March 28, 2008

Ms. K. Walli
Board Secretary
Ontario Energy Board
Suite 2701
2300 Yonge Street
Toronto, Ontario M4P 1E4

Re: Chapleau Public Utilities Corporation
Application for 2008 Electricity Distribution Rates
Board File No EB-2007-0755

Dear Ms. Walli;

Please accept from Chapleau Public Utilities Corporation the responses to Board staff and Vulnerable Energy Consumers Coalition (VECC) interrogatories.

Enclosed with this letter are two (2) hard copies and an electronic version of the documents Exhibits and appendices used to develop the interrogatory responses for the 2008 Distribution Rates.

These documents have been filed on behalf of Chapleau Public Utilities Corporation.

Sincerely,

Original singed by:

____

Peter Ioannou
Regulatory Compliance Services

Enclosure

cc: Marita Morin, Chapleau Public Utilities Corporation.
File

120 Eglinton Avenue East, Suite 1000, Toronto, Ontario, M4P 1E2
416-487-5546

Board Staff Interrogatories
2008 Electricity Distribution Rates
Chapleau Public Utilities Corporation
EB-2007-0755

Operations, Maintenance and Administration

General

1. Ref: Exhibit 4
   Please confirm that Chapleau Public Utilities Corporation (CPUC) has not made changes to the company's accounting policies in respect to capitalization of operation expenses and/or has not made any significant changes to accounting estimates used in allocation of costs between operations and capital expenses post fiscal year end 2004. If any accounting policy changes or any significant changes in accounting estimates have been made post 2004 fiscal year end, please provide all supporting documentation and a discussion highlighting the impact of the changes.

Response

CPUC confirms that it has not made any changes to the company's accounting policies in respect to capitalization of operation expenses and has not made any significant changes to accounting estimates used in allocation of costs between operations and capital expenses post fiscal year end 2004.

2. Ref: Exhibit 4
   Table 1 below was prepared to review CPUC's OM&A expenses: (Rounding differences may occur, but are immaterial to the questions following)

Table 1

	Approved	Historical Yr.	Bridge Year	Test Year
Operations and Maintenance	263,311	274,181	296,913	302,585
Billing & Collecting	65,879	60,018	66,539	64,112
Community Relations	2,607	1,707	1,063	1,200
Executive Salaries and Expense	59,881	59,331	62,672	64,552
Office Supplies and Expense	22,176	19,432	21,661	22,248
Outside Services Employed	38,352	47,795	109,238	60,820
Property Insurance	13,601	12,119	13,000	13,500
Regulatory Expenses	5,734	4,584	5,769	6,000
Misc. General Expenses	6,546	10,612	15,000	12,000
Bank Charges	8,247	8,941	9,883	9,200
Controllable OM&A Expenses	486,334	498,720	601,738	556,217
Low Voltage Charges (8 Months Only)	0	0	0	24,631
Depreciation	37,890	37,370	36,273	36,563
TOTAL OPERATING COSTS	524,224	536,090	638,011	617,411

Table 2 below was prepared to assist in the review of CPUC's forecast OM&A expenses from the evidence provided in Exhibit 4. Note rounding differences may occur, but are immaterial to the following questions. Board staff notes that CPUC is forecasting increases in 2008 Controllable OM&A Expenses of $57,497 or 11.5% from Historical 2006.

Table 2

	Approved	Variance Historical/ Approved	Historical Yr.	Variance Bridge/Historical	Bridge Year	Variance Test/Bridge	Test Year	Variance Test/Historical
Operations and Maintenance	263,311	10,870	274,181	22,732	296,913	5,672	302,585	28,404
		2.2%		4.6%		0.9%		5.7%
Billing & Collecting	65,879	-5,861	60,018	6,521	66,539	-2,427	64,112	4,094
		-1.2%		1.3%		-0.4%		0.8%
Community Relations	2,607	-900	1,707	-644	1,063	137	1,200	-507
		-0.2%		-0.1%		0.0%		-0.1%
Executive Salaries and Expense	59,881	-550	59,331	3,341	62,672	1,880	64,552	5,221
		-0.1%		0.7%		0.3%		1.0%
Office Supplies and Expense	22,176	-2,744	19,432	2,229	21,661	587	22,248	2,816
		-0.6%		0.4%		0.1%		0.6%
Outside Services Employed	38,352	9,443	47,795	61,443	109,238	-48,418	60,820	13,025
		1.9%		12.3%		-8.0%		2.6%
Property Insurance	13,601	-1,482	12,119	881	13,000	500	13,500	1,381
		-0.3%		0.2%		0.1%		0.3%
Regulatory Expenses	5,734	-1,150	4,584	1,185	5,769	231	6,000	1,416
		-0.2%		0.2%		0.0%		0.3%
Misc. General Expenses	6,546	4,066	10,612	4,388	15,000	-3,000	12,000	1,388
		0.8%		0.9%		-0.5%		0.3%
Bank Charges	8,247	694	8,941	942	9,883	-683	9,200	259
		0.1%		0.2%		-0.1%		0.1%
Controllable OM&A Expenses	486,334	12,386	498,720	103,018	601,738	-45,521	556,217	57,497
		2.5%		20.7%		-7.6%		11.5%

Table 3 below was prepared to assist in the review of CPUC's OM&A actual and forecast expenses from the OM&A Cost Table in Exhibit 4. Note rounding differences may occur, but are immaterial to the following questions.

Table 3

Cost Drivers	2006	2007	2008
Opening Balance (Previous Year)	486,334	498,720	601,738
Office supplies		2200	
Travel - Industry meetings		4400	-3000
Bad Debt		4250	-3000
Additional Repairs and Maintenance		22732	
Regulatory Filing Costs	3878	35797	-21675
KPMG - Review of 3Yr Business Plan		21715	-21715
ESA Audit		1702	
OMERS Pension		4568	
Unexplained Difference	8,508	5,654	3,869
Closing Balance (Current Year)	498,720	601,738	556,217

a) Please confirm that CPUC agrees with the three tables as presented above. If CPUC does not agree with any element in the tables please advise why not. If CPUC determines that the tables require modification due to the reconciliation resulting from Table 1 above, please provide amended tables with full explanation of changes made.

<u>Response</u>

Due to the interrogatory responses CPUC has made changes to the above tables for a net adjustment of $6,895 as follows:

1) ***Please see response to interrogatory #3. In 2008 Test year, one time costs from Outside Services Employed increase cost by $11,605.***
2) ***Please see response to interrogatory #4. In 2007 Bridge year "Purchase of Services and Products" from KPMG a reduction in cost of $4,550 and Spi Group a reduction cost of $160.***

Amended Table 1

	Approved	Historical Yr.	Bridge Year	Test Year
Operations and Maintenance	263,311	274,181	296,913	302,585
Billing & Collecting	65,879	60,018	66,539	64,112
Community Relations	2,607	1,707	1,063	1,200
Executive Salaries and Expense	59,881	59,331	62,672	64,552
Office Supplies and Expense	22,176	19,432	21,661	22,248
Outside Services Employed	38,352	47,795	104,528	72,425
Property Insurance	13,601	12,119	13,000	13,500
Regulatory Expenses	5,734	4,584	5,769	6,000
Misc. General Expenses	6,546	10,612	15,000	12,000
Bank Charges	8,247	8,941	9,883	9,200
Controllable OM&A Expenses	486,334	498,720	597028	567,822
Low Voltage Charges (8 Months Only)	0	0	0	24,631
Depreciation	37,890	37,370	36,273	36,563
TOTAL OPERATING COSTS	524,224	536,090	633,301	629,016

Table 2

	Approved	Variance Historical/ Approved	Historical Yr.	Variance Bridge/Historical	Bridge Year	Variance Test/Bridge	Test Year	Variance Test/Historical
Operations and Maintenance	263,311	10,870	274,181	22,732	296,913	5,672	302,585	28,404
		2.2%		4.6%		0.9%		5.7%
Billing & Collecting	65,879	-5,861	60,018	6,521	66,539	-2,427	64,112	4,094
		-1.2%		1.3%		-0.4%		0.8%
Community Relations	2,607	-900	1,707	-644	1,063	137	1,200	-507
		-0.2%		-0.1%		0.0%		-0.1%
Executive Salaries and Expense	59,881	-550	59,331	3,341	62,672	1,880	64,552	5,221
		-0.1%		0.7%		0.3%		1.0%
Office Supplies and Expense	22,176	-2,744	19,432	2,229	21,661	587	22,248	2,816
		-0.6%		0.4%		0.1%		0.6%
Outside Services Employed	38,352	9,443	47,795	61,443	109,238	-48,418	60,820	13,025
		1.9%		12.3%		-8.0%		2.6%
Property Insurance	13,601	-1,482	12,119	881	13,000	500	13,500	1,381
		-0.3%		0.2%		0.1%		0.3%
Regulatory Expenses	5,734	-1,150	4,584	1,185	5,769	231	6,000	1,416
		-0.2%		0.2%		0.0%		0.3%
Misc. General Expenses	6,546	4,066	10,612	4,388	15,000	-3,000	12,000	1,388
		0.8%		0.9%		-0.5%		0.3%
Bank Charges	8,247	694	8,941	942	9,883	-683	9,200	259
		0.1%		0.2%		-0.1%		0.1%
Controllable OM&A Expenses	486,334	12,386	498,720	103,018	601,738	-45,521	556,217	57,497
		2.5%		20.7%		-7.6%		11.5%

Unable to amend table 2 in its entirety.

The following are the amended items only as identified above:

Amended (Partial) Table 2

	Historical	Variance Bridge/ Hist.	*Bridge Yr*	Variance Test/ Bridge	Test Year	Variance Test/Hist Actual
Outside Services Employed	*47,795*	56,733	*104,528*	-32,103	*72,425*	*24,630*
				-30.7%		51.5%
Total	*498,720*	98,308	*597,028*	-29,206	*567,822*	*69,102*
		19.7%		-4.9%		*13.9%*

Amended Table 3

Cost Drivers	2006	2007	2008
Opening Balance (Previous Year)	486,334	498,720	597,028
Office supplies		2200	
Travel - Industry meetings		4400	-3000
Bad Debt		4250	-3000
Additional Repairs and Maintenance		22732	
Regulatory Filing Costs	3878	35797	-21675
Recovery of one time costs			11605
KPMG - Review of 3Yr Business Plan		17166	-17,166
ESA Audit		1702	
OMERS Pension		4568	
Unexplained Difference	8,508	5,493	4,030
Closing Balance (Current Year)	498,720	597,028	567,822

b) Please complete Table 3 to identify the key cost drivers that are contributing to the overall increase of 11.5% over the 2006 Historic Year.

Response

		2008
Opening Balance (2006 Historic Year)		498,720
Operations & Maintenance:		
Salary Increases of 3% for each year (2007 & 2008)	8,150	
Pension Increase	5,050	
Additional Repairs and Maintenance Expense as per Interrogatory # 5	13,700	26,900
Billing and Collecting:		
Salary Increases of 3% for each year (2007 & 2008)	2,800	
Increase write offs	1,300	4,100
Executive salaries and expense:		
Salary Increases of 3% for each year (2007 & 2008)	2,750	
Additional Travel Expense	1,500	4,250
Office Supplies and Expense		
Timing of purchasing supplies	2,816	2,816
Outside Services Employed:		
Additional cost for Regulatory Filings		15,000
Recovery of one time costs (Interrogatory #3)		11,605
Unexplained Difference		4,431
Closing Balance Test Year (2008)		**567,822**

c) Please prepare a comprehensive listing of all operational costs by work unit for smart meter costs included in the 2008 budget. Please include the work unit where the smart meter cost is accounted for in the budget, description of activity, and amount budgeted. In particular, please identify for each of the reported budget amounts whether CPUC considers the cost to be a component of minimum functionality, or if the amount is incidental/incremental to minimum functionality.

Response

CPUC has not included any operating costs for smart meters in 2008. The proposal is that the operating costs for smart meters be included in the 2008 operating budget of $77,034.55, this being the average of operating costs expected to be incurred over the next 3 year period as follows:

2008	*$ 3,197.03*
2009	*$ 96,076.62*
2010	*$131,830.00*
Total	*$231,103.65*

The following is the average operating cost to be incurred by work unit/activity:

Work Unit /Activity	*amount budgeted*
- *Repair of unsafe meter bases*	*$1,014.93*
- *AMRC including WAN*	*$1,253.42*
- *AMCC*	*$18,691.12*
- *AMI operations*	*$36,286.67*
- *AMI Installation Operational Verification Tools (Temp MDMR)*	*$1,894.54*
- *Staff Training*	*$1,080.00*
- *Measurement Canada re-verification*	*$1,976.34*
- *S/M Customer Presentment Tools*	*$180.43*
- *Smart Meter entity MDMR*	*$3,789.07*
- *AMI Security Audits*	*$7,200.00*
- *Contingency*	*$ 3,668.03*

All of the above operating costs are a component of minimum functionality.

Please reference also our response to question # 43 with regards to the proposed method for the recovery of costs.

Regulatory Costs

3. Ref. Exhibit 4
   Please provide the breakdown for actual and forecast, where applicable, for the 2006 Board approved, 2006 actual, 2007 bridge year, and 2008 test year regarding the following regulatory costs and present it in the following table format:

Regulatory Cost Category	Ongoing or One-time Cost?	2006 Board Approved	2006 Actual	2007 (as of Dec 07)	% Change in 2007 vs. 2006	2008 Forecast	% Change in 2008 vs. 2007
1. OEB Annual Assessment Registration Fee Cost awards	Ongoing Ongoing Ongoing	3,286 800 0	2,160 800 0	4,863 800 132	225.1% 0.0% 0.0%	5,050 800 150	3.8% 0.0% 13.6%
2. OEB Hearing Assessments (applicant initiated)		0	0	0	0	0	0
3. OEB Section 30 Costs (OEB initiated)		0	0	0	0	0	0
4. Expert Witness cost for regulatory matters		0	0	0	0	0	0
5. Legal costs for regulatory matters		0	0	0	0	0	0
6. Consultants costs for regulatory matters	Ongoing One-time	0 10,098	0 8,241	0 62,575	0 716.8%	0 18,000 Plus 11,605	0 (211.4%)
7. Operating expenses associated with staff resources allocated to regulatory matters		0	0	0	0	0	0
8. Operating expenses associated with other resources allocated to regulatory matters (please identify the resources)		0	0	0	0	0	0
Other regulatory agency fees or assessments (ESA)	Ongoing	1,648	1,624	1,702	4.8%	1,800	5.6%
9. Any other costs for regulatory matters (please define)		0	0	0	0	0	0

a) Under "Ongoing or One-time Cost", please identity and state if any of the regulatory cost is "One-time Cost" and not expected to be incurred by the applicant during the impending two year period when the applicant is subject to 3rd Generation IRM process or it is "Ongoing Cost" and will continue throughout the 3rd Generation of IRM process.

Response

The table above has been completed as instructed and the "ongoing and one-time-costs" have been identified.

The total one time cost for 2006, 2007 and 2008 is $88,816 plus the adjustment from response to b) below of $11,605.

b) Please state the utility's proposal on how it intends to recover the "One-time" costs as a part of its 2008 rate application.

Response

The recovery of the "one-time costs" of $88,816 was <u>not considered</u> in the original application. However part of the expenditure budgeted in "Purchase of Services", for 2008, is considered to be "one time cost" for a total of $18,000 and is included in the Company's determination of rates.
The Company is proposing to recover the "one-time costs" for 2006, 2007 and 2008 over the next 3 year period, 2009, 2010 and 2011. This will be achieved by dividing the sum of the one-time costs of 2006, 2007 and 2008 by 3 ($8,241 + 62,575 + 18,000 =$ 88,816/3 = $29,605). In order to recover the one-time costs an adjustment is therefore required of $11,605 ($18,000 + $11,605 =$29,605) to increase Operating Expenses and adjust the 2008 Test Year Rates.

This change will adjust the 3 tables in Interrogatory # 2.

<u>Purchase of Services or Products</u>

4. Ref: Exh4/Tab2/Sch3
Pursuant to section 2.5 (Exhibit 4 Operating & Maintenance and Other Costs) of the Filing Requirements for Transmission and Distribution Applications, distribution expenses incurred through the purchase of services or products must be documented and <u>justified</u> if they are to be recovered as part of the revenue requirement:

Please provide the following information:
i. Identity of each company transacting with the applicant.
ii. Summary of the nature of the activity transacted.

iii. Annual aggregate dollar value of transactions for the 2006, 2007, and 2008 rate years.

iv. Descriptions of the specific methodologies used in determining the price (ie: summary of tendering process/summary of cost approach).

Response

The table that was included with the Company's original submission in excel worksheet "Exhibit 4 Operating Costs" in Appendix E is expanded to include items i, ii, and iii above as follows:

	2006 Historical Yr	2007 Bridge Yr	2008 Test Yr
Regulatory Compliance Services			
- IRM application 2007 and 2009 Rates	**3,878**	**0**	**3,000**
- Cost of Service Application	**0**	**14,675**	**0**
- 2nd Generation	**0**	**25,000**	**15,000**
Total	**$3,878**	**$39,675**	**$18,000**
KPMG			
- Annual Audit	**14,629**	**14,437**	**15,000**
- PILs Submission	**2,363**	**0**	**0**
- OEB Audit	**0**	**7,950**	**0**
- 3 Year Business Plan	**0**	**11,450**	**0**
Total	**$16,992**	**$33,837**	**$15,000**
Spi Group			
- EBT License	**2,000**	**0**	**0**
- Annual Maintenance	**2,000**	**2,000**	**2,160**
- Monthly Fee x12	**1,800**	**1,800**	**1,960**
Total	**$5,800**	**$3,960**	**$4,120**
Peterborough Utilities			
- MDMA & MSP Wholesale Meters	**$17,718**	**$17,754**	**$17,800**
MacGillivray Janitorial			
- Janitorial Services	**$2,700**	**$2,700**	**$2,700**
Valentine Farms Snow Removal			
- Snow Removal	**$707**	**$800**	**$800**
Hydro One			
- Weather Normalization	**0**	**$3,500**	**0**
Sudbury Control			
- Infra Red Scan	**0**	**$600**	**$600**
AESI			
- ESA Adit	**0**	**$1,702**	**$1,800**
TOTAL	**$47,795**	**$104,528**	**$60,820**

In our original submission, the estimated total for 2007 bridge year was $109,238. We now have better information and estimate that the total will be $104,528.
Therefore an adjustment of $4,710 to reduce the 2007 bridge year expenditures has been made to the purchase of services from KPMG by $4,550 and from Spi Group by $160.

This change will adjust the 3 tables in Interrogatory # 2.

Re item iv above: Price determination and process taken for the purchase of services is determined as follows:

> ***To purchase the services of local contractors, if more than one contractor is available, the Company contacts the contractors interested in participating through the informal (verbal) issue of a Request for Proposal (RFP), applicants are interviewed and the contract is awarded based on ability to perform at the lowest price. (Please note that these contracts are under $3,000 per annum).***
>
> ***All other services are either specialized in nature that require expert knowledge of our business, including regulatory issues, or due to the Company's (remote) northern location and size with a staff of only 5 employees (1 management, 1 clerk and 3 linepersons) and no locally available companies to perform the services required, Chapleau Public Utilities Corporation will seek guidance and advice through neighbouring distribution utilities and the Electricity Distributors Association in its' search for a suitable company to perform the services required. The price is always negotiated before proceeding. Management has the authority for approvals up to $1,000 and the Board of Directors for all amounts above $1,000.***
>
> ***It must be noted that Chapleau Public Utilities Corporation does not have a tendering policy/process, however the Company is a member of the "North East Purchasing Consortium" with 7 other neighbouring distribution companies and purchase inventory that is common to all utilities. Each utility takes their turn to send a Request for Proposal (RFP) that ultimately achieving cost savings for all participants.***

<u>Shared Services</u>

5. Ref: Exhibit 4

   To comply with section 2.5 (Exhibit 1 Operating & Maintenance and Other Costs) of the Filing Requirements for Transmission and Distribution Applications, please file the following information for each shared services for the 2006, 2007, and 2008 rate years:

   i. type of service
   ii. total annual expense by service

iii. Rationale and cost allocators used for shared costs for each type of service.

Response

Chapleau Public Utilities Corporation (CPUC) does not have any employees nor own any fixed assets other than distribution assets and inventory. CPUC contracts Chapleau Energy Services Corporation (CESC) to supply all labour and equipment required for new construction and repairs and maintenance to the Utility's distribution system, management support, billing and collection, rent, phone, postage office supplies and office equipment.
All services are charged to the Distribution Company at the actual cost of the service plus applicable overhead (benefits) with no mark-up. (See "Pricing" on page 5 of the "Operation and Maintenance Services Agreement" between Chapleau Public Utilities Corporation and Chapleau Energy Services Corporation included in our original submission as page 51).

Chapleau Energy Services Corporation does work for various clients with three of the larger clients being: Chapleau Public Utilities Corporation, Township of Chapleau and Hydro One Networks Inc.

The following are the services supplied by Chapleau Energy Services Corporation to Chapleau Public Utilities Corporation.

Item	Type of Service	Rationale and Cost Allocators	2006	2007	2008
		Cost Allocators	83.6%	86.8%	86.8%
1	Management Support	To manage the operation and regulatory affairs of the Utility.	44,866	47,236	48,653
2	Billing & Collections	To read meters, prepare and mail customer bills and to make collections of the said bills.	41,698	46,748	48,150
3	Distribution System Repairs and Maintenance	To repair & maintain existing distribution system. (Includes On-call expenses of $7,800 per year allocated at 100%)	110,556	119,347	122,873
4	Employee Benefits	Benefits applicable to all full time employees (Includes Vacation and Sick time)	74,432	84,672	84,994
5	Office Supplies	General Office Supplies used by all staff in the performance of their duties.	4,965	5,190	5,250
6	All other Expenses i.e. Utilities, Insurance 'phones, etc.	To pay the Company's share of all other expenses.	23,257	29,972	30,026
7	OH Distr'n Line supplies	Overhead distribution line supplies Allocated at 100%.	18,580	15,120	15,574
8	Truck Expenses	Trucks used for the repair and maintenance of distribution system	65,063	68,292	70,332
	TOTAL		383,417	416,577	425,852

All of the items above are allocated based on the allocators as calculated below, except for the on-call costs of $7,800 (per year) allocated at 100% to item 3 and the overhead distribution line supplies in item 7 purchased for CPUC and allocated at 100%.

The basis to determine the cost allocators is the percentage (%) of actual direct hours worked for Chapleau Public Utilities Corporation divided into the total hours worked by all employees:

Cost Allocators	2006	2007	2008
Actual Hours Worked for CPUC / Total hours worked by all 5 employees	8,453 / 10,118 x 100 = **83.5%**	8,941 / 10,297 x 100 = **86.8%**	8,900 / 10,250 x 100 = **86.8%**

(Please note that due to a calculation error the wrong allocators were identified in the original submission).

The following are the services supplied by Chapleau Public Utilities Corporation to Chapleau Energy Services Corporation.

Item	Type of Service	Rationale and Cost Allocators	2006	2007	2008
1	Material	Actual cost of material used by CESC to repair and maintain existing distribution services of Hydro One Networks Inc.	7,287	1,424	5,000

Chapleau Energy Services Corporation purchases poles, wire and transformers at cost from Chapleau Public Utilities Corporation for the work they perform for Hydro One Networks Inc.

Corporate Cost Allocation

6. Ref: Exhibit 4
Pursuant to section 2.5 (Exhibit 4 Part D) of the Filing Requirements for Transmission and Distribution Applications, Applicants are to file detailed description of the assumptions underlying the corporate cost allocation as well as provide documentation of the overall methodology and policy.

Please provide the documentation described above for any corporate cost allocations between CPUC and the Township of Chapleau.

Response

Please refer to the response to Shared Services item 5 above for corporate cost allocation methodology and policy.

There are no corporate cost allocations between CPUC and the Township of Chapleau.

Employee Compensation

7. Ref: Exhibit 4, page 27
On Page 27, CPUC provides the number of employees by employee type. Please confirm that the number of employees has remained unchanged for the 2006 Board approved year, 2006 actual year, 2007 bridge, and 2008 test year, or, if not, please provide the numbers for each of these years.

Response

The Company confirms that the number of employees (5 + 1 summer student) has remained unchanged for the 2006 Board approved year, 2006 actual year, 2007 bridge, and 2008 test year.

8. Ref: Exhibit 4, page 27
On Page 27, CPUC provides a comparison of total employee compensation and total employee benefits for the 2006 actual year, 2007 bridge, and 2008 test year. Please provide a similar breakdown of total employee compensation and total employee benefits for the 2006 Board approved year.

Response

The 2006 Board approved year for total employee compensation and benefits is as follows:

Compensation	***$201,675***
Benefits	***$ 70,198***

9. Ref: Exhibit 4, page 27
On Page 27, CPUC provides a comparison of employee compensation from 2006 to 2008. Based on the percentage of compensation costs charged to

CPUC, this table indicates that total employee compensation has increased from $141,138 in 2006 to $164,098 in 2008. Please confirm that this is the case and, if so, please provide the rationale and justification for this two-year increase of 16%. If not, please provide the appropriate numbers and similar justification

Response

Please note that the compensation and benefit amounts shown in Exhibit 4 page 27 of our submission for 2006, 2007 and 2008 is the total amount charged by Chapleau Energy Services Corporation (CESC) to Chapleau Public Utilities Corporation (CPUC) and the amounts for comparison therefore should be for 2006 $197,120 and for 2008 $219,676 representing an increase of 11.4%.
The increase of $22,556, between 2006 and 2008, represents:
a) Additional repair and maintenance work in 2008 for $10,551 (approximately 350 hours).
b) Increase in salaries and wages over 2 years, of 3% per annum, for $12,005.

