB-2005-0374 EB-2007-0001

Monday, January 15, 2007

Sheet I4 Break Out Worksheet - Second Run

Instructions:

This is an input sheet for the Break Out of Distribution Assets, Contributed Capital, Amortization, and Amortization Expenses.

****Please see Handbook for detailed instructions****

Enter Net Fixed Assets from <u>approved</u> EDR, Sheet 3-1, cell F12	\$24,244,338

RATE BASE AND DISTRIBUTION ASSETS		BALANCE SHEET ITEMS						
Account	Description	Break out Functions	BREAK OUT (%)	BREAK OUT (\$)	After BO	Contributed Capital - 1995	Accumulated Depreciation - 2105 Capital Contribution	Accumulated Depreciation - 2105 Fixed Assets Only
5720	Amortization of Electric Plant Acquisition Adjustments							
	Total Amortization Expense							



2006 Cost Allocat
Halton Hills Hydro
EB-2005-0374 EB-2
Monday, January 15,
Sheet I4 Break O

Instructions:

This is an input sheet for the Break Out

****Please see Handbook for detailed inst**

Enter Net Fixed Assets from **approved** EDR,
 Sheet 3-1, cell F12

RATE BASE AND DISTRIBUTION ASSETS				EXPENSE ITEMS			
				5705	5710	5715	5720
Account	Description	Accumulated Depreciation - 2120	Asset net of Accumulated Depreciation and Contributed Capital	Amortization Expense - Property, Plant, and Equipment	Amortization of Limited Term Electric Plant	Amortization of Intangibles and Other Electric Plant	Amortization of Electric Plant Acquisition Adjustments
1565	Conservation and Demand Management		355,490				
1805	Land						
1805-1	Land Station >50 kV		-				
1805-2	Land Station <50 kV		354,871				
1806	Land Rights						
1806-1	Land Rights Station >50 kV		-				
1806-2	Land Rights Station <50 kV		4,739				
1808	Buildings and Fixtures						
1808-1	Buildings and Fixtures > 50 kV		-				
1808-2	Buildings and Fixtures < 50 kV		2,336,786	\$62,881			
1810	Leasehold Improvements						
1810-1	Leasehold Improvements >50 kV		-				
1810-2	Leasehold Improvements <50 kV		-				
1815	Transformer Station Equipment - Normally Primary above 50 kV		-				
1820	Distribution Station Equipment - Normally Primary below 50 kV		-				



2006 Cost Allocat

Halton Hills Hydro

EB-2005-0374 EB-2

Monday, January 15,

Sheet I4 Break O

Instructions:

This is an input sheet for the Break Out

****Please see Handbook for detailed inst**

Enter Net Fixed Assets from approved EDR,
Sheet 3-1, cell F12

RATE BASE AND DISTRIBUTION ASSETS				EXPENSE ITEMS			
				5705	5710	5715	5720
Account	Description	Accumulated Depreciation - 2120	Asset net of Accumulated Depreciation and Contributed Capital	Amortization Expense - Property, Plant, and Equipment	Amortization of Limited Term Electric Plant	Amortization of Intangibles and Other Electric Plant	Amortization of Electric Plant Acquisition Adjustments
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)		-				
1820-2	Distribution Station Equipment - Normally Primary below 50 kV Primary)		1,319,001	\$87,846			
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)		-				
1825	Storage Battery Equipment						
1825-1	Storage Battery Equipment > 50 kV		-				
1825-2	Storage Battery Equipment <50 kV		-				
1830	Poles, Towers and Fixtures						
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery		-				
1830-4	Poles, Towers and Fixtures - Primary		5,381,188	\$348,553			



2006 Cost Allocat
Halton Hills Hydro
EB-2005-0374 EB-2
Monday, January 15,
Sheet I4 Break O

Instructions:

This is an input sheet for the Break Out

****Please see Handbook for detailed inst**

Enter Net Fixed Assets from approved EDR,
Sheet 3-1, cell F12

RATE BASE AND DISTRIBUTION ASSETS				EXPENSE ITEMS			
				5705	5710	5715	5720
Account	Description	Accumulated Depreciation - 2120	Asset net of Accumulated Depreciation and Contributed Capital	Amortization Expense - Property, Plant, and Equipment	Amortization of Limited Term Electric Plant	Amortization of Intangibles and Other Electric Plant	Amortization of Electric Plant Acquisition Adjustments
1830-5	Poles, Towers and Fixtures - Secondary		2,092,683	\$135,546			
1835	Overhead Conductors and Devices						
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery		-				
1835-4	Overhead Conductors and Devices - Primary		1,676,328	\$183,793			
1835-5	Overhead Conductors and Devices - Secondary		902,638	\$98,966			
1840	Underground Conduit						
1840-3	Underground Conduit - Bulk Delivery		764,198	\$80,005			
1840-4	Underground Conduit - Primary		411,491	\$43,075			
1840-5	Underground Conduit - Secondary		-				
1845	Underground Conductors and Devices						
1845-3	Underground Conductors and Devices - Bulk Delivery		-				



2006 Cost Allocat
Halton Hills Hydro
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Monday, January 15,
Sheet I4 Break O

Instructions:

This is an input sheet for the Break Out

****Please see Handbook for detailed inst**

Enter Net Fixed Assets from **approved** EDR,
Sheet 3-1, cell F12

RATE BASE AND DISTRIBUTION ASSETS				EXPENSE ITEMS			
				5705	5710	5715	5720
Account	Description	Accumulated Depreciation - 2120	Asset net of Accumulated Depreciation and Contributed Capital	Amortization Expense - Property, Plant, and Equipment	Amortization of Limited Term Electric Plant	Amortization of Intangibles and Other Electric Plant	Amortization of Electric Plant Acquisition Adjustments
1845-4	Underground Conductors and Devices - Primary		1,058,698	\$14,231			
1845-5	Underground Conductors and Devices - Secondary		570,068	\$7,660			
1850	Line Transformers		4,356,008	\$232,093			
1855	Services		212,124	\$24,130			
1860	Meters		1,013,446	\$58,354			
	Total	\$0	22,809,755	\$1,377,133	\$0	\$0	\$0



2006 Cost Allocat
Halton Hills Hydro
EB-2005-0374 EB-2
Monday, January 15,
Sheet I4 Break O

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Enter Net Fixed Assets from approved EDR,
Sheet 3-1, cell F12

RATE BASE AND DISTRIBUTION ASSETS				EXPENSE ITEMS			
				5705	5710	5715	5720
Account	Description	Accumulated Depreciation - 2120	Asset net of Accumulated Depreciation and Contributed Capital	Amortization Expense - Property, Plant, and Equipment	Amortization of Limited Term Electric Plant	Amortization of Intangibles and Other Electric Plant	Amortization of Electric Plant Acquisition Adjustments
	SUB TOTAL from I3						
General Plant		Accumulated Depreciation - 2120	Net Asset	5705 Amortization Expense - Property, Plant, and Equipment	5710 Amortization of Limited Term Electric Plant	5715 Amortization of Intangibles and Other Electric Plant	5720 Amortization of Electric Plant Acquisition Adjustments
1905	Land		\$ -				
1906	Land Rights		\$ -				
1908	Buildings and Fixtures		\$ -				
1910	Leasehold Improvements		\$ -				
1915	Office Furniture and Equipment		\$ 112,859	28,089			
1920	Computer Equipment - Hardware		\$ 160,988	82,545			
1925	Computer Software		\$ 91,641	102,266			
1930	Transportation Equipment	\$ (59,855)	\$ 476,595	171,232		\$13,204	
1935	Stores Equipment		\$ 28,344	4,486			
1940	Tools, Shop and Garage Equipment		\$ 174,193	32,624			



2006 Cost Allocat
Halton Hills Hydro
EB-2005-0374 EB-2
Monday, January 15,
Sheet I4 Break O

Instructions:

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Enter Net Fixed Assets from **approved** EDR,
Sheet 3-1, cell F12

RATE BASE AND DISTRIBUTION ASSETS				EXPENSE ITEMS			
				5705	5710	5715	5720
Account	Description	Accumulated Depreciation - 2120	Asset net of Accumulated Depreciation and Contributed Capital	Amortization Expense - Property, Plant, and Equipment	Amortization of Limited Term Electric Plant	Amortization of Intangibles and Other Electric Plant	Amortization of Electric Plant Acquisition Adjustments
1945	Measurement and Testing Equipment		\$ -				
1950	Power Operated Equipment		\$ -				
1955	Communication Equipment		\$ -				
1960	Miscellaneous Equipment		\$ -				
1970	Load Management Controls - Customer Premises		\$ -				
1975	Load Management Controls - Utility Premises		\$ -				
1980	System Supervisory Equipment		\$ 389,966	34,759			
1990	Other Tangible Property		\$ -				
2005	Property Under Capital Leases		\$ -				
2010	Electric Plant Purchased or Sold		\$ -				
Total		(\$59,855)	\$1,434,583	\$456,001	\$0	\$13,204	\$0
SUB TOTAL from I3 I3 Directly Allocated							
Grand Total		(\$59,855)	\$24,244,338	\$1,833,134	\$0	\$13,204	\$0



2006 Cost Allocat
Halton Hills Hydro
EB-2005-0374 EB-2
Monday, January 15,
Sheet I4 Break O

Instructions:

This is an input sheet for the Break Out

****Please see Handbook for detailed inst**

Enter Net Fixed Assets from **approved** EDR,
Sheet 3-1, cell F12

RATE BASE AND DISTRIBUTION ASSETS				EXPENSE ITEMS			
				5705	5710	5715	5720
Account	Description	Accumulated Depreciation - 2120	Asset net of Accumulated Depreciation and Contributed Capital	Amortization Expense - Property, Plant, and Equipment	Amortization of Limited Term Electric Plant	Amortization of Intangibles and Other Electric Plant	Amortization of Electric Plant Acquisition Adjustments
To be Prorated							
1995	Contributed Capital - 1995						
2105	Accumulated Depreciation - 2105	Balanced					
2120	Accumulated Depreciation - 2120	\$59,855	Balanced				
	Total						
	Net Assets						
Amortization Expenses							
5705	Amortization Expense - Property, Plant, and Equipment			(\$1,833,134)	Balanced		
5710	Amortization of Limited Term Electric Plant				\$0	Balanced	
5715	Amortization of Intangibles and Other Electric Plant					(\$13,204)	Balanced



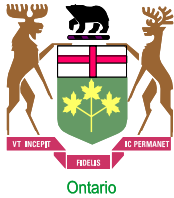
2006 Cost Allocat
Halton Hills Hydro
EB-2005-0374 EB-2
Monday, January 15,
Sheet I4 Break O

Instructions:

This is an input sheet for the Break Out
****Please see Handbook for detailed insti**

Enter Net Fixed Assets from **approved** EDR,
Sheet 3-1, cell F12

RATE BASE AND DISTRIBUTION ASSETS		EXPENSE ITEMS					
		5705	5710	5715	5720		
Account	Description	Accumulated Depreciation - 2120	Asset net of Accumulated Depreciation and Contributed Capital	Amortization Expense - Property, Plant, and Equipment	Amortization of Limited Term Electric Plant	Amortization of Intangibles and Other Electric Plant	Amortization of Electric Plant Acquisition Adjustments
5720	Amortization of Electric Plant Acquisition Adjustments						\$0
	Total Amortization Expense						Balanced



2006 Cost Allocation Information Filing

Halton Hills Hydro Inc.

EB-2005-0374 EB-2007-0001

Monday, January 15, 2007

Sheet I5 Miscellaneous Data Worksheet - Second Run

kMs of Roads in Service Area Where
Distribution Lines Exist

462.71

Deemed Equity Component
of Rate Base (%)

50%

1	2	3	4	5	6	7	8
Residential	GS<50kW	GS 50-999 kW	GS 1000-4999	GS >50- Intermediate	Large Use >5MW	Street Light	Sentinel
11.59	24.86	93.18	205.71			0.52	1.17

Instructions (Cont'd):

Step 3: Insert Approved Monthly
Service Charge (Please refer to
Approved EDR Sheet 8-5 column
W)

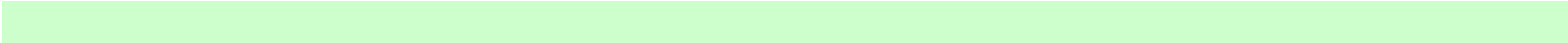
Step 4: Insert Smart Meter Adder
Included in Approved Monthly
Service Charge (Please refer to
Approved EDR Sheet 8-5 column
T)

0.62 0.62 0.62 0.62

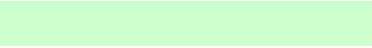


9	10	11	12	13	14	15	16	17	18
Unmetered Scattered Load	Embedded Distributor	Back-up/Standby Power	Rate Class 1	Rate class 2	Rate class 3	Rate class 4	Rate class 5	Rate class 6	Rate class 7

12.12



19	20
Rate class 8	Rate class 9





2006 Cost Allocation Information Filing

Halton Hills Hydro Inc.

EB-2005-0374 EB-2007-0001

Monday, January 15, 2007

Sheet I6 Customer Data Worksheet - Second Run

Total kWhs	450,691,685

Total kW	739,403

Total Approved Distribution Revenue (\$)	\$8,240,410

			1	2	3	4	5	6
	ID	Total	Residential	GS<50kW	GS 50-999 kW	GS 1000-4999	GS >50-Intermediate	Large Use >5MW
Billing Data								
kWh from approved EDR model, Sheet 7-1, Col M	CEN	450,691,685	190,010,801	51,112,907	78,058,805	128,018,479		
kW from approved EDR model, Sheet 7-1, Col S	CDEM	739,403			375,388	356,854		
kW, included in CDEM, from customers with line transformer allowance from approved EDR model, Sheet 6-3, Col P		334,387			26,520	307,867		
Optional - kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-						
KWh excluding KWh from Wholesale Market Participants	CEN EWMP	450,691,685	190,010,801	51,112,907	78,058,805	128,018,479		

kWh - 30 year weather normalized amount		455,129,873	197,399,493	55,850,663	77,651,896	120,493,285	-	-
Approved Distribution Rev from approved EDR, Sheet 7-1, Col AK + Sheet 7-3 Col H	CREV	\$8,240,409	\$4,268,941	\$783,058	\$1,715,052	\$1,397,698		
Bad Debt 3 Year Historical Average from Approved EDR Model	BDHA	\$39,388	\$30,880	\$7,987	\$521	\$0	\$0	\$0
Late Payment 3 Year Historical Average	LPHA	\$85,207	\$58,275	\$26,932				
Weighting Factor - Services			1.0	2.0	10.0	10.0	10.0	30.0
Weighting Factor - Billings			1.0	2.0	7.0	7.0	7.0	15.0
Number of Bills	CNB	111,834	102,036	6,924	1,764	192		
Number of Connections (Unmetered)	CCON	4,206						
Total Number of Customer from Approved EDR, Sheet 7-1, Col H excluding connections	CCA	18,323	17,006	1,154	147	16		
Bulk Customer Base	CCB	-						
Primary Customer Base	CCP	18,323	17,006	1,154	147	16		
Line Transformer Customer Base	CCLT	18,291	17,006	1,154	128	3		
Secondary Customer Base	CCS	18,291	17,006	1,154	128	3		
Weighted - Services	CWCS	24,830	17,006	2,308	1,280	30	-	-
Weighted Meter -Capital	CWMC	1,922,455	1,242,100	280,755	316,600	83,000	-	-
Weighted Meter Reading	CWMR	200,293	166,021	20,772	4,092	9,408	-	-
Weighted Bills	CWNB	130,561	102,036	13,848	12,348	1,344	-	-
Data Mismatch Analysis								
Revenue with 30 year weather normalized kWh		8,392,533	4,434,942	855,641	1,706,112	1,315,538	-	-

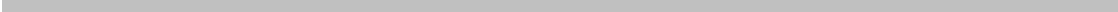
Weather Normalized Data from Hydro

	Total	Residential	GS<50kW	GS 50-999 kW	GS 1000-4999	GS >50-Intermediate	Large Use >5MW
kWh - 30 year weather normalized amount	470,637,571	204,663,794	57,905,967	80,509,486	123,686,357		
2006 EDR Distribution Loss Factor		1.0368	1.0368	1.0368	1.0265		

Bad Debt Data from EDR 2006

Sheet ADJ5 rows 26 - 32, column E
Sheet ADJ5 rows 26 - 32, column F
Sheet ADJ5 rows 26 - 32, column G
Three-year average

	17,776	7,301	1,511			
	44,354	8,629				
	30,511	8,030	52			
39,388	30,880	7,987	521	-	-	-



7	8	9	10	11	12	13	14	15	16
Street Light	Sentinel	Unmetered Scattered Load	Embedded Distributor	Back- up/Standby Power	Rate Class 1	Rate class 2	Rate class 3	Rate class 4	Rate class 5
2,289,646	280,707	920,340							
793	6,368								
2,289,646	280,707	920,340	-	-	-	-	-	-	-

2,467,840	349,354	917,342	-	-	-	-	-	-	-
\$44,066	\$5,303	\$26,291							
\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
1.0	0.1	5.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
12	726	180							
3,944	121	141							
3,944	121	141	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-
12	73	900	-	-	-	-	-	-	-
47,495	6,600	26,205	-	-	-	-	-	-	-

Street Light	Sentinel	Unmetered Scattered Load	Embedded Distributor	Back-up/Standby Power	Rate Class 1	Rate class 2	Rate class 3	Rate class 4	Rate class 5
2,558,657	362,210	951,100							
1.0368	1.0368	1.0368							



-

-

-

-

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-

-

-

-

-

17	18	19	20
Rate class 6	Rate class 7	Rate class 8	Rate class 9
-	-	-	-

-	-	-	-
\$0	\$0	\$0	\$0
1.0	1.0	1.0	1.0
1.0	1.0	1.0	1.0
-	-	-	-
-	-	-	-
-	-	-	-
-	-	-	-
-	-	-	-

Rate class 6	Rate class 7	Rate class 8	Rate class 9

- - - -



2006 Cost Allocation Information Filing

Halton Hills Hydro Inc.

EB-2005-0374 EB-2007-0001

Monday, January 15, 2007

Sheet I7.1 Meter Capital Worksheet - Second Run

	Residential			GS<50kW		
	1	2	3	1	2	3
	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs
Allocation Percentage Weighted Factor			64.61%			15%
Cost Relative to Residential Average Cost			1.00			3.33
Total	17006	1242100	73.03892744	1154	280755	243.2885615

Meter Types

Single Phase 200 Amp - Urban

Single Phase 200 Amp - Rural
Central Meter

Network Meter (Costs to be updated)

Three-phase - No demand

Smart Meters

Demand without IT (usually three-phase)

Demand with IT

Demand with IT and Interval Capability - Secondary

Demand with IT and Interval Capability - Primary

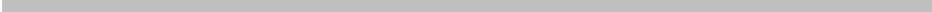
Demand with IT and Interval Capability -Special (WMP)

LDC Specific 1

Cost per Meter (Installed)

50	13,088	654400			0	
150	3,918	587700			0	
250		0		284	71000	
225		0		141	31725	
210		0		643	135030	
300		0			0	
500		0		86	43000	
2,100		0			0	
2,300		0			0	
10,000		0			0	
40,000		0			0	
		0			0	

LDC Specific 2		0			0	
LDC Specific 3		0			0	



GS 50-999 kW			GS 1000-4999			GS >50-Intermediate			
1	2	3	1	2	3	1	2	3	1
Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters
		16%			4%			0%	
		29.49			71.02			-	
147	316600	2153.741497	16	83000	5187.5	0	0	-	0

	0			0			0		
	0			0			0		
	0			0			0		
	0			0			0		
	0			0			0		
	0			0			0		
	0			0			0		
146	306600			0			0		
	0		10	23000			0		
1	10000		6	60000			0		
	0			0			0		
	0			0			0		

[illegible]

0			0			0			0
0			0			0			0

Load	Embedded Distributor			Back-up/Standby Power			Rate Class 1		
3	1	2	3	1	2	3	1	2	3
Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs
0%			0%			0%			0%
-			-			-			-
-	0	0	-	0	0	-	0	0	-

[illegible]

		0			0			0	
		0			0			0	

Rate class 2			Rate class 3			Rate class 4			
1	2	3	1	2	3	1	2	3	1
Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters
		0%			0%			0%	
		-			-			-	
0	0	-	0	0	-	0	0	-	0

[illegible]

[illegible]

0			0			0			0
0			0			0			0

	Rate class 9			TOTAL		
3	1	2	3	1	2	3
Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs
0%			0%			100%
-			-			1.44
-	0	0	-	18323	1922455	104.9203187
		0		13,088	654400	
		0		3,918	587700	
		0		284	71000	
		0		141	31725	
		0		643	135030	
		0		0	0	
		0		86	43000	
		0		146	306600	
		0		10	23000	
		0		7	70000	
		0		0	0	
		0		0	0	

		0		0	0	
		0		0	0	



2006 Cost Allocation Information Filing

Halton Hills Hydro Inc.

EB-2005-0374 EB-2007-0001

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Sheet I7.2 Meter Reading Worksheet - Second Run

Weighting Factors based on Contractor Pricing

Description		1			2			
		Residential			GS<50kW			
		Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units
	Allocation Percentage Weighted Factor	82.89%			10.37%			
	Cost Relative to Residential Average Cost	1.00			1.92			
	Total	106,285	166,021	1.56	6,924	20,772	3.00	1,764
	Factor							
Residential - Urban - Outside	1.00		0		0			
Residential - Urban - Outside with other services	1.00	75,720	75,720		0			
Residential - Urban - Inside	2.00		0		0			
Residential - Urban - Inside - with other services	1.00	697	697		0			
Residential - Rural - Outside	3.00	29,868	89,604		0			
Residential - Rural - Outside with other services	2.00		0		0			
LDC Specific 1			0		0			
LDC Specific 2			0		0			
GS - Walking	2.00		0		0		1,752	
GS - Walking - with other services	3.00		0		6,924	20,772		

GS - Vehicle with other services --- TOU Read	3.00	0		0	12
GS - Vehicle with other services	3.00	0		0	
LDC Specific 3		0		0	
LDC Specific 4	0.00	0		0	
Interval	49.00	0		0	
LDC Specific 5		0		0	
LDC Specific 6		0		0	



3		4			5			6	
GS 50-999 kW		GS 1000-4999			GS >50-Intermediate			Large Use >5MW	
Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor
	2.04%			4.70%			0.00%		
	1.49			31.37			0.00		
4,092	2.32	192	9,408	49.00	-	-	0	-	-
0			0			0			0
0			0			0			0
0			0			0			0
0			0			0			0
0			0			0			0
0			0			0			0
0			0			0			0
0			0			0			0
0			0			0			0
3,504			0			0			0
0			0			0			0

0		0		0		0
0		0		0		0
0		0		0		0
0		0		0		0
588	192	9,408		0		0
0		0		0		0
0		0		0		0

[illegible]

[illegible]

[illegible]

13		14			15			16	
Rate class 2		Rate class 3			Rate class 4			Rate class 5	
Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor
0.00%		0.00%			0.00%				
0.00		0.00			0.00				
- 0		- - 0			- - 0			- -	
0		0			0			0	
0		0			0			0	
0		0			0			0	
0		0			0			0	
0		0			0			0	
0		0			0			0	
0			0			0			0
0			0			0			0
0			0			0			0
0			0			0			0

[illegible]

[illegible]

[illegible]

20					
Rate class 9			TOTAL		
Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs
0.00%			100.00%		
0.00			35.77		
-	-	0	115,165	200,293	56
0			-	-	
0			75,720	75,720	
0			-	-	
0			697	697	
0			29,868	89,604	
0			-	-	
0			-	-	
0			-	-	
0			1,752	3,504	
0			6,924	20,772	

	0	-	-
	0	-	-
	0	-	-
	0	-	-
	0	204	9,996
	0	-	-
	0	-	-



2006 Cost Allocation Information Filing

Halton Hills Hydro Inc.

EB-2005-0374 EB-2007-0001

Monday, January 15, 2007

Sheet I8 Demand Data Worksheet - Second Run

This is an input sheet for demand allocators.

CP TEST RESULTS	12 CP
NCP TEST RESULTS	4 NCP

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

Customer Classes

CO-INCIDENT PEAK		Total	1 Residential	2 GS<50kW	3 GS 50-999 kW	4 GS 1000-4999	5 GS >50- Intermediate	6 Large Use >5MW	7 Street Light
1 CP									
Transformation CP	TCP1	-							
Bulk Delivery CP	BCP1	-							
Total Sytem CP	DCP1	86,068	30,365	14,338	20,340	20,921			
4 CP									
Transformation CP	TCP4	-							
Bulk Delivery CP	BCP4	-							
Total Sytem CP	DCP4	319,040	145,223	41,346	58,811	71,918			1,182

12 CP							
Transformation CP	TCP12	896,249	416,759	113,289	146,088	212,746	5,323
Bulk Delivery CP	BCP12	896,249	416,759	113,289	146,088	212,746	5,323
Total Sytem CP	DCP12	896,249	416,759	113,289	146,088	212,746	5,323
NON CO INCIDENT PEAK							
1 NCP							
Classification NCP from							
Load Data Provider	DNCP1	110,341	49,381	15,698	22,236	22,091	635
Primary NCP	PNCP1	-					
Line Transformer NCP	LTNCP1	-					
Secondary NCP	SNCP1	-					
4 NCP							
Classification NCP from							
Load Data Provider	DNCP4	394,514	177,339	55,339	70,559	87,824	2,530
Primary NCP	PNCP4	394,514	177,339	55,339	70,559	87,824	2,530
Line Transformer NCP	LTNCP4	314,037	177,339	55,339	61,439	16,467	2,530
Secondary NCP	SNCP4	314,037	177,339	55,339	61,439	16,467	2,530
12 NCP							
Classification NCP from							
Load Data Provider	DNCP12	1,014,585	453,361	133,613	177,363	240,610	7,303
Primary NCP	PNCP12	-					
Line Transformer NCP	LTNCP12	-					
Secondary NCP	SNCP12	-					

8	9	10	11	12	13	14	15	16	17
Sentinel	Unmetered Scattered Load	Embedded Distributor	Back- up/Standby Power	Rate Class 1	Rate class 2	Rate class 3	Rate class 4	Rate class 5	Rate class 6

104

124436

743	1,301
743	1,301
743	1,301

168	132

453	470
453	470
453	470
453	470

1,034	1,301

[illegible]



2006 Cost Allocation Information Filing

Halton Hills Hydro Inc.

EB-2005-0374 EB-2007-0001

Monday, January 15, 2007

Sheet I9 Direct Allocation Worksheet - Second Run

USoA Account #	Accounts	Direct Allocation	Total Allocated to Rate Classifications?	1 Residential	2 GS<50kW	3 GS 50-999 kW	4 GS 1000-4999	5 GS >50-Intermediat

Instructions:

To Allocate Capital Contributions by Rate Classification, Input Allocation on Next Line

1995	Contributions and Grants - Credit	\$0	Yes					

Instructions:

The Following is Used to Allocate Directly Allocated Costs from I3 to Rate Classifications

1805	Land	\$0	Yes					
1806	Land Rights	\$0	Yes					
1808	Buildings and Fixtures	\$0	Yes					
1810	Leasehold Improvements	\$0	Yes					
1815	Transformer Station Equipment - Normally Primary above 50 kV	\$0	Yes					
1820	Distribution Station Equipment - Normally Primary below 50 kV	\$0	Yes					
1825	Storage Battery Equipment	\$0	Yes					
1830	Poles, Towers and Fixtures	\$0	Yes					
1835	Overhead Conductors and Devices	\$0	Yes					
1840	Underground Conduit	\$0	Yes					
1845	Underground Conductors and Devices	\$0	Yes					
1850	Line Transformers	\$0	Yes					
1855	Services	\$0	Yes					
1860	Meters	\$0	Yes					
1905	Land	\$0	Yes					
1906	Land Rights	\$0	Yes					

1908	Buildings and Fixtures	\$0	Yes					
1910	Leasehold Improvements	\$0	Yes					
1915	Office Furniture and Equipment	\$0	Yes					
1920	Computer Equipment - Hardware	\$0	Yes					
1925	Computer Software	\$0	Yes					
1930	Transportation Equipment	\$0	Yes					
1935	Stores Equipment	\$0	Yes					
1940	Tools, Shop and Garage Equipment	\$0	Yes					
1945	Measurement and Testing Equipment	\$0	Yes					
1950	Power Operated Equipment	\$0	Yes					
1955	Communication Equipment	\$0	Yes					
1960	Miscellaneous Equipment	\$0	Yes					
1970	Load Management Controls - Customer Premises	\$0	Yes					
1975	Load Management Controls - Utility Premises	\$0	Yes					
1980	System Supervisory Equipment	\$0	Yes					
1990	Other Tangible Property	\$0	Yes					
2005	Property Under Capital Leases	\$0	Yes					
2010	Electric Plant Purchased or Sold	\$0	Yes					
2050	Completed Construction Not Classified--Electric	\$0	Yes					
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	\$0	Yes					
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	\$0	Yes					
	Directly Allocated Net Fixed Assets			\$0	\$0	\$0	\$0	\$0
5005	Operation Supervision and Engineering	\$0	Yes					
5010	Load Dispatching	\$0	Yes					
5012	Station Buildings and Fixtures Expense	\$0	Yes					
5014	Transformer Station Equipment - Operation Labour	\$0	Yes					
5015	Transformer Station Equipment - Operation Supplies and Expenses	\$0	Yes					
5016	Distribution Station Equipment - Operation Labour	\$0	Yes					
5017	Distribution Station Equipment - Operation Supplies and Expenses	\$0	Yes					
5020	Overhead Distribution Lines and Feeders - Operation Labour	\$0	Yes					
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	\$0	Yes					

5030	Overhead Subtransmission Feeders - Operation	\$0	Yes					
5035	Overhead Distribution Transformers- Operation	\$0	Yes					
5040	Underground Distribution Lines and Feeders - Operation Labour	\$0	Yes					
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	\$0	Yes					
5050	Underground Subtransmission Feeders Operation	\$0	Yes					
5055	Underground Distribution Transformers - Operation	\$0	Yes					
5065	Meter Expense	\$0	Yes					
5070	Customer Premises - Operation Labour	\$0	Yes					
5075	Customer Premises - Materials and Expenses	\$0	Yes					
5085	Miscellaneous Distribution Expense	\$0	Yes					
5090	Underground Distribution Lines and Feeders - Rental Paid	\$0	Yes					
5095	Overhead Distribution Lines and Feeders - Rental Paid	\$0	Yes					
5096	Other Rent	\$0	Yes					
5105	Maintenance Supervision and Engineering	\$0	Yes					
5110	Maintenance of Buildings and Fixtures - Distribution Stations	\$0	Yes					
5112	Maintenance of Transformer Station Equipment	\$0	Yes					
5114	Maintenance of Distribution Station Equipment	\$0	Yes					
5120	Maintenance of Poles, Towers and Fixtures	\$0	Yes					
5125	Maintenance of Overhead Conductors and Devices	\$0	Yes					
5130	Maintenance of Overhead Services	\$0	Yes					
5135	Overhead Distribution Lines and Feeders - Right of Way	\$0	Yes					
5145	Maintenance of Underground Conduit	\$0	Yes					
5150	Maintenance of Underground Conductors and Devices	\$0	Yes					
5155	Maintenance of Underground Services	\$0	Yes					
5160	Maintenance of Line Transformers	\$0	Yes					
5175	Maintenance of Meters	\$0	Yes					
5305	Supervision	\$0	Yes					

5310	Meter Reading Expense	\$0	Yes					
5315	Customer Billing	\$0	Yes					
5320	Collecting	\$0	Yes					
5325	Collecting- Cash Over and Short	\$0	Yes					
5330	Collection Charges	\$0	Yes					
5335	Bad Debt Expense	\$0	Yes					
5340	Miscellaneous Customer Accounts Expenses	\$0	Yes					
5405	Supervision	\$0	Yes					
5410	Community Relations - Sundry	\$0	Yes					
5415	Energy Conservation	\$0	Yes					
5420	Community Safety Program	\$0	Yes					
5425	Miscellaneous Customer Service and Informational Expenses	\$0	Yes					
5505	Supervision	\$0	Yes					
5510	Demonstrating and Selling Expense	\$0	Yes					
5515	Advertising Expense	\$0	Yes					
5520	Miscellaneous Sales Expense	\$0	Yes					
5605	Executive Salaries and Expenses	\$0	Yes					
5610	Management Salaries and Expenses	\$0	Yes					
5615	General Administrative Salaries and Expenses	\$0	Yes					
5620	Office Supplies and Expenses	\$0	Yes					
5625	Administrative Expense Transferred Credit	\$0	Yes					
5630	Outside Services Employed	\$0	Yes					
5635	Property Insurance	\$0	Yes					
5640	Injuries and Damages	\$0	Yes					
5645	Employee Pensions and Benefits	\$0	Yes					
5650	Franchise Requirements	\$0	Yes					
5655	Regulatory Expenses	\$0	Yes					
5660	General Advertising Expenses	\$0	Yes					
5665	Miscellaneous General Expenses	\$0	Yes					
5670	Rent	\$0	Yes					
5675	Maintenance of General Plant	\$0	Yes					
5680	Electrical Safety Authority Fees	\$0	Yes					
5705	Amortization Expense - Property, Plant, and Equipment	\$0	Yes					
5710	Amortization of Limited Term Electric Plant	\$0	Yes					
5715	Amortization of Intangibles and Other Electric Plant	\$0	Yes					
5720	Amortization of Electric Plant Acquisition Adjustments	\$0	Yes					
6105	Taxes Other Than Income Taxes	\$0	Yes					
6205	Donations	\$0	Yes					
6210	Life Insurance	\$0	Yes					

6215	Penalties	\$0	Yes					
6225	Other Deductions	\$0	Yes					
	Total Expenses			\$0	\$0	\$0	\$0	\$0
	Depreciation Expense			\$0	\$0	\$0	\$0	\$0

Total Net Fixed Assets Excluding Gen Plant	\$27,158,201	Allocated	Residential	GS<50kW	GS 50-999 kW	GS 1000-4999	GS >50-Intermediate
Approved Total PILs	\$938,649	\$0	\$0	\$0	\$0	\$0	\$0
Approved Total Return on Debt	\$923,150	\$0	\$0	\$0	\$0	\$0	\$0
Approved Total Return on Equity	\$1,329,336	\$0	\$0	\$0	\$0	\$0	\$0
		Total	\$0	\$0	\$0	\$0	\$0

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

\$0	\$0	\$0	\$0	\$0
\$0	\$0	\$0	\$0	\$0

Rate class 5	Rate class 6	Rate class 7	Rate class 8	Rate class 9
\$0	\$0	\$0	\$0	\$0
\$0	\$0	\$0	\$0	\$0
\$0	\$0	\$0	\$0	\$0
\$0	\$0	\$0	\$0	\$0

USoA A/C #	Accounts	Categorization		
		Demand	Customer	Customer Component
	Distribution Plant			
1805	Land	DCP		0%
1805-1	Land Station >50 kV	TCP		0%
1805-2	Land Station <50 kV	DCP		0%
1806	Land Rights	DCP		0%
1806-1	Land Rights Station >50 kV	TCP		0%
1806-2	Land Rights Station <50 kV	DCP		0%
1808	Buildings and Fixtures	DCP		0%
1808-1	Buildings and Fixtures > 50 kV	TCP		0%
1808-2	Buildings and Fixtures < 50 kV	DCP		0%
1810	Leasehold Improvements	DCP		0%
1810-1	Leasehold Improvements >50 kV	TCP		0%
1810-2	Leasehold Improvements <50 kV	DCP		0%
1815	Transformer Station Equipment - Normally Primary above 50 kV	TCP		0%
1820	Distribution Station Equipment - Normally Primary below 50 kV	DCP		0%
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	DCP		0%
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	PNCP		0%
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)		CEN	100%
1825	Storage Battery Equipment	DCP		0%
1825-1	Storage Battery Equipment > 50 kV	TCP		0%
1825-2	Storage Battery Equipment <50 kV	DCP		0%
1830	Poles, Towers and Fixtures	DNCP	CCA	40%
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	BCP		0%
1830-4	Poles, Towers and Fixtures - Primary	PNCP	CCP	40%
1830-5	Poles, Towers and Fixtures - Secondary	SNCP	CCS	40%
1835	Overhead Conductors and Devices	DNCP	CCA	40%
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	BCP		0%
1835-4	Overhead Conductors and Devices - Primary	PNCP	CCP	40%
1835-5	Overhead Conductors and Devices - Secondary	SNCP	CCS	40%
1840	Underground Conduit	DNCP	CCA	40%
1840-3	Underground Conduit - Bulk Delivery	BCP		0%
1840-4	Underground Conduit - Primary	PNCP	CCP	40%

1840-5	Underground Conduit - Secondary	SNCP	CCS	40%
1845	Underground Conductors and Devices	DNCP	CCA	40%
1845-3	Underground Conductors and Devices - Bulk Delivery	BCP		0%
1845-4	Underground Conductors and Devices - Primary	PNCP	CCP	40%
1845-5	Underground Conductors and Devices - Secondary	SNCP	CCS	40%
1850	Line Transformers	LTNCP	CCLT	40%
1855	Services		CWCS	100%
1860	Meters		CWMC	100%
1565	Conservation and Demand Management Expenditures and Recoveries		CDMPP	100%
	Accumulated Amortization			
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	See I4 BO Assets		
	Operation			
5005	Operation Supervision and Engineering	1815-1855 D	1815-1855 C	40%
5010	Load Dispatching	1815-1855 D	1815-1855 C	40%
5012	Station Buildings and Fixtures Expense	1808 D		0%
5014	Transformer Station Equipment - Operation Labour	1815 D		0%
5015	Transformer Station Equipment - Operation Supplies and Expenses	1815 D		0%
5016	Distribution Station Equipment - Operation Labour	1820 D		0%
5017	Distribution Station Equipment - Operation Supplies and Expenses	1820 D		0%
5020	Overhead Distribution Lines and Feeders - Operation Labour	1830 & 1835 D	1830 & 1835 C	40%
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	1830 & 1835 D	1830 & 1835 C	40%
5030	Overhead Subtransmission Feeders - Operation	1830 & 1835 D		0%
5035	Overhead Distribution Transformers- Operation	1850 D	1850 C	40%
5040	Underground Distribution Lines and Feeders - Operation Labour	1840 & 1845 D	1840 & 1845 C	40%
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	1840 & 1845 D	1840 & 1845 C	40%
5050	Underground Subtransmission Feeders - Operation	1840 & 1845 D		0%
5055	Underground Distribution Transformers - Operation	1850 D	1850 C	40%
5065	Meter Expense		CWMC	100%

5070	Customer Premises - Operation Labour		CCA	100%
5075	Customer Premises - Materials and Expenses		CCA	100%
5085	Miscellaneous Distribution Expense	1815-1855 D	1815-1855 C	40%
5090	Underground Distribution Lines and Feeders - Rental Paid	1840 & 1845 D	1840 & 1845 C	40%
5095	Overhead Distribution Lines and Feeders - Rental Paid	1830 & 1835 D	1830 & 1835 C	40%
	<u>Maintenance</u>			
5105	Maintenance Supervision and Engineering	1815-1855 D	1815-1855 C	40%
5110	Maintenance of Buildings and Fixtures - Distribution Stations	1808 D		0%
5112	Maintenance of Transformer Station Equipment	1815 D		0%
5114	Maintenance of Distribution Station Equipment	1820 D		0%
5120	Maintenance of Poles, Towers and Fixtures	1830 D	1830 C	40%
5125	Maintenance of Overhead Conductors and Devices	1835 D	1835 C	40%
5130	Maintenance of Overhead Services		1855 C	100%
5135	Overhead Distribution Lines and Feeders - Right of Way	1830 & 1835 D	1830 & 1835 C	40%
5145	Maintenance of Underground Conduit	1840 D	1840 C	40%
5150	Maintenance of Underground Conductors and Devices	1845 D	1845 C	40%
5155	Maintenance of Underground Services		1855 C	100%
5160	Maintenance of Line Transformers	1850 D	1850 C	40%
5175	Maintenance of Meters		1860 C	100%

2006 Cost Allocation Information Filing

Halton Hills Hydro Inc.

EB-2005-0374 EB-2007-0001

Monday, January 15, 2007

Sheet E2 Allocator Worksheet - Second Run

Details:

The worksheet below details how allocators are derived.