10. Ref: Exhibit 4, page 27
On Page 27, CPUC provides a comparison of total employee compensation from 2006 to 2008. Please state whether or not CPUC has overtime compensation. If so, please provide a breakdown of overtime amounts for 2006, including Historical Board Approved and Historical Actual, 2007 and 2008.

Response

The Company does have overtime compensation and is included in total employee compensation as follows:

2006 Board Approved	***$ 2,551***
2006 Historical Actual	***$ 1,199***
2007 Bridge Year	***$1,394***
2008 Test Year	***$1,436***

11. Ref: Exhibit 4, page 27
On Page 27, CPUC provides a comparison of total employee benefits from 2006 to 2008. Based on the percentage of benefit costs charged to CPUC,

this table indicates that total employee benefits have increased from $53,293 in 2006 to $63,491 in 2008. Please confirm that this is the case and, if so, provide the rationale and justification for this two-year increase of 19%. If not, please provide the correct numbers and equivalent rationale and justification.

Response

As in question # 9 above, the benefit amounts shown in Exhibit 4 page 27 of our submission for 2006, 2007 and 2008 is the total amount charged by Chapleau Energy Services Corporation (CESC) to Chapleau Public Utilities Corporation (CPUC) and the amounts for comparison therefore should be, for 2006 $74,432 and for 2008 $84,672, representing an increase of 13.8%.

The increase of $10,240, between 2006 and 2008, represents:
a) Cost allocator increase (due to additional repair and maintenance work in 2008) from 83.5% in 2006 to 86.8% in 2008 for an increase of $3,300.
b) Higher cost for holidays and sick time is due to the 3% per annum increase for salaries and wages of $1,400, and the use of the average of 2006 and 2007 for an increase of $940.
c) Total expense for 2006 should be $15,920 not $11,534. Pension for (4 months) January to April 2006 of $4,386 recorded in variance account instead of expense.
d) Balance of $214 is for inflationary increases over 2 years for group insurance, WSIB, CPP, EI, etc.

12. Ref: Exhibit 4, page 27
On Page 27, CPUC provides a comparison of total employee compensation amounts from 2006 to 2008. Please indicate whether or not CPUC has an employee incentive program and if so, provide a breakdown of amounts paid for 2006, including Historical Board Approved and Historical Actual, 2007 and 2008.

Response

Chapleau Public Utilities Corporation does not have an employee incentive program.

13. Ref: Exhibit 4, page 27
Please provide a breakdown of total employee compensation costs, including salary, wages, and benefits, charged to O&M for the 2006 Board approved year, 2006 actual year, 2007 bridge year and 2008 test year.

Response

	2006 Board Approved Year	2006 Historical Year	2007 Bridge Year	2008 Test Year
Compensation - Wages	114,190	110,556	119,347	122,873
Benefits	70,198	74,432	84,672	84,994

Rate Base

14. Ref: General
a) Please provide Chapleau's Code of Business Conduct.

Response

Chapleau Public Utilities Corporation Code of Business Conduct is attached as Appendix A.

b) For the years 2002 to 2008 inclusive, please provide a table listing the following information (actual dollars where available, or expected, planned or projected, or % where indicated):
i Smart Meter Capital Expenditures;
ii. Capital Expenditures excluding smart meters;
iii. Total Capital Expenditures including and excluding smart meters;
iv. Depreciation;
v. Construction Work in Progress
vi. Number of customer additions by class

Response

Information as requested for items i. to v. inclusive is presented in the following table:

YEAR	(i) Smart Meter Capital Expenditure	(ii) All Other Capital Expenditure	(iii) Total Capital Expenditure	(iv) Depreciation	(v) Construction Work in Process
2002 Actual	0	1,701	1,701	39,855	0
2003 Actual	0	10,991	10,991	38,513	0
2004 Actual	0	34,785	34,785	37,890	0
2005 Actual	0	33,219	33,219	37,731	0
2006 Actual	0	24,292	24,292	37,370	0
2007 Expected	0	9,402	9,402	36,273	0
2008 Planned	29,361	34,500	63,861	36,563	0

Response to item vi – Number of customer additions / (deletions) by class.

YEAR	Residential	General Service <50 kW	General Service >50 kW	Unmetered Scattered Load	Sentinel Lighting	Street Lighting
2002	(7)	1	0	0	0	0
2003	11	(13)	(1)	0	(3)	0
2004	2	1	(1)	0	(3)	0
2005	5	4	0	0	0	0
2006	19	(2)	1	0	0	0
2007	(36)	1	0	0	0	0
2008	13	0	0	0	0	0

15. Ref: Exh 2/Rate Base Summary Table, Page 24
    a) There appear to be some minor inconsistencies in the summary data when compared to data in Appendix E (see Table below)

	Historic Year 2006 Summary/ Appendix E $	Bridge Year 2007 Summary/ Appendix E $	Test Year 2008 Summary/ Appendix E $
Net Fixed Assets	909, 160	881,309/882,289	908,647/909,588
Working Capital	309,108/389,108	427,090/415,715	412,747/402,243
Rate Base	1,298, 268	1,308,399/1,298,005	1,321,394/1,311,831

Please clarify and confirm the correct numbers.

<u>Response</u>

The following table identifies the correct summary data for Rate Base in our original submission.

	Historic Year 2006	Bridge Year 2007	Test Year 2008
Net Fixed Assets	$909,160	$882,289	$909,588
Working Capital	$389,108	$415,715	$402,243
Rate Base	$1,298,268	$1,298,005	$1,311,831

Due to various corrections the above table has been modified as follows:

	Historic Year 2006	Bridge Year 2007	Test Year 2008
Net Fixed Assets	$909,161	$882,290	$909,588
Working Capital	$389,129	$414,985	$403,984
Rate Base	$1,298,290	$1,297,275	$1,313,572

6. Ref: Exh2/Appendix E/Assets and Depreciation and Capital Expenditures
   a) Net Assets Decline: for 2006 to 2008 these declined from $915,699 to $895,938. Please provide an explanation for this decline.

   b) 2008 Capital Expenditure Increase: Capital Expenditures for 2006, 2007 and 2008 total $24,292, $9,402 and $34,500 respectively excluding smart meter projects. This is a 105% increase in the 2008 projected capital expenditure as compared to the average 2006 and 2007. Please provide an explanation for this increase.

      i. Please identify if any 2006 capital projects were carried over to the 2007.

      ii. Please identify if any 2007 capital projects are carried over to the 2008 test year.

      iii. Please elaborate on utility's plan and capability in completing all proposed 2008 capital expenditures in the 2008 test year.

Response

a) Please note that the numbers shown in the above question are the averages of opening and closing balances, not the 2006 and 2008 year end net assets.
The closing balance of net assets for 2006 is $909,160 and for 2008 is $909,588. This represents a minor increase of $428.

b) Capital Expenditures increase in 2008 is mainly due to the installation of 3 regulators for a total value of $23,500. The purpose of this capital expenditure is to increase voltage levels to CSA requirements as recommended by the EnerSpectrum Group who performed a "System Analysis for Loss Optimization" on the Company's distribution system (the study was attached for the Boards' information as Appendix D in our original submission).

- ***i. There were no capital projects carried over from 2006 to 2007.***
- ***ii. There are no capital projects carried over from 2007 to 2008.***
- ***iii. The Company's Board of Directors and Management is committed to capital expenditures in 2008 to a) reduce line losses, increase voltage levels and b) engage smart meter consultants (including legal costs) for a fee of $29,361. The Company has set aside funds to achieve this.***

17. Ref: Exh2/Appendix E, Rate Base

a) For the years 2002 to 2006 inclusive, please complete the following table including actual dollars and % where indicated. Please identify the cost drivers, as indicated in the table. Examples of cost drivers are: building new transformer station, replacement of obsolete poles, replacement of aging underground cables, etc. Please identify the type and amount of any one-time, unusual expenditure occurred in any particular year that caused the change outside the given threshold, as provided in the table. Please exclude the smart meters from the $ amount for the capital expenditure figures used in the table.

Response

A	B	$ Change (A-B)	% Change (A/B)	Cost Drivers for the change (increase or decrease) if the % change is either less than zero or more than 10%
2003 1,310,382	2002 1,371,358	(60,976)	(4.4)	Reduced net fixed Assets (Depreciation higher than Asset Add'ns) by $27,523. Reduced Working Capital Allowance (Mainly due to COP) $33,453.
2004 1,315,100	2003 1,310,382	4,718	0.4	Less than 10%
2005 1,329,026	2004 1,315,100	13,926	1.1	Less than 10%
2006Actual 1,298,268	2005 1,329,026	(30,758)	(2.3)	Reduced net fixed Assets (Depreciation higher than Asset Add'ns) by $13,077 Reduced Working Capital Allowance for COP $12,430 and Expenses $5,250
2006 Actual 1,298,290	2006 Board Approved 1,336,649	(38,359)	(2.9)	Reduced net fixed Assets (Depreciation higher than Asset Add'ns) by $34,683 Reduced Working Capital Allowance Mainly due to COP $4,410
2007 BridgeYear 1,297,275	2006 Actual 1,298,290	(1,015)	(0.1)	No comment – Variance too small
2008 Test Year 1,313,572	2007 Bridge Year 1,297,275	16,297	1.3	Reduced net fixed Assets (Depreciation higher than Asset Add'ns) by $1,476 Reduced Working Capital Allowance for COP $6,644 and for Expenses $6,828.

The above table has been completed as instructed and smart meter capital expenditures excluded from the table (2008 Test Year).

18. Ref: Exh2/Working Capital/Appendix E
Electricity Supply Expense and 15% thereof for Working Capital: 2006 & 2007 compared to 2008 projected:

    Based on the reduced economy and closures of industry and commerce mentioned on page 18, how is that expectation of lower electricity consumption reflected in the figure of $2,681,620, a figure close to those of 2006 and 2007? Please explain the assumptions leading to the 2008 forecast of electricity supply costs.

Response

The assumptions leading to the_2008 forecast for electricity supply cost are as follows:

As indicated on page 18 of our submission “Major reduction in consumption levels occurred between 2002 and 2005 stabilizing in 2006” and presented the following tables to justify the statement:

	Residential kWh	<50kW kWh	>50kW kWh	Total
2002	16,842,271	6,062,613	10,415,498	33,320,382
2006	14,458,522	5,457,642	7,723,163	27,639,327
Change	2,383,749	604,971	2,692,335	5,681,055
%	14.2%	10.0%	25.8%	17.1%

Population 2002	2,766
Population 2006	2,428
Change (reduction)	12.2%

There were no major economic changes in 2007 from 2006 and therefore forecast data for 2007 bridge year were developed using the actual data to June and the average of 2005 and 2006 from July to December. As no major changes were anticipated in 2008 the average data from 2006 and the forecast data from 2007 were used to determine the consumption levels for 2008. The forecast of electricity costs for 2008 was also based on the same assumptions (average cost of electricity 2006 and 2007) as illustrated by the following table:

Year	Consumption kWh	Consumption $	Price per kWh $
2006	29,569,274	1,721,671	0.0582
2007	30,316,796	1,782,162	0.0588
2008	29,943,035	1,751,917	0.0585

Cost of Capital

19. Ref: Exhibit 6 – Short-term Debt
In the table shown under Item 2 “Capital Structure”, CPUC has not included a short-term debt component in the proposed capital structure for the 2008 Test Year.

Section 2.1.1 of the *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* (the "Board Report") states that:

"The Board has determined that short-term debt should be factored into rate setting, and that a deemed amount should be included in the capital structures of electricity distributors. **The short-term debt amount will be fixed at 4% of rate base**." [Emphasis in Original]

The Board Report states the following in section 2.2.2:

> "**The Board has determined that the deemed short-term debt rate will be calculated as the average of the 3-month bankers' acceptance rate plus a fixed spread of 25 basis points.**
>
> This is consistent with the Board's method for accounting interest rates (i.e. short-term carrying cost treatment) for variance and deferral accounts. The Board will use the 3-month bankers' acceptance rate as published on the Bank of Canada's website, for all business days of the same month as used for determining the deemed long-term debt rate and the ROE.
>
> For the purposes of distribution rate-setting, the deemed short-term debt rate will be updated whenever a cost of service rate application is filed. The deemed short-term debt rate will be applied to the deemed short-term debt component of a distributor's rate base. Further, consistent with updating of the ROE and deemed long-term rate, the deemed short-term debt rate will be updated using data available three full months in advance of the effective date of the rates." [Emphasis in original]

a) If CPUC is proposing to <u>not</u> include a short term debt component in the 2008 Test Year for the purposes of setting its revenue requirement and distribution rates, please provide the reasons that CPUC is proposing to deviate from the Board Report.
b) If CPUC is proposing to comply with the Board Report, please provide CPUC's estimate of the short-term debt rate, showing the calculations, data used and identifying in detail the sources of the data used.
c) Please identify if CPUC is proposing that the deemed short-term debt rate would be updated based on January 2008 *Consensus Forecasts* and Bank of Canada data, in accordance with the methodology documented in section 2.2.2 of Board Report. If CPUC is <u>not</u> proposing to follow the methodology in the Board Report, please provide CPUC's reasons for varying from the methodology in the Board Report.

Response

CPUC is proposing to comply with the Board Report to include a Short Term debt component in the 2008 Test Year for the purposes of setting its revenue requirement and distribution rates and will apply the short-term debt rate at 4.47% as per the Boards' letter of March 7, 2008, re: "Cost of Capital Parameter Updates for 2008 Cost of Service Applications.

See also responses to question 22 below.

20. Ref: Exhibit 6 and 2006 Audited Financial Statements – Long-Term Debt
In a Note at the bottom of the table labelled "Cost of Capital and Rate of Return", CPUC states that "Long Term Debt is payable to the Township of Chapleau for an unspecified term at a debt rate cost of 7.25%". CPUC has used the 7.25% as its long-term debt cost in its Application.

Note 7 of CPUC's 2006 Audited Financial Statements notes that "The loan is repayable to the Corporation of the Township of Chapleau (the "Township"). The loan bears interest at 7.25%, is unsecured and has no specified terms of repayment. Payment of interest has been postponed indefinitely and the Township has indicated that they will not demand repayment within the next twelve months."

The Board Report, in section 2.2.1, documents the following policy for setting the long-term debt rate:

> "For rate-making purposes, the Board considers it appropriate that further distinctions be made between affiliated debt and third party debt, and between new and existing debt.
>
> **The Board has determined that for embedded debt the rate approved in prior Board decisions shall be maintained for the life of each active instrument, unless a new rate is negotiated, in which case it will be treated as new debt.**
>
> **The Board has determined that the rate for new debt that is held by a third party will be the prudently negotiated contracted rate. This would include recognition of premiums and discounts.**

For new affiliated debt, the Board has determined that the allowed rate will be the lower of the contracted rate and the deemed long-term debt rate. This deemed long-term debt rate will be calculated as the Long Canada Bond Forecast plus an average spread with "A/BBB" rate corporate bond yields. The Long Canada Bond Forecast is comprised of the 10-year Government of Canada bond yield forecast (*Consensus Forecast*) plus the actual spread between 10-year and 30-year bond yields observed in Bank of Canada data. The average spread with "A/BBB" rate corporate bond yields is calculated from the observed spread between Government of Canada Bonds and "A/BBB" corporate bond yield data of the same term from Scotia Capital Inc., both available from the Bank of Canada.
For all variable-rate debt and for all affiliate debt that is callable on demand the Board will use the current deemed long-term debt rate. When setting distribution rates at rebasing these debt rates will be adjusted regardless of whether the applicant makes a request for the change." [Emphasis in original]

a) Please provide a copy of the current loan agreement between CPUC and the Township of Chapleau.
b) Please explain how the terms of the loan comply with the Board's guidelines for long-term debt treatment for rate-setting as documented in section 2.2.1 of the Board Report.
c) Is CPUC paying interest on the loan principal, or is interest payment still postponed as stated in Note 7 of the 2006 Audited Financial Statements?
d) If interest payments on the loan are still being postponed:
   i. Please explain, in detail, the reasons for why interest payment was postponed.
   ii. Please explain how the postponed interest is being treated with respect to the loan. Were the terms for the postponement negotiated between CPUC and the Township of Chapleau?
   iii. When does CPUC expect that it will be able to resume interest payment on the loan to the Township of Chapleau? If CPUC does not believe that it will be able to resume interest payment as a result of approved distribution rates resulting from its application, please explain why it does not believe that it will be able to pay its interest expense.

<u>Response</u>

a) There is no loan agreement between CPUC and the Township of Chapleau. There is the Indenture between the Corporation of the Township of Chapleau and Chapleau

PUC and Resolutions passed by the Township. Resolutions are attached as Appendix B.

b) ***The Company's long term debt (from The Township of Chapleau) is an embedded debt bearing interest at 7.25% and this rate has been approved in previous Board decisions. CPUC will comply with Board's guidelines for long-term debt treatment for rate-setting and will apply a long-term debt rate of 6.10% as per the Boards' letter of March 7, 2008, re: "Cost of Capital Parameter Updates for 2008 Cost of Service Applications".***

c) ***CPUC is not paying interest on the loan principal. It is the Company's intent to pay the interest obligation to their shareholder, the Township of Chapleau, but has not been able to achieve sufficient distribution revenues in the past to do so. The interest is postponed as stated in Note 7 of the 2006 Audited Financial Statements.***

d) ***The interest is still being postponed.***
   i. ***The interest payment has been postponed because the company was not able make the required payment.***
   ii. ***The postponed interest has been waived until such times as the PUC deficit is eliminated. The terms of the postponement have been negotiated with the Township of Chapleau.***
   iii. ***The Company will be in a position to pay the interest to the Township of Chapleau for the 2009 fiscal year.***

21. Ref: Exhibit 6 – Return on Equity
CPUC shows a Return on Equity of 9.00% under the proposed Capital Structure for the 2008 Test Year and in the table labelled "Cost of Capital and Rate of Return".

a) Please provide the derivation of the proposed ROE of 9.00%, showing all calculations, the data used, and identifying in detail the sources of all data used.
b) Please confirm if CPUC is seeking a fixed return of 9.00%, or is proposing that, for purposes of finalizing CPUC'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 as documented in Appendix A of the Board Report. If CPUC is

proposing a fixed ROE of 9.00%, please provide a detailed explanation for CPUC's proposal to vary from the Board's Cost of Capital guidelines as documented in section 2.3 and Appendix B of the Board Report.

Response

a) CPUC is not proposing to use a fixed ROE. The intent is to use the updated ROE as instructed by the Board.

b) The Company intents to use the updated ROE of 8.57%, from the January 2008 Consensus Forecasts, as per the Boards' letter of March 7, 2008, re: "Cost of Capital Parameter Updates for 2008 Cost of Service Applications". An adjustment will be made to the ROE to recalculate the Company's revenue requirement.

22. Ref: Exhibit 6 – Capital Structure
In the table labelled "Cost of Capital and Rate of Return", CPUC provides the capital structure for the Board Approved 2006, Historical Year 2006 and Test Year 2006.

a) Please confirm if the Historical Year 2006 is actuals for the 2006 calendar/fiscal year. If the Historical Year 2006 data are not actuals, please explain what these data represent.
b) Please explain why the Total Rate Base for the Historical Year 2006 and Test Year 2008 match at $2,243,060.
c) Please update the table below, taking into account any updated information provided in response to interrogatories, showing the following information for each of the years:
   i. 2006 Board-approved;
   ii. 2006 Actual;
   iii. 2007 Bridge; and
   iv. 2008 Test.

Response

a) The Company confirms that the historical year 2006 capital structure is the actual for 2006.
b) Test year 2008 has been updated with new information being made available since the original submission.

c) ***The following tables have been updated with new information being made available since the original submission.***

2006 Board Approved

	Dollars ($)	Ratio (%)	Rate (%)	Rate X Ratio /100 (%)
Debt				
Long-term	1,853,685	99.99	7.25	7.25
Short-term	0			
Total Debt	1,853,685	99.99		7.25
Equity				
Common Equity	100	0.01	9.0	0.0
Preference shares	0	0		0
Total Equity	100	0.01		0.0
Weighted Average Cost of Capital	1,853,785	100%		7.25

2006 Actual

	Dollars ($)	Ratio (%)	Rate (%)	Rate X Ratio /100 (%)
Debt				
Long-term	1,321,493	58.9	7.25	4.27
Short-term	360,727	16.1	7.25	1.17
Total Debt	1,682,220	75.0		5.44
Equity				
Common Equity	560,840	25.0	9.0	2.25
Preference shares	0	0		0
Total Equity	560,840	25.0		2.25
Weighted Average Cost of Capital	2,243,060	100%		7.69

2007 Bridge Year

	Dollars ($)	Ratio (%)	Rate (%)	Rate X Ratio /100 (%)
Debt				
Long-term	1,121,529	50.0	7.25	3.63
Short-term	0			
Total Debt	1,121,529	50.0		3.63
Equity				
Common Equity	1,121,529	50.0	9.0	4.50
Preference shares	0			

Total Equity	1,121,529	50.0		4.50
Weighted Average Cost of Capital	2,243,058	100%		8.13

2008 Test Year

	Dollars ($)	Ratio (%)	Rate (%)	Rate X Ratio /100 (%)
Debt				
Long-term	1,183,970	49.3	6.10	3.01
Short-term	96,062	4.0	4.47	0.18
Total Debt	1,280,032	53.3		3.19
Equity				
Common Equity	1,121,529	46.7	8.57	4.00
Preference shares	0	0		
Total Equity	1,121,529	46.7		4.00
Weighted Average Cost of Capital	2,401,561	100%		7.19

23. Ref: Exhibit 6 and Exhibit 7 – Weighted Average Cost of Capital
In Exhibit 6, in the table labelled "Calculation of Return on Equity and Debt", CPUC shows a Weighted Average Cost of Capital ("WACC") of 8.07%. In Exhibit 7, "Calculation of Revenue Deficiency or Surplus", CPUC shows the WACC as a "Required Return", but also shows an entry "Actual Return 10.08%". In a note at the bottom of the table, CPUC states "The Company requests that Net Utility Income be $132,222 or 10.8%".

a) Please confirm what WACC – 8.07%, 10.08% or 10.8% - CPUC is requesting in its Application.
b) If CPUC is requesting a WACC other than that calculated in Exhibit 6, taking into account any updated information provided in response to interrogatories:
   i) Please provide CPUC's detailed explanation for deviating from the Cost of Capital guidelines in the Board Report; and
   ii) Please calculate the Return on Equity that CPUC is proposing in order to achieve the proposed WACC. Please reconcile this ROE calculation with CPUC's response of interrogatory #22 above.
   iii) Please re-calculate the table in Exhibit 7 taking into account any updated information provide in response to interrogatories.

<u>Response</u>

a) ***In the original submission, CPUC is requesting a Weighted Average Cost of Capital of 10.08%.***
b) ***CPUC is requesting a WACC other than that calculated in our Exhibit 6.***
Due to updated information being made available the Company requests a WACC of 7.19% as calculated above in response to interrogatory # 22.
   i. ***The Company is not deviating from the Cost of Capital guidelines in the Board Report.***
   ii. ***The Return on Equity that CPUC is proposing to use is the updated ROE of 8.57%, from the January 2008 Consensus Forecasts, as per the Boards' letter of March 7, 2008, re: "Cost of Capital Parameter Updates for 2008 Cost of Service Applications".***
   iii. ***The company's Base Distribution Revenue Requirement and net Utility Income taking into account updated information is as follows:***

Proposed Rate Base		***$ 1,313,572***
Return on Rate Base at 7.25%		***$ 95,280***
Expenses		
Operations & Maintenance	***$ 366,697***	
Depreciation	***36,563***	
Administration	***201,125***	
Low Voltage Charge	***36,903***	***$ 641,288***
Sub Total		***$ 736,568***
Less Other Revenue		***$ 44,980***
Base Distribution Revenue Requirement		***$691,588***

The Company requests that Net Utility Income be $95,280 or 7.25%.

Load Forecasts

24. Ref: Exhibit 3/page 26 of 184
On page 26, CPUC provides a description for the development of its forecast: "Load Forecast was developed using actual consumption data. Normalization Methodology (weather) has not been applied to the data." No other textual information regarding the development of the forecast is

provided. An Excel spreadsheet containing the forecasting calculations is presented without description.

Ensuring that number of customers, kWh and kW forecasts are addressed, please provide a comprehensive description of the methodology and model CPUC employed to develop its forecast, identifying and rationalizing all assumptions made, explaining why no weather normalization was utilized, and referencing all data sources.

Response

Consumption forecast for Bridge Year (2007) was developed using actual data to May 2007 and the average of the previous two years from June to December.
Consumption forecast for Test Year 2008 was developed using the average data for 2006 (actual) and the new forecast data developed for Bridge Year 2007.
No other data from prior years was used due to the major reduction in consumption levels that occurred between 2002 and 2005 and eventually stabilizing in 2006.
The Company is comfortable that the data used reflects a realistic forecast of the 2008 consumption levels.

The Cost of Service Informational Filing showed that weather normalization impact on the 2004 actual data was minor by reducing actual consumptions by 1.0% (Actual kWh 31,492,664 and Weather Normalised kWh 31,162,261) and therefore does not warrant conversion of the 2008 forecast data.
The Company feels that the consumption data used to develop rates will very closely reflect Weather Normalized data rates.