			1	2	3	4	5	6	7	8	9
Explanation	ID and Factors	Total	Residential	GS<50kW	GS 50-999 kW	GS 1000-4999	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load

Demand Allocators

1 cp

Transformation CP	TCP1	-	0	0	0	0	0	0	0	0	0
Bulk Delivery (SubTransmission) CP	BCP1	-	0	0	0	0	0	0	0	0	0
Distribution CP (Total System)	DCP1	100.00%	35.28%	16.66%	23.63%	24.31%	0.00%	0.00%	0.00%	0.00%	0.12%

4 cp

Transformation CP	TCP4	-	0	0	0	0	0	0	0	0	0
Bulk Delivery (SubTransmission) CP	BCP4	-	0	0	0	0	0	0	0	0	0
Distribution CP (Total System)	DCP4	100.00%	45.52%	12.96%	18.43%	22.54%	0.00%	0.00%	0.37%	0.04%	0.14%

12 cp

Transformation CP	TCP12	100.00%	46.50%	12.64%	16.30%	23.74%	0.00%	0.00%	0.59%	0.08%	0.15%
Bulk Delivery (SubTransmission) CP	BCP12	100.00%	46.50%	12.64%	16.30%	23.74%	0.00%	0.00%	0.59%	0.08%	0.15%
Distribution CP (Total System)	DCP12	100.00%	46.50%	12.64%	16.30%	23.74%	0.00%	0.00%	0.59%	0.08%	0.15%

NON CO INCIDENT PEAK

1 NCP

Distribution NCP (Total System)	DNCP1	100.00%	45.06%	14.32%	20.29%	20.16%	0.00%	0.00%	0.00%	0.11%	0.07%
Primary NCP	PNCP1	-	0	0	0	0	0	0	0	0	0
Line Transformer NCP	LTNCP1	-	0	0	0	0	0	0	0	0	0
Secondary NCP	SNCP1	-	0	0	0	0	0	0	0	0	0

4 NCP

Distribution NCP (Total System)	DNCP4	100.00%	45.29%	14.13%	18.02%	22.43%	0.00%	0.00%	0.00%	0.07%	0.06%
Primary NCP	PNCP4	100.00%	41.44%	14.77%	19.41%	24.24%	0.00%	0.00%	0.00%	0.07%	0.07%
Line Transformer NCP	LTNCP4	100.00%	53.27%	18.98%	21.73%	5.84%	0.00%	0.00%	0.00%	0.09%	0.09%
Secondary NCP	SNCP4	100.00%	53.27%	18.98%	21.73%	5.84%	0.00%	0.00%	0.00%	0.09%	0.09%

12 NCP

Distribution NCP (Total System)	DNCP12	100.00%	45.06%	13.28%	17.63%	23.92%	0.00%	0.00%	0.00%	0.05%	0.06%
Primary NCP	PNCP12	-	0	0	0	0	0	0	0	0	0
Line Transformer NCP	LTNCP12	-	0	0	0	0	0	0	0	0	0
Secondary NCP	SNCP12	-	0	0	0	0	0	0	0	0	0

Demand Allocators - Composite

DEMAND 1815-1855	1815-1855 D	100.00%	46.37%	16.25%	20.09%	17.08%	0.00%	0.00%	0.04%	0.08%	0.08%
DEMAND 1808	1808 D	100.00%	46.50%	12.64%	16.30%	23.74%	0.00%	0.00%	0.59%	0.08%	0.15%
DEMAND 1815	1815 D	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DEMAND 1820	1820 D	100.00%	41.44%	14.77%	19.41%	24.24%	0.00%	0.00%	0.00%	0.07%	0.07%
	1815 & 1820										
DEMAND 1815 & 1820	D	100.00%	41.44%	14.77%	19.41%	24.24%	0.00%	0.00%	0.00%	0.07%	0.07%
DEMAND 1830	1830 D	100.00%	44.76%	15.95%	20.06%	19.09%	0.00%	0.00%	0.00%	0.08%	0.07%
DEMAND 1835	1835 D	100.00%	45.58%	16.24%	20.22%	17.80%	0.00%	0.00%	0.00%	0.08%	0.07%
	1830 & 1835										
DEMAND 1830 & 1835	D	100.00%	44.99%	16.03%	20.11%	18.71%	0.00%	0.00%	0.00%	0.08%	0.07%
DEMAND 1840	1840 D	100.00%	45.27%	13.16%	17.06%	23.86%	0.00%	0.00%	0.45%	0.08%	0.13%
DEMAND 1845	1845 D	100.00%	45.58%	16.24%	20.22%	17.80%	0.00%	0.00%	0.00%	0.08%	0.07%
	1840 & 1845										
DEMAND 1840 & 1845	D	100.00%	45.40%	14.49%	18.43%	21.24%	0.00%	0.00%	0.26%	0.08%	0.10%
DEMAND 1850	1850 D	100.00%	53.27%	18.98%	21.73%	5.84%	0.00%	0.00%	0.00%	0.09%	0.09%
DEMAND 1855	1855 D	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DEMAND 1860	1860 D	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

CUSTOMER ALLOCATORS

Billing Data											
kWh	CEN	100.00%	42.16%	11.34%	17.32%	28.40%	0.00%	0.00%	0.51%	0.06%	0.20%
kW	CDEM	100.00%	0.00%	0.00%	50.77%	48.26%	0.00%	0.00%	0.11%	0.86%	0.00%
kWh - Excl WMP	CEN EWMP	100.00%	42.16%	11.34%	17.32%	28.40%	0.00%	0.00%	0.51%	0.06%	0.20%
Dollar Billed (per 2006 EDR)	CREV	100.00%	51.80%	9.50%	20.81%	16.96%	0.00%	0.00%	0.53%	0.06%	0.32%
Bad Debt 3 Year Historical Average	BDHA	100.00%	78.40%	20.28%	1.32%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Late Payment 3 Year Historical Average	LPHA	100.00%	68.39%	31.61%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Number of Bills	CNB	100.00%	91.24%	6.19%	1.58%	0.17%	0.00%	0.00%	0.01%	0.65%	0.16%
Number of Connections (Unmetered)	CCON	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	93.77%	2.88%	3.35%

Total Number of Customer	CCA	100.00%	75.48%	5.12%	0.65%	0.07%	0.00%	0.00%	17.51%	0.54%	0.63%
Subtransmission Customer Base	CCB	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	93.77%	2.88%	3.35%
Primary Feeder Customer Base	CCP	100.00%	75.48%	5.12%	0.65%	0.07%	0.00%	0.00%	17.51%	0.54%	0.63%
Line Transformer Customer Base	CCLT	100.00%	75.59%	5.13%	0.57%	0.01%	0.00%	0.00%	17.53%	0.54%	0.63%
Secondary Feeder Customer Base	CCS	100.00%	75.59%	5.13%	0.57%	0.01%	0.00%	0.00%	17.53%	0.54%	0.63%
Weighted - Services	CWCS	100.00%	68.49%	9.30%	5.16%	0.12%	0.00%	0.00%	15.88%	0.49%	0.57%
Weighted Meter -Capital	CWMC	100.00%	64.61%	14.60%	16.47%	4.32%	0.00%	0.00%	0.00%	0.00%	0.00%
Weighted Meter Reading	CWMR	100.00%	82.89%	10.37%	2.04%	4.70%	0.00%	0.00%	0.00%	0.00%	0.00%
Weighted Bills	CWNB	100.00%	78.15%	10.61%	9.46%	1.03%	0.00%	0.00%	0.01%	0.06%	0.69%
CUSTOMER ALLOCATORS - Composite											
CUSTOMER 1815-1855	1815-1855 C	100.00%	75.30%	5.26%	0.76%	0.05%	0.00%	0.00%	17.46%	0.54%	0.62%
CUSTOMER 1808	1808 C	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CUSTOMER 1815	1815 C	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CUSTOMER 1820	1820 C	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	1815 & 1820 C	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CUSTOMER 1815 & 1820	1830 C	100.00%	75.51%	5.12%	0.63%	0.05%	0.00%	0.00%	17.51%	0.54%	0.63%
CUSTOMER 1830	1835 C	100.00%	75.52%	5.12%	0.62%	0.05%	0.00%	0.00%	17.52%	0.54%	0.63%
CUSTOMER 1835	1830 & 1835 C	100.00%	75.52%	5.12%	0.63%	0.05%	0.00%	0.00%	17.51%	0.54%	0.63%
CUSTOMER 1830 & 1835	1840 C	100.00%	75.48%	5.12%	0.65%	0.07%	0.00%	0.00%	17.51%	0.54%	0.63%
CUSTOMER 1840	1845 C	100.00%	75.52%	5.12%	0.62%	0.05%	0.00%	0.00%	17.52%	0.54%	0.63%
CUSTOMER 1845	1840 & 1845 C	100.00%	75.51%	5.12%	0.63%	0.06%	0.00%	0.00%	17.51%	0.54%	0.63%
CUSTOMER 1840 & 1845	1850 C	100.00%	75.59%	5.13%	0.57%	0.01%	0.00%	0.00%	17.53%	0.54%	0.63%
CUSTOMER 1850	1855 C	100.00%	68.49%	9.30%	5.16%	0.12%	0.00%	0.00%	15.88%	0.49%	0.57%
CUSTOMER 1855	1860 C	100.00%	64.61%	14.60%	16.47%	4.32%	0.00%	0.00%	0.00%	0.00%	0.00%
CUSTOMER 1860											
Composite Allocators											
Net Fixed Assets	NFA	100.00%	56.18%	12.44%	13.61%	11.97%	0.00%	0.00%	5.34%	0.21%	0.25%
Net Fixed Assets Excluding Capital Contribution	NFA ECC	100.00%	56.18%	12.44%	13.61%	11.97%	0.00%	0.00%	5.34%	0.21%	0.25%
5005-5340	O&M	100.00%	66.25%	11.95%	11.22%	6.63%	0.00%	0.00%	3.42%	0.15%	0.38%

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2006 Cost Allocation Information Filing

Halton Hills Hydro Inc.

EB-2005-0374 EB-2007-0001

Monday, January 15, 2007

Sheet E3 Demand Allocator Worksheet - Second Run

Instructions:

Input sheet for Demand Allocators.

PLCC WATTS

400

		1	2	3	4	5	6	7	8
Customer Classes	Total	Residential	GS<50kW	GS 50-999 kW	GS 1000-4999	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel
CCA	22,529	17,006	1,154	147	16	0	0	3,944	121
CCB	4,206	0	0	0	0	0	0	3,944	121
CCP	22,529	17,006	1,154	147	16	0	0	3,944	121
CCLT	22,497	17,006	1,154	128	3	0	0	3,944	121
CCS	22,497	17,006	1,154	128	3	0	0	3,944	121
PLCC-CCA	9,012	6,802	462	59	6	0	0	1,578	48
PLCC-CCB	1,682	0	0	0	0	0	0	1,578	48
PLCC-CCP	9,012	6,802	462	59	6	0	0	1,578	48
PLCC-CCLT	8,999	6,802	462	51	1	0	0	1,578	48
PLCC-CCS	8,999	6,802	462	51	1	0	0	1,578	48
1NCP									
DNCP1	110,341	49,381	15,698	22,236	22,091	0	0	635	168
PNCP1	-	0	0	0	0	0	0	0	0
LTNCP1	-	0	0	0	0	0	0	0	0
SNCP1	-	0	0	0	0	0	0	0	0
PLCC - 1NCP									
DNCP1A	109,601	49,381	15,698	22,236	22,091	0	0	0	120
PNCP1A	-	0	0	0	0	0	0	0	0
LTNCP1A	-	0	0	0	0	0	0	0	0
SNCP1A	-	0	0	0	0	0	0	0	0

4 NCP

DNCP4	394,514	177,339	55,339	70,559	87,824	0	0	2,530	453
PNCP4	394,514	177,339	55,339	70,559	87,824	0	0	2,530	453
LTNCP4	314,037	177,339	55,339	61,439	16,467	0	0	2,530	453
SNCP4	314,037	177,339	55,339	61,439	16,467	0	0	2,530	453

PLCC - 4NCP

DNCP4A	391,565	177,339	55,339	70,559	87,824	0	0	0	259
PNCP4A	362,248	150,129	53,493	70,324	87,798	0	0	0	259
LTNCP4A	281,822	150,129	53,493	61,234	16,462	0	0	0	259
SNCP4A	281,822	150,129	53,493	61,234	16,462	0	0	0	259

12NCP

DNCP12	1,014,585	453,361	133,613	177,363	240,610	0	0	7,303	1,034
PNCP12	-	0	0	0	0	0	0	0	0
LTNCP12	-	0	0	0	0	0	0	0	0
SNCP12	-	0	0	0	0	0	0	0	0

PLCC - 12NCP

DNCP12A	1,006,024	453,361	133,613	177,363	240,610	0	0	0	453
PNCP12A	-	0	0	0	0	0	0	0	0
LTNCP12A	-	0	0	0	0	0	0	0	0
SNCP12A	-	0	0	0	0	0	0	0	0

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Uniform System of Accounts - Detail Accounts:					Classification and Allocation		
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint
1565	Conservation and Demand Management Expenditures and Recoveries	CDM Expenditures and Recoveries	dp			O&M	
1608	Franchises and Consents	Other Distribution Assets	gp				
1805	Land		dp	DDCP			
1805-1	Land Station >50 kV		dp	TCP	TCP12		
1805-2	Land Station <50 kV		dp	DCP	DCP12		
1806	Land Rights		dp	DDCP			
1806-1	Land Rights Station >50 kV		dp	TCP	TCP12		
1806-2	Land Rights Station <50 kV		dp	DCP	DCP12		
1808	Buildings and Fixtures		dp	DDCP			
1808-1	Buildings and Fixtures > 50 kV		dp	TCP	TCP12		
1808-2	Buildings and Fixtures < 50 KV		dp	DCP	DCP12		
1810	Leasehold Improvements		dp	DDCP			
1810-1	Leasehold Improvements >50 kV		dp	TCP	TCP12		
1810-2	Leasehold Improvements <50 kV		dp	DCP	DCP12		
1815	Transformer Station Equipment - Normally Primary above 50 kV		dp	TCP	TCP12		
1820	Distribution Station Equipment - Normally Primary below 50 kV		dp	DCP	DCP12		
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)		dp	DCP	DCP12		
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)		dp	PNCP	PNCP4		

Uniform System of Accounts - Detail Accounts:					Classification and Allocation		
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)		dp			CEN	
1825	Storage Battery Equipment		dp	DDCP			
1825-1	Storage Battery Equipment > 50 kV		dp	TCP	TCP12		
1825-2	Storage Battery Equipment <50 kV		dp	DCP	DCP12		
1830	Poles, Towers and Fixtures		dp	DDNCP			
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery		dp	BCP	BCP12		
1830-4	Poles, Towers and Fixtures - Primary		dp	PNCP	PNCP4	CCP	x
1830-5	Poles, Towers and Fixtures - Secondary		dp	SNCP	SNCP4	CCS	x
1835	Overhead Conductors and Devices		dp	DDNCP			
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery		dp	BCP	BCP12		
1835-4	Overhead Conductors and Devices - Primary		dp	PNCP	PNCP4	CCP	x
1835-5	Overhead Conductors and Devices - Secondary		dp	SNCP	SNCP4	CCS	x
1840	Underground Conduit		dp	DDNCP			
1840-3	Underground Conduit - Bulk Delivery	Land and Buildings	dp	BCP	BCP12		
1840-4	Underground Conduit - Primary	Land and Buildings	dp	PNCP	PNCP4	CCP	x
1840-5	Underground Conduit - Secondary	Land and Buildings	dp	SNCP	SNCP4	CCS	x
1845	Underground Conductors and Devices	Land and Buildings	dp	DDNCP			

Uniform System of Accounts - Detail Accounts:					Classification and Allocation		
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint
1845-3	Underground Conductors and Devices - Bulk Delivery	TS Primary Above 50	dp	BCP	BCP12		
1845-4	Underground Conductors and Devices - Primary	DS	dp	PNCP	PNCP4	CCP	x
1845-5	Underground Conductors and Devices - Secondary	Other Distribution Assets	dp	SNCP	SNCP4	CCS	x
1850	Line Transformers	Poles, Wires	dp	LTNCP	LTNCP4	CCLT	x
1855	Services	Services and Meters	dp			CWCS	
1860	Meters	Services and Meters	dp			CWMC	
1905	Land	Land and Buildings	gp				
1906	Land Rights	Land and Buildings	gp				
1908	Buildings and Fixtures	General Plant	gp				
1910	Leasehold Improvements	General Plant	gp				
1915	Office Furniture and Equipment	Equipment	gp				
1920	Computer Equipment - Hardware	IT Assets	gp				
1925	Computer Software	IT Assets	gp				
1930	Transportation Equipment	Equipment	gp				
1935	Stores Equipment	Equipment	gp				
1940	Tools, Shop and Garage Equipment	Equipment	gp				
1945	Measurement and Testing Equipment	Equipment	gp				
1950	Power Operated Equipment	Equipment	gp				
1955	Communication Equipment	Equipment	gp				
1960	Miscellaneous Equipment	Equipment	gp				
1970	Load Management Controls - Customer Premises	Other Distribution Assets	gp				

Uniform System of Accounts - Detail Accounts:					Classification and Allocation		
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint
1975	Load Management Controls - Utility Premises	Other Distribution Assets	gp				
1980	System Supervisory Equipment	Other Distribution Assets	gp				
1990	Other Tangible Property	Other Distribution Assets	gp				
1995	Contributions and Grants - Credit	Contributions and Grants	co		Break out	Breakout	
2005	Property Under Capital Leases	Other Distribution Assets	gp				
2010	Electric Plant Purchased or Sold	Other Distribution Assets	gp				
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	Accumulated Amortization	accum dep		Break out	Breakout	
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	Accumulated Amortization	accum dep		Break out	Breakout	
3046	Balance Transferred From Income	Equity	NI				
4080	Distribution Services Revenue	Distribution Services Revenue	CREV				
4082	Retail Services Revenues	Other Distribution Revenue	mi				
4084	Service Transaction Requests (STR) Revenues	Other Distribution Revenue	mi				
4090	Electric Services Incidental to Energy Sales	Other Distribution Revenue	mi				
4205	Interdepartmental Rents	Other Distribution Revenue	mi				
4210	Rent from Electric Property	Other Distribution Revenue	mi				
4215	Other Utility Operating Income	Other Distribution Revenue	mi				
4220	Other Electric Revenues	Other Distribution Revenue	mi				

Uniform System of Accounts - Detail Accounts:					Classification and Allocation		
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint
4225	Late Payment Charges	Late Payment Charges	mi				
4235	Miscellaneous Service Revenues	Specific Service Charges	mi				
4240	Provision for Rate Refunds	Other Distribution Revenue	mi				
4245	Government Assistance Directly Credited to Income	Other Distribution Revenue	mi				
4305	Regulatory Debits	Other Income & Deductions	mi				
4310	Regulatory Credits	Other Income & Deductions	mi				
4315	Revenues from Electric Plant Leased to Others	Other Income & Deductions	mi				
4320	Expenses of Electric Plant Leased to Others	Other Income & Deductions	mi				
4325	Revenues from Merchandise, Jobbing, Etc.	Other Income & Deductions	mi				
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	Other Income & Deductions	mi				
4335	Profits and Losses from Financial Instrument Hedges	Other Income & Deductions	mi				
4340	Profits and Losses from Financial Instrument Investments	Other Income & Deductions	mi				
4345	Gains from Disposition of Future Use Utility Plant	Other Income & Deductions	mi				
4350	Losses from Disposition of Future Use Utility Plant	Other Income & Deductions	mi				
4355	Gain on Disposition of Utility and Other Property	Other Income & Deductions	mi				
4360	Loss on Disposition of Utility and Other Property	Other Income & Deductions	mi				

Uniform System of Accounts - Detail Accounts:					Classification and Allocation		
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint
4365	Gains from Disposition of Allowances for Emission	Other Income & Deductions	mi				
4370	Losses from Disposition of Allowances for Emission	Other Income & Deductions	mi				
4390	Miscellaneous Non-Operating Income	Other Income & Deductions	mi				
4395	Rate-Payer Benefit Including Interest	Other Income & Deductions	mi				
4398	Foreign Exchange Gains and Losses, Including Amortization	Other Income & Deductions	mi				
4405	Interest and Dividend Income	Other Income & Deductions	mi				
4415	Equity in Earnings of Subsidiary Companies	Other Income & Deductions	mi				
4705	Power Purchased	Power Supply Expenses (Working Capital)	cop				
4708	Charges-WMS	Power Supply Expenses (Working Capital)	cop				
4710	Cost of Power Adjustments	Power Supply Expenses (Working Capital)	cop				
4712	Charges-One-Time	Power Supply Expenses (Working Capital)	cop				
4714	Charges-NW	Power Supply Expenses (Working Capital)	cop				
4715	System Control and Load Dispatching	Other Power Supply Expenses	cop				
4716	Charges-CN	Power Supply Expenses (Working Capital)	cop				

Uniform System of Accounts - Detail Accounts:					Classification and Allocation		
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint
4730	Rural Rate Assistance Expense	Power Supply Expenses (Working Capital)	cop				
5005	Operation Supervision and Engineering	Operation (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x
5010	Load Dispatching	Operation (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x
5012	Station Buildings and Fixtures Expense	Operation (Working Capital)	di	1808 D	1808 D	1808 C	
5014	Transformer Station Equipment - Operation Labour	Operation (Working Capital)	di	1815 D	1815 D	1815 C	
5015	Transformer Station Equipment - Operation Supplies and Expenses	Operation (Working Capital)	di	1815 D	1815 D	1815 C	
5016	Distribution Station Equipment - Operation Labour	Operation (Working Capital)	di	1820 D	1820 D	1820 C	
5017	Distribution Station Equipment - Operation Supplies and Expenses	Operation (Working Capital)	di	1820 D	1820 D	1820 C	
5020	Overhead Distribution Lines and Feeders - Operation Labour	Operation (Working Capital)	di	1830 & 1835 D	1830 & 1835 D	1830 & 1835 C	x
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	Operation (Working Capital)	di	1830 & 1835 D	1830 & 1835 D	1830 & 1835 C	x
5030	Overhead Subtransmission Feeders - Operation	Operation (Working Capital)	di	1830 & 1835 D	1830 & 1835 D	1830 & 1835 C	
5035	Overhead Distribution Transformers- Operation	Operation (Working Capital)	di	1850 D	1850 D	1850 C	x
5040	Underground Distribution Lines and Feeders - Operation Labour	Operation (Working Capital)	di	1840 & 1845 D	1840 & 1845 D	1840 & 1845 C	x

Uniform System of Accounts - Detail Accounts:					Classification and Allocation		
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	Operation (Working Capital)	di	1840 & 1845 D	1840 & 1845 D	1840 & 1845 C	x
5050	Underground Subtransmission Feeders - Operation	Operation (Working Capital)	di	1840 & 1845 D	1840 & 1845 D	1840 & 1845 C	
5055	Underground Distribution Transformers - Operation	Operation (Working Capital)	di	1850 D	1850 D	1850 C	x
5065	Meter Expense	Operation (Working Capital)	cu			CWMC	
5070	Customer Premises - Operation Labour	Operation (Working Capital)	cu			CCA	
5075	Customer Premises - Materials and Expenses	Operation (Working Capital)	cu			CCA	
5085	Miscellaneous Distribution Expense	Operation (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x
5090	Underground Distribution Lines and Feeders - Rental Paid	Operation (Working Capital)	di	1840 & 1845 D	1840 & 1845 D	1840 & 1845 C	x
5095	Overhead Distribution Lines and Feeders - Rental Paid	Operation (Working Capital)	di	1830 & 1835 D	1830 & 1835 D	1830 & 1835 C	x
5096	Other Rent	Operation (Working Capital)	di				
5105	Maintenance Supervision and Engineering	Maintenance (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x
5110	Maintenance of Buildings and Fixtures - Distribution Stations	Maintenance (Working Capital)	di	1808 D	1808 D	1808 C	
5112	Maintenance of Transformer Station Equipment	Maintenance (Working Capital)	di	1815 D	1815 D	1815 C	
5114	Maintenance of Distribution Station Equipment	Maintenance (Working Capital)	di	1820 D	1820 D	1820 C	

Uniform System of Accounts - Detail Accounts:					Classification and Allocation		
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint
5120	Maintenance of Poles, Towers and Fixtures	Maintenance (Working Capital)	di	1830 D	1830 D	1830 C	x
5125	Maintenance of Overhead Conductors and Devices	Maintenance (Working Capital)	di	1835 D	1835 D	1835 C	x
5130	Maintenance of Overhead Services	Maintenance (Working Capital)	di	1855 D	1855 D	1855 C	
5135	Overhead Distribution Lines and Feeders - Right of Way	Maintenance (Working Capital)	di	1830 & 1835 D	1830 & 1835 D	1830 & 1835 C	x
5145	Maintenance of Underground Conduit	Maintenance (Working Capital)	di	1840 D	1840 D	1840 C	x
5150	Maintenance of Underground Conductors and Devices	Maintenance (Working Capital)	di	1845 D	1845 D	1845 C	x
5155	Maintenance of Underground Services	Maintenance (Working Capital)	di	1855 D	1855 D	1855 C	
5160	Maintenance of Line Transformers	Maintenance (Working Capital)	di	1850 D	1850 D	1850 C	x
5175	Maintenance of Meters	Maintenance (Working Capital)	cu	1860 D	1860 D	1860 C	
5305	Supervision	Billing and Collection (Working Capital)	cu			CWNB	
5310	Meter Reading Expense	Billing and Collection (Working Capital)	cu			CWMR	
5315	Customer Billing	Billing and Collection (Working Capital)	cu			CWNB	
5320	Collecting	Billing and Collection (Working Capital)	cu			CWNB	
5325	Collecting- Cash Over and Short	Billing and Collection (Working Capital)	cu			CWNB	

Uniform System of Accounts - Detail Accounts:					Classification and Allocation		
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint
5330	Collection Charges	Billing and Collection (Working Capital)	cu			CWNB	
5335	Bad Debt Expense	Bad Debt Expense (Working Capital)	cu			BDHA	
5340	Miscellaneous Customer Accounts Expenses	Billing and Collection (Working Capital)	cu			CWNB	
5405	Supervision	Community Relations (Working Capital)	ad				
5410	Community Relations - Sundry	Community Relations (Working Capital)	ad				
5415	Energy Conservation	Community Relations - CDM (Working Capital)	ad				
5420	Community Safety Program	Community Relations (Working Capital)	ad				
5425	Miscellaneous Customer Service and Informational Expenses	Community Relations (Working Capital)	ad				
5505	Supervision	Other Distribution Expenses	ad				
5510	Demonstrating and Selling Expense	Other Distribution Expenses	ad				
5515	Advertising Expense	Advertising Expenses	ad				
5520	Miscellaneous Sales Expense	Other Distribution Expenses	ad				
5605	Executive Salaries and Expenses	Administrative and General Expenses (Working Capital)	ad				
5610	Management Salaries and Expenses	Administrative and General Expenses (Working Capital)	ad				

Uniform System of Accounts - Detail Accounts:					Classification and Allocation		
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint
5615	General Administrative Salaries and Expenses	Administrative and General Expenses (Working Capital)	ad				
5620	Office Supplies and Expenses	Administrative and General Expenses (Working Capital)	ad				
5625	Administrative Expense Transferred Credit	Administrative and General Expenses (Working Capital)	ad				
5630	Outside Services Employed	Administrative and General Expenses (Working Capital)	ad				
5635	Property Insurance	Insurance Expense (Working Capital)	ad				
5640	Injuries and Damages	Administrative and General Expenses (Working Capital)	ad				
5645	Employee Pensions and Benefits	Administrative and General Expenses (Working Capital)	ad				
5650	Franchise Requirements	Administrative and General Expenses (Working Capital)	ad				
5655	Regulatory Expenses	Administrative and General Expenses (Working Capital)	ad				
5660	General Advertising Expenses	Advertising Expenses	ad				
5665	Miscellaneous General Expenses	Administrative and General Expenses (Working Capital)	ad				
5670	Rent	Administrative and General Expenses (Working Capital)	ad				
5675	Maintenance of General Plant	Administrative and General Expenses (Working Capital)	ad				

Uniform System of Accounts - Detail Accounts:					Classification and Allocation		
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint
5680	Electrical Safety Authority Fees	Administrative and General Expenses (Working Capital)	ad				
5685	Independent Market Operator Fees and Penalties	Power Supply Expenses (Working Capital)	cop				
5705	Amortization Expense - Property, Plant, and Equipment	Amortization of Assets	dep	PRORATED	Break out	Breakout	
5710	Amortization of Limited Term Electric Plant	Amortization of Assets	dep	PRORATED	Break out	Breakout	
5715	Amortization of Intangibles and Other Electric Plant	Amortization of Assets	dep	PRORATED	Break out	Breakout	
5720	Amortization of Electric Plant Acquisition Adjustments	Other Amortization - Unclassified	dep	PRORATED	Break out	Breakout	
5730	Amortization of Unrecovered Plant and Regulatory Study Costs	Amortization of Assets	dep				
5735	Amortization of Deferred Development Costs	Amortization of Assets	dep				
5740	Amortization of Deferred Charges	Amortization of Assets	dep				
6005	Interest on Long Term Debt	Interest Expense - Unclassified	INT				
6105	Taxes Other Than Income Taxes	Other Distribution Expenses	ad				
6110	Income Taxes	Income Tax Expense - Unclassified	Input				
6205	Donations	Charitable Contributions	ad				
6210	Life Insurance	Insurance Expense (Working Capital)	ad				
6215	Penalties	Other Distribution Expenses	ad				

Uniform System of Accounts - Detail Accounts:					Classification and Allocation		
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint
6225	Other Deductions	Other Distribution Expenses	ad				



2006 Cost Allocation Information Filing

Halton Hills Hydro Inc.

EB-2005-0374 EB-2007-0001

Monday, January 15, 2007

Sheet E5 Reconciliation Worksheet - Second Run

Details:

The worksheet below shows reconciliation of costs included and excluded in the Trial Balance.

USoA Account #	Accounts	Financial Statement	Financial Statement - Asset Break Out includes Acc Dep and Contributed Capital	Adjusted TB	Excluded from COSS	Excluded	Included	Balance in O5
1565	Conservation and Demand Management Expenditures and Recoveries							
1608	Franchises and Consents							
1805	Land							
1805-1	Land Station >50 kV							
1805-2	Land Station <50 kV							
1806	Land Rights							
1806-1	Land Rights Station >50 kV							
1806-2	Land Rights Station <50 kV							
1808	Buildings and Fixtures							
1808-1	Buildings and Fixtures > 50 kV							
1808-2	Buildings and Fixtures < 50 kV							
1810	Leasehold Improvements							
1810-1	Leasehold Improvements >50 kV							
1810-2	Leasehold Improvements <50 kV							
1815	Transformer Station Equipment - Normally Primary above 50 kV							
1820	Distribution Station Equipment - Normally Primary below 50 kV							
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)							
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)							
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)							
1825	Storage Battery Equipment							
1825-1	Storage Battery Equipment > 50 kV							
1825-2	Storage Battery Equipment <50 kV							
1830	Poles, Towers and Fixtures							

	Poles, Towers and Fixtures -
1830-3	Subtransmission Bulk Delivery
1830-4	Poles, Towers and Fixtures - Primary
1830-5	Poles, Towers and Fixtures - Secondary
1835	Overhead Conductors and Devices
	Overhead Conductors and Devices -
1835-3	Subtransmission Bulk Delivery
1835-4	Overhead Conductors and Devices - Primary
	Overhead Conductors and Devices -
1835-5	Secondary
1840	Underground Conduit
1840-3	Underground Conduit - Bulk Delivery
1840-4	Underground Conduit - Primary
1840-5	Underground Conduit - Secondary
1845	Underground Conductors and Devices
	Underground Conductors and Devices - Bulk
1845-3	Delivery
	Underground Conductors and Devices -
1845-4	Primary
	Underground Conductors and Devices -
1845-5	Secondary
1850	Line Transformers
1855	Services
1860	Meters
1905	Land
1906	Land Rights
1908	Buildings and Fixtures
1910	Leasehold Improvements
1915	Office Furniture and Equipment
1920	Computer Equipment - Hardware
1925	Computer Software
1930	Transportation Equipment
1935	Stores Equipment
1940	Tools, Shop and Garage Equipment
1945	Measurement and Testing Equipment
1950	Power Operated Equipment
1955	Communication Equipment
1960	Miscellaneous Equipment
1970	Load Management Controls - Customer
	Premises
1975	Load Management Controls - Utility
	Premises
1980	System Supervisory Equipment
1990	Other Tangible Property
1995	Contributions and Grants - Credit
2005	Property Under Capital Leases

2010	Electric Plant Purchased or Sold
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment
2120	Accumulated Amortization of Electric Utility Plant - Intangibles
3046	Balance Transferred From Income
4080	Distribution Services Revenue
4082	Retail Services Revenues
4084	Service Transaction Requests (STR) Revenues
4090	
	Electric Services Incidental to Energy Sales
4205	Interdepartmental Rents
4210	Rent from Electric Property
4215	Other Utility Operating Income
4220	Other Electric Revenues
4225	Late Payment Charges
4235	Miscellaneous Service Revenues
4240	Provision for Rate Refunds
4245	Government Assistance Directly Credited to Income
4305	Regulatory Debits
4310	Regulatory Credits
4315	Revenues from Electric Plant Leased to Others
4320	
	Expenses of Electric Plant Leased to Others
4325	
	Revenues from Merchandise, Jobbing, Etc.
4330	Costs and Expenses of Merchandising, Jobbing, Etc.
4335	Profits and Losses from Financial Instrument Hedges
4340	Profits and Losses from Financial Instrument Investments
4345	Gains from Disposition of Future Use Utility Plant
4350	Losses from Disposition of Future Use Utility Plant
4355	Gain on Disposition of Utility and Other Property
4360	Loss on Disposition of Utility and Other Property
4365	Gains from Disposition of Allowances for Emission
4370	Losses from Disposition of Allowances for Emission

4390	Miscellaneous Non-Operating Income
4395	Rate-Payer Benefit Including Interest
4398	Foreign Exchange Gains and Losses, Including Amortization
4405	Interest and Dividend Income
4415	Equity in Earnings of Subsidiary Companies
4705	Power Purchased
4708	Charges-WMS
4710	Cost of Power Adjustments
4712	Charges-One-Time
4714	Charges-NW
4715	System Control and Load Dispatching
4716	Charges-CN
4730	Rural Rate Assistance Expense
5005	Operation Supervision and Engineering
5010	Load Dispatching
5012	Station Buildings and Fixtures Expense
5014	Transformer Station Equipment - Operation Labour
5015	Transformer Station Equipment - Operation Supplies and Expenses
5016	Distribution Station Equipment - Operation Labour
5017	Distribution Station Equipment - Operation Supplies and Expenses
5020	Overhead Distribution Lines and Feeders - Operation Labour
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses
5030	Overhead Subtransmission Feeders - Operation
5035	Overhead Distribution Transformers- Operation
5040	Underground Distribution Lines and Feeders - Operation Labour
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses
5050	Underground Subtransmission Feeders - Operation
5055	Underground Distribution Transformers - Operation
5065	Meter Expense
5070	Customer Premises - Operation Labour
5075	Customer Premises - Materials and Expenses
5085	Miscellaneous Distribution Expense

5090	Underground Distribution Lines and Feeders - Rental Paid
5095	Overhead Distribution Lines and Feeders - Rental Paid
5096	Other Rent
5105	Maintenance Supervision and Engineering
5110	Maintenance of Buildings and Fixtures - Distribution Stations
5112	Maintenance of Transformer Station Equipment
5114	Maintenance of Distribution Station Equipment
5120	Maintenance of Poles, Towers and Fixtures
5125	Maintenance of Overhead Conductors and Devices
5130	Maintenance of Overhead Services
5135	Overhead Distribution Lines and Feeders - Right of Way
5145	Maintenance of Underground Conduit
5150	Maintenance of Underground Conductors and Devices
5155	Maintenance of Underground Services
5160	Maintenance of Line Transformers
5175	Maintenance of Meters
5305	Supervision
5310	Meter Reading Expense
5315	Customer Billing
5320	Collecting
5325	Collecting- Cash Over and Short
5330	Collection Charges
5335	Bad Debt Expense
5340	Miscellaneous Customer Accounts Expenses
5405	Supervision
5410	Community Relations - Sundry
5415	Energy Conservation
5420	Community Safety Program
5425	Miscellaneous Customer Service and Informational Expenses
5505	Supervision
5510	Demonstrating and Selling Expense
5515	Advertising Expense
5520	Miscellaneous Sales Expense
5605	Executive Salaries and Expenses
5610	Management Salaries and Expenses

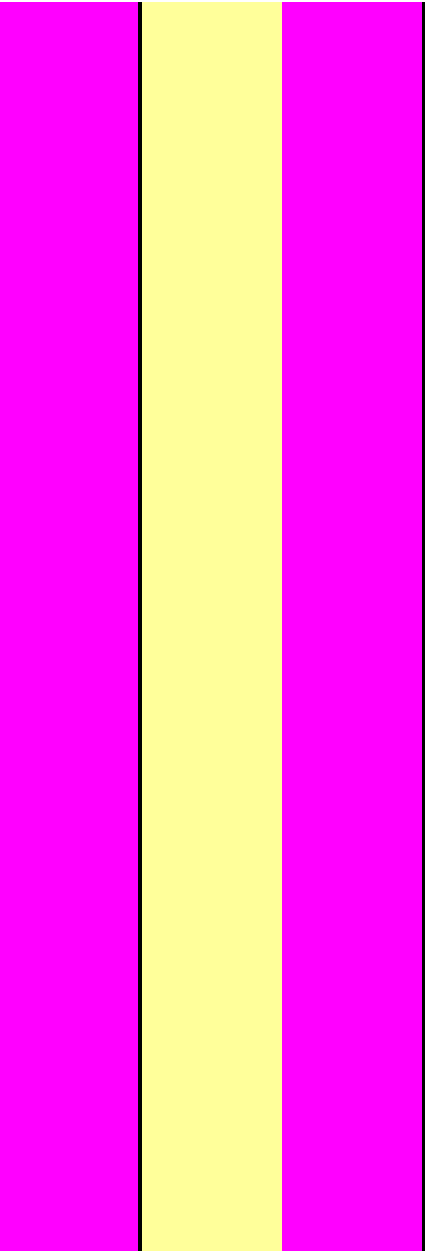
5615	General Administrative Salaries and Expenses						
5620	Office Supplies and Expenses						
5625	Administrative Expense Transferred Credit						
5630	Outside Services Employed						
5635	Property Insurance						
5640	Injuries and Damages						
5645	Employee Pensions and Benefits						
5650	Franchise Requirements						
5655	Regulatory Expenses						
5660	General Advertising Expenses						
5665	Miscellaneous General Expenses						
5670	Rent						
5675	Maintenance of General Plant						
5680	Electrical Safety Authority Fees						
5685	Independent Market Operator Fees and Penalties						
5705	Amortization Expense - Property, Plant, and Equipment						
5710	Amortization of Limited Term Electric Plant						
5715	Amortization of Intangibles and Other Electric Plant						
5720	Amortization of Electric Plant Acquisition Adjustments						
5730	Amortization of Unrecovered Plant and Regulatory Study Costs						
5735	Amortization of Deferred Development Costs						
5740	Amortization of Deferred Charges						
6005	Interest on Long Term Debt						
6105	Taxes Other Than Income Taxes						
6110	Income Taxes						
6205	Donations						
6210	Life Insurance						
6215	Penalties						
6225	Other Deductions						
Total		\$22,335,554	\$29,933,917	\$52,269,471	Control	(\$4,707) \$52,269,471	\$52,274,178 \$52,269,471

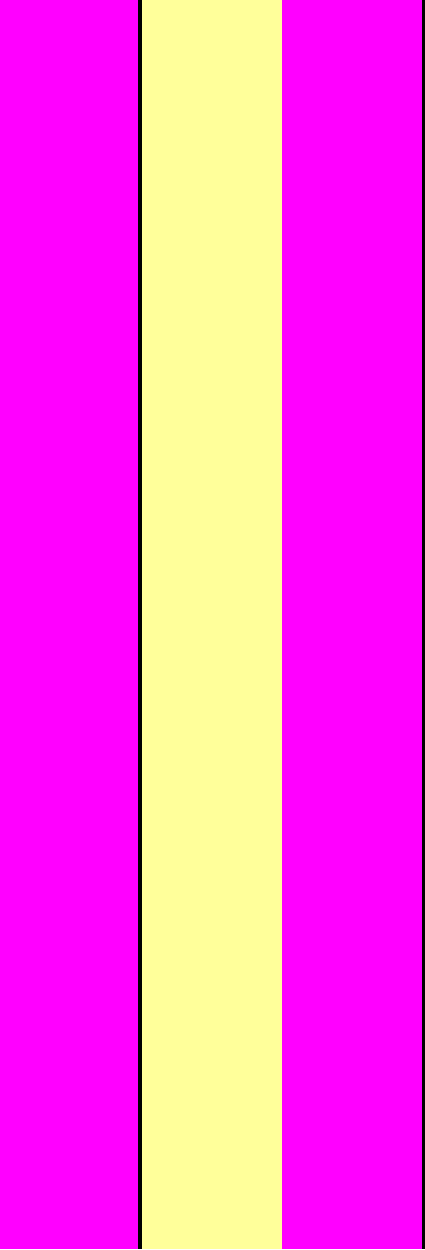
Grouping by Allocator		Adjusted TB	Excluded from COSS	Excluded	Included	Balance in O5	Difference	Balance in O4 Summary
1808	\$	2,329	\$ -	\$ -	2,329	\$ 2,329	\$ -	2,329