25. Ref: Exhibit 3 (a)
In the Excel spreadsheet that forms Exhibit 3 (a), the Applicant presents a spreadsheet containing the forecasting calculations.

a) At cells C-E59 it states: “2008 estimates are the average of 2005/6/7” whereas at cell I-P109 it states: “2008 Forecast of Data is the average consumption level for 2006 and 2007 for all classes”. Please clarify this apparent contradiction.

b) Cells B56 and B73 identify “Adjustments”. Please explain what these adjustments are, how they are determined and the rationale for including them.

c) The number of customers forecasted for 2008 (e.g. cell C99) is calculated as the average number of customers for the two preceding years. Please provide the rationale for this assumption.

d) Cells R85-S99 presents the historical and forecast values for number of customers and kWh load.
   i. Please confirm that the 2002-2006 historical customer growth is about zero per annum,
   ii. Please confirm that the 2006-2008 forecasted customer growth is about -0.3% per annum,
   iii. Please confirm that the 2002-2006 historical kWh load growth is about -4.2% per annum,
   iv. Please confirm that the 2006-2008 forecast kWh load growth is about 0.4% per annum,
   v. Please rationalize how a historic zero customer growth drove a negative load growth whereas a forecast negative customer growth is expected to drive a positive load growth, and
   vi. Please identify the anticipated events that are expected to drive the reversal noted in v. above.

Response

a) ***The statement at cell C-59 should have read "2008 estimates are the average of 2006/7".***

b) ***The explanation for these adjustments was given in cell I-117 under item 5 which states: "Customer transfers: 1 from GS <50kW to GS >50kW and 1 from GS >50kW to GS <50kW - Data adjusted for 2007 and 2008".***

In 2007, in preparation for this rate submission, it was identified that there should have been 2 customer transfers in 2007 as identified above. The 1st customers' kW consumption averaged over 50 kW/Month and the 2nd customers' kW consumption averaged less than 50 kW/Month and therefore necessitated the transfer of consumptions between the classes.

In order to reflect more realistically the customer class consumptions and revenues for 2007 and 2008 the following adjustments were made to both years:

	GS < 50kW			GS >50 kW		
Customer	***kWh***	***kW***	***Ave. kW/Mth***	***kWh***	***kW***	***Ave. kW/Mth***
1	***(194,820)***	***(693)***	***57.75***	***194,820***	***693***	***57.75***
2	***147,540***	***424***	***35.33***	***(147,540)***	***(424)***	***35.33***
Net Adjustment	***(47,280)***	***(269)***		***47,280***	***269***	

c) ***The number of customers forecasted for the Residential class should have been the same as the 2007 (1,164). There is no rationale for using the average for the two preceding years. The number of customers, of 1,164, will be adjusted in the rates calculations.***

d) ***i. The 2002-2006 historical customer growth is about zero per annum.***
ii. The 2006-2008 forecasted customer growth is about -0.3% per annum.
iii. The 2002-2006 historical kWh load growth is about -4.2% per annum.
iv. The 2006-2008 forecast kWh load growth is about 0.4% per annum.
v. The historical customer growth per annum of zero and the increase in forecasted load growth is due to the use of average consumptions of 2006 and 2007. It must be noted that this is a very minor growth that represents an average increase per customer of 11.4 kWh (10.9 kWh for residential) per month and should not warrant further consideration.
vi. No comment. Please see response to v. above.

Loss Factors

26. Refs:
    i. Exhibit following Exhibit 8 (b), Excel file tab "2008 Tariff Sheet", Tariff of Rates and Charges - Effective May 1, 2008
    ii. EB-2007-0515, Tariff of Rates and Charges - Effective May 1, 2007
    iii. EB-2005-0349, Tariff of Rates and Charges - Effective May 1, 2006
    iv. Exhibit 3 (a), Excel file tab "Exhibit 3 (a) Op. Rev.", Section on "Loss Factor Calculation" and "Notes to this Page"

The 1st, 2nd and 3rd references respectively provide total loss factors (TLF) for 2008 (proposed), 2007 (approved) and 2006 (approved). The 4th reference provides loss factor calculations and info on mitigating measures.

With respect to CPUC's proposal of a TLF for Secondary Metered Customer < 5,000 kW of 1.0613 for 2008 in the 1st reference:

a) Please provide the distribution loss factor (DLF) and corresponding Supply Facility Loss Factor (SFLF).

b) Please provide details of the calculation used to obtain the DLF value, for example by showing data for each year 2004 – 2006 in the framework of the 2006 EDR Handbook Schedule 10-5.

c) Please explain why the proposed TLF is significantly higher than the TLF of 1.0497 in both the 2nd and 3rd references for 2006 and 2007 respectively.

d) Pease provide information on measures (other than the planned investment of $23,500 for the replacement of conductors in 2007 mentioned in the 4th reference) that CPUC intends to take to bring about a reduction in losses.

<u>Response</u>

a) The Distribution Loss Factor (DLF) is 1.0565 and corresponding Supply Facility Loss Factor (SFLF) is 1.0045.

b) The Distribution Loss Factor of 1.0565 was calculated using the average of 5 years 2003 to 2007. To calculate the DLF in the framework of the 2006 EDR Handbook Schedule 10-5, the result will be as follows:

		2004	2005	2006
A	Wholesale kWh (IMO)	32,654,946	31,058,652	29,569,274
B	Wholesale kWh for Large Use customers (IMO)	0	0	0
C	Net wholesale kWh (IMO) (A)-(B)	32,654,946	31,058,652	29,569,274
D	Retail kWh (Distributor)	30,980,687	29,014,570	27,963,997
E	Retail kWh for Large Use customers (1% loss)	0	0	0
F	Net Retail kWh (D)-(E)	30,651,703	29,014,570	27,963,997
G	Loss Factor (C) / (F)	1.0540	1.0705	1.0574
H	Distribution Loss Adjustment Factor (3 Year Ave.)			1.0606

The DLF as calculated of 1.0606 will be used to adjust the rate submission.

Please note that the Retail kWh used for 2004 in the EDR Handbook Schedule 10-5 of 30,651,703 have been adjusted in the above calculation to 30,980,946.

c) The proposed TLF of 1.0606, as calculated above, is significantly higher than the TLF of 1.0497 in both the 2nd and 3rd references for 2006 and 2007 respectively because of errors that occurred in the recording of the 2002 and 2003 kWh with loss factors of 1.0352

and 1.0346 respectively. The loss factors identified for 2002 and 2003 are too low to be realistic as CPUC is an embedded utility with losses being applied from Hydro One Networks Inc., through the IMO, of 1.0350 and therefore losses recorded in the EDR Handbook Schedule 10-5 were wrong. No effort will be made to correct this.

d) CPUC is also proposing additional measures to bring about a reduction in losses (as identified in our original submission, Exhibit 4 page 29) to purchase and install 2 Capacitors at a cost of $10,000.00, under the CDM program, and to make contact with the larger commercial customers, in the >50kW class, who's power factors requires improvement, to offer advice and education as to the various methods on how to improve their power factor and reduce their own consumptions and costs.

Low Voltage Wheeling Cost

27. Ref: Exhibit 9/Section 5 (page 43), and Exhibit 1/Pro Forma Operating Statements (page 145 of 184)
Low Voltage Revenue and Charges are shown as $0 for 2006 and 2007, with the forecast for 2008 as $36,947 in Exhibit 1.
    b) Please explain how the forecast amount for 2008 has been derived, and if possible please provide the billing quantities and amounts that have been paid to the host distributor for each LV service (eg. Shared Line, Shared DS, etc) during 2006 and 2007.
    c) Please provide the amounts that are allocated to each rate class in 2008, including an explanation of the basis for these amounts.

Response

b) The forecast amount for 2008 was derived from the actual historical data that was available at the time of the original submission that included the actual from July 2006 to September 2007. The forecast amount therefore was taken from the latest actual charges from October 2006 to September 2007 being $36,947.

The billing quantities are as follows:

	Shared Line		***Shared D/S***		***Total***
Month	***Quantity***	***$ Amount***	***Quantity***	***$ Amount***	***$ Amount***

	kW		kW		
October '06	***214.81***	***135.33***	***934.02***	***1,559.81***	***1,695.14***
November	***194.88***	***122.78***	***1,384.37***	***2,311.90***	***2,434.68***
December	***168.62***	***106.23***	***1,672.56***	***2,791.51***	***2,897.74***
January '07	***153.0***	***96.39***	***1,855.45***	***3,098.60***	***3,194.99***
February	***155.61***	***98.03***	***2,174.16***	***3,630.85***	***3,728.88***
March	***155.91***	***98.22***	***2,467.02***	***4,119.92***	***4,218.14***
April	***163.66***	***103.10***	***2,693.61***	***4,498.33***	***4,601.43***
May	***157.64***	***99.31***	***2,505.99***	***4,185.00***	***4,284.31***
June	***148.37***	***93.47***	***2,037.60***	***3,402.79***	***3,496.26***
July	***195.82***	***123.88***	***1,331.36***	***2,232.69***	***2,356.57***
August	***206.17***	***130.51***	***1,183.58***	***1,986.04***	***2,116.55***
September	***207.81***	***131.55***	***1,066.94***	***1,790.32***	***1,921.87***
Total	***2,122.31***	***1,338.80***	***21,306.66***	***35,607.76***	***36,946.56***

c) The total amount of $36,947 was allocated on the basis of the total kWh per class for 2008 and determined the kW and kWh rate, by dividing the kW or kWh into the $ amount allocated to each class, as follows:

	2008 kWh	Allocation %	Allocation $	2008 kW	Proposed Rate
Residential	***14,611,894***	***51.81***	***19,143.22***	***0***	***0.0013/kWh***
GS <50kW	***5,492,773***	***19.48***	***7,196.15***	***0***	***0.0013/kWh***
GS <50kW	***7,770,248***	***27.55***	***10,179.90***	***21,169***	***0.4809/kW***
Un metered Scattered Load	***6,991***	***0.02***	***9.16***	***0***	***0.0013/kWh***
Sentinel Lights	***23,871***	***0.08***	***31.27***	***66***	***0.4738/kW***
Street Lights	***295,064***	***1.05***	***386.57***	***780***	***0.4956/kW***
Total	***28,200,840***	***100.00***	***36,946.56***	***22,015***	

The above Low Voltage rates have not been used in the above format. The total cost of $36,947 has been included with the distribution expenses of $641,288, in the excel worksheet "Exhibit 2 Rate Base", that determined the Company's Revenue Requirement.

Cost Allocation

28. Please file the "rolled-up" version of Run 2 of the Informational Filing EB-2007-0001 as an official part of the record of this Application. (The hard

copy reply needs to include only the input tables Sheets I3 – I 8 and output tables O1 and O2.)

To calculate revenue to cost ratios that would be applicable to the test year,

a) Please provide a table that shows
   - Column a), the proposed customer rate classes,
   - Column b), the class revenue requirements in the informational filing, (Worksheet O1, row 35), expressed as a percentage of the total revenue requirement,
   - Column c), a calculation of the 2008 revenue requirements from distribution rates (e.g. revenue requirement net of revenue from specific service charges times the percentages calculated in column b),
   - Column d), the proposed revenue at proposed rates per Exhibit 9 / page 43 / second column in the second table
   - Column e), the ratio of column c) to column d)

b) Please provide any comments on whether the ratios calculated in column e) are reasonably valid indications of class revenue to cost ratios that the Board could use with reference to the Board report "Cost Allocation for Electricity Distributors", November 28, 2007. If any of the calculated ratios are not reasonable, please explain why they are too high or too low.

<u>Response</u>

Hard copy input tables Sheets I3 – I 8 and output tables O1 and O2 are in Appendix F.

a) Table prepared as requested.

(A) Customer Rate Class	*(B) Revenue Requirement*	*(C) 2008 Revenue Requirement*	*(D) Proposed Revenue*	*(E) Ratio (C) to (D)*
Residential	*63.20%*	*$ 597,443*	*$ 598,982*	*99.74*
GS <50kW	*20.13%*	*190,293*	*186,053*	*102.28*
GS <50kW	*10.84%*	*102,473*	*145,219*	*70.56*
Un metered Scattered Load	*0.33%*	*3,119*	*1,547*	*201.62*
Sentinel Lights	*0.39%*	*3,687*	*1,834*	*238.33*
Street Lights	*5.11%*	*48,306*	*11,685*	*413.40*
Total	*100.00%*	*$ 945,321*	*$ 945,321*	*0.00*

b) Please note that the revenue of $945,321 in columns (C) & (D) excludes revenue from specific service charges, but is inclusive of all other charges (Transmission, LV, WMS, etc.)

and therefore cannot be compared with the revenue requirement from worksheet O1, row 36.

29. Ref: Exhibit 8/page 35-36
The Informational Filing showed (first table, p. 35) that five classes were under-contributing. In the proposed changes (first table, p. 36) it is proposed that two of the classes would be adjusted by an amount more than their respective under-contribution, whereas three of the classes are adjusted by an amount less than their under-contribution. Notably, streetlights are shown as under-contributing by $27,226 and the adjustment upward is only $3500. Please provide the rationale for the different treatment of the various rate classes.

Response

The Informational Filing on page 35, first table, shows that five classes were under-contributing is based on a lower revenue requirement of $644,385 than that shown in the proposed changes (first table, page 36) of $688,519 therefore the proposal that two of the classes would be adjusted by an amount more than their respective under-contribution is correct.
Special consideration should be given to Street Lighting, Sentinel Lighting and Unmetered Scattered Load classifications because in the cost allocation study, a street light or sentinel light connection is equivalent to a customer and therefore costs allocated are based on 780 and 66 connections respectively which is the biggest driver that caused the results for these classes. This can be argued that a street light is like any other appliance or light in a home. It just happens to be outside on the street. In this case, a street light would be incremental load much like a stove or refrigerator and it would attract very little customer costs if any at all.
In CPUC's view, this is an issue that needs to be discussed further with the OEB and other market participants. As a result, changes should not be made fully to Street Lighting or Sentinel Lighting or Unmetered Scattered Load revenue pricing until this issue has been resolved.
Based on the above rationale it was felt that a portion of the under contribution will be applied to these customer classes so as to not exceed the 10% threshold.

Rate Design

30. Ref: Exhibit 9/section 5 (page 43), and section 6 (pages 43 – 46)

Volumetric Rates: In section 5 (second table, final column) the percentage increase in revenue from volumetric charges is shown as 17.4%. However, in the detailed tables in section 6, the percentage increases in the volumetric charges range from 21.0% for Residential up to 102% for GS>50 kW and 103.9% for Streetlighting. Since the overall percentage should be a weighted average of the detailed percentages, it is apparent that some cost component(s) are missing from the overall figure.

a) Please confirm whether the rate adder for LV costs is included in both percentages, or only the detailed percentages.
b) Please provide information on any other cost components that contribute to the discrepancy.

Response

a) In section 5 (second table, final column) the percentage increase in revenue from volumetric charges is shown as 17.4% representing the increase for all customer classes before the addition of the Low Voltage charge, whereas the detailed tables in section 6, the volumetric charge is inclusive of the Low Voltage rate.
To properly compare the increase in revenue, the volumetric charge should also include the Low Voltage charge as illustrated below with a partial table from page 35:

	2007 Total Revenue $	2008 Total Revenue $	Revenue Change $	Percent Change
Rate Base - Volumetric charge	220,513	258,790	38,278	17.4%
Low Voltage Rate	0.0	36,903	36,903	N/A
TOTAL	220,513	295,693	75,181	34.1%

The percentage increase for comparison is therefore 34.1%.

b) There are no other cost components that contribute to the discrepancy.

31. Ref: Exhibit 9/Existing Rate Schedule (page 38) and Proposed Rate Schedule (page 41)
Retail Transmission Service Rates: In light of the relatively small decrease in the wholesale rate for Line and Transformation Connection and also in

the decrease being proposed by the host distributor HONI, please explain why the Applicant is proposing such large decreases in the Retail Transmission Service Rate (eg from $0.0050 to $0.0019 per kWh for the Residential class).

Considering the decrease in the proposed Retail Transmission Service rates and the decreases in the regulatory asset rate rider for all classes, please confirm that the proposed decreases are correct, eg that there is no double counting of a variance account or a forecast decrease in some element of cost.

Response

The Retail Transmission Connection Service Rate was a major concern for CPUC as the revenue always exceeded the costs from HONI by approximately a 3 to 1 ratio as illustrated in our original submission in the excel worksheet "Exhibit 5(b) RSVA accounts". From 2003 to the (Forecast) Test Year 2008, over-collections have been averaging at approximately $96,000 per year. In the Company's 2006 EDR submission, the Company requested an adjustment to the transmission rates, but, due to the potential cash flow problems that this would cause, the request was not approved.
The decreases will be adjusted to reflect the new uniform Transmission Rates for Ontario Transmitters, effective November 1, 2007 as per the Board's EB-2007-0759 Rate Order approving reductions to the wholesale transmission network rate by 28% and the combined change in the wholesale transmission line connection and transformation connection rates by 5%. The Retail Transmission Network and Connection Service Rates have been adjusted in exhibit 5 (a and b) to reflect the above rate reductions.
The proposed decreases are correct, and that there is no double counting of a variance account or a forecast decrease in some element of cost.

32. Ref: Exhibit 9/section 6 (pages 43-46)
<u>Wholesale Market Service Rates</u>: Please provide the cost basis for proposing to decrease the Wholesale Market Service Rate from $0.0052 to $0.0041 per kWh for each class.

Response

The following partial table was taken from our original submission illustrated in the excel worksheet "Exhibit 5(b) RSVA accounts" for the Wholesale Market Service Rate which is inclusive of the Rural Rate. Actual billings and cost was available to September 2007.
Forecast for the balance of the Bridge Year (2007) was developed using the actual data to September 2007 and the average of the previous two years from October to December.
Forecast for Test Year 2008 was developed using the average data for 2006 (actual) and the new forecast data developed for Bridge Year 2007.

	2006	***2007***	***2008***
Cost	***154,627.78***	***152,307.76***	***A 153,467.77***
Revenue	***186,803.07***	***184,401.64***	***B 185,602.36***
Variance	***(32,175.29)***	***(32,093.88)***	***(32,134.59)***

The rate was determined as follows: A/B x$ 0.61= $0.51.
The new combined rate for Wholesale Market Service Rate for all customer classes is $0.41 and Rural Rate is $0.10.

Deferral and Variance Accounts

33. Ref: Exh 3/Sch 1 & 2
    a. Please explain why the net income related to the 2006 historical actual shown in the pro forma operating statements differs from the 2006 net income shown in the 2006 audited financial statements.
    b. Explain why there is a decrease in net income for 2007 as shown in the 2007 pro forma operating statements.
    c. Are there any reconciling items pertaining between the audited financial statements and the Reporting and Record-Keeping Requirements? If so, please provide a schedule detailing and explaining these differences.

Response

a.&b. Explanation of the 2006 Actual Net Income between the 2006 Audited Financial statements and the Pro Forma operating statements.
Please note that Energy Sales and Power Purchased is not included in Pro Forma Statements.

Detail	Audited Financials	Pro Forma Statements	Adjustment Required	Explanation
Energy Sales	$2,089,075	0	($45,642)	ITEM 1 Energy Sales includes Regulatory Asset Variances. This will be adjusted in Audited Financials as a Prior Year Adjustment.
Distribution Revenue	$567,925	$567,927	0	
Retailer Charges	0	$1,382	($1,382)	ITEM 2 Retailer Charges duplicated in Pro Forma (included in DX Revenue)
Misc. (Other) Revenue	$34,500	$42,657	$8,158	ITEM 3 Audited Financials Prior Year (2005) Debit Adj. of $8,158 in Other Rev.
Sub Total	$2,691,500	$611,964		
Power Purchased	$2,043,433			Please see ITEM 1.
Operations and Maintenance	$262,647	$262,647	0	
Admin & Gen.	$164,663	$164,521	$142	ITEM 4 Office Supplies understated in Pro Forma
Bill. & Coll.	$63,918	$63,918	0	
Amortization	$37,370	$37,370	0	
Net Income	$119,469	$83,508	0	
Adjustments ITEM 1 2 3 4	 ($45,642) 0 $8,158 	 0 ($1,382) 0 ($142)		
Adj. Net Income	$81,985	$81,984		

c. Items 1 and 3 above pertain to reconciling items between the Audited Financial statements and the Reporting and Record-Keeping Requirements.

34. Ref: Exh 5/Tab 1/Sch 1/Exh 5(c)
CPUC is requesting disposition of regulatory variance accounts in Exhibit 5 (c). The totals in the exhibit do not agree to totals reported to the Board as per 2.1.1 of the Reporting and Record Keeping Requirements for the period ending December 31, 2006. Please provide the information as shown in the attached continuity schedule [2008 Regulatory Assets Recovery Worksheet] for regulatory assets and provide a further schedule reconciling the continuity schedule with the amounts requested for disposition on Exhibit 5 (c). Please note that forecasting principal transactions beyond December 31, 2006 and the accrued interest on these forecasted balances and including them in the attached continuity schedule is optional.

Response

The continuity schedule for the 2008 Regulatory Assets Recovery Worksheet has been completed and is included with this submission as Appendix I. 2.1.1 of the Reporting and Record Keeping Requirements for the period ending December 31, 2006 that is reported at the end of January 2007 does not have all year end adjustments. Trial Balance that is reported at the end of April has all adjustments.

During completion of the continuity worksheet, it was identified that various adjustments were required to be made as follows:

An adjustment was made by the CPUC's auditors at year end 2006 in account 1525 Misc. Deferred Debits cell T32 for a credit of $903.98 to clear this account to $0.00 and debited account 5665 Misc. General Expense. No impact to disposition of regulatory assets.

A debit adjustment of $3,294.24 was made in 2007 by management in account 1590 Recovery of Regulatory Asset Balances cell AA59. This was to adjust an error made in 2006 in cell X59.

A debit adjustment of $53,513.82 was made in 2007 by management in account 1590 Recovery of Regulatory Asset Balances cells AD59 for $48,537.68 (Principal) and AF59 for $4,976.14 (Interest) to transfer the recoveries of Conservation and Demand Management Expenditures that were recorded in error. Corresponding credits were made to cells AD38 and AF38.

An adjustment was made in 2006 by management to credit $1,659.50 in account 1508 Other Regulatory Assets - Sub-Account - OEB Cost Assessments cell T25 and charged to account 5655 Regulatory Expenses. Applicable interest was also adjusted in cell AF25 for $76.78 credit and debit account 4405 Interest Earned.

Adjustments were made to account 1508 Other Regulatory Assets - Sub-Account - Pension Contributions in 2006 for a credit of $12,936.78 for 2005 and a credit of $13,727.10 for 2006 in cell T26. An interest adjustment was also made for a credit of $241.00 in cell AF26 and debit account 4405 Interest Earned.

Reconciliation - Principal Amounts to December 31, 2006.

Account	Continuity Schedule	Amount Requested	Variance	Explanation
Wholesale Market Service	(23,259)	(23,259)	0	
Transmission Network	(28,448)	(28,448)	0	
Transmission Connect'n	(160,924)	(160,924)	0	
OEB Cost Assessment	3,508	3,827	(319)	J. E. adjustment not picked up
Pension Contributions	17,323	17,323	0	
Low Voltage Variance	13,195	13,195	0	
Cost of Power	(39,330)	(39,330)	0	
Smart Meters	(2,419)	(2,419	0	Not included in disposition
CDM Expenditures and Recoveries	3,960	3,960	0	Not included in disposition
Recovery of Regulatory Asset Balances	(10,617)	(10,617)	0	
Total	(227,011)	(226,692)	(319)	

The amounts shown in the continuity schedule are the correct amounts. Amounts for disposition have been adjusted to reflect the continuity schedule amounts.

Reconciliation - Interest Amounts to December 31, 2006.

Account	Continuity Schedule	Amount Requested	Variance	Explanation
Wholesale Market Service	(2,690)	(2,509)	(181)	
Transmission Network	2,709	2,679	30	
Transmission Connect'n	(36,420)	(33,382)	(3,038)	
OEB Cost Assessment	251	229	22	
Pension Contributions	927	927	0	
Low Voltage Variance	119	119	0	

Cost of Power	5,349	5,380	(31)	
Smart Meters	(51)	(51)	0	Not included in disposition
CDM Expenditures and Recoveries	189	189	0	Not included in disposition
Recovery of Regulatory Asset Balances	(27,614)	(27,614)	0	
Total	(57,231)	(54,033)	(3,198)	

The amounts shown in the continuity schedule are the correct amounts. Amounts for disposition have been adjusted to reflect the continuity schedule amounts.

Reconciliation - Closing Amounts for Disposition to April 30, 2008 (before forecasted transactions).

Account	Continuity Schedule	Amount Requested	Variance	Explanation
Wholesale Market Service	(27,372)	(27,372)	0	
Transmission Network	(27,480)	(27,480)	0	
Transmission Connect'n	(207,193)	(207,193)	0	
OEB Cost Assessment Adjustment	3,973 (77)	3,896	0	
Pension Contributions Adjustment	19,310 (241)	19,069	0	
Low Voltage Variance	14,121	14,121	0	
Cost of Power	(36,389)	(36,389)	0	
Smart Meters	(2,618)	0	(2,618)	Not ready for disposition. Additional charges still to come in 2007 and 2008.
CDM Expenditures and Recoveries Adjustment Adjustment	4,391 (48,538) (4,976)	0	(49,123)	Adjustments made to correct error. Not ready for disposition. Additional charges still to come in 2007 and 2008.
Recovery of Regulatory Asset Balances Adjustment Adjustment	(35,586) 48,538 4,976	17,928	0	Adjustments made to correct error.
Total	(295,161)	(243,420)	0	

Exhibit 5 (c) has been adjusted to reflect the amount for disposition, being a refund to customers, for ($243,420) as per the above table.

35. Ref: Exh 5/Tab 1/Sch 2
In this exhibit, the account numbers do not match the appropriate account names (e.g. account 1586 is identified as RSVA Power). Please provide a brief description of each of the deferral and variance accounts used by CPUC with the correct account number.