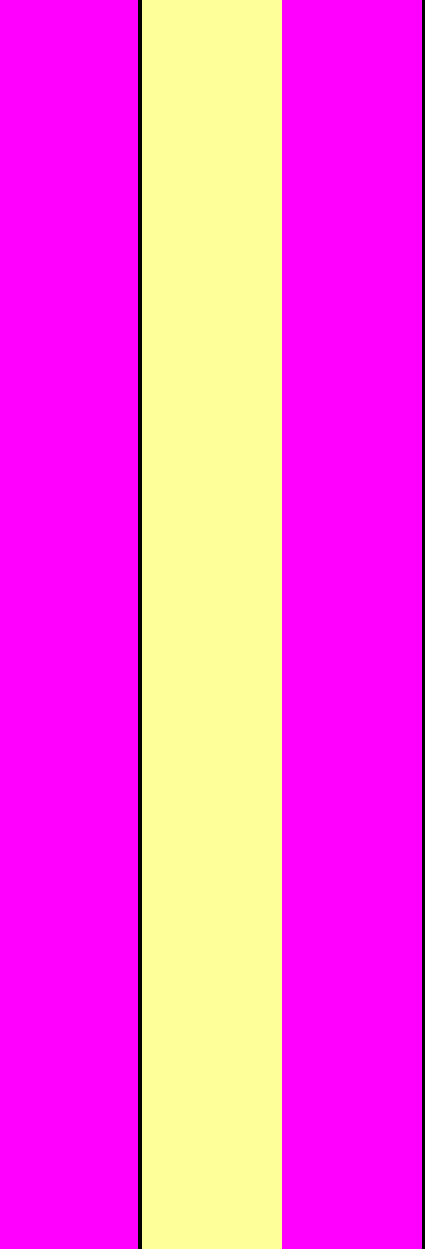
1815	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-
1820	\$	131,779	\$	-	\$	-	\$	131,779	\$	131,779	\$	-	\$	131,779
1830	\$	42,329	\$	-	\$	-	\$	42,329	\$	42,329	\$	-	\$	42,329
1835	\$	98,769	\$	-	\$	-	\$	98,769	\$	98,769	\$	-	\$	98,769
1840	\$	5,547	\$	-	\$	-	\$	5,547	\$	5,547	\$	-	\$	5,547
1845	\$	16,062	\$	-	\$	-	\$	16,062	\$	16,062	\$	-	\$	16,062
1850	\$	246,997	\$	-	\$	-	\$	246,997	\$	246,997	\$	-	\$	246,997
1855	\$	76,389	\$	-	\$	-	\$	76,389	\$	76,389	\$	-	\$	76,389
1860	\$	4,621	\$	-	\$	-	\$	4,621	\$	4,621	\$	-	\$	4,621
1815-1855	\$	268,126	\$	-	\$	-	\$	268,126	\$	268,126	\$	-	\$	268,126
1830 & 1835	\$	126,788	\$	-	\$	-	\$	126,788	\$	126,788	\$	-	\$	126,788
1840 & 1845	\$	101,843	\$	-	\$	-	\$	101,843	\$	101,843	\$	-	\$	101,843
BCP	\$	1,007,800	\$	-	\$	-	\$	1,007,800	\$	1,007,800	\$	-	\$	1,007,800
BDHA	\$	38,593	\$	-	\$	-	\$	38,593	\$	38,593	\$	-	\$	38,593
Break Out	\$	(4,198,730)	\$	-	\$	-	\$	(4,198,730)	\$	(4,198,730)	\$	-	\$	(4,198,731)
CCA	\$	11,677	\$	-	\$	-	\$	11,677	\$	11,677	\$	-	\$	11,677
CDMPP	\$	444,180	\$	-	\$	-	\$	444,180	\$	444,180	\$	-	\$	444,180
CEN	\$	4,754,680	\$	-	\$	-	\$	4,754,680	\$	4,754,680	\$	-	\$	4,754,680
CEN EWMP	\$	25,929,123	\$	-	\$	-	\$	25,929,123	\$	25,929,123	\$	-	\$	25,929,123
CREV	\$	(8,240,409)	\$	-	\$	-	\$	(8,240,409)	\$	(8,240,409)	\$	-	\$	(8,240,409)
CWCS	\$	271,718	\$	-	\$	-	\$	271,718	\$	271,718	\$	-	\$	271,718
CWMC	\$	1,269,291	\$	-	\$	-	\$	1,269,291	\$	1,269,291	\$	-	\$	1,269,291
CWMR	\$	124,505	\$	-	\$	-	\$	124,505	\$	124,505	\$	-	\$	124,505
CWNB	\$	225,638	\$	-	\$	-	\$	225,638	\$	225,638	\$	-	\$	225,638
DCP	\$	2,923,098	\$	-	\$	-	\$	2,923,098	\$	2,923,098	\$	-	\$	2,923,098
LPHA	\$	(125,845)	\$	-	\$	-	\$	(125,845)	\$	(125,845)	\$	-	\$	(125,845)
LTNCP	\$	5,040,858	\$	-	\$	-	\$	5,040,858	\$	5,040,858	\$	-	\$	5,040,858
NFA	\$	239,908	\$	-	\$	(4,707)	\$	244,615	\$	239,908	\$	-	\$	239,908
NFA ECC	\$	3,163,886	\$	-	\$	-	\$	3,163,886	\$	3,163,886	\$	-	\$	3,163,886
O&M	\$	1,890,172	\$	-	\$	-	\$	1,890,172	\$	1,890,172	\$	-	\$	1,890,172
PNCP	\$	12,043,215	\$	-	\$	-	\$	12,043,215	\$	12,043,215	\$	-	\$	12,043,215
SNCP	\$	4,334,536	\$	-	\$	-	\$	4,334,536	\$	4,334,536	\$	-	\$	4,334,536
TCP	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-
Total	\$	52,269,471	\$	-	\$	(4,707)	\$	52,274,178	\$	52,269,471	\$	-	\$	52,269,471

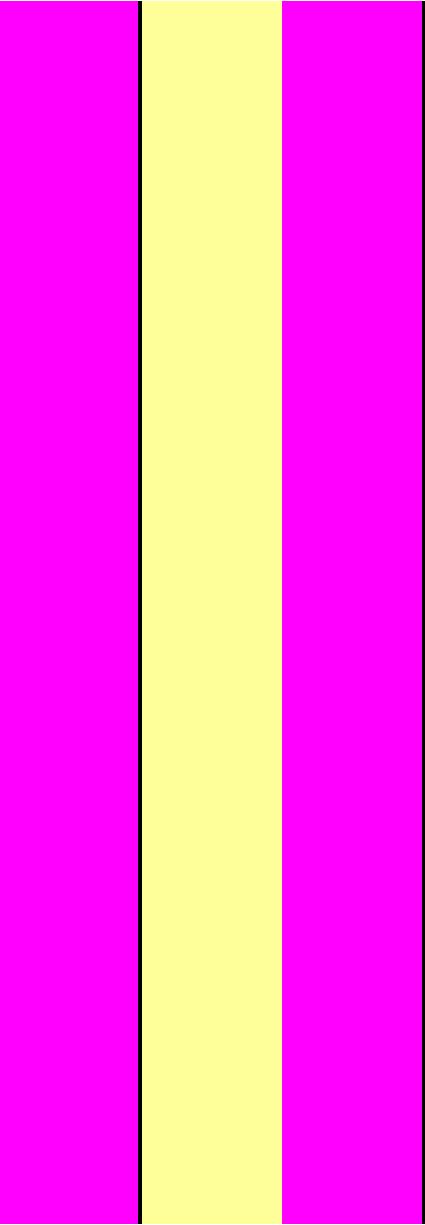


Difference	Balance in O4 Summary	Difference









\$	-
\$	-
\$	-
\$	-
\$	-
\$	-
\$	-
\$	-
\$	-
\$	-
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\$	1
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\$	-
\$	-
\$	-
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\$	-
\$	-
\$	-
\$	-
\$	-
\$	4,707
\$	-
\$	-
\$	-
\$	-
\$	-

\$	4,708



2006 Cost Allocation

Halton Hills Hydro Inc.

EB-2005-0374 EB-2007-0001

Monday, January 15, 2007

Sheet E5 Reconciliation Worksheet - Second Run

If you have completed the Cost Allocation filing model and prepared to submit your findings to the Ontario Energy Board, please note that you have 2 saving options.

OPTION #1 - Detailed

Step 1: Save this file as "LDCname_Detailed_CA_model_RUN#.xls"

Step 2: Printout sheets I2, I4, and O1

OPTION #2 - Rolled Up

Step 1: Save this file as "LDCname_Detailed_CA_model_RUN#.xls"

Step 2: **Click on the Option 2 Button**

Step 3: **Save this file as "LDCname_RolledUp_CA_model_RUN#.xls"**

Step 4: Printout sheets I2, I4, and O1

OPTION 2

OEB STAFF INTERROGATORIES

APPENDIX F

Determination of Net Utility Income and Calculation of Revenue Deficiency

**DETERMINATION OF NET UTILITY INCOME AND CALCULATION OF REVENUE
DEFICIENCY**

	2008 Test using 2007 Existing Rates (\$)	Comments
Revenue		
Distribution Revenue	9,672,375	Exhibit 3, Tab 1, Schedule 2
Other Operating Revenue (Net)	960,000	Exhibit 3, Tab 1, Schedule 2
Total Revenue	10,632,375	
Costs and Expenses		
Distribution Costs		
Operation & Maintenance	5,093,000	
Depreciation & Amortization	2,190,723	
Property & Capital Taxes	195,000	
Interest	1,266,740	
Total Costs and Expenses	8,745,463	
Utility Income Before Income Taxes	2,114,493	
Income Taxes	836,500	
Utility Income	\$1,277,993	
Utility Proposed Rate Base	37,954,174	
Required Return@7.451%	2,827,966	Exhibit 6, Tab 1, Schedule 4, Page 3
Required Return	2,827,966	
Utility Income	1,277,993	
Revenue Deficiency	1,549,973	

OEB STAFF INTERROGATORIES

APPENDIX G

SMART METER INVESTMENT PLAN



HALTON HILLS HYDRO INC.
(ED-2002-0553)

SMART METER INVESTMENT PLAN
(BOARD FILE #EB-2006-0246)

DECEMBER 15, 2006

1. **CONTACT INFORMATION**

Arthur A Skidmore
Chief Financial Officer
519-853-3700 Ext 225
askidmore@haltonhillshydro.com

2. Did you submit a Smart Meter Investment Plan (“SMIP”) as part of your 2006 EDR rate application?

In the 2006 EDR rate application from Halton Hills Hydro we stated that implementation would begin in 2007 with a target of 6,000 meters. The information is contained in Manager’s Summary Chapter 3, 3.1 Tier 1 Adjustments.

3. If you have made any significant changes to your SMIP subsequent to your application, please provide details of the changes (both here in general terms and as a component of the following questions).

The timing of our implementation has changed from what was included in our EDR filing. We still intend to implement smart meters in our community in 2007. We will be issuing a RFP (copy attached as Exhibit 1) in December 2006 with responses due in 2007. We want to ensure that we are getting a smart solution for the expenditure required.

4. For the 2006 rate year, how much money has been included in the Board approved revenue requirement for the SMIP? How is this being recovered from your customers?

The Ontario Energy Board’s response is included below:

“As noted in your application, you asked for 6,000 smart meters to be installed in 2006. Assuming start date for installation as May 2006 and uniform installation each month \$3.50 per meter month is equivalent to a value of \$1.90 per month per meter installed. (Use 12 meters, one per month with \$3.50 applied to the cumulative value for one year (\$273) divided by 12 meters divided by 12 months). The 6000 is multiplied by \$1.90 multiplied by 12 months (\$136,800) and divided by the number of metered customers you have (18,323) divided by twelve months. From this you get a rounded value of \$0.62 per metered “

5. What is your SMIP in the 2006 rate year? If you do not have a SMIP in the 2006 rate year, what are your intentions for future years?

Halton Hills Hydro Inc. SMIP Timeline

<u>Date</u>	<u>Action</u>
December 15, 2006	File SMIP with Ontario Energy Board
December 22, 2006	Issue RFP
December 22, 2006 - January 20, 2007	Receive RFP responses
January 20, 2007 – March 31, 2007	Review and evaluate Responses
April 1, 2007 – June 30, 2007	Design, build, test communication infrastructure
July 1, 2007	Review expired meters, order 2007 Smart meters – Quantity 3,500
September 1, 2007 – December 31, 2007	Installation of 3,323 meters
2008	Installation of 5,000 meters
2009	Installation of 5,000 meters
2010	Installation of 5,000 meters

6. Specifically, and in as much detail as possible, please provide the following information for your planned implementation of the SMIP:
- The number of meters installed by class and by year, both in absolute terms and as a percentage of the class;
 - The capital expenditures and amortization by class and by year;
(Assumed cost/meter including communication is \$250/meter)
 - The operating expenses by class and by year;
(Assumed operating costs @\$1/meter/month)
(Assumed yearly meter installation performed equally throughout the year)
 - The effect of the SMIP on the level of the allowance for PILs.
(Assumed 36.12% gross up)

RESIDENTIAL – 17,004

Year	# of Meters	Capital Expenditures	Operating Expenses	Amortization	PIL's	Total (Excluding Amortization)
2007	3,323	\$830,750	\$10,000	\$17,300	\$290,206	\$1,130,956
2008	4,560	1,140,000	67,000	116,730	345,405	\$1,552,405
2009	4,560	1,140,000	121,000	211,730	291,585	\$1,552,585
2010	4,561	1,140,250	177,000	306,740	237,131	\$1,130,956

GENERAL SERVICE – 1,319

Year	# of Meters	Capital Expenditures	Operating Expenses	Amortization	PIL's	Total (Excluding Amortization)
2007	-					
2008	440	\$110,000	5,300	9,200	34,495	\$149,795
2009	440	110,000	10,600	18,400	29,257	149,857
2010	439	109,750	15,900	27,600	24,020	149,670

7. If you previously submitted a plan and have made changes to it, please provide a similar set of responses to question 7 for both the original plan and the changes between plans.

The only other plan submitted was the plan included in our 2006 EDR application that was referred to in questions #2

8. With respect to funding for the SMIP, please provide comments as to whether you consider that the existing funding recovered through the 2006 rates and/or the proposed adjustment for 2007 rates is sufficient, or indicate why that funding and timing is not sufficient for your SMIP needs and what action you consider necessary to ameliorate the situation. Please ensure that these comments are as detailed and specific as possible, both with respect to the level of the funding and the timing of such a revision.

We would not consider existing funding through our 2006 rates to be sufficient for the expenditure outlined in question #6. In our opinion funding should match the investment plan as outlined in question #6. Therefore, we would expect additional 2007 funding to be $(\$1,130,956 - \$136,800(2006) - \$136,800(2007)) = \$857,356$. However, we are unclear what the statement “proposed adjustment for 2007 rates” means and therefore have assumed that our \$857,356 is the proposed adjustment.

9. Please provide any additional comments that you believe would be helpful to the Board in its understanding of your SMIP and what you consider to be the requirements for the efficient and effective implementation of this government sponsored initiative.

It is Halton Hills Hydro's intention to fully support the government's Smart Metering initiative. Having the proper funding mechanism in place will enable our utility to implement a solution that will benefit all ratepayers in our community.

Respectfully Submitted:

Daniel P. Guatto,
President

Arthur A. Skidmore
Chief Financial Officer



Request for Proposal
For a
Turn-Key Electric Advanced Metering Solution

Reference # AMI-001

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1 INSTRUCTIONS TO PROPONENTS

Structure of Document and Files Provided

Structure of the Request for Proposal (RFP) document is in accordance with the Table of Contents located at the beginning of the RFP.

1.2 SCHEDULE

The proposed schedule is as follows;

Submit proposals:	January 20, 2007
Evaluate bids, interview Proponents and award contract at the sole discretion of Halton Hills Hydro and Ottawa PUC Networks Inc.	January 20 to February 1, 2007

Halton Hills Hydro and Ottawa PUC Networks Inc. reserve the right to change and or modify this schedule at any time.

1.3 FORM OF RESPONSE

In order to allow a consistent evaluation of the proposals, it is required that information be presented in accordance with the Format for Submission – Part 6 and 7 included in the Request for Proposal documents. There is no need to include standard marketing materials. All questions are to be addressed and answers are to be clear and concise. Failure to comply with all or any of the above **will** cause your proposal to be rejected without further consideration.

1.4 PROPOSAL DUE DATE

Proposals are due on January 20, 2007. At that time, please be prepared to submit your proposal as follows:

- **Electronic submission of proposal submitted to: gcameron@agsi.ca**
- **A CD and 4 Hardcopy Versions submitted in a sealed envelope to: Geoffrey Cameron, 116 Gulp St, Unit C, Georgetown, ON L7G 4A3.**

1.5 MANDATORY REQUIREMENTS

Proponent's response must satisfy the Overall Response, and business mandatory requirements for their submission to be further considered for evaluation. Section 3 of this RFP

1.6 EVALUATION CRITERIA

All proposals must meet all identified mandatory requirements including but not limited to the above and as outlined in the RFP for further evaluation consideration of the submitted proposal.

As part of the Evaluation Process, proposals will be evaluated using "best value" criteria including technical capabilities, service and support capabilities, total cost of ownership including financial incentives, commercial terms and conditions and other possible factors applied solely at Halton Hills Hydro and Ottawa PUC Network's Inc. discretion and equally to all proposals. All proposals received will be evaluated in each of the areas identified below. Any such proposal must clearly define the benefits to Ottawa PUC Networks Inc. both financially and otherwise, from its acceptance.

COMMERCIAL

- Compliance with the Commercial Terms and Conditions

FINANCIAL

- Financial viability
- Lowest cost of ownership
- Lowest Additional costs i.e.
- Terms of Payment

TECHNICAL

- Solution Capability / Functionality
- Solution Architectural Compliance
- Integration/Interface capability

SERVICE AND SUPPORT

- Proposed Solution Implementation
- Data Conversion Capability
- Proposed Service Levels
- Employee interface
- Project Plan and schedule
- Understanding of Ottawa PUC Networks Inc. requirements

1.7 CONTACT

All correspondence must be directed to Geoff Cameron at the **e-mail** address below. While we conduct the solicitation and evaluation of the proposal process, you shall not contact any individual in Ottawa PUC Networks Inc. with respect to this requirement other than Geoff Cameron. **Failure to comply with this requirement will cause your proposal to be rejected.** Thank you for your co-operation in this matter.

Inquiries with respect to this RFP must be directed only in writing by e-mail to:
Geoff Cameron – gcameron@agsi.ca

At the sole discretion of Halton Hills Hydro and Ottawa PUC Networks Inc., the question and the response may be distributed to all the respondents.

During the period prior to the submission of proposals, any alterations to the proposal documents will be issued to prospective proponents as written addenda. The proponent shall list in its proposal all addenda that were considered when its proposal was prepared.

1.8 DISCLAIMER

The proposals solicited are solely for the benefit of Halton Hills Hydro and Ottawa PUC Networks Inc. Halton Hills Hydro and Ottawa PUC Networks Inc. do not make any claims or promises whatsoever that the final award will be based on any perceived, assumed or stated criteria. Halton Hills Hydro and Oshawa PUC Networks Inc. makes no representation whatsoever that it will accept any proposal, nor will it be precluded from accepting any other proposal or other offer.

Each company responding to this RFP, invited or otherwise, shall bear all expenses incurred by the preparation and presentation of its response. Halton Hills Hydro and Oshawa PUC Networks Inc. will therefore be entitled to reject, and Halton Hills Hydro and Oshawa PUC Networks Inc. will reject, any claim made against it in this matter, regardless of the results of the RFP process.

2 STANDARD TERMS & CONDITIONS

2.2 DEFINITIONS

OPUCN - The Oshawa PUC Networks Inc., its successors and assigns.

HHH - Halton Hills Hydro Inc., its successors and assigns.

Bidder - The person, firm or corporation submitting a proposal to the OPUCN.

Company - The person, firm or corporation to whom the HHH and / or OPUCN awards a Contract, its successors and assigns.

Contract - The purchase order authorizing the Company to do the work, the proposal, the bonds or security (if any), the Company's quotation and change notices, appendices, and addenda (if any).

Subcontractor - A person, firm or corporation having a Contract with the Company for any part of the work.

Proposal Document - The documents issued by the HHH and / or OPUCN in response to which proposals are invited for the performance of Work or supply of equipment.

Work - All labour, materials, products, articles, equipment, fixtures, services, supplies, acts required, furnished or performed by the Company, which is subject of the Contract.

2.3 SUBMISSION OF PROPOSAL

Bidders must submit proposals and pricing on the forms supplied by the OPUCN and HHH.

The Bidders designated signing officer must sign the proposal form.

The signature submitted on any joint bid is on behalf of each of the Bidders.

If the Bidder is not a limited company, he must submit a copy of the most recent business or partnership registration form filed by the Bidder with the Ministry of Consumer and Commercial Relations.

Proposals must be legible, written in ink, or typewritten and the Bidder's authorized signing officer must initial erasures, over-writings or strikeouts.

Failure to return the proposal form on invitation may result in the removal of the Bidder from the OPUCN's / HHH Bidder's list.

The OPUCN / HHH will not consider any proposals received after the closing time.

Should a dispute arise from the terms and conditions of the proposal form, regarding meaning, intent or ambiguity, the decision of the OPUCN / HHH shall be final.

2.4 CONTRACT DOCUMENTS AND ORDER OF PROCEDURE

The contract documents shall consist of, the purchase order, the Proposal Document, and the Company's quotation.

The order in which the documents and portions thereof, named above, take precedence, notwithstanding their issued or executed chronological order.

Amendments to the Contract, in the form of purchase order alterations, shall take precedence over the documents or portions thereof amended thereby. Purchase order alterations, appendices and addenda to any contract document become part of that document.

The intent of the contract is that the Company supply Work that is fit and suitable for the OPUCN's and HHH's intended use and complete for a particular purpose.

None of the conditions contained in the Bidder's standard or general conditions of sale have any effect unless explicitly agreed to by the OPUCN and /or HHH and specifically referred to in the purchase order.

The laws of the Province of Ontario govern the interpretation of the contract.

2.5 CLARIFICATION OF PROPOSAL DOCUMENTS

It is a requirement of the Bidder, prior to submission of its proposal, to forward all requests for any clarification of Proposal Documents to the appropriate designate calling the proposal.

No officer, agent or employee of the OPUCN and / or HHH can orally authorize an alteration to any portion of the documents.

Every notice, advice or other communications pertaining thereto are as follows:

- (a) Prior to completion closing time, in the form of a written addendum;
- (b) After the OPUCN's and /or HHH's acceptance of a proposal, in writing, signed by an authorized officer of the Company, and accepted by the OPUCN.

2.6 PROOF OF ABILITY

The OPUCN and / or HHH reserves the right to request evidence of the Bidders ability, as well as any Subcontractor, in terms of experience and facilities, to perform the Work by the specified delivery date. The OPUCN and /or HHH reserves the right to approve or disapprove the use of any of the company's equipment.

2.7 DELIVERY

The Company is responsible for delivering or completing the Work specified or called for in or under the proposal as soon as possible within the period specified, unless otherwise stated, after receipt of a purchase order.

Each delivery must include a detailed delivery invoice, showing the exact quantity of goods, services, materials, articles, or equipment. The OPUCN and HHH are not bound to accept the particulars of the invoice signed by Forman's, Stockkeeper's or other receiver's receipts.

Unless otherwise stated, all work pursuant to a purchase order based on the proposal, is subject to inspection by the OPUCN and /or HHH at the point of receipt, unloading, or the site of work or service.

The Company is responsible for arranging completion of the Work as specified in the Contract.

2.8 PRICING REQUIREMENTS

Quote each item separately, in Canadian Funds, F.O.B. destination.

Prices bid must include all incidental costs and the Company deemed satisfied as to the full requirements of the quotation. The OPUCN and HHH will not accept claims for extra work and any additional work needs written authorization before commencement. Should the Company require more information or clarification, they must do so before the submission of the quotation.

Payment is full compensation for all costs related to the Work, including operating and overhead costs to provide work to the satisfaction of the OPUCN and / or HHH.

All prices quoted shall include applicable customs duty, excise tax, freight, insurance and all charges of any kind attributable to the work. Goods and Services Tax and Provincial Sales Tax are extra and not shown, unless otherwise specified herein.

If the Bidder intends to manufacture or fabricate any part of the Work outside Canada, it shall arrange its shipping procedures so that its agent or representative in Canada is the importer of record for custom purposes.

Should any additional or variation in tax or duty be imposed by the Government of Canada or the Province of Ontario that are directly applicable to the Work specified or called for in the quotation by the Bidder and before the delivery or the Work and pursuant to a purchase order issued, by the OPUCN, the appropriate increase or decrease in the price of the Work changes as of the effective date.

2.9 TERMS OF PAYMENT

The OPUCN and HHH reserve the right to hold back appropriate moneys until 45 days after the completion of Work.

Payments made thereunder, including final payment, shall not relieve the Company from its obligations or liabilities under the Contract.

Acceptance by the Company of the final payment, shall constitute a waiver of claims by the company against the OPUCN and HHH, except those previously made in writing in accordance with the Contract and still unsettled.

The OPUCN and HHH shall have the right to withhold from any sum otherwise payable to the Company such amount as may be sufficient to remedy any defect or deficiency in the Work, pending correction of it.

2.10 PATENTS AND COPYRIGHTS

The Company shall, at its expense, defend all claims, actions or proceedings against the OPUCN and / or HHH based on any allegations that the Work or any part of the Work constitutes an infringement of any patent, copyright or other proprietary right, and shall pay to the OPUCN and / or HHH all costs, damages, charges and expenses, including its lawyers' fees on a solicitor and his own client basis occasioned to the OPUCN and / or HHH by reason thereof.

The Company shall pay all royalties and patent license fees required for the Work.

If the Work or any part thereof is in any action or proceeding held to constitute an infringement, the Company shall forthwith either secure for the OPUCN and / or HHH the right to continue using the Work or shall at the Company's expense, replace the infringing Work with non-infringing Work or modify it so that the Work no longer infringes.

2.11 ALTERNATIVES AND EQUIVALENTS

The OPUCN and / or HHH may consider equivalents or alternatives where the mark or brand (if applicable) accompanies the quotation, unless otherwise stated. The OPUCN and / or HHH reserves the right to determine the equivalency of all alternatives and its decision shall be final.

2.12 ASSIGNMENT

The Company shall not assign the Contract or any portion thereof without the prior written consent of the OPUCN and HHH.

2.13 LAWS AND REGULATIONS

The Company shall comply with relevant Federal, Provincial and Municipal statutes and by-laws pertaining to the Work and its performance. The Company shall be responsible for ensuring similar compliance by its suppliers and Subcontractors.

The laws of the Province of Ontario govern the interpretation of the contract.

2.14 CORRECTION OF DEFICITS

If at any time prior to one year after the actual delivery date or completion of the Work, (or specified warranty or guarantee period if longer than one year) any part of the Work becomes defective or is

deficient or fails to meet the requirements of the Contract, the Company, upon request, shall make good every such defect, deficiency or failure without cost to the OPUCN and / or HHH. The Company shall pay all transportation costs for Work both ways between the Company's factory and repair depot and the point of use.

2.15 BID ACCEPTANCE

The OPUCN and HHH reserves the right to award by item, or part thereof, groups of items, or parts thereof, or all items of the proposals, and to award contracts to one or more Bidders submitting identical quotations as to price; to accept or reject any quotations in whole or in part; to waive irregularities and omissions, if in so doing, it serves the best interests of the OPUCN and HHH. No liability shall accrue to the OPUCN or HHH for any decision in this regard.

Proposals shall be irrevocable for 120 days after the official closing time.

The placing in mail or delivery to the Bidder's shown address, given in the notice of award to a Bidder, by the OPUCN and / or HHH, shall constitute notice of acceptance of the Contract, by the OPUCN and / or HHH, to the extent described in the notice of award.

2.16 DEFAULT BY COMPANY

- (a) If the Company commits any act of bankruptcy or if a receiver is appointed on account of its insolvency or in respect of any of its property, or if the Company makes a general assignment for the benefit of its creditors; then, in any such case, the OPUCN and / or HHH may, without notice, terminate the Contract.
- (b) The OPUCN and / or HHH reserves the right to terminate the contract upon expiration of ten days from the date of written notice to the Company if the Company:
 - i) Fails to comply with any request, instruction or order of the OPUCN and / or HHH;
 - ii) fails to pay its accounts;
 - iii) fails to comply with or persistently disregards statutes, regulations, by-laws or directives of relevant authorities relating to the Work;
 - iv) fails to prosecute the Work with skill and diligence, or assigns or sublets the Contract or any portion thereof; without the OPUCN's and / or HHH's prior written consent;
 - v) refuses to correct defective work; or is otherwise in default in carrying out its part of any of the terms, conditions and obligations of the Contract.
- (c) Any termination of the Contract by the OPUCN and / or HHH, as per section 2.16 (b), shall be without prejudice to any other rights or remedies the OPUCN and / or HHH may have and without incurring any liability whatsoever in respect thereto.
- (d) If the OPUCN and / or HHH terminates the Contract, it is entitled to:
 - i) take possession of all Work in progress, data, materials and software then at the project site (at no additional charge for retention or use of the software equipment), and finish the

Work by whatever means the OPUCN and / or HHH may deem appropriate under the circumstances;

- ii) withhold any further payments to the Company until completion of the work and the expiry of all obligations under the Correction of Defects section;
- iii) recover from the Company loss, damage and expense incurred by the OPUCN and / or HHH by reason of the Company's default (which may be deducted from any moneys due or becoming due to the Company, any balance to be paid by the Company to the OPUCN and / or HHH).

2.17 CONTRACT CANCELLATION

If the OPUCN and / or HHH deems it necessary, it reserves the right to immediately cancel any uncompleted or unperformed portion of the Work or part thereof. In the event of such a cancellation the OPUCN and / or HHH and the Company may negotiate a settlement.

The OPUCN and / or HHH shall not be liable to the Company for loss of anticipated profit on the cancelled portion or portions of the Work.

2.18 QUANTITIES

Where approximate quantities exist, no guarantee of accuracy exists and the numbers given are without any liability on behalf of the OPUCN and / or HHH. Quantities given are for comparison purposes only.

The OPUCN and HHH accepts only payment by the unit, complete at the quoted rate, on actual acceptable quantities.

2.19 SAMPLES

Upon request, samples submitted are strictly in accordance with instructions. The request for samples, subsequent to the opening of proposals, requires that delivery must follow within (5) working days after the request, unless the OPUCN and / or HHH grants additional time. Samples submitted are free of charge and returned at the Bidder's expense, if so requested, provided tests do not destroy the product, or providing they are not a requirement for comparison purposes.

The acceptance of the samples by the OPUCN and / or HHH shall be at its sole discretion and any such acceptance in no way implies relief of the Company from its obligations under the Contract.

2.20 SURETY

The Company shall, if the OPUCN and / or HHH in its absolute discretion so desires, satisfy surety requirements by providing a deposit in the form of a certified cheque, bank draft or money order or other form of surety, in an amount determined by the OPUCN and / or HHH. The OPUCN and / or HHH may

hold this surety until 60 days after the day on which all Work covered by the Contract is complete and accepted. The OPUCN and / or HHH may return the surety before the 60 days provided satisfactory evidence indicating that all liabilities incurred by the Company in carrying out the Work have expired or satisfied discharged or provided for and the receipt of a clearance certificate from the Workers' Compensation Board issued.

Failure to furnish the surety within two weeks from date of request thereof by the OPUCN and / or HHH shall make the award of the contract by the OPUCN and / or HHH subject to withdrawal.

2.21 WORKPLACE SAFETY AND INSURANCE BOARD

All of the Company's personnel must be covered by the insurance plan under the Workplace Safety and Insurance Act, 1997. Upon request by the Group, an original Letter of Good Standing from the Workplace Safety and Insurance Board shall be provided prior to the commencement of Work indicating all payments by the Company to the Board have been made. Prior to final payment, a Certificate of Clearance must be issued indicating all payments by the Company to the Board in conjunction with the subject Contract have been made and that the Group will not be liable to the Board for future payments in connection with the Company's fulfillment of the contract. Further Certificates of Clearance or other types of certificates shall be provided upon request.

2.22 INSURANCE

Upon request by the OPUCN and / or HHH , the Company shall take out and keep in force a policy of liability insurance in the amount of \$5,000,000 inclusive per occurrence (or such larger amount as may be required) naming the OPUCN and HHH as additional named insured, and a certified copy of such policy or certificate provided prior to commencement of the Work. Further certified copies shall be provided upon request.

2.23 LIABILITY

The Company agrees to defend, at all times, fully indemnify and save harmless the OPUCN and HHH from all actions, suits, claims and demands, losses, costs, charges and expenses arising by reason of injury or death to any person(s) or any property or charges brought or made against or incurred by the OPUCN or HHH from or relating to the Work performed or not yet performed herein.

2.24 PROJECT SITE WORKING CONDITIONS

The onus shall be upon the Bidder to investigate the project site and inform itself, before bidding, of all the physical and working conditions and administrative practices.

2.25 SAFETY

The Company shall be responsible for being aware of all governing regulations including any established by the OPUCN and HHH related to employee health and safety. The Company shall keep its employees and Subcontractors informed of such regulations.

2.26 UNPAID ACCOUNTS

The Company shall indemnify the OPUCN and HHH from all claims arising out of the unpaid accounts relating to the Work. The OPUCN and / or HHH shall have the right at any time to require satisfactory evidence that the Work in respect of which any payment made or not yet made by the OPUCN and / or HHH is free and clear of liens, attachments, claims, demands, charges or other encumbrances.

2.27 SUSPENSION OF WORK

The OPUCN and / or HHH may without invalidating the Contract, suspend Work by the Company, from time to time, in part or in whole for such reasonable period of time as the OPUCN and / or HHH may determine.

The resumption and completion of Work after the suspension shall be governed by the schedule established by the OPUCN and / or HHH.

2.28 CHANGES IN THE WORK

The OPUCN and / or HHH may, without invalidating the Contract, direct the Company to make changes to the Work. When a change causes an increase or decrease in the Work, the Contract price increases or decreases by the application of unit prices as per the quantum of such increases or decreases, or in absence of applicable unit prices, by an amount to be agreed upon between the OPUCN and /or HHH and the Company. All such changes shall be in writing and approved by the OPUCN and / or HHH.

3 TERMS OF REFERENCE

3.2 BACKGROUND – ADVANCED METERING INFRASTRUCTURE SOLUTION

Oshawa PUC Networks Inc. (OPUCN) is an electric distribution company serving the City of Oshawa Ontario, Canada. OPUCN serves approximately 50,000 customers across a geographical territory of 160 square kilometers. OPUCN has a significant base of industrial, institutional and commercial customers in addition to their residential customers. The City of Oshawa is one of the fastest growing municipalities in Canada. This growth is projected to accelerate into the foreseeable.

Halton Hills Hydro Inc. (HHH) is an electric distribution company servicing the Town of Halton Hills Ontario, Canada. HHH serves approximately 20,000 customers across a geographical territory of 245.7 square kilometers. HHH customer base is a mix of urban and rural customers situated on and around the Niagara escarpment.

OPUCN and HHH have partnered on this Request for Proposal (RFP) in order to collaborate on identifying possible solutions with regards to the Ontario Ministry of Energy Legislative Initiative for replacing traditional electric metering infrastructure with a new Advanced Metering Infrastructure (AMI). The OPUCN and HHH collaboration effort on this RFP is in the hope of being able to maximize the business and technical value to both utilities for the entire AMI implementation.

3.3 ADVANCED METERING INFRASTRUCTURE DEFINITIONS

“AMCC” is an advanced metering control computer that is used to retrieve or receive and temporarily store Meter Reads before or as they are being transmitted to the MDM/R. The information stored in the AMCC is available to log maintenance and transmission faults and issue reports on the overall health of the AMI to the distributor.

“AMCD” is an advanced metering communication device that is housed either under the meter’s glass or outside the meter. It transmits Meter Reads from the meter directly or indirectly to the AMCC.

“AMI” means an advanced metering infrastructure. It includes the meter, AMCD, LAN, AMRC, AMCC, WAN and related hardware, software and connectivity required for a fully functioning system that complies with this Specification. With some technologies, an AMI does not include AMRCs. An AMI does not include the MDM/R.

“AMRC” is an advanced metering regional collector that collects Meter Reads over the LAN from the AMCD and transmits these Meter Reads to the AMCC.

“Daily Read Period” means the 24-hour period for collecting Meter Reads, subject to the two periods annually during which changes to and from daylight savings time take place. The Daily Read Period ends at 12:00 midnight of each day.

“LAN” means a local area network, the communication network that transmits Meter Reads from the AMCD to the AMRC.

“meter multiplier” is the factor by which the register reading must be multiplied to obtain the registration in the stated units.

“Meter Read” is a number generated by a meter that reflects cumulative electricity consumption at a specific point in time.

“MDM/R” means the meter data management and meter data repository functions within which Meter Reads are processed to produce rate-ready data and are stored for future use.

“WAN” means a wide area network, the communication network that transmits Meter Reads from the AMRC to the AMCC or, in some systems from the AMCD directly to the AMCC, and from the AMCC to the MDM/R.

3.4 OVERALL VISION

OPUCN and HHH are required to implement an Advanced Metering Infrastructure that will adhere to new legislative requirements and support the culture of conservation initiative in the Province of Ontario Canada. Both OPUCN and HHH have a similar philosophy of investing in the solution that provides the best value for their customers and shareholders. Value is considered a blend of a reliable and robust AMI investment with advanced functionality at a reasonable price.

OPUCN and HHH believe that it is critical to select an AMI solution that is based on open technologies and standards that will provide a future proofed investment over the lifespan of the AMI infrastructure. It is OPUCN and HHH intention to select a vendor solution that will provide a robust and scalable solution while at the same time meeting budgetary requirements.

OPUCN and HHH also believe it is critical that they become self sufficient in managing the entire infrastructure. This will include all aspects of AMI management, maintenance, planning, expansion, data management, data integration to other corporate systems and system integration / scalability for load control and other customer service solutions.

3.5 BUSINESS PROBLEM DESCRIPTION

OPUCN and HHH requests proposals from vendors to provide a turn key solution that can provide a complete end-to-end AMI implementation for their respective utilities. The focus of this RFP is to provide all infrastructure and related services in order to meet all Ontario Ministry of Energy regulatory requirements while at the same time providing an open, robust and scalable solution to leverage this infrastructure for future opportunities. This solution must include:

- Hardware;
 - o AMCD's;
 - o AMRC's;
 - o AMCC;
- Software;
- Communications infrastructure;
 - o Lan;
 - o Wan;
- System Integration Services;
 - o AMCD readings to AMRC's;

- o AMRC readings to AMCC (leveraging utility Fiber and / or wireless where applicable);
 - o AMCC to MDM/R; and
 - o MDM/R to Customer Information System (CIS);
- System Diagnostics; and
- Services;
 - o Installation and Testing;
 - o Training; and
 - o Support.

This proposed turn-key solution must be founded on open architecture and integrate with OPUCN's and HHH's enterprise computing and telecommunication environments. The AMI solution must be compatible and work with or enhance other applications to leverage the value of this investment in such areas as:

- CDM / DR;
- Load limiting;
- Outage management;
- System optimization;
- SCADA;
- CIS; and
- More

The AMCC database must be in Oracle and be accessible via web services for corporate system integration. Openness, redundancy, robustness and scalability of the system will be key decision factors, as well as cost, by OPUCN and HHH to ensure a low risk implementation and a high value solution for their rate payers.

3.6 PROJECT SCOPE

The proposed solution must provide at a very minimum all the functionality and reliability requirements of the Ontario Ministry of Energy as legislated under "The Functional Specification for an Advanced Metering Infrastructure" dated July 14, 2006. The major thrust of the proposal is to provide a turn-key implementation of an AMI solution including all aspects of hardware, software, communications, system integration, training and support. The solution at all times must leverage OPUCN and HHH infrastructure including affiliate fiber and wireless as possible.

As the scope and size of an turn-key AMI implementation is significant, OPUCN and HHH will take a re-iterative approach for their utility wide roll-outs.

It is planned, based upon the expected responses, that HHH will begin its first stage of the AMI roll-out in 2007. Upon satisfactory results of the vendor's initial turn-key AMI implementation roll-out stage, HHH will then complete its roll-out over a 3 year period ending in 2010. OPUCN will commence its roll-out in 2008 with completion in 2010. Exact roll-out requirements of the OPUCN will be confirmed based upon the evaluation of the RFP responses.