Response

Description of Deferral and Variance accounts:

Account Number	***Description***
1580	***RSVA - Wholesale Market Service Charge***
1584	***RSVA - Retail Transmission Network Charge***
1586	***RSVA - Retail Transmission Connection Charge***
1550	***Low Voltage Variance Account***
1508	***Other Reg. Assets – Sub-Account - Pension Contribution***
1508	***Other Reg. Assets – Sub-Account - OEB Cost Assessment***
1555	***Smart Meter Capital & recovery Offset Var. – Sub-A/c - Recoveries***
1565	***Conservation & Demand Management Expenditures and Recoveries***
1588	***RSVA – Power (including Global Adjustment)***
1588	***RSVA – Power – Sub-Account - Global Adjustment***
1590	***Recovery of Regulatory Asset Balances***

36. Ref: Exhibit 2
   a. Is CPUC using the Board-prescribed interest rate, as per the Board's letter to LDCs dated November 28, 2006, for construction work in progress (CWIP) since May 1, 2006?
   b. If not, what interest rate has LDC been using for CWIP?
   c. If not using the Board-prescribed interest rates, what would the impact on rate base, revenue requirement, and CWIP be if the LDC did use the prescribed interest rates?

Response

CPUC does not have construction work in progress (CWIP).

37. Ref: Exh 5/Tab1/Sch2/Pg1&2
   a. Is CPUC currently using account 1590?
   b. If not, why?
   c. If so, has CPUC transferred previous 2006 EDR Board-approved amounts for regulatory asset recovery to 1590, as instructed in the

Board's letter dated November 28, 2006? When did CPUC do this transfer?

d. Please update Exhibits 5 (a, b, c) if necessary, to reflect the appropriate transfers and include account 1590.

Response

a. ***Yes - CPUC is currently using account 1590.***

c. ***As instructed in the Board's letter dated November 28, 2006, CPUC has transferred previous 2006 EDR Board-approved amounts for regulatory asset recovery, to account 1590, at December 31, 2006 (year end).***

d. ***Exhibits 5 a, b and c have been updated to reflect the appropriate transfers including account 1590.***

38. Ref: Exh5 (a), (b) & (c), Exh 5/Tab1/Sch3

a. For low voltage costs from Hydro One, what account did CPUC use before May 1, 2006? After May 1, 2006?

b. LV charges were applied to the 2006 EDR rates as per the 2006 EDR final model at Tab 7-2 Allocation LV Wheeling. This means that part of the revenue collected from customers should be allocated to account 4075 LV Charges instead of 4080 Distribution Revenue. Why did CPUC not allocate part of its distribution revenue to account 4075, LV Charges which would impact account 1550?

c. In its 2006 EDR decision for CPUC, the Board approved LV charges. Why does CPUC indicate that LV charges were not applied to the 2006 EDR rates as per Exhibit 5/Tab1/Schedule 3?

Response

a. ***Prior to May 1, 2006 CPUC used account number 2405 (Other regulatory liability) for Low Voltage charges from Hydro One. The first monthly billing after May 1, 2006 was in July 2006 and was applied to account 1550.***

b. ***CPUC did not apply any Low Voltage charges to the 2006 EDR rates and therefore did not collect revenue from customers. Please refer to the approved EDR model.***

c. ***Please see response to (b) above.***

39. Ref: Exh5/Tab1/Sch6
CPUC is proposing to refund the deferral and variance accounts to customers over a period of 4 years, beginning May 1, 2008 and ending April 30, 2012.
    a) What is the regulatory precedent for having a greater than three year period for the rate riders, seeing the company will be rebased in 2011?
    b) Why is the company suggesting that refunding deferral and variance accounts over less than four year period will place the company in financial risk when it is projecting to hold more than $400,000 in cash as per Exhibit 1, Pro Forma Operating Statements, page 23?
    c) What would be the impact the company refunding the balance over a three year period?
    d) Please provide a schedule showing the calculation of the rate riders assuming that the deferral and variance accounts are refunded over a three year period.

Response

CPUC will refund the deferral and variance accounts, as indicated in the response to interrogatory #40, over a three year period thereby reducing the annual amount of refund from $101,023 to $81,140.

a. ***There is no regulatory precedent.***
b. ***This is no longer a concern for CPUC.***
c. ***This is no longer a concern for CPUC.***
d. ***The schedule showing the calculation of the rate riders to refund deferral and variance accounts over a three year period is shown in "Exhibit 5(c) Regulatory Assets" line 44.***

Please note that changes, as identified in the above responses to interrogatories 34, 37 and 40 have been applied to this schedule.

40. Ref: Exh 5 c)
Usual practise in the electricity sector is to use audited numbers for the last fiscal year as the basis for balances in the deferral and variance accounts for disposition, with interest forecasted up to the start of the new rate year. Please provide the rationale for principal transactions being forecast beyond December 31, 2006.

Response

There was no rationale for principal transactions being forecast beyond December 31, 2006. CPUC felt this was the requirement of the OEB to forecast all transactions for disposition to April 30, 2008. Based on the requirement that CPUC does not have to forecast principal transactions to April 30, 2008, and as these principal transactions will reduce the amount for disposition (refund to customers), the Company will refund the December 31, 2006 variance account balances over a three year period instead on four as originally requested.
This response affects responses to interrogatories 34, 37 and 39.

Specific Service Charges

41. Ref: Exhibit 3, Other Revenue
Page 24 states as follows:

> "Specific Service Charges for 2006 and part of 2007 were not always collected. As of August 2007 the Board of Directors of the Company authorized staff to collect all Specific Service Charges. For the 2007 Test Year, full collection of fees beginning in August will be made except for Arrears Certificate."

a) Please explain why Specific Service Charges for 2006 and 2007 were not always collected.

b) Please provide a more detailed explanation as to why collection of the Arrears Certificate charge did not begin in August 2007. Please state whether CPUC intends to apply for the discontinuance of this charge and if not, why not.

Response

a. Specific Service Charges for 2006 and 2007 were not always collected due to difficult economic conditions being experienced by the residents of the Township of Chapleau.
b. The collection of the Arrears Certificate charge did not begin in August 2007 because this charge can no longer be applied to the Municipal tax-roll and therefore the lawyer (only one in town) no longer applies for an Arrears Certificate.
CPUC will not apply for the discontinuance of this charge at this time. Consideration will be given at the next rate submission.

42. Ref: Exhibit 9, Pages 39 & 42
In the 2006 Board Approved Tariff of Rates and Charges, it is shown that the "Disconnect/Reconnect at meter – during regular hours" charge is $65.00. In the 2008 Proposed Rate Schedule page 42, the charge is $60.00. Please state whether CPUC is applying to amend this charge and if so, please provide the rationale for the proposal to reduce this charge.

Response

In the 2008 Proposed Rate Schedule page 42, the charge shown for "Disconnect/Reconnect at meter – during regular hours" as $60.00 is a typographical error the correct amount is $65.00.

Smart Meters

CPUC 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 CPUC's 2007 IRM application (EB-2007-0515), the Board confirmed its understanding that CPUC would not be undertaking any smart metering activity (i.e. discretionary metering activity) in 2007.

43. Ref: Exhibit 1/Tab 1/Sch 6
On page 13, CPUC states that it "has not included in the application any costs related to Smart Metering because the Company has not yet filed with the Board its application for the Smart Metering Investment Program. At the present time Chapleau Public Utilities Corporation has approval to charge $0.26 per metered customer. 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."

a) Please confirm if any costs have been incurred by CPUC 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) Please confirm that, in Test Year 2008, CPUC is applying to maintain its current rate adder which was approved by the Board in the April 12, 2007 Decision and Order (EB-2007-0515). If not,
   i. What is the Smart Meter Rate Adder CPUC is intending to implement in Test Year 2008?

ii. Please provide justification for the amount of this Smart Meter Rate Adder and explain fully how the new amount for Smart Meter Rate Adder was determined.

Response

a) Chapleau PUC has not been authorized to undertake smart meter installations.
Chapleau PUC is a member of the Northeast Ontario utilities working group (referred to in some documents as District 9) who are working together to meet the government mandate of smart meter installations by the end of 2010. The District group through its consultant is participating as an observer in the London Hydro Smart Meter RFP process. The Ministry of Energy has been informed of the status and approach by the Northeast utilities with respect to smart meters. The Assistant Deputy Minister, Consumer and Regulatory Affairs, has provided correspondence dated December 21, 2007, that the Ministry of Energy will recommend to Cabinet an amendment to O. Reg. 427/06 to accommodate London Hydro and consortium members as well as any other LDC's outside the consortium (CPUC as part of the District 9 group) that have chosen to participate in the process (Letter attached as Appendix C). Subject to the evaluation process and negotiations with the AMI vendors and installation vendors, Chapleau PUC is tentatively scheduled to commence with implementation spring of 2009.

i) Chapleau PUC has incurred costs with respect to the smart metering initiative. Chapleau PUC incurred $7,468.46 for consulting fee's in 2007 that was charged to our CDM Plan and $2,282.89 to date in 2008 for consulting fee's that were charged to our variance account to be offset by the smart meter rate adder of $0.26.

II) Chapleau PUC has not installed any smart meters.

b) Recovery of Smart Meter costs.

It is imperative that the Board considers the recovery of operating and capital expenditure costs that will soon become a burden on the utility if left unattended.
It is expected that CPUC expenditures over the next 3 years will be as follows:

	Operating Cost	Capital Cost
2008	$3,197	$29,361
2009	$96,077	$528,639
2010	$131,104	$44,834
	$230,378	$602,834
3 Year Average	$76,793	

CPUC is proposing to increase the Smart Meter rate as follows:

For capital expenditures the current smart meter rate adder of $0.26 to be increased to $1.50 per month and for the recovery of operating expenditures set up a rate rider for a period of 3 years for $4.76 per month (monitored through a variance account) per metered customer calculated as follows:

Capital Expenditure.
Depreciation of 4% on total meter capital expenditure of $602,834 is $24,113 divided by the 2008 metered customer count of 1,344 is $1.50 per month.

Operating Expenses.
Divide the 3 year average of $76,793 of operating cost by the number of metered customers of 1,344 is $4.76 per month.

CPUC has not included the above increases to the Rate schedule.

CPUC requests that the Board consider the approval of the above Smart Meter Rate(s) or to a comparable rate

that will cover the expected capital and operating expenditures over the next 3 years.

Conservation and Demand Management (CDM)

44. Ref: Exhibit 4 and Appendix D
CPUC is requesting $10,000 as part of its CDM plan to install capacitors to reduce line losses.

   a) Please provide a detailed discussion on what plans were in place to reduce line losses prior to the decision to install the capacitors.

   b) Why does CPUC consider the installation of capacitors to be a CDM program, as opposed to being part of overall infrastructure investment?

   c) In addition to the $10,000 under the CDM program, CPUC has requested $23,500 in capital expenditures to improve voltages. On what basis has CPUC made this distinction between capital expenditures, and CDM expenditures?

   d) What differential rate treatment does CPUC expect between the $10,000 requested under the CDM program for capacitor installation, and the $23,500 requested as capital expenditures for voltage improvement?

   e) Appendix D refers to Appendices 1 – 4, however these appendices do not appear to be included as part of CPUC's application. Please provide Appendices 1 – 4.

Response

a. CPUC's original plan was to hire a consultant to do a study on how CPUC could reduce system losses and optimize performance of our distribution system. CPUC engaged Enerspectrum Group to propose a process to study and identify where system losses exist and improvements to the distribution system that will reduce and improve our system. The study was completed and was included in our original application. From this report it was determined that installing 2 sets of capacitor banks would help our load loss. CPUC requested from the Board an extension of the completion date for incremental third tranche CDM expenditures from September 30, 2007 to April 30, 2008 and to reallocate a total of ($10,000) from its Smart Meter Study to its System

Improvement program in order to reduce system losses and help improve system power factors. The Board approved the deadline extension and the reallocation of funds on October 31, 2007.

b. ***CPUC considers the installation of capacitors to be a CDM program because the installation of capacitors will reduce reactive load on the system reducing line losses and improving overall system power factor.***

c. ***The study undertaken by CPUC "System Analysis for Loss Optimization" is broken into two phases. Phase 1 is phase balancing and voltage regulation, which will bring the system to CSA voltage levels. This phase requires the installation of 3 regulators at a cost of $23,500 in capital expenditures. This phase will not lower line losses, therefore not a CDM program.***

a. ***CPUC's intent was to put the $10,000 for capacitors into CDM expenditures because the capacitors are to improve line losses and as indicated in (c) above took the required action to improve voltage levels to CSA specifications. The rate treatment under CDM is that expenditures up to $43,807.27 (3rd tranche of MARR) have already been included in the 2005 Rate Adjustment and capital expenditures are part of the Company's Rate Base.***

b. ***Appendices 1 to 4 in EneSpectrum Group's report, at the bottom of the 2nd page, that are missing from the report are as follows:***

Appendices 1 and 2 are maps of CPUC's distribution system that are too bulky to include (size 3 feet by 4 feet) with the report.

Appendices 3 and 4 are attached as Appendix D.

45. Ref: Exhibit 4, page 29
CPUC indicates that the cost of purchasing and installing 3 regulators is $23,500, however in Appendix D CPUC cites the cost as $25,400. Please clarify the cost of purchasing and installing the 3 regulators.

Response

The EneSpectrum report, shows the estimated cost to be 25,400, however CPUC was able to secure a price of $23,500.

Payments in Lieu of Taxes (PILs)

46. Ref: Exhibit 3, page 29

For the 2006 tax year, please provide the following:

i. Actual federal T2 tax return and supporting schedules – signed original and any returns that were subsequently amended and re-filed;
ii. Actual Ontario CT23 tax return and supporting schedules – signed original and any returns that were subsequently amended and re-filed;
iii. Financial statements that were submitted with the tax returns to the Ministry of Finance;
iv. Notices of Assessment, and any Notice(s) of Re-assessment, including Statement of Adjustments, received from the Ministry of Finance for the 2006 tax year; and
v. Any correspondence between the Ministry of Finance and CPUC regarding any tax items, or tax filing positions that may be in dispute, or under consideration or review, that may affect the tax situation of the utility for 2006 or future years.

Response

All of the above (I. to iv.) are attached as Appendix E, and v. is not applicable.

47. Ref: Exhibit 3, page 29

Using the applied-for 2008 regulatory net income, and forecasting forward, will CPUC be able to utilize the non-capital tax loss carry-forwards shown before these losses expire? In what year does CPUC expect to have to pay PILs income tax?

Response

It is estimated that CPUC will only be able to utilize a portion (approximately $210,000) of the non-capital tax loss carry-forwards up to 2012, before the balance of these losses expire ($8,000 will expire in 2010, $252,000 in 2011 and $258,000 in 2012). CPUC is unable to substantiate this.

APPENDIX A

CHAPLEAU PUBLIC UTILITIES CORPORATION

Code of Business Conduct

Quick reference

1 Introduction

Much has changed and is changing at Chapleau Public Utilities Corporation. We are a new organization with a new name. We have a new image that we are aggressively promoting and a new direction – to be "best in class" in energy delivery in Chapleau. This means focusing our efforts on putting our customers first in everything we do, and for the first time, our business is facing competition as electricity moves to the open market. We have set high standards for Chapleau Public Utilities Corporation, so there will be increased pressure to perform. With all of these changes and challenges, we can expect to face new and sometimes difficult ethical issues.

But what has not changed at Chapleau Public Utilities Corporation are the principles that guide us – principles that have built trust and confidence among employees, and with our customers, business partners and communities. Integrity, excellence and citizenship will continue to define how we do business at Chapleau Public Utilities Corporation.

Our Code of Business Conduct is based on these core principles. We can look to it, together with Chapleau Public Utilities Corporation's policies and procedures as our guide when conducting day-to-day business, and when facing decisions involving ethical issues. Take the time to read through this booklet and keep it close at hand for future reference. With the Code of Business Conduct as guidance, we can be confident that all of us who work for Chapleau Public Utilities Corporation, including our Board of Directors, employees, agents, consultants, contractors and business partners will continue to make the right choices.

When each of us can do our best, we can be sure that we will reach our goal of being the best.

2 Our Principles

Everyone who works at Chapleau Public Utilities Corporation follows certain principles when conducting business. These principles are the foundation of Chapleau Public Utilities Corporation's Code of Business Conduct and for the policies that reinforce it.

Chapleau Public Utilities Corporation expects every employee, at every level, to conduct herself or himself in accordance with this Code and will hold employees accountable for their conduct. If employees do not comply with this Code, they will be subject to disciplinary procedures, up to and including dismissal. Parallel expectations and associated consequences apply to our agents, consultants, contractors and business partners. For Chapleau Public Utilities Corporation to be successful, we must continue to earn the trust and confidence of our customers and stakeholders. Each business action and decision provides us with this opportunity.

Integrity, Excellence, and Citizenship.
These are the principles Chapleau Public Utilities Corporation stands for. They point the way to business conduct that makes for successful individuals and a successful company.

Integrity

Conducting business with unfailing honesty is what integrity is all about. So what does integrity mean at Chapleau Public Utilities Corporation? Integrity means that every employee at every level of the organization:

- Conducts business lawfully and ethically, establishing honest dealings in all relationships and expecting the same of those with whom we have business relationships.
- Avoids conflict of interest between their personal interests and their role in the conduct of company business.
- Does not disclose sensitive or confidential information inappropriately.
- Recognizes the value of competition and does not engage in practices that seek to reduce the openness and fairness of competition. We do not prevent others from competing freely and fairly with us, except when constrained by law.
- Protects the company's assets and uses them responsibly.

Excellence

Chapleau Public Utilities Corporation is on a journey to be the "best in class" in energy delivery in Chapleau. Our ambitious goals demand excellence from everyone in the organization. How do we demonstrate excellence?

- In our attitude towards our work, a commitment to providing our customers with service and products of the best value.
- By striving for continuous performance improvement, always looking for innovations that help our customers and the business.
- By seizing opportunities to upgrade our own skills and to develop the talents and abilities of others.
- By fostering and maintaining respectful and trusting relationships with our colleagues, working collaboratively with them in a team effort to reach for excellence in everything we do.

Citizenship

Every day, our work at Chapleau Public Utilities Corporation touches the lives of hundreds of people across the area. They depend on us, and we have a responsibility to them. We can show our citizenship by:

- Respecting and supporting the social and cultural fabric of the communities where we work, live, and serve.
- Conducting our business in an environmentally-responsible manner.
- Conducting our business in a way that protects the health and safety of our fellow employees and the public.
- Treating our fellow employees and all others with respect and dignity. We value the diversity of human beings. We do not tolerate the harassment of any person.

3 Code of Business Conduct

This section describes the standards of business conduct Chapleau Public Utilities Corporation expects from every employee at every level of responsibility. These standards of conduct apply in every part of the company and to any subsidiary, whether operating domestically or internationally. The standards apply to all Chapleau Public Utilities Corporation employees, and to the extent feasible, are equally applicable to our agents, consultants, contractors and business partners.

We honour all laws, regulations and contractual obligations.

If there is a case where the Code does not provide the answer to a particular ethical issue, or if you have questions about our Code of Business Conduct, talk to your supervisor. If they cannot answer your question, they will direct you to Chapleau Public Utilities Corporation's Secretary-Treasurer.

3.1 Work Environment

3.1.1 Safety and Health

Safety and health are one of the keys to the success of the company. Healthy employees working safely are essential to achieving our business goals. We all have accountability for safety and health. Fulfilling our individual accountabilities is a vital and fundamental requirement of every employee's job. Supervisors will have prime responsibility for managing safety and health and will visibly support practices and programs that promote excellence. Each of us has a personal responsibility to come to work fit for duty, to work safely and to identify, report, and where appropriate, correct workplace hazards.

The delivery of products and services in a safe manner is essential to the success of the business. We are committed to minimizing the risk of injury to the public associated with our operations and the provision of services.

3.1.2 Diversity

We value the background, experience, perspective, and talent of each individual. We strive to create a workforce that reflects the diverse populations of the communities in which we operate. We regard differences as positive: they help us provide better products and services to our customers.

We do not discriminate in hiring and employment practices on grounds prohibited by applicable law, which includes such grounds as race, ancestry, color, place of origin, sex, ethnic origin, age, marital and family status, physical abilities, sexual orientation, creed, religion, or citizenship.

3.1.3 Harassment

We treat customers, clients, suppliers, and colleagues with dignity and respect.

We do not tolerate personal harassment, including behavior that demeans, threatens, or humiliates a person or group of people. We do not tolerate sexual or racial harassment. We do not tolerate comments or conduct that ridicule or disparage a group of employees, even if not directed at a particular employee. We do not tolerate any behaviors that may promote physical violence in the workplace. Workplace violence often begins with harassment. We have a duty to take preventive action by bringing forward information relating to emerging situations in the workplace that may result in physical violence.

3.1.4 Work Performance

As employees, we take accountability for our work and for our results. We expect to be evaluated by such standards as quality, quantity, timeliness, and whether the work has been completed safely and within the limits of allocated resources. In our increasingly competitive environment, these standards are constantly rising and we are committed to giving our full effort in everything we do. We recognize that we must continue to seek new ways to be more effective and efficient. We expect our supervisors to follow leadership practices that promote an environment where high performance is encouraged. We expect our supervisors to set clear expectations and to provide appropriate support and timely feedback. We expect a work environment in which suggestions for improvement are welcomed and implemented where appropriate.

3.1.5 Developing our Potential

As a company, we recognize that the capability and commitment of our people is an immensely valuable asset that is critical to our business success. Supervisors are expected to treat employees in a manner that encourages commitment. At the same time, supervisors are held accountable for maintaining and enhancing the capability of their unit. Although each of us is responsible for our own career planning and development, we understand that the company will support our active pursuit of a jointly agreed and supported development plan. As a result, we can expect to increase our personal contribution and value as well as our collective capability within the company.

3.2 Conflict of Interest

3.2.1 Avoiding Conflicts of Interest

We avoid any conflict of interest; that is, we avoid any situation where our personal interest interferes in any way or even appears to interfere with the interests of Chapleau Public Utilities Corporation and the making of decisions with honesty and integrity. There are three broad guidelines for avoiding conflicts of interest:

- Any business decision for Chapleau Public Utilities Corporation is to be based on merit and made strictly in the best interest of Chapleau Public Utilities Corporation;
- No personal benefits, whether direct or indirect are to be derived for ourselves, family members or friends as a result of reaching business decisions on behalf of Chapleau Public Utilities Corporation; and
- We are to avoid any situation that may – or even appear to – create a conflict of interest between our personal interests and those of Chapleau Public Utilities Corporation.

Areas of conflict of interest that may arise in the course of our day-to-day work are covered in other sections. We have an obligation to declare any conflict of interest any potential or perceived conflict of interest to management at any level or to the Secretary-Treasurer, as outlined under “compliance”.

3.2.2 Outside Business Activities

While we all have a right for personal freedom outside working hours, certain outside business activities may constitute a conflict of interest.

We do not serve as directors of any organization that supplies to Chapleau Public Utilities Corporation, buys goods or services from Chapleau Public Utilities Corporation, without the approval of the Secretary-Treasurer.

We may work for another organization, including one set up by ourselves, provided it is not a supplier, a commercial or industrial customer, or a competitor of Chapleau Public Utilities Corporation, or does not affect our work performance at Chapleau Public Utilities Corporation. Where it is not clear whether external work interferes with our duty to Chapleau Public Utilities Corporation or affects our work performance at Chapleau Public Utilities Corporation, it is the responsibility of the employee to seek the prior approval of the Secretary-Treasurer. We do not perform work for the other organization on Chapleau Public Utilities Corporation time, nor do we use Chapleau Public Utilities Corporation equipment, supplies, personnel or intellectual property for the use of the other organization.

We do not promote any non-Chapleau Public Utilities Corporation product or service to others during working hours. Customers and colleagues from the outside activity may not contact us at Chapleau Public Utilities Corporation workplaces. We do not sell products and services from our outside work to Chapleau Public Utilities Corporation.

3.2.3 Investments

Investment in a Chapleau Public Utilities Corporation competitor or supplier can create a potential conflict of interest. We and our immediate family members – including common-law relationships – normally may not hold any ownership or financial interest in any organization that competes with any business activity of Chapleau Public Utilities Corporation or that sells goods and services to the company where that interest may give rise to a potential or perceived conflict of interest. Exceptions include where the interest is exercised through a blind trust, or equivalent, such as a mutual fund, or as discussed below.

While, as an example, ownership of less than five per cent of the issued shares of a publicly-traded corporation would be permitted for an employee and immediate family members in total, there may be situations in which such ownership would give rise to the potential for conflict of interest. Any holdings which exceed these limits will be approved only on an exception basis, and must receive prior approval from the Secretary-Treasurer.

It is the responsibility of employees to disclose to the Secretary-Treasurer, any investments which contravene these guidelines. With respect if the investment or financial interest exceeds five per cent of the issued shares or the value of the company or if an investment below this level could be perceived to create a potential conflict of interest. As well, disclosure is not required for investments held in a blind trust or equivalent, such as a mutual fund.

In addition, in order to avoid conflict of interest situations, when we are aware that a family member or a friend has more than five percent ownership in a competitor or supplier of Chapleau Public Utilities Corporation, we must inform the Secretary-Treasurer, both of the ownership interest and of our relationship to the investor. It is the responsibility of management to ensure that the employee appreciates the potential conflict of interest that might arise from his/her relationship with the investor.

3.2.4 Confidential Information

Confidential information includes proprietary, technical, business, marketing strategies, financial, trade secret, intellectual property, joint-venture, and personal information about customers and employees that is not made available publicly. We are responsible for knowing what information must remain in confidence and for seeking clarification from our supervisor if in doubt.