3.7 ACCEPTANCE CRITERIA

OPUCN and HHH plan to subject the implemented turn-key AMI solution to appropriate Quality Control processes to verify that all components of all features are functioning and in good working order. The Vendor will be notified of, and is expected to replace or correct all components fail. These corrections will be done within 1 business day of notification.

4 Form of Response Table - Schedule A

The following questions are mandatory for the vendors to respond about their turn-key solution. Vendor's response format must follow the format of questions below and answer each question.

Schedule A – Functional Specifications Worksheet

Vendor Instructions: Please fill in this table and return with your proposal. Details about each function must be detailed in the main proposal and identified by the appropriate section number.

(Vendor Name goes here)

Advanced Metering Infrastructure - General

Question	Required Function	Details	Compliant Yes/No
A1	The AMI must be meter (AMCD) agnostic.	Please specify that the AMI is meter agnostic and has not been designed for a specific "Smart Meter (AMCD)" hardware manufacturer.	
A1.1	a) List the smart meter hardware manufacturers that will integrate with the proposed AMI solution. b) Describe the system architecture in regards to its ability to communicate with the different AMCD hardware vendors.		
A2	What is your proposed AMI primary communication infrastructure solution		
A2.1	Is your network self-healing?		
A2.2	Is your network self-configuring?		
A2.3	Do you require to undertake a propagation study?		
A2.4	If short listed, would you be willing to undertake a propagation study at your own expense?		
A3	Does your proposed AMI solution guarantee the legislative minimum reliability requirement to successfully collect and transmit to the AMCC and MDM/R at least 98.0% of the Meter Reads from all AMCD's deployed by a distributor in any daily read period?		
A3.1	Explain how your proposed AMI solution will ensure and guarantee that all legislative requirements are met and adhered to for the successful collection and transmission to the AMCC and MDM/R for at least 98.0% of the Meter Reads from all AMCD's deployed by a distributor in any daily read period. Above and beyond the minimum legislative requirements please specify your		

guaranteed reliability.

A4	System must be capable of leveraging the client's fibre-back haul and / or wireless communication infrastructure.	Please specify that your system is capable of integrating with the client's fibre-back haul and / or wireless communication infrastructure.
A4.1		Does your AMI communications network support TCP/IP?
A4.2	Describe your proposed solutions integration to the client's fibre-back haul and / or wireless communication infrastructure. List any assumptions you have considered for this integration.	
A5	Environmental weather operating requirements.	Does your proposed AMI solution operate effectively during extreme weather events including: • Sustained cold weather of -45 Celsius; Sustained hot weather of +65 Celsius; • Sustained high winds in excess of 100 km/h; • Sustained Heavy Precipitation including: Rain, Hail, Ice Pellets / Sleet, and Snow Fall; • Severe Lightning; and • Build up of snow and / or ice on AMI infrastructure?
A5.1	Specify in detail below the environmental operating specifications of the entire AMI solution, including individual components (AMCD's, AMRC's, LAN, WAN etc.) and the overall proposed deployed integrated solution as it relates to the environmental weather operating requirements specified above in question 5.0.	
A6	Geographic and related topographical operating requirements.	Does your proposed AMI solution operate effectively in diverse geographic and topographic environment that includes: • High density customer locations; • Rural low density customer locations; • Large bodies of water; • High density treed vegetation (coniferous and deciduous); • Niagara escarpment; and • Significant topographic elevation changes?
A6.1	Specify in detail below the geographic and topographical operating	

specifications of the entire AMI solution, including individual components (AMCD's, AMRC's, LAN, WAN etc.) and the overall proposed deployed integrated solution as it relates to the operating requirements specified above in question 6.0.

Advanced Metering Communication Device (AMCD) Smart Meter Preference

A7.0	Requirement for new digital meters.	Will you be supplying new digital meters?
A7.1		Does the meter allow for either Time of Use or Interval reading capability?
A7.2	Please specify the suggested meter manufacturer(s) you plan to deploy as part of the turn-key implementation.	
A7.3	Manufacturer meter sealed	Is the Meter Communication installed and sealed at the manufacturer?
A8.0	Requirement for Multiple meter base support.	Does your proposed solution support multiple meter types?
A8.1	Document all meter types your proposed turn-key solution will support e.g. a-base, s-base, CMS, 600V Delta, poly phase meters etc.	
A9.0	Requirement for net metering support.	Does your proposed solution support net metering?
A9.1	Requirement for Standard Offer Contract (SOC) Metering	Does your proposed solution support SOC metering?
A10.0	Measurement Canada Approval	Is your proposed meter Measurement Canada Approved or Pending?
A10.1		What is the seal period of your meter?
A10.2		Will your meter qualify for meter extension?
A11.0	Meter Data Storage	In the event of a communications failure, will the meter store the metered data until communication has been re-established?
A11.1	Please describe details of metered data stored by meters including amount of data that the proposed individual meters can store. Please indicate what happens to the data if meter storage capacity is exceeded.	

AMI Preferred Advanced Functionality

A12.0	Load Control	Does your proposed solution allow for remote load control by the utility?
A12.1	Specify the remote load control features and options of your proposed turn-key solution.	
A13.0	Load Limiting	Does your proposed solution allow for load limiting of service?

- A13.1 Specify the Load Limiting features and options your proposed turn-key solution offers. Specify if the load limiting device is built into the meter or if it is an add-on (separate module / device).
- A14.0 Remote Disconnect Does your proposed solution allow for remote disconnect?
- A14.1 Specify the remote disconnect features and options your proposed turn-key solution offers. If disconnect is available but is not remote, please state as such, indicate if disconnect module is built into the meter or is it an add-on (separate module / device).
- A16.0 Tamper proofing requirement. Does your proposed AMCD solution include tamper proofing features and alarms?
- A16.1 Specify the AMCD tamper proof features and alarms of the AMI ad your proposed AMCD devices.
- A17.0 Data Security Is your data transmission secure between all aspects of your turn-key AMI solution including all devices and network connections?
- A17.1 Explain in detail your data security features across the entire AMI infrastructure. Additionally provide your AMI infrastructure security upgrade policies and procedures.
- A18.0 Real time AMCD failure alerts. Does your proposed AMI solution provide for real-time AMCD failure alerts to the AMCC?
- A18.1 Please describe the details of your proposed turn-key solution power outage restoration, recording, and notification system.
- A19.0 Real time AMCD restoration notification. Does your proposed AMI solution provide for real-time AMCD restoration of service?
- A19.1 Please describe the details of your proposed turn-key solutions power restoration, recording, and notification system.
- A20.0 Infrastructure Upgrades Does the proposed solution allow for remote upgrades to firmware?
- A20.1 Does the proposed solution allow for remote upgrades to software?
- A21.0 Diagnostics Does the proposed solution include diagnostic tools"
- A21.1 Please indicate what system diagnostic tools are available.
- A22.0 Signal Hopping If your proposed solution is wireless at the meter level, does it allow for self-adjusting signal hopping about the spectrum so as not interfere with other frequencies?
- A22.1 If your system allows for self adjusting signal hopping, explain the ability for the solution to detect interference from another source frequency and self adjust so as not to interfere.

System Integration

A23.0	AMCC ownership of the LDC	Will the AMCC be physically resident at the LDC?
A24.0	Oracle Database Platform Preference	Will the AMCC database be stored within an Oracle 10g RDBMS?
A25.0	Open Database Standard Adherence	Is the data accessible by the LDC for other application needs as required?
A25.1	Open Standards Architecture	Is the proposed solution built upon open standards?
A25.2	Please indicate what standards the proposed solution conforms to (including in-house load control)	
A25.3	Two-way Communication	Does the proposed solution allow for two-way communication to in realtime?
A26.0	Services Oriented Architecture (SOA) Adherence via XML / SOAP protocols.	Is the AMI solution including the AMCC database founded solution on a Services Oriented Architecture for LDC system integration purposes?
A26.1	Provide a logical architecture description and diagram that addresses SOA interfaces of the AMI to support various LDC applications including: • SCADA (Survellant); • OMS (Future Oracle based); • CIS (Harris / HTE); • GIS (Oracle / SPATIALinfo); and • Engineering Analysis (Dromey Design (D.E.S.S.) / CYME).	
A27.0	AMCC Data Export	Does the AMCC allow for easy export of data, including incremental changes, to support non SOA LDC utility applications (e.g. CableCad, Load Shifting etc.)
A28.0	Advanced Data Analysis Functionality	Does the proposed AMI solution provide advanced data analysis / reading capability?
A28.1	Power Quality Readings	Does the proposed AMI solution provide Power Quality analysis readings and writing to the AMCC?
A28.2	Current Draw	Does the proposed AMI solution provide Current Draw analysis readings and writing to the AMCC?
A28.3	Voltage Monitoring	Does the proposed AMI solution provide Voltage Monitoring readings and writing to the

A28.4	Please specify if your proposed solution provide power quality data for (Yes/No foreach)	AMCC? • Voltage (Line-to-line, Line-to-Neutral, Line-to-Line-to-Line) • Current (Amps) • kW Consumed • kW Delivered • Outage Management / Restoration • Sag/ Swell • Can Max./ Min. points be set for voltage monitoring? • Harmonics
A28.5	Indicate how power quality is stored and retrieved.	
A28.6	Specify other data analyzed and recorded to the AMCC by the proposed AMI infrastructure.	
A29.0	Customer Load Limiting Ability	Does the proposed AMI solution include the functionality for Customer Load Limiting ability?
A29.1	Explain the proposed AMI solution can assist in the ability to provide Customer Load Limiting Functionality.	
A30.0	Distribution Automation?	Does the AMI communication infrastructure have support for distribution automation e.g. SCADA?
A30.1	Explain how the proposed AMI solution can support distribution automation.	
A31.0	Scalability	Is your proposed solution scalable to allow for future LDC customer growth? Is there a limit to scalability?

Schedule B – Functional Specifications Worksheet

AMI Legislative Functionality Requirement Compliance

Confirm that the proposed turn-key AMI solution will meet all minimum Legislation as per the “ **FUNCTIONAL SPECIFICATION FOR AN ADVANCED METERING INFRASTRUCTURE**” as mandated by the Ontario Ministry of Energy and legislated by the Ontario Government

Confirm the turn-key AMI solution addresses and meets the following functional specifications of the advanced metering infrastructure as defined in the “**FUNCTIONAL SPECIFICATION FOR AN ADVANCED METERING INFRASTRUCTURE**” legislation:

Minimum Functionality

B1.0	AMI shall collect Meter Reads on an hourly basis from all AMCDs deployed by a distributor and transmit these same Meter Reads to the AMCC and MDM/R, as required, in accordance with the

- B1.1 Specifications.
A Meter Read shall be collected, dated and time stamped at the end of each hour (i.e. midnight as represented by 24:00).
- B1.2 The date and time stamping of Meter Reads shall be recorded as year, month, day, hour, minute (i.e. YYYY-MM-DD hh:mm).
- B1.3 All meters shall have a meter multiplier of one (1).

Performance Requirements

- B2.0 Collection and Transmission of Meter Reads
AMI shall successfully collect and transmit to the AMCC and MDM/R at least 98.0% of the Meter Reads from all AMCDs deployed by a distributor in any Daily Read Period.
- B2.1 Meter Reads unsuccessfully collected or transmitted shall not be due to the same AMI component (including, without limitation, any AMCD) during any three (3) month consecutive time period.
- B2.2 AMI shall be able to collect and transmit Meter Reads during its operating life without requiring a field visit.
- B2.3 Transmission Accuracy
Over the Daily Read Period, 99.9% of the Meter Reads received by the AMCC shall contain the same information as that collected by all AMCDs deployed by the distributor.
- B2.4 AMI shall be capable of providing Meter Reads with a precision of at least 10 Watt-hours (0.01 kWh).

Technical Requirements

- B3.0 When an AMI includes AMRCs, the AMRCs shall have the ability to store meter data to accommodate the performance requirements as per section B2.0, B2.1, B2.2, B2.3 and B2.4.
- B3.1 Time Synchronization
AMI shall be operated and synchronized to Official Time, as set by the National Research Council of Canada.
- B3.2 AMI shall have the capability of adjusting for changes due to local daylight savings time.
- B3.3 AMI installed within a distributor's service area shall

B3.4		have the capability of accommodating more than one (1) time zone. Time synchronization shall be maintained in the AMI to the specified accuracy parameters set out in section B2.0 following a loss of power.
B3.5		All Meter Reads shall adhere to accurate time synchronization processes to ensure an accurate accounting of electricity consumption at each meter.
B4.0	Time Accuracy	At all times, time accuracy in the AMI shall not exceed a ± 1.5 minute variance from the time established in section B3.1.
B4.1		AMI shall be able to prove that time accuracy does not exceed the permitted time variance identified in section B3.1.
B5.0	Loss and Restoration of Power	AMI shall detect and identify the interval in which a loss of power occurred during a Daily Read Period.
B5.1		AMI shall detect and identify the interval in which power was restored following a loss of power.
B6.0	Environmental Tolerances	All AMI components (except the AMCC) shall operate and meet the requirements in these Specifications within a temperature range of minus thirty degrees Celsius (-30°C) to positive sixty-five degrees Celsius ($+65^{\circ}\text{C}$), and within a humidity range of zero percent (0%) to ninety-five percent (95%) non-condensing.

Advanced Metering Communication Device (AMCD)

B7.0	Installation Within the Meter	The AMCD shall not impair the ability of the meter to be visually read.
B7.1		Meters in which an AMCD is installed shall be able to be installed in existing meter sockets or enclosures.
B7.2		AMCD shall meet or exceed ANSI standards to withstand electrical surges and transients.
B8.0	Labelling	The AMCD shall be permanently labelled with: (1) Legally required labelling; (2) Manufacturer's name; (3) Model number; (4) AMCD identification number;

(5) Input/output connections;
(6) Date of manufacture; and
(7) Bar code for tracking and inventory management.

B9.0

When installed at a consumer's location, the meter shall visibly display, as a minimum, the AMCD identification number, meter serial number and LDC badge number for the meter.

B10.0

The AMCD shall be able to be initialized or programmed during, or prior to, field installation.

Transmission of Meter Reads

B11.0

All Meter Reads collected during the Daily Read Period shall be received by the AMCC and transferred to the MDM/R no later than 5:00 a.m. local time following the Daily Read Period. Meter Reads are not required to be transmitted in a single transmission and may be transmitted as frequently as necessary in order to meet the requirements in section B11.0.

B12.0

AMCC shall transfer the information identified in section B11.0 using an approved protocol and file structure.

B13.0

Advanced Metering Regional Collectors (AMRC)

B14.0

LAN Communication Infrastructure

The spectrum allocation and wattage of the radio signal used by an AMI shall not impede neighbouring frequencies.

B15.0

When an AMI includes AMRCs

The AMI shall provide for the continuous powering of AMRCs regardless of their location and placement.

B15.1

All AMCDs shall be able to collect and transmit Meter Reads when one or more AMRC has a loss of power.

B15.2

Memory and software parameters shall be maintained at all AMRC during a loss of power, whether by the provision of backup/alternate power or other solution.

Advanced Metering Control Computer (AMCC)

B16.0

Each AMCC shall have the ability to store a rolling sixty (60) days of Meter Reads.

B16.1

A distributor shall not aggregate

B16.2

Meter Reads into rate periods or calculate consumption data from the Meter Reads collected through its AMI either in its AMCC or any other component. The AMCC shall be able to perform basic operational verification of Meter Reads received before transmitting these Meter Reads to the MDM/R.

Customer Account Information

B17.0

The proposed solution will support the distributors requirement to provide initial information associated with customer accounts to the MDM/R on a date to be determined.

B17.1

The proposed solution will support on an ongoing basis, the distributors requirement to provide information associated with any change to the initial information identified in section B17.0 to the MDM/R at a frequency to be determined.

Monitoring & Reporting Capability

B18.0

The AMI shall have non-critical reporting functionality and critical reporting functionality as required in this section B18.0. Information generated from this reporting functionality shall be available to the MDM/R.

B19.0

Non-critical reporting

At the completion of every Daily Read Period and following a transmission of Meter Reads, the AMCC shall generate a status report that includes information regarding anomalies and issues affecting the integrity of the AMI or any component of the AMI including information related to any foreseeable impact that such anomalies or issues might have on the AMI's ability to collect and transmit Meter Reads.

B19.1

In addition to section B19.0, the AMCC shall generate reports:
(1) Confirming successful initialization of the AMCD's installed in the field;
(2) Confirming data linkages among an AMCD identification

number, LDC badge number, serial number and customer account;

(3) Confirming that the MDM/R has successfully received notification of any changes to customer account information;

(4) Confirming that the AMCC has successfully made changes to customer account information following receipt of same from the MDM/R;

(5) Confirming the successful collection and transmission of Meter Reads or logging all unsuccessful attempts to collect and transmit Meter Reads, identifying the cause, and indicating the status of the unsuccessful attempt(s) pursuant to section B2.0, B2.1, and B2.2;

(6) Confirming the accuracy of the Meter Reads received by the AMCC pursuant to section B2.3;

(7) Confirming that all Meter Reads have a precision of at least 10 Watthours (0.01 kWh) pursuant to section B2.4;

(8) Confirming whether the Meter Reads acquired within the Daily Read Period are in compliance with the time accuracy levels identified in section B4.0 and B4.1;

(9) Confirming whether time synchronization within the AMI or any components of the AMI has been reset within the Daily Read Period;

(10) Identifying the intervals in which a loss of power occurred and at which power was restored, following a loss of power;

(11) Addressing the functionality of the AMCD communication link, including status indicators related to the AMCD and AMRC;

(12) Identifying suspected instances of tampering, interference and theft; Flagging potential network, meter and AMCD issues; and

(14) Identifying any other instances that impact or could potentially impact the AMI's ability to collect and transmit

B19.2		Meter Reads to the AMCC and/or MDM/R on a daily basis. Following a transmission of Meter Reads or at the completion of every Daily Read Period, the information in section B19.1 (5) shall be stored and used by the AMCC to assess compliance with the requirement specified in section B2.1.
B19.3		The reports generated in sections B19.0 and B19.1 shall be made available to the MDM/R with a frequency to be determined.
B20.0	Critical reporting: Critical events are defined to include any AMI operational issue that could adversely impact the collection and transmission of Meter Reads during any Daily Read Period.	The AMI shall identify and report the following to the distributor: (1) AMCD failures; (2) AMRC failures; (3) Issues related to the storage capacity of any component of the AMI; (4) Communication links failures; (5) Network failures; and (6) Loss of power and restoration of power.
B20.1		The reports generated in section B20.0 shall be made available to the MDM/R.

Security and Authentication

B21.0		The AMI shall have security features to prevent unauthorized access to the AMI and meter data and to ensure authentication to all AMI elements.

Proven Technology

B22.0		The proposed AMI solution electricity AMCD device has a minimum of 5000 units of the same electricity AMCD device functioning in the field as part of one or more functioning AMI.

Regulatory Requirements

B23.0		The AMI shall meet all applicable federal, provincial and municipal laws, codes, rules, directions, guidelines, regulations and statutes (including any requirements of any applicable regulatory authority, agency, board, or department including Industry Canada, the Canadian Standards Association, the Ontario Energy Board and the

Electrical Safety Authority)
(collectively, "Laws"). For
greater certainty, the AMI shall
meet all applicable Laws that
are necessary for the
measurement of data and/or the
transmission of data to and from
the consumers within the
Province of Ontario, including
Laws applicable to metering,
safety and telecommunications.

Water or Natural Gas Meter Reads

B24.0

The AMI should be capable of
supporting an increased number
of Meter Reads associated with
the reading and transmission of
water and/or natural gas meters
through additional ports on the
AMCD, through optionally
available multi-port AMCDs, or
through additional AMCD/AMRC
devices that are compatible with
operating on the AMI. When
procuring AMI, distributors shall
obtain an indication of the
capabilities of the proposed AMI
to read water and natural gas
meters, indicating the makes
and models of such meters that
can be read, and any
requirements for retrofitting
them.

5 Form of Response Schedule C – Solution Overview and Mandatory Responses Written Format

5.2 MANDATORY VENDOR RESPONSE - VENDOR'S LOGICAL ARCHITECTURE SOLUTION OVERVIEW

1. Provide your proposed AMI solution end-to-end integrated architecture, including all hardware, communications, and system integration.
2. Provide your proposed turn-key AMI solution's end-to-end implementation workflow.
3. The turn-key AMI solution must be founded on "open" standards and be robust and scalable to provide as yet unknown / undefined applications as documented in this RFP document. The clients wish to invest in a system that will have the ability to provide on-going new benefits to both the utility and their customers. Please provide an overview of your proposed solution and how it can provide a "future proofed" infrastructure allowing the clients to provide enhanced services and

benefits over time. Please describe the type of future solution you see your proposed AMI turn-key solution supporting over time.