We do not disclose confidential information – except as required by law – to anyone outside Chapleau Public Utilities Corporation, including family and friends, even after we have left Chapleau Public Utilities Corporation's employ. Within Chapleau Public Utilities Corporation, we do not disclose sensitive information to colleagues other than is necessary to ensure that we can effectively perform our assigned work. We protect confidential information against theft, fraudulent use, loss, unauthorized access, or misuse (notably as it relates to how we collect, store and retain confidential information on our computer assets). We recognize that any unauthorized use of confidential information exposes Chapleau Public Utilities Corporation to legal, commercial and liability risks.

Personal information about employees must be managed and kept in a confidential manner respecting the privacy of the individual, and taking into account our obligations under any applicable legislation and our business practices.

3.2.5 Purchasing and Suppliers

We protect Chapleau Public Utilities Corporation's reputation by refusing to make purchasing decisions based on favouritism, prejudice, preferential treatment or personal gain. We make them honestly and with integrity, using such criteria as competitive pricing, quality, quantity, delivery, and service. We refuse involvement in purchasing decisions that could lead to a conflict of interest, and we declare to the Secretary-Treasurer all conflicts or potential conflicts, seeking guidance from our Secretary-Treasurer when we are uncertain.

We treat suppliers courteously, respectfully, and in a professional manner.

We inform suppliers of our Code of Business Conduct and we expect suppliers to abide by it. Non-compliance should be communicated to our supervisor and a decision made by the accountable supervisor on a case-by-case basis about what actions should be taken. An example of an action would be to discuss our ethics with suppliers and make it known to them their conduct is unacceptable. A relationship with a supplier should be ended if there is a lack of improvement, consistent with any contractual obligations.

3.2.6 Conducting Business Relationships Gifts and Entertainment

Chapleau Public Utilities Corporation employees, agents and business partners do not offer, give, solicit, or receive any form of bribe or kickback. We also exercise due diligence to ensure that agents and representatives acting on Chapleau Public Utilities

Corporation's behalf are not themselves offering bribes and kickbacks.

Exchanges of reasonable business gifts and entertainment (e.g. meals, beverages, and invitations to recreational or social outings) are courtesies designed to build understanding and goodwill among business partners and reflect commonly acceptable business practice.

The problem arises when they begin to compromise, or even appear to compromise our ability to make objective and fair business decisions. When this occurs we are involved in a conflict of interest situation.

The onus is on everyone to use good judgment and think about the implications before accepting or giving gifts, entertainment of similar favors. They should be of a nature and amount that should not constitute a real personal enrichment of the recipient, avoid embarrassment, and would not reflect favorably on Chapleau Public Utilities Corporation or the recipient, if subjected to public scrutiny.

Such practices are permissible only where they serve a legitimate business purpose, are appropriate to the business responsibilities of the individual, do not impose any sense of obligation on the recipient, are properly recorded, and are of a nature that Chapleau Public Utilities Corporation could and would reciprocate. In no circumstances are we to give or receive cash or equivalent vouchers. We exercise integrity, prudence and judgment in incurring and approving business expenses.

As a participant in the marketplace, Chapleau Public Utilities Corporation or its subsidiaries may engage in promotional activities such as contests or giveaways. Such activities are forms of advertising. Their purpose is to promote the company's products and services and is an accepted industry practice.

3.2.7 Insider Trading and Personal Advantage

We do not divulge confidential or proprietary information that we learn in our work for our company and its affiliates, and their customers and suppliers, to any unauthorized person, or release confidential information in advance of its authorized release. We do not use for private speculation or personal advantage, data or information that is not available to the general public.

3.3 Protecting the Environment

3.3.1 The Environment

We will comply with all environmental laws and regulations and will move beyond compliance where it makes good business sense to do so. We will increase our competitiveness and maximize value to shareholders by making efficient use of resources, preventing pollution and reducing environmental impacts and liabilities to the extent that is reasonably achievable. We will set environmental objectives and targets, monitor our performance relative to expectations, and implement programs to achieve continual improvement.

Supervisors are expected to provide visible leadership and employees are expected to know and comply with corporate and subsidiary policies, procedures and standards which incorporate legal requirements and generally accepted industry practices.

3.4 Safeguarding Company Assets

3.4.1 Proper Use of Assets

We protect the company's assets (fixed and moveable property, personnel, information, intellectual property and commodities), use them properly, safely, efficiently, and only for Chapleau Public Utilities Corporation business. We do not use company assets in a manner that compromises our competitive business practices or offends, harasses, or promotes unacceptable behavior (improper use of email and Internet).

We protect our assets from theft, fraud, destruction, vandalism or neglect. We dispose of company property in an ethical and approved manner. Internal or employee theft or fraud will not be tolerated.

Any use of company assets for a non-business reason (charitable work, for example) must be approved by the Secretary-Treasurer. Effective protection of our company assets can enhance our competitive edge.

3.4.2 Accounting and Finance

Chapleau Public Utilities Corporation will conduct its financial affairs only for lawful and proper purposes in accordance with approved authorities, and properly record resulting transactions. No undisclosed funds or accounts may be established. All cash and bank account and other business transactions are handled in a manner that avoids any questions of bribery, kickbacks, other illegal or improper payments or any suspicion of impropriety whatsoever.

3.4.3 Business Reporting

All Chapleau Public Utilities Corporation reports, accounting records, research reports, sales reports, expense accounts, time sheets, and other documents must accurately and clearly represent the relevant facts or true nature of a transaction.

3.4.4 Managing Risk

We will appropriately identify and control the company's risks, within the limits of our accountabilities and allocated resources. This does not mean eliminating all risks, but rather it means mitigating the risks to acceptable levels for the company. Risk is defined as any possible event that may adversely impact the company's business objectives. We will understand the business objectives relevant to our work, and ask our supervisors for help or information on objectives where these are not understood. If, in our opinion, there are situations where risks are not being appropriately controlled, either by other Chapleau Public Utilities Corporation employees or by contract employees, we will discuss the situation with our supervisors and, if not resolved, we will consult the Secretary-Treasurer for direction.

3.4.5 Using Email and the Internet

Access to email and the Internet is made available to promote effective work related research, improve our development and enhance corporate wide communication. Since the Internet is an "open" environment and accessible to numerous users, care must be taken to protect all information, including information of a commercially sensitive or confidential nature.

When using email or the Internet we will not download programs not already supported by Chapleau Public Utilities Corporation, participate in non-work-related chat lines, access sites carrying socially or politically offensive material, send chain letters, send threatening, slanderous or harassing messages or send, view or obtain pornographic material.

We will also not use the Internet to play games, gamble, conduct personal business or financial ventures, post or send messages under disguised identification or send confidential information unless effectively protected (i.e. using encryption).

3.5 Relationships

3.5.1 Relationships with Customers

In all aspects of doing business with customers, we strive to build a strong and mutually valued relationship. We demonstrate that Chapleau Public Utilities Corporation is a customer-focused company in every transaction. We strive to give our customers high value reliable products and services. We seek customers' views on issues affecting them, consider their views, and give them feedback where possible. Customers are given the information they need to make informed choices and they receive truthful information about our products and services. Their safety and health is protected. We respect our customers' privacy and diversity. In all interactions with customers, every employee shall act as an ambassador of Chapleau Public Utilities Corporation thereby treating customers courteously, respectfully, and in a professional manner.

3.5.2 Fair Competition

We obey the laws governing competition, not conspiring with anyone to lessen fair competition. We do not engage in anti-competitive practices or illegal activities such as price-fixing, bid-rigging, and kickbacks. We support competitive procurement practices and engage a variety of methods and processes to do this.

Information about competitors must be gathered in a lawful manner. We do not, either directly or through a third party, misrepresent ourselves, use a third party, or offer bribes or gifts, to solicit proprietary information about competitors. Sensitive or proprietary information is not solicited from Chapleau Public Utilities Corporation employees who once worked for a competitor.

3.5.3 Relationships with Non-profit and Professional Organizations

We have a civic responsibility to contribute to our communities and to our professional organizations, proven our participation does not interfere with our duty to Chapleau Public Utilities Corporation. We avoid participating in any activity that may interfere with our duties to Chapleau Public Utilities Corporation. We only perform services for an organization on company time when we have prior approval from our supervisor. If we act as a spokesperson for an organization, we make it clear we are speaking for that organization or for ourselves, and not acting as a spokesperson or representative of Chapleau Public Utilities Corporation.

3.5.4 Political Participation

As private citizens, we take part in the democratic process at any level, including campaigning in elections, on our own time. Prior company approval is required if we need a leave of absence to participate, and our participation must be kept strictly separate from our association with Chapleau Public Utilities Corporation.

3.5.5 Conducting International Business

We apply Chapleau Public Utilities Corporation's Code of Business Conduct to all the company's operations, international as well as domestic. Chapleau Public Utilities Corporation employees, agents and joint venture partners comply with the letter and spirit of domestic and foreign legal requirements as they apply to all business activities.

Chapleau Public Utilities Corporation employees, agents and business partners are committed to ensuring that internationally-recognized human rights, including the rights of women, children, and indigenous and tribal peoples, are respected in all Chapleau Public Utilities Corporation activities, wherever Chapleau Public Utilities Corporation does business.

We consult with relevant government authorities and local communities to ensure a project does not pose a disproportionate physical, social, or economic danger to the neighboring populations, property, or environment.

4 Ensuring Compliance

At Chapleau Public Utilities Corporation, we are committed to building upon our well-earned reputation as an ethical and credible company. For each of us, this means living up to the principles of integrity, excellence and citizenship in everything we do, as well as ensuring complete compliance with our *Code of Business Conduct.*

Your accountabilities and reporting responsibilities are outlined below. If you have any questions or concerns about your obligations, be sure to discuss them with the Secretary-Treasurer.

5 Accountabilities

Employees throughout the organization and in all businesses are expected to comply with the Code of Business Conduct. This means reading the Code and making sure that you fully understand it, and it means declaring all potential conflicts of interest and reporting any suspected violations as soon as they become known.

If you are aware of conduct that may violate the Code, or even appears to violate the Code, you have an obligation to report it to your supervisor without delay.

If you don't feel comfortable raising the issue with your supervisor, take your concerns to the Secretary-Treasurer of Chapleau Public Utilities Corporation who will initiate an appropriate investigation and provide feedback to you. In all reporting, you are assured that there will be no reprisals. Wherever possible, your identity will be kept confidential.

Supervisors, in addition to their responsibilities as employees, are charged with making sure that their employees understand and comply with the Code. As the first point of contact for employees who have questions regarding the Code and ethical issues, supervisors need to be a knowledgeable and reliable source of advice, and they must ensure that employees feel comfortable bringing their concerns forward. Supervisors must avoid breaching an employee's confidence. If this proves to be unavoidable, the supervisor is obliged to inform the employee of the disclosure. Suspected violations of the Code are to be reported by supervisors without delay to the Secretary-Treasurer.

The Secretary-Treasurer is accountable for making sure that the appropriate actions are taken to investigate and resolve known or suspected violations of the Code, and for ensuring the tracking and reporting on Code of Business Conduct violations.

Appendix B

Township Resolutions

TOWNSHIP OF • CANTON DE
CHAPLEAU
PROSPERITY • INDUSTRY
PROSPÉRITÉ • DILIGENCE
CHAPLEAU, ONT.

CENTRE CIVIQUE DE CHAPLEAU CIVIC CENTRE
P.O. BOX - C.P. 129
CHAPLEAU, ONTARIO
P0M 1K0
TEL. (705) 864-1330
FAX (705) 864-1824
www.township.chapleau.on.ca

RESOLUTION 4-60:

A. Byham - K. Swanson

Whereas the Township of Chapleau has charged a rate of 10% on the loans payable and mortgage to the PUC:

And Whereas, the rate of 10% has been deemed to be excessive in light of the Distribution Rate Handbook deemed debt rate of 7.25%

Therefore, the Township of Chapleau agrees to waive all interest charges on the loans payable and mortgage advanced to the PUC for fiscal year 2006.

Further, at the end of fiscal 2006, Council shall adjust the rate charged on the loans and mortgage to a rate deemed appropriate at that time.

And whereas 100% debt financing has been determined to no longer be appropriate for the PUC, the Township of Chapleau agrees to convert loans payable by the PUC to the Township of Chapleau as at December 31st, 2005 into common shares of the PUC such that the value of common shares acquired is equal to 25% of the Township's entire investment.

Carried.

Certified true copy.

C.A.O.

TOWNSHIP OF • CANTON DE CHAPLEAU
PROSPERITY • INDUSTRY
PROSPÉRITÉ • DILIGENCE
CHAPLEAU, ONT.

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P0M 1K0
TEL. (705) 864-1330
FAX (705) 864-1824
www.township.chapleau.on.ca

THE TOWNSHIP OF CHAPLEAU   Chapleau, Ont   January 22, 2007

Order in Council

RESOLUTION 3-49:
A. Byham – J. Tremblay
Whereas the Corporation of the Township of Chapleau has previously passed Resolution 4-60 to convert loans payable by the PUC to the Township as at December 31, 2005 into common shares of the PUC such that the value of the common shares is equal to 25% of the Township investment

And whereas it has been determined prudent to adopt the "Deemed Capital Structure" (50% debt-50% equity) and "Deemed Interest Rate" (6.25%) identified by the Ontario Energy Board in the 2006 Electricity Distribution Rate Handbook

Therefore, the Township of Chapleau agrees to convert such debt and liabilities owing to it by the PUC, so as to create the desired capital structure. Such conversion shall take place as soon as is reasonably possible

Further, interest on the balance of debt owing to the Township after the conversion will continue to be waived in 2006, with the rate identified in the Electricity Distribution Rate Handbook reinstated effective January 1, 2007.

Carried.

Certified true copy.

C.A.O.

Carried ...x....
Defeated ....
Tabled ....

Earle J. Freeborn
Mayor

Appendix C

Ministry of Energy Letter

Ministry of Energy

880 Bay Street
3rd Floor
Toronto ON M7A 2C1

Tel: (416) 325-6544
Fax: (416) 325-7041

Ministère de l'Énergie

880, rue Bay
3e étage
Toronto ON M7A 2C1

Tél: (416) 325-6544
Téléc.: (416) 314-7041

Ontario

Office of Consumer & Regulatory Affairs

December 21, 2007

Mr. Bernie Watts
Chief Executive Officer
London Hydro Inc.
111 Horton Street
P.O. Box 3060
London, ON, N6A 4J8

Dear ~~Mr. Watts~~, Bernie

I understand that London Hydro and a consortium of more than 20 additional local distribution companies (LDCs) are currently working diligently considering bids received from the now closed smart meter RFP. I want to personally congratulate London Hydro and consortium members on the hard work and collaboration that has resulted in a process that strives to ensure economies of scale, cost-effectiveness, and best value for customers. We are eager to see the results from this process to establish a second round of smart meter procurement in the province.

In our letter to London Hydro on July 25, 2007, the government reiterated its view that, wherever possible, individual procurements of the same product should be combined to capture any economic benefits from a common statement of work. This was also communicated in subsequent discussions between Ministry staff and London Hydro regarding the consideration of options for allowing LDCs outside of the consortium to participate in the procurement process.

As you are no doubt well aware, this procurement has attracted attention from LDCs across the province and several have expressed an interest in participating. I am appreciative of the work done by London Hydro to develop a participation process that offers non-consortium LDCs with an opportunity to investigate a suitable technology for their own customers. I understand that the participation guidelines ensure that the integrity of the procurement process (which will be monitored by London Hydro's fairness commissioner) will be maintained in the event of expanded LDC participation. The participation process also provides opportunities for both consortium and other LDCs to achieve greater cost-savings and volumetric discounts in those cases where the same bidder's technology is selected.

Following the successful completion of the RFP and Minister Phillips' approval, the Ministry will recommend to Cabinet an amendment to O. Reg. 427/06 to accommodate London Hydro and consortium members as well as any other LDCs outside the consortium that have chosen to participate in the process. As you know, the Ministry cannot bind Cabinet's decision making. As such, nothing in this letter shall be construed as obligating the Cabinet or the legislature of the Province of Ontario to approve or promulgate the proposed amending regulation.

Please accept my congratulations on your accomplishments to date on this initiative. I encourage you to continue the dedication you have shown thus far toward the successful implementation of smart metering for your customers.

Sincerely,

Rosalyn Lawrence

Rosalyn Lawrence
Assistant Deputy Minister
Consumer and Regulatory Affairs

cc:

Electricity Distributors Association

Niagara Erie Power Alliance

Cornerstone Hydro Electric Concepts Group

District 9

Whitby Hydro

Appendix D

EneSpectrum Report

Appendices

Appendix 3 – Loss Summaries

Winter:

Ultimate

SEASON	DAY	TEMP	DESS SCALE FACTOR	# DAYS	DAILY LOSSES (KWHRS) HOUR 1	2	3	4	5	6	7	DAILY LOSSES (KWHRS) HOUR 8	9	10	11	12	13	14	15	16	17	DAILY LOSSES (KWHRS) HOUR 18	19	20	21	22	23	24	DAILY TOTAL	SEASON TOTAL
WINTER	WEEKDAY	-10	1	86	166.29	156.86	147.12	144.03	138.89	135.42	146.28	165.4	185.39	201.96	216.38	217.25	248.51	221.29	226.96	243.53	230.34	213.27	197.78	210.48	240.28	211.76	190.16	179.3	4634.93	398603.98
TOTAL				86	14300.94	13490	12652	12387	11945	11646	12580	14,224	15944	17369	18609	18684	21372	19031	19519	20944	19609	18341.22	17009	18101	20664	18211	16354	15420	398604	
WINTER	WEEKEND	-10	1	35	163.03	154.12	142.75	142.32	137.58	134.86	145.92	162.17	181.19	195.67	211.12	211.79	241.19	216.21	222.02	239.06	224.94	208.3	191.33	204.07	234.69	206.69	185.79	173.86	4530.69	
TOTAL				35	5706.05	5394.2	4996.3	4981.2	4815.3	4720.1	5107.2	5,676	6341.7	6848.5	7389.2	7412.7	8441.7	7567.4	7770.7	8367.8	7872.9	7290.5	6696.6	7142.5	8214.2	7234.2	6502.7	6085.1	158574.2	
				121																										
					119596.76	ON-PEAK						119,597	ON-PEAK			199	ON_PEAK kW					119596.8	ON-PEAK			GRAND TOTAL			557178.1	
					158233.12	MID-PEAK						158,233	MID-PEAK									158233.1	MID-PEAK							
					279348.25	OFF-PEAK						279,348	OFF-PEAK									279348.3	OFF-PEAK							
					557178.13	TOTAL						557,178	TOTAL									557178.1	TOTAL							

Ultimate + Cap

SEASON	DAY	TEMP	DESS SCALE FACTOR	# DAYS	DAILY LOSSES (KWHRS) HOUR 1	2	3	4	5	6	7	DAILY LOSSES (KWHRS) HOUR 8	9	10	11	12	13	14	15	16	17	DAILY LOSSES (KWHRS) HOUR 18	19	20	21	22	23	24	DAILY TOTAL	SEASON TOTAL
WINTER	WEEKDAY	-10	1	86	159.16	150.19	141.68	138.14	132.41	129.43	139.87	159.14	176.72	192.34	207.7	208.47	238.53	212.3	217.75	234.97	221.17	203.89	189.76	200.45	232.63	202.23	181.93	170.3	4441.16	
TOTAL				86	13687.76	12916	12184	11880	11387	11131	12029	13686	15198	16541	17862	17928	20514	18258	18727	20207	19021	17534.54	16319	17239	20006	17392	15646	14646	381939.8	
WINTER	WEEKENDS PLUS STAT HOLIDAYS	-10	1	35	155.97	147.5	136.78	136.47	131.14	128.88	139.52	155.96	172.65	187.28	200.94	201.55	232.64	207.29	212.87	230.55	215.84	199.06	184.86	195.28	224.2	197.29	176.71	166.41	4337.64	
TOTAL				35	5458.95	5162.5	4787.3	4776.5	4589.9	4510.8	4883.2	5458.6	6042.8	6554.8	7032.9	7054.3	8142.4	7255.2	7450.5	8069.3	7554.4	6967.1	6470.1	6834.8	7847	6905.2	6184.9	5824.4	151817.4	
				121																										
					114380	ON-PEAK						114,380	ON-PEAK			190	ON PEAK kW					114380	ON-PEAK			GRAND TOTAL			533757.2	
					0																	0								
					152052.3	MID-PEAK						152,052	MID-PEAK									152052.3	MID-PEAK							
					0																	0								
					267324.86	OFF-PEAK						267,325	OFF-PEAK									267324.9	OFF-PEAK							
					0																	0								
					533757.16	TOTAL						533,757	TOTAL									533757.2	TOTAL							

SAVINGS	
5,217	ON-PEAK
6,181	MID-PEAK
12,023	OFF-PEAK
23,421	TOTAL

KW SAVINGS	
9	ON-PEAK

Chapleau Distribution System Optimization & TRC Analysis

Summer:

Ultimate

SEASON	DAY	TEMP	DESS SCALE FACTOR	# DAYS	DAILY LOSSES (KWHRS) HOUR 1	2	3	4	5	6	7	DAILY LOSSES (KWHRS) HOUR 8	9	10	11	12	13	14	15	16	17	DAILY LOSSES (KWHRS) HOUR 18	19	20	21	22	23	24	DAILY TOTAL	SEASON TOTAL
WINTER	WEEKDAY	25	1	86	100.19	97.44	94.89	93.53	92.22	91.37	94.56	101.37	107.13	113.23	117.25	117.45	126.07	118.58	119.99	124.65	119.71	114.3	109.24	112.04	122.1	113.78	107.2	103.68	2611.97	224629.42
TOTAL				86	8616.34	8379.8	8160.5	8043.6	7930.9	7857.8	8132.2	8,718	9213.2	9737.8	10084	10101	10842	10198	10319	10720	10295	9829.8	9394.6	9635.4	10501	9785.1	9219.2	8916.5	224629.4	
WINTER	WEEKEND	25	1	35	97.84	95.46	92.28	92.29	91.25	91.25	90.95	94.29	98.9	103.95	113.21	113.26	121.57	114.7	116.23	121.28	115.72	109.72	105.6	108.24	117.53	109.13	104.03	100.81	2519.49	
TOTAL				35	3424.4	3341.1	3229.8	3230.2	3193.8	3193.8	3183.3	3,300	3461.5	3638.3	3962.4	3964.1	4255	4014.5	4068.1	4244.8	4050.2	3840.2	3696	3788.4	4113.6	3819.6	3641.1	3526.4	88182.15	
				121																										
					66612.16	ON-PEAK						66,612	ON-PEAK			111	ON_PEAK kW					66612.16	ON-PEAK			GRAND TOTAL			312811.6	
					82760.38	MID-PEAK						82,760	MID-PEAK									82760.38	MID-PEAK							
					163439.03	OFF-PEAK						163,439	OFF-PEAK									163439	OFF-PEAK							
					312811.57	TOTAL						312,812	TOTAL									312811.6	TOTAL							

Ultimate + Cap

SEASON	DAY	TEMP	DESS SCALE FACTOR	# DAYS	DAILY LOSSES (KWHRS) HOUR 1	2	3	4	5	6	7	DAILY LOSSES (KWHRS) HOUR 8	9	10	11	12	13	14	15	16	17	DAILY LOSSES (KWHRS) HOUR 18	19	20	21	22	23	24	DAILY TOTAL	SEASON TOTAL
WINTER	WEEKDAY	25	1	86	97.07	94.6	92.34	91.5	90.44	89.53	92.86	98.74	103.98	108.54	112.14	112.31	120.15	113.81	115.09	118.86	114.87	109.79	106.45	108.79	116.83	109.17	103.73	100.31	2521.9	
TOTAL				86	8348.02	8135.6	7941.2	7869	7777.8	7699.6	7986	8491.64	8942.3	9334.4	9644	9658.7	10333	9787.7	9897.7	10222	9878.8	9441.94	9154.7	9355.9	10047	9388.6	8920.8	8626.7	216883.4	
WINTER	WEEKENDS PLUS STAT HOLIDAYS	25	1	35	94.8	92.69	90.23	90.31	89.18	89.12	92.6	96.34	100.68	104.67	108.25	108.28	115.81	109.59	111.45	115.6	111.02	106.31	102.92	105.1	112.96	105.65	100.65	97.54	2451.95	
TOTAL				35	3318	3244.2	3158.1	3160.9	3121.3	3119.2	3241	3371.9	3530.8	3663.5	3788.8	3789.8	4053.4	3835.7	3900.8	4046	3885.7	3720.85	3602.2	3678.5	3953.6	3697.8	3522.8	3413.9	85818.25	
				121																										
					64364.98	ON-PEAK						64,365	ON-PEAK			107	ON PEAK kW					64364.98	ON-PEAK			GRAND TOTAL			302701.7	
					0																	0								
					79213.74	MID-PEAK						79,214	MID-PEAK									79213.74	MID-PEAK							
					0																	0								
					159122.93	OFF-PEAK						159,123	OFF-PEAK									159122.9	OFF-PEAK							
					0																	0								
					302701.65	TOTAL						302,702	TOTAL									302701.7	TOTAL							

SAVINGS	
2,247	ON-PEAK
3,547	MID-PEAK
4,316	OFF-PEAK
10,110	TOTAL

kW SAVINGS	
4	ON-PEAK

Chapleau Distribution System Optimization & TRC Analysis

Shoulder:

Ultimate with Cap

SEASON	DAY	TEMP	DESS SCALE FACTOR	# DAYS	DAILY LOSSES (KWHRS) HOUR 1	2	3	4	5	6	7	DAILY LOSSES (KWHRS) HOUR 8	9	10	11	12	13	14	15	16	17	DAILY LOSSES (KWHRS) HOUR 18	19	20	21	22	23	24	DAILY TOTAL	SEASON TOTAL
SPRING	WEEKDAY	5	1	87	114.31	109.58	105.65	104.28	102.24	100.99	105.99	115.41	123.97	131.24	138.77	139.08	153	140.82	143.22	151.03	144.69	135.3	129.27	133.67	149.04	134.5	125.06	119.69	3050.8	265419.6
	TOTAL			87	9944.97	9533.5	9191.6	9072.4	8894.9	8786.1	9221.1	10040.67	10785	11418	12073	12100	13311	12251	12460	13140	12586	11771.1	11246	11629	12966	11702	10880	10413	265419.6	
SPRING	WEEKENDS PLUS STAT HOLIDAYS	5	1	35	111.83	107.51	103.02	102.98	101.23	100.55	105.71	112.37	120.68	127.15	133.46	133.64	148.29	136.79	139.3	147.5	138.76	131.53	125.44	129.65	143.65	130.66	121.72	116.67	2970.09	
	TOTAL			35	3914.05	3762.9	3605.7	3604.3	3543.1	3519.3	3699.9	3932.95	4223.8	4450.3	4671.1	4677.4	5190.2	4787.7	4875.5	5162.5	4856.6	4603.55	4390.4	4537.8	5027.8	4573.1	4260.2	4083.5	103953.15	
				122																										
					0	ON-PEAK							ON-PEAK									0	ON-PEAK			GRAND TOTAL			369372.75	
					179481.87	MID-PEAK						179,482	MID-PEAK									179481.9	MID-PEAK							
					189890.88	OFF-PEAK						189,891	OFF-PEAK									189890.9	OFF-PEAK							
					369372.75	TOTAL						369,373	TOTAL									369372.8	TOTAL							

Ultimate

SEASON	DAY	TEMP	DESS SCALE FACTOR	# DAYS	DAILY LOSSES (KWHRS) HOUR 1	2	3	4	5	6	7	DAILY LOSSES (KWHRS) HOUR 8	9	10	11	12	13	14	15	16	17	DAILY LOSSES (KWHRS) HOUR 18	19	20	21	22	23	24	DAILY TOTAL	SEASON TOTAL
SPRING	WEEKDAY	5	1	87	119.06	114.5	109.23	107.67	105.31	103.74	108.97	119.62	129.41	137.3	144.15	144.52	159.31	146.42	148.98	157.24	149.74	141.17	134.24	139.23	153.88	140.48	130.86	125.35	3170.38	
	TOTAL			87	10358.22	9961.5	9503	9367.3	9162	9025.4	9480.4	10406.94	11259	11945	12541	12573	13860	12739	12961	13680	13027	12261.79	11679	12113	13388	12222	11385	10905	275823.06	
SPRING	WEEKENDS PLUS STAT HOLIDAYS	5	1	35	116.48	111.35	106.44	106.33	104.26	103.29	108.69	116.97	125.99	133.06	139.87	140.09	154.51	142.3	144.98	153.64	145.45	137.26	130.25	135.05	149.51	136.49	127.4	122.2	3091.86	
	TOTAL			35	4076.8	3897.3	3725.4	3721.6	3649.1	3615.2	3804.2	4093.95	4409.7	4657.1	4895.5	4903.2	5407.9	4980.5	5074.3	5377.4	5090.8	4604.1	4558.8	4726.8	5232.9	4777.2	4459	4277	108215.1	
				122																										
					0	ON-PEAK							ON-PEAK									0	ON-PEAK			GRAND TOTAL			384038.16	
					186675.03	MID-PEAK						186,675	MID-PEAK									186675	MID-PEAK							
					0																									
					197363.13	OFF-PEAK						197,363	OFF-PEAK									197363.1	OFF-PEAK							
					384038.16	TOTAL						384,038	TOTAL									384038.2	TOTAL							

SAVINGS	
0	ON-PEAK
7,193	MID-PEAK
7,472	OFF-PEAK
14,665	TOTAL

Appendix 4 – TRC Analysis

Net Present Value$_{TRC}$

Utility

Name of Utility:	Chapleau PUC
Number of years in study:	30

Project Description

Name of Project:	Chapleau PUC System Optimization
Description:	Phase 2 - Capacitor Installation

- OEB Residential Table
- OEB Commercial Table
- OEB Industrial Table
- Direct Input

- k$
- $

User Inputs

Discount rate	7.25%	
Unit Annual Energy Savings	0	kW/unit
Number of Units Delivered		
Free Ridership Rate		

Output

NPV ($)	49,361.91

LDC Avoided Costs		Present	2008	2009	2010	2011
Avoided Energy			3,595.79	3,427.27	3,469.14	3,455.09
Avoided Generation Capacity			306.69	343.33	293.70	350.93
Avoided Transmission Capacity			23.09	23.66	24.24	24.86
Avoided Distribution Capacity			-	64.57	66.19	67.84
Avoided Distribution Losses			-	-	-	-
Other Avoided Costs						
Other Benefits						
Total (undiscounted) Avoided Costs	-		3,925.56	3,858.84	3,852.27	3,898.73
LDC Program Costs						
LDC OM&A Costs						
LDC Capital Costs		- 10,000.00				
Incremental Equipment Costs						
Participant Costs						
Total Program Costs		- 10,000.00	-	-	-	-
Total Avoided Costs less Program Costs		- 10,000.00	3,925.56	3,858.84	3,852.27	3,898.73

			2008	2009	2010	2011
Present value factor	7.3%	1.000	0.966	0.900	0.839	0.783
Present value of cash flows		- 10,000.00	3,790.56	3,474.25	3,233.87	3,051.63
Accumulated present value of cash flows		- 10,000.00	- 6,209.44	- 2,735.19	498.68	3,550.31

NPV TRC	49,361.91

Chapleau Distribution System Optimization & TRC Analysis

Net Present Value$_{TRC}$

Utility

Name of Utility:	
Number of years in study:	

Project Description

Name of Project:	
Description:	

- OEB Residential Table
- OEB Commercial Table
- OEB Industrial Table
- Direct Input

User Inputs

Discount rate	
Unit Annual Energy Savings	
Number of Units Delivered	
Free Ridership Rate	

LDC Avoided Costs	2012	2013	2014	2015	2016	2017
Avoided Energy	3,603.62	3,906.58	4,107.87	4,401.15	4,494.94	4,587.63
Avoided Generation Capacity	333.60	253.07	191.57	95.15	110.43	123.00
Avoided Transmission Capacity	25.47	26.13	26.79	27.44	28.14	28.84
Avoided Distribution Capacity	69.54	71.28	73.06	74.88	76.76	78.68
Avoided Distribution Losses	-	-	-	-	-	-
Other Avoided Costs						
Other Benefits						
Total (undiscounted) Avoided Costs	4,032.22	4,257.06	4,399.29	4,598.62	4,710.27	4,818.15
LDC Program Costs						
LDC OM&A Costs						
LDC Capital Costs						
Incremental Equipment Costs						
Participant Costs						
Total Program Costs	-	-	-	-	-	-
Total Avoided Costs less Program Costs	4,032.22	4,257.06	4,399.29	4,598.62	4,710.27	4,818.15

	2012	2013	2014	2015	2016	2017
Present value factor	0.730	0.680	0.634	0.592	0.552	0.514
Present value of cash flows	2,942.77	2,896.84	2,791.26	2,720.50	2,598.18	2,478.03
Accumulated present value of cash flows	6,493.09	9,389.93	12,181.18	14,901.68	17,499.86	19,977.88

NPV TRC	

Chapleau Distribution System Optimization & TRC Analysis

Net Present Value$_{TRC}$

Utility

Name of Utility:	
Number of years in study:	

Project Description

Name of Project:	
Description:	

- OEB Residential Table
- OEB Commercial Table
- OEB Industrial Table
- Direct Input

User Inputs

Discount rate	
Unit Annual Energy Savings	
Number of Units Delivered	
Free Ridership Rate	

LDC Avoided Costs	2018	2019	2020	2021	2022	2023
Avoided Energy	4,693.31	4,775.79	4,870.02	4,990.53	5,108.58	5,228.70
Avoided Generation Capacity	130.07	133.15	130.85	157.23	172.43	181.67
Avoided Transmission Capacity	29.54	30.28	31.06	31.80	32.62	33.44
Avoided Distribution Capacity	80.64	82.66	84.73	86.84	89.01	91.24
Avoided Distribution Losses	-	-	-	-	-	-
Other Avoided Costs						
Other Benefits						
Total (undiscounted) Avoided Costs	4,923.56	5,021.87	5,116.66	5,266.40	5,402.65	5,535.05
LDC Program Costs						
LDC OM&A Costs						
LDC Capital Costs						
Incremental Equipment Costs						
Participant Costs						
Total Program Costs	-	-	-	-	-	-
Total Avoided Costs less Program Costs	4,923.56	5,021.87	5,116.66	5,266.40	5,402.65	5,535.05

	2018	2019	2020	2021	2022	2023
Present value factor	0.480	0.447	0.417	0.389	0.362	0.338
Present value of cash flows	2,361.07	2,245.42	2,133.14	2,047.15	1,958.15	1,870.53
Accumulated present value of cash flows	22,338.95	24,584.37	26,717.51	28,764.66	30,722.81	32,593.34

NPV TRC	

Net Present Value$_{TRC}$

Utility

Name of Utility:	
Number of years in study:	

Project Description

Name of Project:	
Description:	

- OEB Residential Table
- OEB Commercial Table
- OEB Industrial Table
- Direct Input

User Inputs

Discount rate	
Unit Annual Energy Savings	
Number of Units Delivered	
Free Ridership Rate	

LDC Avoided Costs	2024	2025	2026	2027	2028	2029
Avoided Energy	5,347.88	5,467.69	5,467.69	5,467.69	5,467.69	5,467.69
Avoided Generation Capacity	183.07	172.63	172.63	172.63	172.63	172.63
Avoided Transmission Capacity	34.26	35.13	35.13	35.13	35.13	35.13
Avoided Distribution Capacity	93.52	95.86	95.86	95.86	95.86	95.86
Avoided Distribution Losses	-	-	-	-	-	-
Other Avoided Costs						
Other Benefits						
Total (undiscounted) Avoided Costs	5,658.74	5,771.30	5,771.30	5,771.30	5,771.30	5,771.30
LDC Program Costs						
LDC OM&A Costs						
LDC Capital Costs						
Incremental Equipment Costs						
Participant Costs						
Total Program Costs	-	-	-	-	-	-
Total Avoided Costs less Program Costs	5,658.74	5,771.30	5,771.30	5,771.30	5,771.30	5,771.30

	2024	2025	2026	2027	2028	2029
Present value factor	0.315	0.294	0.274	0.255	0.238	0.222
Present value of cash flows	1,783.05	1,695.59	1,580.97	1,474.10	1,374.45	1,281.54
Accumulated present value of cash flows	34,376.39	36,071.98	37,652.95	39,127.05	40,501.50	41,783.04

NPV TRC	

Appendix E

Tax Returns for 2006

Canada Revenue Agency / Agence du revenu du Canada

BUSINESS CONSENT FORM

Use this form to consent to the release of confidential information about your Business Number (BN) account(s) to the representative named below, or to cancel consent for an existing representative.

- Complete Parts 1, 2, and 5 to name a representative.
- Complete Parts 3, 4 and 5 to cancel consent for an existing representative.
- Complete all parts of this form if you want to both name a new representative and cancel consent for an existing representative.

If you have questions, such as where to send this form, call us at 1-800-959-5525.

Part 1 – Consent to release of information to a representative

Client's name: CHAPLEAU PUBLIC UTILITIES CORPORATION Business Number: 89149 3322 RC0001

I consent to the release of confidential information about my BN account(s) by the Canada Customs and Revenue Agency to the representative named below.

KPMG LLP
Representative's name (If a firm, enter the name of the firm. If an individual, enter the first and last name of the individual.)

If you named a firm as your representative, and you want to specify a particular individual of that firm, enter that individual's first and last name.

(705) 675-8500
Representative's telephone number

Extension

(705) 675-7586
Representative's fax number

Part 2 – Details of consent

A. Which accounts?

I request that this consent apply to all accounts. [X] OR

I request that this consent apply only to the following accounts.
(Check the appropriate box or boxes. If you wish to authorize access to more than one account of the same type, for example RP0002 and RP0003, please print account numbers in the spaces provided.)

Corporate income tax	RC0001	[ ]	RC	______	RC	______
GST/HST	RT0001	[ ]	RT	______	RT	______
Payroll deductions	RP0001	[ ]	RP	______	RP	______
Import/Export	RM0001	[ ]	RM	______	RM	______

B. Which years?

I request that this consent apply to all years. [X] OR

I request that this consent apply only to the following years:

1. All year-ends up to: ______ Year Month Day
2. All year-ends beginning in: ______ Year Month Day and all years after that.
3. The following year-ends only: ______ Year Month Day ______ Year Month Day
   ______ Year Month Day ______ Year Month Day

RC59 E (01)

Canada

Part 3 – Cancellation of consent to release of information to a representative

Client's name: ______________________ Business Number: ____________

I cancel all previous consents for all representatives. ☐ OR

I cancel my consent to the release of confidential information about my BN account(s) by the Canada Customs and Revenue Agency to the representative named below.

Representative's name (If a firm, enter the name of the firm. If an individual, enter the first and last name of the individual.)

If you named a firm as your representative, and you want to cancel the consent for a particular individual of that firm, enter that individual's first and last name.

Representative's telephone number

Representative's fax number

Part 4 – Details of cancellation of consent

A. Which accounts?

I request that this cancellation of consent apply to all accounts. ☐ OR

I request that this cancellation of consent apply only to the following accounts.

(Check the appropriate box or boxes. If you wish to cancel access to more than one account of the same type, for example RP0002 and RP0003, please print account numbers in the spaces provided.)

Corporate income tax	RC0001	☐	RC ______	RC ______
GST/HST	RT0001	☐	RT ______	RT ______
Payroll deductions	RP0001	☐	RP ______	RP ______
Import/Export	RM0001	☐	RM ______	RM ______

B. Which years?

I request that this cancellation of consent apply to all years. ☐ OR

I request that this cancellation of consent apply only to the following years:

1. All year-ends up to: ____________ Year Month Day
2. All year-ends beginning in: ____________ Year Month Day and all years after that.
3. The following year-ends only: ____________ Year Month Day ____________ Year Month Day
   ____________ Year Month Day ____________ Year Month Day

Part 5 – Signature

Your name MARITA MORIN Title SECRETARY-TRESURER

This form must be signed by an owner, partner, director, trustee, or officer.

Sign here ► ______________________ Date 2007-11-23 Year Month Day

WE WILL NOT PROCESS THIS FORM IF IT IS NOT SIGNED

Canada Revenue Agency / Agence du revenu du Canada

T2 CORPORATION INCOME TAX RETURN

200

055 Do not use this area

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 corporation 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."

Identification

Business Number (BN) 001 89149 3322 RC0001

Corporation's name

002 CHAPLEAU PUBLIC UTILITIES CORPORATION

Has the corporation changed its name since the last time you filed your T2 return? 003 1 Yes [ ] 2 No [X]

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 [X]
(If *Yes*, complete lines 011 to 018)

011 P.O. BOX 670
012
City 015 CHAPLEAU — Province, territory, or state 016 ON
Country (other than Canada) 017 — Postal code/Zip code 018 P0M 1K0

To which tax year does this return apply?

Tax year start 060 2006-01-01 (YYYY MM DD) — Tax year-end 061 2006-12-31 (YYYY MM DD)

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? 063 1 Yes [ ] 2 No [X]

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 [X]
(If *Yes*, complete lines 021 to 028)

021 c/o
022
023
City 025 — Province, territory, or state 026
Country (other than Canada) 027 — Postal code/Zip code 028

Is the corporation a professional corporation that is a member of a partnership? 067 1 Yes [ ] 2 No [X]

Is this the first year of filing after:

Incorporation? 070 1 Yes [ ] 2 No [X]
Amalgamation? 071 1 Yes [ ] 2 No [X]
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 [X]
If *Yes*, complete and attach Schedule 24.

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 [X]
(If *Yes*, complete lines 031 to 038)

031 110 LORNE STREET SOUTH
032
City 035 CHAPLEAU — Province,territory, or state 036 ON
Country (other than Canada) 037 — Postal code/Zip code 038 P0M 1K0

Is this the final tax year before amalgamation? 076 1 Yes [ ] 2 No [X]

Is this the final return up to dissolution? 078 1 Yes [ ] 2 No [X]

Is the corporation a resident of Canada?

080 1 Yes [X] 2 No [ ] If *No*, give the country of residence on line 081 and complete and attach Schedule 97.
081

040 **Type of corporation at the end of the tax year**

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

If the type of corporation changed during the tax year, provide the effective date of the change 043 ____ YYYY MM DD

Is the non-resident corporation claiming an exemption under an income tax treaty? 082 1 Yes [ ] 2 No [X]
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

Do not use this area

091	092	093	094	095	096
100					

T2 E (06) Canada

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 *Income Tax Regulations*?	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	X	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	X	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	X	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	X	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
Is the corporation a non-resident-owned investment corporation claiming an allowable refund?	226		26*
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.**

Attachments – continued from page 2

		Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	256		T1134-A
Did the corporation have any controlled foreign affiliates?	258		T1134-B
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174

Additional information

		1 Yes	2 No
Is the corporation inactive?	280		X
Has the major business activity changed since the last return was filed? (enter *Yes* for first-time filers)	281		X

What is the corporation's major business activity? 282 ______
(Only complete if *Yes* was entered at line 281.)

If the major business activity involves the resale of goods, show whether it is wholesale or retail 283 — 1 Wholesale [X] 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	ELECTRICITY DISTN	285	95.000 %
286	SERVICE WORK	287	5.000 %
288		289	%

		1 Yes	2 No
Did the corporation immigrate to Canada during the tax year?	291		X
Did the corporation emigrate from Canada during the tax year?	292		X

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.			300	156,839	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	156,839			
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		156,839	►	156,839	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")					C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions			355		D
Taxable income (amount C **plus** amount D)			360		
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)					Z

* This amount is equal to 3 times the Part VI.1 tax payable at line 724.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7	400	156,839	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 form Part I tax	405		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 / Number of days in the tax year	/ 365	=		1
300,000	x	Number of days in the tax year in 2005 and in 2006 / Number of days in the tax year	365 / 365	=	300,000	2
400,000	x	Number of days in the tax year after 2006 / Number of days in the tax year	/ 365	=		3
		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 *** ______ D) / 11,250 = ______ E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0")	425	300,000	F

Small business deduction

Whichever amount is the least: A, B, C or F							G1
Amount G1		x	Number of days in the tax year before 2008 / Number of days in the tax year	365 / 365	x 16 %	=	G2
Amount G1		x	Number of days in the tax year in 2008 / Number of days in the tax year	/ 365	x 16.5 %	=	G3
Amount G1		x	Number of days in the tax year after 2008 / Number of days in the tax year	/ 365	x 17 %	=	G4

Small business deduction – total of amounts G2, G3, and G4 (enter amount G on line 9)	430		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 / Number of days in the tax year	/ 365	x 2 %	=	I
Amount H		x	Number of days in the tax year in 2005 / Number of days in the tax year	/ 365	x 3 %	=	J
Amount H		x	Number of days in the tax year in 2006 / Number of days in the tax year	365 / 365	x 5 %	=	K
Amount H		x	Number of days in the tax year after 2006 / Number of days in the tax year	/ 365	x 7 %	=	L

Resource deduction – total of amounts I, J, K, and L (enter amount M on line 10)	438		M

Accelerated tax reduction

Canadian-controlled private corporations throughout the taxation year that claimed the small business deduction

Reduced business limit (amount from line 425)	300,000 x 300,000 / line 4 above =	300,000	A
Net active business income (amount from line 400) *		156,839	B
Taxable income from line 360 **minus** 3 times the amount at line 636** on, and **minus** any amount that, because of federal law, is exempt from Part I Tax	C		
Deduct:			
Aggregate investment income (amount from line 440)	D		
Amount C **minus** amount D (if negative, enter "0")	▶		E
Amount A, B, or E above, whichever is less			F
Amount Z from Part 9 of Schedule 27 x 100 / 7 =	G		
Amount QQ from Part 13 of Schedule 27	H		
Taxable resource income (amount from line 435)	I		
Amount used to calculate the credit union deduction (amount E in Part 3 of Schedule 17)	J		
Amount on line 400, 405, 410, or 425 of the small business deduction, whichever is less	K		
Total of amounts G, H, I, J, and K	▶		L
Amount F **minus** amount L (if negative, enter "0")			M
Accelerated tax reduction – 7.00 % of amount M (enter amount N on line 637)			N

* If the amount at line 450 of Schedule 7 is positive, members of partnerships need to use Schedule 70 to calculate net active business income.

** Calculate the amount of foreign business income tax credit deductible at line 636 without reference to the corporate tax reductions under section 123.4.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360			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		
Amount used to calculate the accelerated tax reduction (amount M)	G1		
Total of amounts B, C, D, E, F, G, and G1	▶		H
Amount A **minus** amount H (if negative, enter "0")			I

Amount I	x	Number of days in the tax year before 2008 / Number of days in the tax year	365 / 365	x 7 %	=	J1
Amount I	x	Number of days in the tax year in 2008 / Number of days in the tax year	/ 365	x 7.5 %	=	J2
Amount I	x	Number of days in the tax year in 2009 / Number of days in the tax year	/ 365	x 8 %	=	J3
Amount I	x	Number of days in the tax year after 2009 / Number of days in the tax year	/ 365	x 9 %	=	J4

General tax reduction for Canadian-controlled private corporations – total of amounts J1, J2, J3, and J4 (enter amount J on line 638) ..... J

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

General tax reduction (continued)

Amount S		x	Number of days in the tax year before 2008 / Number of days in the tax year	365 / 365	x	7 %	=		T1
Amount S		x	Number of days in the tax year in 2008 / Number of days in the tax year	/ 365	x	7.5 %	=		T2
Amount S		x	Number of days in the tax year in 2009 / Number of days in the tax year	/ 365	x	8 %	=		T3
Amount S		x	Number of days in the tax year after 2009 / Number of days in the tax year	/ 365	x	9 %	=		T4

General tax reduction – total of amounts T1, T2, T3, and T4 (enter amount T on line 639) . . . . T

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 % = ______
(amount L from Part 2 of Schedule 7) (if negative, enter "0") ______ ▶ ______ B

Amount A **minus** amount B (if negative, enter "0") . . . . ______ C

Taxable income from line 360 . . . . ______

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 = ______

______ ▶ ______

x 26 2 / 3 % = ______ D

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780) . . . . ______

Deduct: Corporate surtax from line 600 . . . . ______

Net amount . . . . ______ ▶ ______ E

Refundable portion of Part I tax – Amount C, D, or E, whichever is the least . . . . **450** ______ F

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the preceding tax year . . . . **460** ______
Deduct: Dividend refund for the previous tax year . . . . **465** ______
______ ▶ ______ G

Add the total of:

Refundable portion of Part I tax from line 450 above . . . . ______
Total Part IV tax payable from line 360 of Schedule 3 . . . . ______
Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation . . . . **480** ______
______ ▶ ______ H

Refundable dividend tax on hand at the end of the tax year – Amount G **plus** amount H . . . . **485** ______

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 of Schedule 3 . . . . ______ x 1 / 3 ______ I

Refundable dividend tax on hand at the end of the tax year from line 485 above . . . . ______ J

Dividend refund – Amount I or J, whichever is less (enter this amount on line 784) . . . . ______

Part I tax

Base amount of Part I tax – 38.00 % of taxable income (line 360 or amount Z, whichever applies) . . . . 550 ______ A

Corporate surtax calculation

Base amount from line A above		1
Deduct:		
10 % of taxable income (line 360 or amount Z, whichever applies)		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:

28.00 % of taxable income from line 360		a		
28.00 % of taxed capital gains		b		6
Part I tax otherwise payable (line A **plus** lines C and D **minus** line F)		c		

Total of lines 2 to 6		7
Net amount (line 1 **minus** line 7)		8

Corporate surtax

line 8 ______ x 4 % x Number of days in the tax year before 2008 365 / Number of days in the tax year 365 = 600 ______ B

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			
Deduct:			
Amount on line 400, 405, 410, or 425, whichever is the least			
Net amount		▶	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) ______ E

Deduct:

Small business deduction from line 430			9
Federal tax abatement	608		
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		
Accelerated tax reduction from amount N	637		
Resource deduction from line 438			10
General tax reduction for CCPCs from amount J	638		
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		▶	F

Part I tax payable – Line E **minus** line F (enter amount G on line 700) . . . . ______ G

Summary of tax and credits

Federal tax

Part I tax payable	700	
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		

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 Québec, Ontario, and Alberta)	760	
Provincial tax on large corporations (New Brunswick and Nova Scotia)	765	

Total tax payable 770 ____ 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		
Allowable refund for non-resident-owned investment corporations from Schedule 26	804	
Provincial and territorial capital gains refund from Schedule 18	808	
Provincial and territorial refundable tax credits from Schedule 5	812	
Tax instalments paid	840	
Total credits	890	

____ B

Refund code 894 ____ Overpayment ____

Balance (line A **minus** line B) ____

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 ____

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 ____ Branch number

914 ____ Institution number

918 ____ Account number

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 X

Certification

I, 950 MORIN (Last name) 951 MARITA (First name) 954 SECRETARY-TRESURER (Position, office, or rank)

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 2007-11-23 Date (yyyy/mm/dd) ____ Signature of the authorized signing officer of the corporation 956 (705) 864-0111 Telephone number

Is the contact person the same as the authorized signing officer? If *No*, complete the information below . . . 957 1 Yes X 2 No ☐

958 ____ Name 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 X 2 Français / French ☐

Canada Revenue Agency / Agence du revenu du Canada

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 100

Name of corporation	Business Number	Tax year end Year Month Day
CHAPLEAU PUBLIC UTILITIES CORPORATION	89149 3322 RC0001	2006-12-31