4. Provide a sample data model of the information stored within the AMCC.
5. Provide an overview of AMI interface to the LDC and a sample of the AMI data presentment to the LDC.

5.3 MANDATORY VENDOR RESPONSE – VENDOR LICENSING, SUPPORT AND TRAINING

1. The clients wish to be self sufficient in moving forward with the AMI system maintenance, planning and expansion. Describe in detail the following information in regards to your turn-key AMI solution including:
 2. Knowledge transfer and training for LDC AMI infrastructure management and planning;
 3. Knowledge transfer for LDC AMI infrastructure maintenance;
 4. Knowledge transfer for AMCC management, development and system integration;
 5. Turn-key AMI solution warranty;
 6. Turn-key AMI solution licensing requirements;
 7. All initial 3rd party costs and on-going yearly maintenance; and
 8. Turn-key AMI solution support capability and levels.

5.4 MANDATORY RESPONSE – PROJECT MANAGEMENT APPROACH

Project Control

The Vendor must describe the methodology for creating and maintaining various project control mechanisms for all phases throughout the project.

Specific project management/control software, hardware or manual products used for project control should be listed and samples included.

Project Status

The Vendor must describe in detail, the methodology for monitoring the status of the turn-key project. Minimum project management requirements are:

- Work status (in-progress, completed or future) based on structured subdivisions of the work scope into tasks and sub-tasks, typically a Work Breakdown Structure (WBS).
- Status of the project schedule which is based on the same work subdivisions (WBS) and including forecasts of early and/or late completions.
- Problem areas and issues with potential impact to project progress and completion.

The above requirements must be included in a bi-weekly project status report to OPUCN and / or HHH by the second working day following the end of the report period. The contents of these reports should be included in the Vendor's proposal as samples.

Communications

The Vendor must outline and describe the most efficient and cost-effective method for handling client-communications which will insure OPUCN and HHH has sufficient information to monitor, report and evaluate the project status. The Vendor must also describe optimum methods for problem-resolution regarding data conversion and solution configuration. These methods must be approved by OPUCN and / or HHH, in writing, prior to the start of conversion.

Change Control

The Vendor must describe the criteria to evaluate proposed changes and the method for processing changes. Any changes must be approved in writing by OPUCN and / or HHH prior to implementation. Changes may include, but are not limited to the following:

- Technical specifications
- Method or manner of performance of the work
- Scope of work

5.5 MANDATORY RESPONSE – SOLUTION SUPPORT

1. Describe your solution support plan including maintenance, updates and technical help.
2. What is your support framework (in-house, partners) – response time, time available, number of staff and physical location?
3. What is your certification and training availability?

5.6 MANDATORY RESPONSE – VENDOR REFERENCES

Oshawa PUC Networks and /or Halton Hills Hydro will contact references as part of the evaluation process. Three references must be included with RFP submission. The following must be included and as outlined in Part 4 Form of Response:

- Contact name, title, company name, telephone information,
- Description of services provided. Include duration and timing of engagement.
- Details of specific challenges faced.
- Details of specific service level arrangements.
- References should highlight any contracts with diverse challenges.

5.7 PRICING

Appendix A includes a pricing schedule for vendor proposal cost response. The vendor must complete submit this schedule in a separate envelope from the main response.

6 VENDOR SIGNATURE

1.0 Exceptions

We have reviewed the Vendor Instructions, Commercial Terms & Conditions and Terms of Reference. We understand that failure to explicitly express any exception in this space will deem acceptance.

2.0 Signature

The undersigned is duly authorized to bind the Proponent and hereby warrants and represents the following:

- The data provided pursuant to this document is accurate in all respects,
- All RFP documents have been thoroughly reviewed,
- The Proponent has the current capability to provide the proposed solution,
- Offers shall be open for acceptance for 120 days

SIGNATURE

NAME

TITLE

DATE

OEB STAFF INTERROGATORIES

APPENDIX H

Regulatory Asset Continuity Schedule

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	HALTON HILLS HYDRO INC.	LICENCE NUMBER	ED-2002-0552
NAME OF CONTACT	ARTHUR SKIDMORE	DOCID NUMBER	EB-2007-0696
E-mail Address	askidmore@haltonhillshydro.com		
VERSION NUMBER	v3.0	PHONE NUMBER	519-853-3700
Date	13-Nov-07	(extension)	ext 225

Enter appropriate data in cells which are highlighted in yellow only.
Enter the total applied for Regulatory Asset amounts for each account in the appropriate cells below:
Debits should be recorded as positive numbers and credits should be recorded as negative numbers.
Repeat cells going across as necessary for each year in application

2005										
Account Description	Account Number	Opening Principal Amounts as of Jan-1-05 ¹	Transactions (additions) during 2005, excluding interest and adjustments ⁶	Transactions (reductions) during 2005, excluding interest and adjustments ⁶	Adjustments during 2005 - instructed by Board ²	Adjustments during 2005 - other ³	Closing Principal Balance as of Dec-31-05	Opening Interest Amounts as of Jan-1-05	Interest Jan-1 to Dec31-05	Closing Interest Amounts as of Dec-31-05
RSVA - Wholesale Market Service Charge	1580	\$ 140,097	\$ 799,639				\$ 939,736	\$ 41,280	\$ 31,904	\$ 73,184
RSVA - One-time Wholesale Market Service	1582	\$ 56,885	\$ 28,000				\$ 84,885	\$ 3,715	\$ 5,192	\$ 8,907
RSVA - Retail Transmission Network Charge	1584	\$ 849,912	\$ (99,554)				\$ 750,358	\$ 50,853	\$ 35,729	\$ 86,582
RSVA - Retail Transmission Connection Charge	1586	\$ 411,478	\$ 347,113				\$ 758,591	\$ 30,297	\$ 32,681	\$ 62,978
Sub-Totals		\$ 1,458,372	\$ 1,075,198		\$ -	\$ -	\$ 2,533,570	\$ 126,145	\$ 105,506	\$ 231,651
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	\$ -	\$ 75,121	\$ -			\$ 75,121	\$ -	\$ 3,688	\$ 3,688
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	\$ -	\$ 170,947	\$ -			\$ 170,947	\$ -	\$ 8,391	\$ 8,391
Other Regulatory Assets - Sub-Account - Other ⁷	1508	\$ -	\$ -	\$ -			\$ -			\$ -
Other Regulatory Assets - Sub-Account - Other ⁷	1508	\$ -	\$ -	\$ -			\$ -			\$ -
Other Regulatory Assets - Sub-Account - Other ⁷	1508	\$ -	\$ -	\$ -			\$ -			\$ -
Retail Cost Variance Account - Retail	1518	\$ (485)	\$ 7,291	\$ -			\$ 6,806			\$ -
Retail Cost Variance Account - STR	1548	\$ 6,952	\$ -	\$ (2,464)			\$ 4,488			\$ -
Misc. Deferred Debits	1525	\$ -	\$ 156,802			\$ (80,539)	\$ 76,263	\$ -	\$ 17,886	\$ 17,886
LV Variance Account	1550	\$ -					\$ -			\$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555	\$ -					\$ -			\$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555	\$ -					\$ -			\$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Met	1555	\$ -					\$ -			\$ -
Smart Meter OM&A Variance	1556	\$ -					\$ -			\$ -
Conservation and Demand Management Expenditures and Recoveries	1565	\$ -		\$ (401,399)			\$ (401,399)			\$ -
CDM Contra	1566	\$ -	\$ 456,507				\$ 456,507			\$ -
Qualifying Transition Costs ⁸	1570	\$ 311,056	n/a	n/a	\$ (40,126)		\$ 270,930	\$ 60,137	\$ 20,402	\$ 80,539
Pre-Market Opening Energy Variances Total ⁵	1571	\$ 265,377	n/a	n/a		\$ 1,200	\$ 266,577	\$ 51,306	\$ 19,283	\$ 70,589
Extra-Ordinary Event Costs	1572	\$ -					\$ -			\$ -
Deferred Rate Impact Amounts	1574	\$ -					\$ -			\$ -
Other Deferred Credits	2425	\$ -					\$ -			\$ -
Sub-Totals		\$ 582,900	\$ 866,668	\$ (403,863)	\$ (40,126)	\$ (79,339)	\$ 926,240	\$ 111,443	\$ 69,650	\$ 181,093
Deferred Payments in Lieu of Taxes	1562					see PILs reconciliation requested				
2006 PILs & Taxes Variance	1592					see PILs reconciliation requested				
Sub-Totals						see PILs reconciliation requested				
Total		\$ 2,041,272	\$ 1,941,866	\$ (403,863)	\$ (40,126)	\$ (79,339)	\$ 3,459,810	\$ 237,588	\$ 175,156	\$ 412,744
The following is not included in the total claim but is included on a memo basis:										
Deferred PILs Contra Account ⁸	1563					see PILs reconciliation requested				
RSVA - Power (including Global Adjustment)	1588	\$ 2,135,535	\$ 348,310				\$ 2,483,845	\$ 147,331	\$ 84,945	\$ 232,276
RSVA - Power - Sub-Account - Global Adjustment ⁴	1588	\$ -	\$ (190,500)				\$ (190,500)	\$ -	\$ (6,906)	\$ (6,906)
Recovery of Regulatory Asset Balances	1590			\$ (1,413,047)			\$ (1,413,047)			\$ -

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¹ As per general ledger, if does not agree to Dec-31-04 balance filed in 2006 EDR then provide supplementary analysis

² Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs write-off, and etc.

³ Provide supporting statement indicating nature of this adjustments and periods they relate to

⁴ Not included in sub-total

⁵ Closed April 30, 2002

⁶ For RSVA accounts only, report the net additions to the account during the year. For all other accounts, record the additions and reductions separately.

⁷ Please describe "other" components of 1508 and add more component lines if necessary.

⁸ 1563 is a contra-account and is not included in the total but is shown on a memo basis. Account 1562 establishes the obligation to the ratepayer.

⁹ Interest projected on December 31, 2006 closing principal balance.

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	HALTON HILLS HYDRO INC.
NAME OF CONTACT	ARTHUR SKIDMORE
E-mail Address	askidmore@haltonhillshydro.com
VERSION NUMBER	v3.0
Date	13-Nov-07

2006												
Account Description	Account Number	Opening Principal Amounts as of Jan-1-06	Transactions (additions) during 2006, excluding interest and adjustments ⁶	Transactions (reductions) during 2006, excluding interest and adjustments ⁶	Adjustments during 2006 - instructed by Board ²	Adjustments during 2006 - other ³	Transfer of Board-approved amounts to 1590 as per 2006 EDR	Closing Principal Balance as of Dec-31-06	Opening Interest Amounts as of Jan-1-06	Interest Jan-1 to Dec31-06	Transfer of Board-approved amounts to 1590 as per 2006 EDR	Closing Interest Amounts as of Dec-31-06
RSVA - Wholesale Market Service Charge	1580	\$ 939,736	\$ (573,941)				\$ (169,333)	\$ 196,462	\$ 73,184	\$ 24,231	\$ (54,823)	\$ 42,592
RSVA - One-time Wholesale Market Service	1582	\$ 84,885	\$ 22,591				\$ (59,015)	\$ 48,461	\$ 8,907	\$ 3,583	\$ (9,214)	\$ 3,276
RSVA - Retail Transmission Network Charge	1584	\$ 750,358	\$ (146,740)				\$ (567,993)	\$ 35,625	\$ 86,582	\$ 28,391	\$ (133,012)	\$ (18,039)
RSVA - Retail Transmission Connection Charge	1586	\$ 758,591	\$ (166,240)				\$ (1,140,363)	\$ (548,012)	\$ 62,978	\$ 8,694	\$ (70,073)	\$ 1,599
Sub-Totals		\$ 2,533,570	\$ (864,330)		\$ -	\$ -	\$ (1,936,704)	\$ (267,464)	\$ 231,651	\$ 64,899	\$ (267,122)	\$ 29,428
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	\$ 75,121						\$ 75,121	\$ 3,688	\$ 3,423	\$ -	\$ 7,111
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	\$ 170,947						\$ 170,947	\$ 8,391	\$ 7,791		\$ 16,182
Other Regulatory Assets - Sub-Account - Other ⁷	1508	\$ -					\$ (38,179)	\$ (38,179)	\$ -			\$ -
Other Regulatory Assets - Sub-Account - Other ⁷	1508	\$ -						\$ -	\$ -			\$ -
Other Regulatory Assets - Sub-Account - Other ⁷	1508	\$ -						\$ -	\$ -			\$ -
Retail Cost Variance Account - Retail	1518	\$ 6,806	\$ 4,244				\$ 485	\$ 11,535	\$ -		\$ 47	\$ 47
Retail Cost Variance Account - STR	1548	\$ 4,488	\$ 174				\$ (6,952)	\$ (2,290)	\$ -		\$ (672)	\$ (672)
Misc. Deferred Debits	1525	\$ 76,263		\$ (14,968)			\$ (21,785)	\$ 39,510	\$ 17,886		\$ -	\$ 17,886
LV Variance Account	1550	\$ -	\$ 21,076					\$ 21,076	\$ -	\$ (1,202)		\$ (1,202)
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555	\$ -		\$ (71,906)				\$ (71,906)	\$ -	\$ (844)		\$ (844)
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555	\$ -						\$ -	\$ -			\$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Met	1555	\$ -						\$ -	\$ -			\$ -
Smart Meter OM&A Variance	1556	\$ -						\$ -	\$ -			\$ -
Conservation and Demand Management Expenditures and Recoveries	1565	\$ (401,399)	\$ 152,360					\$ (249,039)	\$ -			\$ -
CDM Contra	1566	\$ 456,507		\$ (207,468)				\$ 249,039	\$ -			\$ -
Qualifying Transition Costs ⁸	1570	\$ 270,930	n/a	n/a			\$ (311,056)	\$ (40,126)	\$ 80,539	\$ 7,631	\$ (50,082)	\$ 38,088
Pre-Market Opening Energy Variances Total ⁵	1571	\$ 266,577	n/a	n/a		\$ (27,267)	\$ (265,377)	\$ (26,067)	\$ 70,589	\$ 13,429	\$ (76,959)	\$ 7,059
Extra-Ordinary Event Costs	1572	\$ -						\$ -	\$ -			\$ -
Deferred Rate Impact Amounts	1574	\$ -						\$ -	\$ -			\$ -
Other Deferred Credits	2425	\$ -						\$ -	\$ -			\$ -
Sub-Totals		\$ 926,240	\$ 177,854	\$ (294,342)	\$ -	\$ (27,267)	\$ (642,864)	\$ 139,621	\$ 181,093	\$ 30,228	\$ (127,666)	\$ 83,655
Deferred Payments in Lieu of Taxes	1562											
2006 PILs & Taxes Variance	1592											
Sub-Totals												
Total		\$ 3,459,810	\$ (686,476)	\$ (294,342)	\$ -	\$ (27,267)	\$ (2,579,568)	\$ (127,843)	\$ 412,744	\$ 95,127	\$ (394,788)	\$ 113,083
The following is not included in the total claim but is included on a memo basis:												
Deferred PILs Contra Account ⁸	1563											
RSVA - Power (including Global Adjustment)	1588	\$ 2,483,845	\$ 628,053				\$ (2,135,535)	\$ 976,363	\$ 232,276	\$ 156,545	\$ (353,766)	\$ 35,055
RSVA - Power - Sub-Account - Global Adjustment ⁴	1588	\$ (190,500)	\$ 48,603					\$ (141,897)	\$ (6,906)	\$ (5,488)		\$ (12,394)
Recovery of Regulatory Asset Balances	1590	\$ (1,413,047)		\$ (1,504,395)			\$ 4,715,103	\$ 1,797,661	\$ -	\$ (157,394)	\$ 748,554	\$ 591,160

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SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	HALTON HILLS HYDRO INC.
NAME OF CONTACT	ARTHUR SKIDMORE
E-mail Address	askidmore@haltonhillshydro.com
VERSION NUMBER	v3.0
Date	13-Nov-07

Account Description	Account Number	Projected Interest on Dec 31 -06 balance from Jan 1, 2007 to Dec 31, 2007 ⁹	Projected Interest on Dec 31 -06 balance from Jan 1, 2008 to April 30, 2008 ⁹	Claim before Forecasted Transactions	Forecasted Transactions, Excluding Interest from Jan 1, 2007 to Dec 31, 2007	Forecasted Transactions, Excluding Interest from Jan 1, 2008 to April 30, 2008	Projected Interest from Jan 1, 2007 to April 30, 2008 on Forecasted Transx (Excl Interest) from Jan 1, 2007 to December 31, 2007	Projected Interest from Jan 1, 2008 to April 30, 2008 on Forecasted Transx (Excl Interest) from Jan 1, 2008 to April 30, 2008	Total Claim
RSVA - Wholesale Market Service Charge	1580	\$ 9,018	\$ 3,006	\$ 251,077					\$ 251,077
RSVA - One-time Wholesale Market Service	1582	\$ 2,224	\$ 741	\$ 54,703					\$ 54,703
RSVA - Retail Transmission Network Charge	1584	\$ 1,635	\$ 545	\$ 19,766					\$ 19,766
RSVA - Retail Transmission Connection Charge	1586	\$ (25,154)	\$ (8,385)	\$ (579,951)					\$ (579,951)
Sub-Totals		\$ (12,277)	\$ (4,092)	\$ (254,405)	\$ -	\$ -	\$ -	\$ -	\$ (254,405)
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	\$ 3,448	\$ 1,149	\$ 86,829					\$ 86,829
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	\$ 7,846	\$ 2,615	\$ 197,591					\$ 197,591
Other Regulatory Assets - Sub-Account - Other ⁷	1508	\$ (1,752)	\$ (584)	\$ (40,516)					\$ (40,516)
Other Regulatory Assets - Sub-Account - Other ⁷	1508			\$ -					\$ -
Other Regulatory Assets - Sub-Account - Other ⁷	1508			\$ -					\$ -
Retail Cost Variance Account - Retail	1518	\$ 529	\$ 176	\$ 12,288					\$ 12,288
Retail Cost Variance Account - STR	1548	\$ (105)	\$ (35)	\$ (3,102)					\$ (3,102)
Misc. Deferred Debits	1525	\$ 1,814	\$ 605	\$ 59,814					\$ 59,814
LV Variance Account	1550	\$ 967	\$ 322	\$ 21,164					\$ 21,164
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555	\$ (3,300)	\$ (1,100)	\$ (77,151)					\$ (77,151)
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555			\$ -					\$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Met	1555			\$ -					\$ -
Smart Meter OM&A Variance	1556			\$ -					\$ -
Conservation and Demand Management Expenditures and Recoveries	1565	\$ (11,431)	\$ (3,810)	\$ (264,280)					\$ (264,280)
CDM Contra	1566	\$ 11,431	\$ 3,810	\$ 264,280					\$ 264,280
Qualifying Transition Costs ⁹	1570	\$ (1,842)	\$ (614)	\$ (4,494)					\$ (4,494)
Pre-Market Opening Energy Variances Total ⁹	1571	\$ (1,196)	\$ (399)	\$ (20,603)					\$ (20,603)
Extra-Ordinary Event Costs	1572			\$ -					\$ -
Deferred Rate Impact Amounts	1574			\$ -					\$ -
Other Deferred Credits	2425			\$ -					\$ -
Sub-Totals		\$ 6,409	\$ 2,136	\$ 231,821	\$ -	\$ -	\$ -	\$ -	\$ 231,821
Deferred Payments in Lieu of Taxes	1562								
2006 PILs & Taxes Variance	1592								
Sub-Totals				\$ -					\$ -
Total		\$ (5,868)	\$ (1,956)	\$ (22,584)	\$ -	\$ -	\$ -	\$ -	\$ (22,584)
The following is not included in the total claim but is included on a memo basis:									
Deferred PILs Contra Account ⁸	1563								
RSVA - Power (including Global Adjustment)	1588	\$ 44,815	\$ 14,938	\$ 1,071,171	\$ 506,834	\$ 44,719	\$ 31,018	\$ 684	\$ 1,654,427
RSVA - Power - Sub-Account - Global Adjustment ⁴	1588			\$ (154,291)					\$ (154,291)
Recovery of Regulatory Asset Balances	1590	\$ 70,736	\$ 6,467	\$ 2,466,024	\$ (1,738,274)	\$ (597,240)			\$ 130,510