Balance sheet information

Account	Description	GIFI		Amount	Prior year
	Assets				
	Total current assets	1599	+	1,387,515	1,616,427
	Total tangible capital assets	2008	+	2,175,939	2,151,647
	Total accumulated amortization of tangible capital assets	2009	–	1,266,778	1,229,408
	Total intangible capital assets	2178	+		
	Total accumulated amortization of intangible capital assets	2179	–		
	Total long-term assets	2589	+		
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	2,296,676	2,538,666
	Liabilities				
	Total current liabilities	3139	+	287,599	868,182
	Total long-term liabilities	3450	+	2,191,747	2,425,164
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	2,479,346	3,293,346
	Shareholder equity				
	Total shareholder equity (mandatory field)	3620	+	-182,670	-754,680
	Total liabilities and shareholder equity	3640	=	2,296,676	2,538,666
	Retained earnings				
	Retained earnings/deficit – end (mandatory field)	3849	=	-743,510	-754,780

* Generic item

Current Assets

Form identifier 1599

Account	Description	GIFI	Amount	Prior year
	Cash and deposits			
	* Cash and deposits	1000		
	Cash	1001	173,608	495,139
	Deposits in Canadian banks and institutions – Canadian currency	1002		
	Deposits in Canadian banks and institutions – foreign currency	1003		
	Deposits in foreign banks – Canadian currency	1004		
	Deposits in foreign banks – foreign currency	1005		
	Credit union central deposits	1006		
	Other cash like instruments	1007		
	Cash and deposits	+	173,608	495,139
	Accounts receivable			
	* Accounts receivable	1060		
	Trade accounts receivable	1062	508,681	549,663
	Trade accounts receivable from related parties	1064		
	Taxes receivable	1066		
	Interest receivable	1067		
	Holdbacks receivable	1068		
	Leases receivable	1069		
	Accounts receivable from employees	1071		
	Amounts receivable from members of NPOs	1073		
	Accounts receivable	+	508,681	549,663
	Allowance for doubtful accounts			
	* Allowance for doubtful accounts	1061		
	Allowance for doubtful trade accounts receivable	1063		
	Allowance for doubtful trade accounts receivable from related parties	1065		
	Allowance for doubtful amounts contained in leases receivable	1070		
	Allowance for doubtful accounts receivable from employees	1072		
	Allowance for doubtful accounts	–		
	Inventories			
	* Inventories	1120		
	Inventory of goods for sale	1121		
	Inventory parts and supplies	1122	43,787	29,309
	Inventory properties	1123		
	Inventory of aggregates	1124		
	Work in progress	1125		
	Raw materials	1126		
	Inventory of securities	1127		
	Inventories	+	43,787	29,309
	Short-term investments			
	* Short-term investments	1180		
	Canadian term deposits	1181		
	Canadian shares	1182		
	Canadian bonds	1183		
	Canadian treasury bills	1184	651,121	527,563
	Securities purchased under resale agreements	1185		
	Other short-term Canadian investments	1186		
	Short-term foreign investments	1187		
	Short-term investments	+	651,121	527,563

Loans and notes receivable

* Loans and notes receivable	1240			
Demand loans receivable	1241			
Other loans receivable	1242			
Notes receivable	1243			
Mortgages receivable	1244			
Loans and notes receivable		+		

Due from shareholder(s)/director(s)

* Due from shareholder(s)/director(s)	1300			
Due from individual shareholder(s)	1301			
Due from corporate shareholder(s)	1302			
Due from director(s)	1303			
Due from shareholder(s)/director(s)		+		

* Investment in joint venture(s)/partnership(s)	1360	+		

* Due from joint venture(s)/partnership(s)	1380	+		

Due from/investment in related parties

* Due from/investment in related parties	1400			
Demand notes from related parties	1401			
Interest receivable from related parties	1402			
Loans/advances due from related parties	1403			
Due from/investment in related parties		+		

* Customers' liability under acceptances	1460	+		

Other current assets

* Other current assets	1480			5,553
Future (deferred) income taxes	1481			
Accrued investment income	1482			
Taxes recoverable/refundable	1483			
Prepaid expenses	1484		10,318	9,200
Drilling advances	1485			
Security/tender deposits	1486			
Other current assets		+	10,318	14,753

Total current assets	1599	=	1,387,515	1,616,427

* Generic item

Tangible Capital Assets and Accumulated Amortization

Form identifier 2008/2009

Account	Description	GIFI		Tangible capital assets		Accumulated amortization	Prior year
	Land						
	* Land	1600	+	141			140
	Land improvements	1601	+				
	Accumulated amortization of land improvements	1602			–		
	Total			141			
	Depletable assets						
	* Depletable assets	1620	+				
	*Accumulated amortization of depletable assets	1621			–		
	Petroleum and natural gas properties	1622	+				
	Accumulated amortization of petroleum and natural gas properties	1623			–		
	Mining properties	1624	+				
	Accumulated amortization of mining properties	1625			–		
	Deferred exploration and development charges	1626	+				
	Accumulated amortization of deferred exploration and development charges	1627			–		
	Quarries	1628	+				
	Accumulated amortization of quarries	1629			–		
	Gravel pits	1630	+				
	Accumulated amortization of gravel pits	1631			–		
	Timber limits	1632	+				
	Accumulated amortization of timber limits	1633			–		
	Total						
	Buildings						
	* Buildings	1680	+				
	*Accumulated amortization of buildings	1681			–		
	Manufacturing and processing plant	1682	+				
	Accumulated amortization of manufacturing and processing plant	1683			–		
	Buildings under construction	1684	+				
	Total						
	Machinery, equipment, furniture and fixtures						
	* Machinery, equipment, furniture, and fixtures	1740	+				
	*Accumulated amortization of machinery, equipment, furniture, and fixtures	1741			–		
	Motor vehicles	1742	+				
	Accumulated amortization of motor vehicles	1743			–		
	Tools and dies	1744	+				
	Accumulated amortization of tools and dies	1745			–		
	Construction and excavating equipment	1746	+				
	Accumulated amortization of construction and excavating equipment	1747			–		
	Forestry and logging equipment	1748	+				
	Accumulated amortization of forestry and logging equipment	1749			–		
	Fishing gear and nets	1750	+				
	Accumulated amortization of fishing gear and nets	1751			–		
	Mining equipment	1752	+				
	Accumulated amortization of mining equipment	1753			–		
	Oil and gas systems	1754	+				

Machinery, equipment, furniture and fixtures (continued)

Accumulated amortization of oil and gas systems	1755			−	
Production equipment for resource industries	1756	+			
Accumulated amortization of production equipment for resource industries	1757			−	
Production equipment for other than resource industries	1758	+			
Accumulated amortization of production equipment for other than resource industries	1759			−	
Exploration equipment	1760	+			
Accumulated amortization of exploration equipment	1761			−	
Shipping equipment	1762	+			
Accumulated amortization of shipping equipment	1763			−	
Ships and boats	1764	+			
Accumulated amortization of ships and boats	1765			−	
Aircraft	1766	+			
Accumulated amortization of aircraft	1767			−	
Signs	1768	+			
Accumulated amortization of signs	1769			−	
Small tools	1770	+			
Accumulated amortization of small tools	1771			−	
Radio and communication equipment	1772	+			
Accumulated amortization of radio and communication equipment	1773			−	
Computer equipment/software	1774	+			
Accumulated amortization of computer equipment/software	1775			−	
Musical instruments	1776	+			
Accumulated amortization of musical instruments	1777			−	
Satellites	1778	+			
Accumulated amortization of satellites	1779			−	
Earth stations	1780	+			
Accumulated amortization of earth stations	1781			−	
Machinery and equipment under construction	1782	+			
Transportation equipment	1783	+			
Accumulated amortization of transportation equipment	1784			−	
Other machinery and equipment	1785	+			
Accumulated amortization of other machinery and equipment	1786			−	
Furniture and fixtures	1787	+			
Accumulated amortization of furniture and fixtures	1788			−	
Total					

Other tangible capital assets

* Other tangible capital assets	1900	+	2,175,798			2,151,507
*Accumulated amortization of other tangible capital assets	1901			−	1,266,778	1,229,408
Logging roads	1902	+				
Accumulated amortization of logging roads	1903			−		
Asphalt and parking areas	1904	+				
Accumulated amortization of asphalt and parking areas	1905			−		
Wharves	1906	+				
Accumulated amortization of wharves	1907			−		

Other tangible capital assets (continued)

		Code				
	Fences	1908	+			
	Accumulated amortization of fences	1909			–	
	Capital leases – buildings	1910	+			
	Accumulated amortization of capital leases – buildings	1911			–	
	Capital leases – equipment	1912	+			
	Accumulated amortization of capital leases – equipment	1913			–	
	Capital leases – vehicles	1914	+			
	Accumulated amortization of capital leases – vehicles	1915			–	
	Capital leases – others	1916	+			
	Accumulated amortization of capital leases – others	1917			–	
	Leasehold improvements	1918	+			
	Accumulated amortization of leasehold improvements	1919			–	
	Other capital assets under construction	1920	+			
	Campsites	1921	+			
	Accumulated amortization of campsites	1922			–	
	Total			2,175,798	1,266,778	

	Total tangible capital assets	2008	=	2,175,939		2,151,647

	Total accumulated amortization of tangible capital assets	2009			= 1,266,778	1,229,408

* Generic item

Current Liabilities

Form identifier 3139

Account	Description	GIFI		Amount	Prior year
	* Bank overdraft	2600	+		
	Amounts payable and accrued liabilities				
	* Amounts payable and accrued liabilities	2620			
	Trade payables	2621		267,048	664,277
	Trade payables to related parties	2622			
	Holdbacks payable	2623			
	Wages payable	2624			
	Management fees payable	2625			
	Bonuses payable	2626			
	Employee deductions payable	2627			
	Withholding taxes payable	2628			
	Interest payable	2629			203,905
	Amounts payable to members of NPOs	2630			
	Amounts payable and accrued liabilities		+	267,048	868,182
	* Taxes payable	2680	+		
	Short-term debt				
	* Short-term debt	2700			
	Loans from Canadian banks	2701			
	Liability for securities sold short	2702			
	Liability for securities sold under repurchase agreements	2703			
	Gold and silver certificates	2704			
	Cheques and other items in transit	2705			
	Lien notes	2706			
	Credit card loans	2707			
	Short-term debt		+		
	* Deferred income	2770	+		
	Due to shareholder(s)/director(s)				
	* Due to shareholder(s)/director(s)	2780			
	Due to individual shareholder(s)	2781			
	Due to corporate shareholder(s)	2782			
	Due to director(s)	2783			
	Due to shareholder(s)/director(s)		+		
	* Due to joint venture(s)/partnership(s)	2840	+		
	Due to related parties				
	* Due to related parties	2860		20,551	
	Demand notes due to related parties	2861			
	Interest payable to related parties	2862			
	Advances due to related parties	2863			
	Due to related parties		+	20,551	

* Current portion of long-term liability	2920	+		
* Bankers' acceptances	2940	+		

Other current liabilities

* Other current liabilities	2960			
Deposits received	2961			
Dividends payable	2962			
Future (deferred) income taxes	2963			
Reserves for guarantees, warranties, or indemnities	2964			
General provisions/reserves	2965			
Crew shares	2966			
Other current liabilities		+		

Total current liabilities	3139	=	287,599	868,182

* Generic item

Long-term Liabilities

Form identifier 3450

Account	Description	GIFI		Amount	Prior year
	Long-term debt				
	* Long-term debt	3140		360,727	717,560
	Mortgages	3141		1,321,493	1,321,493
	Farm credit corporation loan	3142			
	Chartered bank loan	3143			
	Credit Union/Caisse Populaire loan	3144			
	Provincial government loan	3145			
	Supply company loan	3146			
	Private loan	3147			
	Central, league, and federation loans	3148			
	Line of credit	3149			
	Liability for securities sold short	3150			
	Liability for securities sold under repurchase agreements	3151			
	Lien notes	3152			
	Long-term debt		+	1,682,220	2,039,053
	* Deposit liabilities of financial institutions	3200	+		
	* Bonds and debentures	3210	+		
	* Deferred income	3220	+		
	* Future (deferred) income taxes	3240	+		
	Due to shareholder(s)/director(s)				
	* Due to shareholder(s)/director(s)	3260			
	Due to individual shareholder(s)	3261			
	Due to corporate shareholder(s)	3262			
	Due to director(s)	3263			
	Due to shareholder(s)/director(s)		+		
	* Due to members	3270	+		
	* Due to joint venture(s)/partnership(s)	3280	+		
	Due to related parties				
	* Due to related parties	3300			
	Amounts owing to related Canadian parties	3301			
	Amounts owing to related foreign parties	3302			
	Due to related parties		+		

Other long-term liabilities

* Other long-term liabilities	3320		509,527	386,111
Long-term obligations/commitments/capital leases	3321			
Reserves for guarantees, warranties, or indemnities	3322			
Provision for site restoration	3323			
Contributions to qualifying environmental trust	3324			
General provisions/reserves	3325			
Preference shares restated	3326			
Member allocations	3327			
Deferred revenue from incomplete contracts	3328			
Other long-term liabilities		+	509,527	386,111

Total long-term liabilities	3450	=	2,191,747	2,425,164

* Generic item

Shareholder Equity

Form identifier 3620

Account	Description	GIFI		Amount	Prior year
	* Common shares	3500	+	560,840	100
	* Preferred shares	3520	+		
	Contributed and other surplus				
	* Contributed and other surplus	3540			
	Contributed surplus	3541			
	Appraisal surplus	3542			
	General reserve	3543			
	Contributed and other surplus		+		
	* Head office account	3570	+		
	* Retained earnings/deficit	3600	+	-743,510	-754,780
	Total shareholder equity	3620	=	-182,670	-754,680

* Generic item

Retained Earnings/Deficit

Form identifier 3849

Account	Description	GIFI		Amount	Prior year
	* Retained earnings/deficit – start	3660	+	-862,979	-488,681
	* Net income/loss	3680	+	119,469	-266,099
	Dividends declared				
	* Dividends declared	3700			
	Cash dividends	3701			
	Patronage dividends	3702			
	Dividends declared		–		
	* Prior period adjustments	3720	+		
	Other items affecting retained earnings				
	* Other items affecting retained earnings	3740			
	Share redemptions	3741			
	Special reserves	3742			
	Currency adjustments	3743			
	Unusual revenue items	3744			
	Interfund transfer	3745			
	Other items affecting retained earnings		+		
	Retained earnings/deficit – end	3849	=	-743,510	-754,780

* Generic item

Canada Revenue Agency / Agence du revenu du Canada

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 125

Name of corporation	Business Number	Tax year end Year Month Day
CHAPLEAU PUBLIC UTILITIES CORPORATION	89149 3322 RC0001	2006-12-31

Income statement information

Description	GIFI	
Operating name	0001	CHAPLEAU PUBLIC UTILITES CORPORATION
Description of the operation	0002	ELECTRICITY DISTRIBUTION COMPANY
Sequence Number	0003	01

Account	Description	GIFI		Amount	Prior year
	Income statement information				
	Total sales of goods and services	8089	+	2,657,000	2,642,790
	Cost of sales	8518	–	2,043,433	2,118,568
	Gross profit/loss	8519	=	613,567	524,222
	Cost of sales	8518	+	2,043,433	2,118,568
	Total operating expenses	9367	+	564,712	823,077
	Total expenses (mandatory field)	9368	=	2,608,145	2,941,645
	Total revenue (mandatory field)	8299	+	2,727,614	2,675,546
	Total expenses (mandatory field)	9368	–	2,608,145	2,941,645
	Net non-farming income	9369	=	119,469	-266,099
	Farming income statement information				
	Total farm revenue (mandatory field)	9659	+		
	Total farm expenses (mandatory field)	9898	–		
	Net farm income	9899	=		
	Net income/loss before taxes and extraordinary items	9970	=	119,469	-266,099
	Extraordinary items and income (linked to Schedule 140)				
	Extraordinary item(s)	9975	–		
	Legal settlements	9976	–		
	Unrealized gains/losses	9980	+		
	Unusual items	9985	–		
	Current income taxes	9990	–		
	Deferred income tax provision	9995	–		
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	119,469	-266,099

Revenue

Form identifier 8299

Account	Description	GIFI		Amount	Prior year
	* Trade sales of goods and services	8000	+	2,657,000	2,642,790
	* Sales of goods and services to related parties	8020	+		
	* Interdivisional sales	8030	+		

Sales from resource properties

Account	Description	GIFI		Amount	Prior year
	* Sales from resource properties	8040			
	Petroleum and natural gas sales	8041			
	Petroleum and natural gas sales to related parties	8042			
	Gas marketing	8043			
	Processing revenue	8044			
	Pipeline revenue	8045			
	Seismic sales	8046			
	Mining revenue	8047			
	Coal revenue	8048			
	Oil sands revenue	8049			
	Royalty income	8050			
	Oil and gas partnership/joint venture income/loss	8051			
	Mining partnership/joint venture income/loss	8052			
	Other production revenue	8053			
	Sales from resource properties		+		

Account	Description	GIFI		Amount	Prior year
	Total sales of goods and services	8089	=	2,657,000	2,642,790

Investment revenue

Account	Description	GIFI		Amount	Prior year
	* Investment revenue	8090		4,684	5,090
	Interest from foreign sources	8091			
	Interest from Canadian bonds and debentures	8092			
	Interest from Canadian mortgage loans	8093			
	Interest from other Canadian sources	8094		48,509	19,207
	Dividend income	8095			
	Dividends from Canadian sources	8096			
	Dividends from foreign sources	8097			
	Investment revenue		+	53,193	24,297

Interest income (financial institutions)

Account	Description	GIFI		Amount	Prior year
	* Interest income (financial institutions)	8100			
	Loan interest	8101			
	Securities interest	8102			
	Deposits with banks interest	8103			
	Interest income (financial institutions)		+		

Commission revenue

Account	Description	GIFI		Amount	Prior year
	* Commission revenue	8120			
	Commission income on real estate transactions	8121			
	Commission revenue		+		

Rental revenue

	* Rental revenue	8140			
	Real estate rental revenue	8141			
	Film rental revenue	8142			
	Rental revenue		+		

	* Vehicle leasing	8150	+		

Fishing revenue

	* Fishing revenue	8160			
	Fish products	8161			
	Other marine products	8162			
	Fishing grants, credits, and rebates	8163			
	Fishing subsidies	8164			
	Compensation for loss of fishing income or property	8165			
	Sharesman income	8166			
	Fishing revenue		+		

Realized gains/losses on disposal of assets

	* Realized gains/losses on disposal of assets	8210			
	Realized gains/losses on sale of investments	8211			
	Realized gains/losses on sale of resource properties	8212			
	Realized gains/losses on disposal of assets		+		

NPO amounts received

	* Non-Profit organizations amounts received	8220			
	Membership fees	8221			
	Assessments	8222			
	Gifts	8223			
	Gross sales and revenues from organizational activities	8224			
	NPO amounts received		+		

Other revenue

	* Other revenue	8230		17,421	8,459
	Foreign exchange gains/losses	8231			
	Income/loss of subsidiaries/affiliates	8232			
	Income/loss of other divisions	8233			
	Income/loss of joint ventures	8234			
	Income/loss of partnerships	8235			
	Realization of deferred revenues	8236			
	Royalty income other than resource	8237			
	Alberta royalty tax credits	8238			
	Management and administration fees	8239			
	Telecommunications revenue	8240			
	Consulting fees	8241			
	Subsidies and grants	8242			
	Sale of by-products	8243			
	Deposit services	8244			
	Credit services	8245			
	Card services	8246			
	Patronage dividends	8247			
	Insurance recoveries	8248			
	Expense recoveries	8249			
	Bad debt recoveries	8250			
	Other revenue		+	17,421	8,459

	Total revenue	8299	=	2,727,614	2,675,546

* Generic item

Cost of Sales

Form identifier 8518

Account	Description	GIFI		Amount	Prior year
	Opening inventory				
	* Opening inventory	8300			
	Opening inventory – finished goods	8301			
	Opening inventory – raw materials	8302			
	Opening inventory – goods in process	8303			
	Opening inventory		+		
	* Purchases/cost of materials	8320	+	2,043,433	2,118,568
	* Direct wages	8340	+		
	* Benefits on direct wages	8350	+		
	* Trades and sub-contracts	8360	+		
	* Production costs other than resource	8370	+		
	Resource production costs				
	* Resource production costs	8400			
	Pipeline operations	8401			
	Drilling	8402			
	Site restoration costs	8403			
	Gross overriding royalty	8404			
	Freehold royalties	8405			
	Other producing properties rental	8406			
	Prospect/geological	8407			
	Well operating, fuel and equipment	8408			
	Well abandonment and dry holes	8409			
	Other lease rentals	8410			
	Exploration expenses	8411			
	Development expenses	8412			
	Resource production costs		+		
	Crown charges				
	* Crown charges	8435			
	Crown royalties	8436			
	Crown lease rentals	8437			
	Freehold mineral tax	8438			
	Mining taxes	8439			
	Oil sand leases	8440			
	Saskatchewan resource surcharge	8441			
	Crown charges		+		

Other direct costs

	* Other direct costs	8450			
	Equipment hire and operation	8451			
	Log yard	8452			
	Forestry costs	8453			
	Logging road costs	8454			
	Stumpage costs	8455			
	Royalty costs	8456			
	Freight in and duty	8457			
	Inventory write down	8458			
	Direct cost amortization of tangible assets	8459			
	Direct cost amortization of natural resource assets	8460			
	Overhead expenses allocated to cost of sales	8461			
	Other direct costs		+		

Closing inventory

	* Closing inventory	8500			
	Closing inventory – finished goods	8501			
	Closing inventory – raw materials	8502			
	Closing inventory – goods in process	8503			
	Closing inventory		–		

	Cost of sales	8518	=	2,043,433	2,118,568

* Generic item

Operating Expenses

Form identifier 9367

Account	Description	GIFI		Amount	Prior year
	Advertising and promotion				
	* Advertising and promotion	8520			
	Advertising	8521			
	Donations	8522			
	Meals and entertainment	8523			
	Promotion	8524			
	Advertising and promotion		+		
	* Amortization of intangible assets	8570	+		
	* Goodwill impairment loss	8571	+		
	* Bad debt expense	8590	+		
	Loan losses				
	* Loan losses	8610			
	Provision for loan losses	8611			
	Loan losses		+		
	Employee benefits				
	* Employee benefits	8620			
	Group insurance benefits	8621			
	Employer's portion of employee benefits	8622			
	Contributions to deferred income plans	8623			
	Employee benefits		+		
	* Amortization of natural resource assets	8650	+		
	* Amortization of tangible assets	8670	+	37,370	37,731
	Insurance				
	* Insurance	8690			
	Life insurance on executives	8691			
	Insurance		+		
	Interest and bank charges				
	* Interest and bank charges	8710		36,114	8,815
	Interest on short-term debt	8711			
	Interest on bonds and debentures	8712			
	Interest on mortgages	8713			250,445
	Interest on long-term debt	8714			
	Bank charges	8715			
	Credit card charges	8716			
	Collection and credit costs	8717			
	Interest and bank charges		+	36,114	259,260

Interest paid (financial institutions)

		Code		
	* Interest paid (financial institutions)	8740		
	Interest paid on deposits	8741		
	Interest paid on bonds and debentures	8742		
	Interest paid (financial institutions)	+		

Business taxes, licences, and memberships

		Code		
	* Business taxes, licences, and memberships	8760		
	Memberships	8761		
	Business taxes	8762		
	Franchise fees	8763		
	Government fees	8764		
	Business taxes, licences, and memberships	+		

		Code		
	* New Brunswick tax on large corporations	8780 +		

		Code		
	* Nova Scotia tax on large corporations	8790 +		

Office expenses

		Code		
	* Office expenses	8810		
	Office stationery and supplies	8811		
	Office utilities	8812		
	Data processing	8813		
	Office expenses	+		

Professional fees

		Code		
	* Professional fees	8860		
	Legal fees	8861		
	Accounting fees	8862		
	Consulting fees	8863		
	Architect fees	8864		
	Appraisal fees	8865		
	Laboratory fees	8866		
	Medical fees	8867		
	Veterinary fees	8868		
	Brokerage fees	8869		
	Transfer fees	8870		
	Management and administration fees	8871		
	Refining and assay	8872		
	Registrar and transfer agent fees	8873		
	Restructuring costs	8874		
	Security commission fees	8875		
	Training expense	8876		
	Studio and recording	8877		
	Professional fees	+		

Rental

* Rental	8910		
Real estate rental	8911		
Occupancy costs	8912		
Condominium fees	8913		
Equipment rental	8914		
Motor vehicle rentals	8915		
Moorage (boat)	8916		
Storage	8917		
Quota rental	8918		
Rental	+		

Repairs and maintenance

* Repairs and maintenance	8960		
Repairs and maintenance – buildings	8961		
Repairs and maintenance – vehicles	8962		
Repairs and maintenance – boats	8963		
Repairs and maintenance – machinery and equipment	8964		
Repairs and maintenance	+		

Other repairs and maintenance

* Other repairs and maintenance	9010	262,647	291,278
Machine shop expense	9011		
Road costs	9012		
Security	9013		
Garbage removal	9014		
Other repairs and maintenance	+	262,647	291,278

Salaries and wages

* Salaries and wages	9060		
Commissions	9061		
Crew share	9062		
Bonuses	9063		
Directors fees	9064		
Management salaries	9065		
Employee salaries	9066		
Salaries and wages	+		

* Sub-contracts	9110 +		

Supplies

* Supplies	9130		
Small tools	9131		
Shop expense	9132		
Uniforms	9133		
Laundry	9134		
Food and catering	9135		
Fishing gear	9136		
Nets and traps	9137		
Salt, bait, and ice	9138		
Camp supplies	9139		
Computer-related expenses	9150		
Upgrade	9151		
Internet	9152		
Supplies	+		

* Property taxes	9180	+		

Travel expenses

* Travel expenses	9200			
Meetings and conventions	9201			
Travel expenses		+		

Utilities

* Utilities	9220			
Electricity	9221			
Water	9222			
Heat	9223			
Fuel costs	9224			
Telephone et telecommunications	9225			
Utilities		+		

Other expenses

* Other expenses	9270			
Cash over/short	9271			
Reimbursement of parent company expense	9272			
Selling expenses	9273		63,918	52,929
Shipping and warehouse expense	9274			
Delivery, freight and express	9275			
Warranty expenses	9276			
Royalty expenses – resident	9277			
Royalty expenses – non-resident	9278			
Dumping charges	9279			
Land fill fees	9280			
Vehicle expenses	9281			
Research and development	9282			
Withholding taxes	9283			
General and administrative expenses	9284		164,663	181,879
Interdivisional expenses	9285			
Interfund transfer	9286			
Other expenses		+	228,581	234,808

Total operating expenses	9367	=	564,712	823,077

* Generic item

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SCHEDULE 141

NOTES CHECKLIST

Corporation's name	Business Number	Tax year end Year Month Day
CHAPLEAU PUBLIC UTILITIES CORPORATION	89149 3322 RC0001	2006-12-31

- This schedule should be completed from the perspective of the person who prepared or reported on the **financial statements**. This person is referred to as the "accounting practitioner", in this schedule.
- For more information, see RC4088, *Guide to the General Index of Financial Information (GIFI) for Corporations* and T4012, *T2 Corporation – Income Tax Guide*.
- Attach a copy of this schedule, along with any Notes to the financial statements, to the GIFI.

Part 1 – Accounting practitioner information

		1 Yes	2 No
Does the accounting practitioner have a professional designation?	095	X	
Is the accounting practitioner connected* with the corporation?	097		X

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Note
If the accounting practitioner does not have a professional designation **or** is connected with the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you do have to complete Part 4.

Part 2 – Type of involvement

Choose the option that represents the highest level of involvement of the accounting practitioner: **198**

Completed an auditor's report	1	X
Completed a review engagement report	2	
Conducted a compilation engagement	3	

Part 3 – Reservations

If you selected option "1" or "2" under **Type of involvement** above, answer the following question:

		1 Yes	2 No
Has the accounting practitioner expressed a reservation?	099		X

Part 4 – Other information

		1 Yes	2 No
Were notes to the financial statements prepared?	101	X	
If *Yes*, complete lines 102 to 107 below:			
Are any values presented at other than cost?	102		X
Has there been a change in accounting policies since the last return?	103		X
Are subsequent events mentioned in the notes?	104		X
Is re-evaluation of asset information mentioned in the notes?	105		X
Is contingent liability information mentioned in the notes?	106	X	
Is information regarding commitments mentioned in the notes?	107	X	
Does the corporation have investments in joint venture(s) or partnership(s)?	108		X
If *Yes*, complete line 109 below:			
Are you filing financial statements of the joint venture(s) or partnership(s)?	109		

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SCHEDULE 1

NET INCOME (LOSS) FOR INCOME TAX PURPOSES

Corporation's name	Business Number	Tax year end Year Month Day
CHAPLEAU PUBLIC UTILITIES CORPORATION	89149 3322 RC0001	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			119,469	A
Add:				
Amortization of tangible assets	104	37,370		
Subtotal of additions		37,370 ▶	37,370	
Other additions:				
Miscellaneous other additions:				
Subtotal of other additions	199	0 ▶	0	
Total additions	500	37,370 ▶	37,370	
Deduct:				
Subtotal of deductions		0 ▶	0	
Other deductions:				
Miscellaneous other deductions:				
Total	394			
Subtotal of other deductions	499	0 ▶	0	
Total deductions	510	0 ▶	0	
Net income (loss) for income tax purposes – enter on line 300 of the T2 return			156,839	

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SCHEDULE 4

CORPORATION LOSS CONTINUITY AND APPLICATION

Name of corporation	Business Number	Tax year-end Year Month Day
CHAPLEAU PUBLIC UTILITIES CORPORATION	89149 3322 RC0001	2006-12-31

- For use by a corporation to determine the continuity and use of available losses; to determine the current-year non-capital loss, farm loss, restricted farm loss, and limited partnership loss; to determine the amount of restricted farm loss and limited partnership loss that may be applied in a year; and to request a loss carryback to previous years.
- The corporation can choose whether or not to deduct an available loss from income in a tax year. It can deduct losses in any order. However, for each type of loss, deduct the oldest loss first.
- In accordance with subsection 111(4) of the *Income Tax Act*, when control has been acquired no amount of capital loss incurred for a tax year ending (TYE) before that time is deductible in computing taxable income in a TYE after that time AND no amount of capital loss incurred in a TYE after that time is deductible in computing taxable income of a TYE before that time.
- When control has been acquired, subsection 111(5) provides for similar treatment of non-capital and farm losses, except as listed in paragraphs 111(5)(a) & (b).
- For information on these losses, see the *T2 Corporation – Income Tax Guide*.
- File one completed copy of this schedule with the T2 return, or send it by itself to the tax centre where the return is filed.
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the federal *Income Tax Act*.

Part 1 – Non-capital losses

Determination of current-year non-capital loss

Net income (loss) for income tax purposes		156,839
Deduct: (increase a loss)		
Net capital losses deducted in the year (enter as a positive amount)		
Taxable dividends deductible under sections 112, 113, or subsection 138(6)		
Amount of Part VI.1 tax deductible		
Amount deductible as prospector's and grubstaker's shares – Paragraph 110(1)(d.2)		
Subtotal (if positive, enter "0")		
Deduct: (increase a loss)		
Section 110.5 and/or subparagraph 115(1)(a)(vii) – Addition for foreign tax deductions		
Subtotal		
Add: (decrease a loss)		
Current-year farm loss		
Current-year non-capital loss (if positive, enter "0")		

Continuity of non-capital losses and request for a carryback

	Line		
Non-capital loss at the end of preceding tax year		849,456	
Deduct: Non-capital loss expired *	100		
Non-capital losses at beginning of tax year	102	884,573	
Add: Non-capital losses transferred on an amalgamation or the wind-up of a subsidiary corporation	105		
Current-year non-capital loss (from calculation above)	110		884,573
Deduct:			
Other adjustments (includes adjustments for an acquisition of control)	150		
Section 80 – Adjustments for forgiven amounts	140		
Subsection 111(10) – Adjustments for fuel tax rebate			
Deduct:			
Amount applied against taxable income (enter on line 331 of the T2 return)	130	156,839	
Amount applied against taxable dividends subject to Part IV tax	135		156,839
Subtotal			727,734
Deduct – Request to carry back non-capital loss to:			
First preceding tax year to reduce taxable income	901		
Second preceding tax year to reduce taxable income	902		
Third preceding tax year to reduce taxable income	903		
First preceding tax year to reduce taxable dividends subject to Part IV tax	911		
Second preceding tax year to reduce taxable dividends subject to Part IV tax	912		
Third preceding tax year to reduce taxable dividends subject to Part IV tax	913		
Non-capital losses – Closing balance	180		727,734

* A non-capital loss expires as follows:
- After **7** tax years if it arose in a tax year ending before March 23, 2004;
- After **10** tax years if it arose in a tax year ending after March 22, 2004 and ending before 2006; or
- After **20** tax years if it arose in a tax year ending in 2006 and later.

An allowable business investment loss becomes a net capital loss as follows:
- After **7** tax years if it arose in a tax year ending before March 23, 2004;
- After **10** tax years if it arose in a tax year ending after March 22, 2004.

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Canada

Election under paragraph 88(1.1)(f)

Paragraph 88(1.1)(f) election indicator . . . . 190 Yes ☐
Loss from a wholly owned subsidiary deemed to be a loss of the parent from its immediately preceding tax year.

Part 2 - Capital losses

Continuity of capital losses and request for a carryback

Capital losses at end of preceding tax year	200		
Capital losses transferred on an amalgamation or the wind-up of a subsidiary corporation	205		
Deduct:			
Other adjustments (includes adjustments for an acquisition of control)	250		
Section 80 – Adjustments for forgiven amounts	240		
Add:		Subtotal	
Current-year capital loss (from Schedule 6 calculation)		210	
Unused non-capital losses from the 11th preceding tax year*		A	
Allowable business investment losses (ABIL) incurred in the 11th preceding tax year*		B	
Enter amount from line A or B, whichever is less	215		
Allowable business investment loss expired as non-capital loss: line 215 divided by inclusion rate** 75.0000 %		220	
		Subtotal	

Note: If there has been an amalgamation or a wind-up of a subsidiary, do a separate calculation of the allowable business investment loss expired as non-capital loss for each predecessor or subsidiary. Add all these amounts and enter the total at line 220 above.

Deduct: Amount applied against current-year capital gain (see Note 1)		225	
		Subtotal	

Deduct – Request to carry back capital loss to: (see Note 2)

	Capital gain (100%)		Amount carried back (100%)	
First preceding tax year		951		
Second preceding tax year		952		
Third preceding tax year		953		
Capital losses – Closing balance			280	

Note 1

On line 332 of the T2 return, enter the amount from line 225 multiplied by 50%.

Note 2

Enter on lines 225, 951, 952, or 953, whichever applies, the actual amount of the loss. At the time of the application of the loss carryback, the net capital loss amount will be calculated at the inclusion rate of the year to which the net capital loss is applied.

*
- Losses from the 11th preceding tax year to be entered at line A and line B are those incurred in a tax year ending after March 22, 2004. If they were incurred in a tax year ending before March 23, 2004, enter the losses from the 8th preceding tax year.
- For non-capital losses, enter at line A the portion that has not been used in previous years and the current year. For allowable business investment losses, enter the full amount at line B.

** The inclusion rate is the one that you used to calculate your ABIL referred to at line B. Therefore, use one of the following inclusion rates, whichever applies:

- For ABILs incurred in 1999 and preceding tax years, use 0.75.
- For ABILs incurred in 2000 and 2001 tax years, the inclusion rate is equal to amount M on Schedule 6 - version T2SCH6(01).
- For ABILs incurred in 2002 and later tax years, use 0.5.

Part 3 – Farm losses

Continuity of farm losses and request for a carryback

Farm losses at end of preceding tax year			
Deduct: Farm loss expired after 10 tax years *	300		
Farm losses at beginning of tax year	302		
Add: Farm losses transferred on an amalgamation or the wind-up of a subsidiary corporation	305		
Current-year farm loss	310		
Deduct:			
Other adjustments (includes adjustments for an acquisition of control)	350		
Section 80 – Adjustments for forgiven amounts	340		
Amount applied against taxable income (enter on line 334 of the T2 return)	330		
Amount applied against taxable dividends subject to Part IV tax	335		
Subtotal			
Deduct – Request to carry back farm loss to:			
First preceding tax year to reduce taxable income	921		
Second preceding tax year to reduce taxable income	922		
Third preceding tax year to reduce taxable income	923		
First preceding tax year to reduce taxable dividends subject to Part IV tax	931		
Second preceding tax year to reduce taxable dividends subject to Part IV tax	932		
Third preceding tax year to reduce taxable dividends subject to Part IV tax	933		
Farm losses – Closing balance		380	

* A farm loss expires as follows:
- After **7** tax years if it arose in a tax year ending before March 23, 2004;
- After **10** tax years if it arose in a tax year ending after March 22, 2004 and ending before 2006; or
- After **20** tax years if it arose in a tax year ending in 2006 and later.

Part 4 – Restricted farm losses

Current-year restricted farm loss

Total losses for the year from farming business ..... 485 ______ C

Minus the deductible farm loss:

$2,500 plus D or E, whichever is less ..... $ 2,500

(Amount C above ______ – $2,500) divided by 2 = ______ D

$ 6,250 E ______ 2,500 F

Current-year restricted farm loss (amount C minus amount F) (enter this amount on line 410) ......

Continuity of restricted farm losses and request for a carryback

Restricted farm losses at end of preceding tax year			
Deduct: Restricted farm loss expired after 10 tax years *	400		
Restricted farm losses at beginning of tax year	402		
Add: Restricted farm losses transferred on an amalgamation or the wind-up of a subsidiary corporation	405		
Current-year restricted farm loss (enter on line 233 of Schedule 1)	410		
Deduct:			
Amount applied against farming income (enter on line 333 of the T2 return)	430		
Section 80 – Adjustments for forgiven amounts	440		
Other adjustments	450		
Subtotal			
Deduct – Request to carry back restricted farm loss to:			
First preceding tax year to reduce farming income	941		
Second preceding tax year to reduce farming income	942		
Third preceding tax year to reduce farming income	943		
Restricted farm losses – Closing balance		480	

Note

The total losses for the year from all farming businesses are calculated without including scientific research expenses.

* A restricted farm loss expires as follows:
- After **7** tax years if it arose in a tax year ending before March 23, 2004;
- After **10** tax years if it arose in a tax year ending after March 22, 2004 and ending before 2006; or
- After **20** tax years if it arose in a tax year ending in 2006 and later.

Part 5 – Listed personal property losses

Continuity of listed personal property loss and request for a carryback

Listed personal property losses at end of preceding tax year				
Deduct: Listed personal property loss expired after seven tax years			500	
Listed personal property losses at beginning of tax year			502	
Add: Current-year listed personal property loss (from Schedule 6)			510	
			Subtotal	
Deduct:				
Amount applied against listed personal property gains (enter on line 655 of Schedule 6)	530			
Other adjustments	550			
			Subtotal	
Deduct – Request to carry back listed personal property loss to:				
First preceding tax year to reduce listed personal property gains	961			
Second preceding tax year to reduce listed personal property gains	962			
Third preceding tax year to reduce listed personal property gains	963			
Listed personal property losses – Closing balance			580	

Part 7 – Limited partnership losses

Current-year limited partnership losses

1	2	3	4	5	6	7
Partnership identifier	Fiscal period ending	Corporation's share of limited partnership loss	Corporation's at-risk amount	Total of corporation's share of partnership investment tax credit, farming losses, and resource expenses	Column 4 **minus** column 5 If negative, enter "0".	Current-year limited partnership losses Column 3 - 6
600	602	604	606	608		620

Total (enter this amount on line 222 of Schedule 1)

Limited partnership losses from prior tax years that may be applied in the current year

1	2	3	4	5	6	7
Partnership identifier	Fiscal period ending	Limited partnership losses at end of preceding tax year	Corporation's at-risk amount	Total of corporation's share of partnership investment tax credit, business or property losses, and resource expenses	Column 4 **minus** column 5 If negative, enter "0".	Limited partnership losses that may be applied in the year. The lesser of columns 3 and 6
630	632	634	636	638		650

Continuity of limited partnership losses that can be carried forward to future tax years

Partnership identifier	Limited partnership losses at end of preceding tax year	Limited partnership losses transferred on an amalgamation or the wind-up of a subsidiary	Current-year limited partnership losses (from column 620)	Limited partnership losses applied (cannot exceed column 650)	Limited partnership losses closing balance (662 + 664 + 670 - 675)
660	662	664	670	675	680

Total (enter this amount on line 335 of the T2 return)

Non-Capital Loss Continuity Workchart

Part 6 – Analysis of balance of losses by year of origin

Non-capital losses

Year of origin	Balance at beginning of year	Loss incurred in current year	Adjustments and transfers	Loss carried back Parts I & IV	Applied to reduce: Taxable income	Applied to reduce: Part IV tax	Balance at end of year
Current	N/A				N/A		
2005	338,514	N/A		N/A			338,514
2004	296,896	N/A		N/A			296,896
2003	172,330	N/A		N/A	80,006		92,324
2002	23,143	N/A		N/A	23,143		
2001	53,690	N/A		N/A	53,690		
2001		N/A		N/A			
2000		N/A		N/A			*
Total	884,573				156,839		727,734

Farm losses

Year of origin	Balance at beginning of year	Loss incurred in current year	Adjustments and transfers	Loss carried back Parts I & IV	Applied to reduce: Taxable income	Applied to reduce: Part IV tax	Balance at end of year
Current	N/A				N/A		
2005		N/A		N/A			
2004		N/A		N/A			
2003		N/A		N/A			
2002		N/A		N/A			
2001		N/A		N/A			
2001		N/A		N/A			
2000		N/A		N/A			
1999		N/A		N/A			
1998		N/A		N/A			
1997		N/A		N/A			*
Total							

Restricted farm losses

Year of origin	Balance at beginning of year	Loss incurred in current year	Adjustments and transfers	Loss carried back Parts I & IV	Applied to reduce: Taxable income	Applied to reduce: Part IV tax	Balance at end of year
Current	N/A				N/A	N/A	
2005		N/A		N/A		N/A	
2004		N/A		N/A		N/A	
2003		N/A		N/A		N/A	
2002		N/A		N/A		N/A	
2001		N/A		N/A		N/A	
2001		N/A		N/A		N/A	
2000		N/A		N/A		N/A	
1999		N/A		N/A		N/A	
1998		N/A		N/A		N/A	
1997		N/A		N/A		N/A	*
Total						N/A	

* **This balance expires this year and will not be available next year.**

Canada Revenue Agency — Agence du revenu du Canada

SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
CHAPLEAU PUBLIC UTILITIES CORPORATION	89149 3322 RC0001	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 [X]

	1 Class number 200	Description	2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year) 201	3 Cost of acquisitions during the year (new property must be available for use)* 203	4 Net adjustments** 205	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** 211	7 Reduced undepreciated capital cost	8 CCA rate % 212	9 Recapture of capital cost allowance (line 107 of Schedule 1) 213	10 Terminal loss (line 404 of Schedule 1) 215	11 Capital cost allowance (column 7 **multiplied** by column 8; or a lower amount) (line 403 of Schedule 1)**** 217	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) 220
1	1	BUILDING	979			0		979	4	0	0		979
2	1	ELECT DIST EQUIPMENT	926,598	24,293		0	12,147	938,744	4	0	0		950,891
		Total	927,577	24,293			12,147	939,723					951,870

* 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.

T2 SCH 8 (06) Canada

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
CHAPLEAU PUBLIC UTILITIES CORPORATION	89149 3322 RC0001	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.

	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust)	Provide only one number per shareholder: Business Number	Social insurance number	Trust number	Percentage common shares	Percentage preferred shares
	100	200	300	350	400	500
1	CORPORATION OF THE TOWNSHIP OF CHAPLEAU	10808 9400 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

Ontario

Ministry of Finance
Corporations Tax
33 King St. West
PO Box 622
Oshawa ON L1H 8H6

Authorizing or Cancelling a Representative

Complete this form to:

- **authorize** the release of confidential information about the Corporations Tax, Mining Tax or Electricity Act account(s) to the representative named below.
- **cancel** an existing authorization.

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
CHAPLEAU PUBLIC UTILITIES CORPORATION	6379730	2006-12-31

Part 1 Client Information

Legal Name: CHAPLEAU PUBLIC UTILITIES CORPORATION

Phone number: (705) 864-0111

Mailing address
Apt./Suite/Unit no. Street number and name / PO Box, RR: P.O. BOX 670

City: CHAPLEAU
Province/Territory: ON
Postal code: P0M 1K0

This authorization applies to the following statute(s) and account number(s).

- X **Corporations Tax Act** 6379730
- ☐ **Mining Tax Act**
- ☐ **Electricity Act**

Part 2 Authorize the release of information to a representative

Name of representative (If a firm, name of firm.)
Last / First: KPMG LLP

Phone number: (705) 675-8500
Fax number: (705) 675-7586

Mailing address
Apt./Suite/Unit no. Street number and name / PO Box, RR: 144 Pine Street Box 700

City: Sudbury
Province/Territory: ON
Postal code: P3E 4R6

If your representative is a firm, and you want a specific person in the firm to represent you, state their name and title.
If you do not identify a specific individual in the firm, you are authorizing the Ministry of Finance to deal with anyone from that firm.

Name of person in firm
Last / First:

Title:

Part 3 Authorization scope and applicable years

X Representative to **deal fully** on your behalf with the Ministry of Finance.

or

☐ Representative to **deal in a limited manner** on your behalf, for matters specified here. (e.g., account inquiry, applications, annual returns, payments, etc.) ▼

X Representative to act for **all years**, including all previous and future years.

or

☐ Representative to act for **specific year or years** (describe). ▼

Part 4 Cancel the release of information to a representative

Name of representative (If a firm, name of firm.)
Last / First:

If your representative is an individual within a firm, state their name and title.

Name of person in firm
Last / First:

Title:

Part 5 Signature *This form will not be accepted unless it is completed fully, signed and dated.*

I authorize the Ministry of Finance to:

- release confidential information about the tax accounts specified in Part 1 and to deal with the representative named in Part 2 in the manner described in Part 3; and/or
- cancel an existing authorization as described in Part 4.

Name
Last / First: MORIN MARITA

Title / Relationship to Corporation: SECRETARY-TRESURER

Phone number: (705) 864-0111

Signature

Date 2007-11-23

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.

Ministry Use

MGS Annual Return Required? *(Not required if already filed or Annual Return exempt. Refer to Guide)* [X] Yes [ ] No

Corporation's Legal Name *(including punctuation)* CHAPLEAU PUBLIC UTILITIES CORPORATION	**Ontario Corporations Tax Account No. (MOF)** 6379730
Mailing Address P.O. BOX 670 CHAPLEAU ON CA P0M 1K0	This Return covers the Taxation Year Start (year month day): 2006-01-01 End (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): 1999-08-19
Registered/Head Office Address P.O. BOX 670 CHAPLEAU ON CA P0M 1K0	Ontario Corporation No. (MGS): 1800066
Location of Books and Records 110 LORNE STREET SOUTH CHAPLEAU ON CA P0M 1K0	Canada Revenue Agency Business No. If applicable, enter 89149 3322 RC0001
Name of person to contact regarding this CT23 Return: MARITA MORIN Telephone No.: (705) 864-0111 Fax No.:	Jurisdiction Incorporated: ONTARIO
Address of Principal Office in Ontario *(Extra-Provincial Corporations only)* (MGS) Ontario Canada	If not incorporated in Ontario, indicate the date Ontario business activity commenced and ceased: Commenced (year month day): Ceased (year month day): [X] *Not Applicable*
Former Corporation Name *(Extra-Provincial Corporations only)* [X] *Not Applicable* (MGS)	
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). No. of Schedule(s): If there is **no change** to the Directors'/Officers'/Administrators' information previously submitted to MGS, please check (X) this box. Schedule(s) A and K are not required (MGS). [X] **No Change**	Preferred Language / *Langue de préférence* [X] English *anglais* [ ] French *français* 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)*

MARITA MORIN

Title D [X] Director O [ ] Officer P [ ] 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 (X) **box(es) and complete required information.**

Type of corporation

1

1 [X] 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 owned by Canadian Residents (nearest percent) ____ %

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 [X] 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 — year ____ month ____ day ____

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

Complete if applicable

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

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

Specify major business activity ____

Allocation – *If you carry on a business through a permanent establishment in a jurisdiction outside Ontario, you may allocate that portion of taxable income deemed earned in that jurisdiction to that jurisdiction (s.39) (Int.B. 3008).*

DOLLARS ONLY

		Line	Amount
Net Income (loss) for Ontario purposes (per reconciliation schedule, page 15)	±	From 690	156,839
Subtract: Charitable donations	–	1	
Subtract: Gifts to Her Majesty in right of Canada or a province and gifts of cultural property *(Attach schedule 2)*	–	2	
Subtract: Taxable dividends deductible, per federal Schedule 3	–	3	
Subtract: Ontario political contributions *(Attach Schedule 2A)* (Int.B. 3002R)	–	4	
Subtract: Federal Part VI.1 tax ______ x 3	–	5	
Subtract: Prior years' losses applied – Non-capital losses	–	From 704	156,839
Net capital losses (page 16) From 715 ______ x inclusion rate 50.000000 % =	–	714	
Farm losses	–	From 724	
Restricted farm losses	–	From 734	
Limited partnership losses	–	From 754	
Taxable Income (Non-capital loss)	=	10	

Addition to taxable income for unused foreign tax deduction for federal purposes + 11 ______

Adjusted Taxable Income 10 + 11 (if 10 is negative, enter 11) = 20 ______

Taxable Income

Number of Days in Taxation Year

From 10 (or 20 if applicable) ______ x 30 100.0000 % Ontario Allocation x 12.5 % x [Days after Dec. 31, 2002 and before Jan. 1, 2004] 33 ______ ÷ [Total Days] 73 365 = + 29 ______

From 10 (or 20 if applicable) ______ x 30 100.0000 % Ontario Allocation x 14 % x [Days after Dec. 31, 2003] 34 365 ÷ [Total Days] 73 365 = + 32 ______

Income Tax Payable (before deduction of tax credits) 29 + 32 = 40 ______

Incentive Deduction for Small Business Corporations (IDSBC) (s.41)

If this section is not completed, the IDSBC will be denied.

Did you claim the federal Small Business Deduction (fed.s.125(1)) in the taxation year or would you have claimed the federal Small Business Deduction had the provisions of fed.s.125(5.1) not been applicable in the taxation year? (X) ☐ Yes ☒ No

* Income from active business carried on in Canada for federal purposes (fed.s.125(1)(a)) 50 ______

Federal taxable income, less adjustment for foreign tax credit (fed.s.125(1)(b)) + 51 ______

Add: Losses of other years deducted for federal purposes (fed.s.111) + 52 ______

Subtract: Losses of other years deducted for Ontario purposes (s.34) – 53 ______

= ______ ▶ 54 ______

Federal Business limit (line 410 of the T2 Return) for the year before the application of fed.s.125(5.1) 55 300,000

Ontario Business Limit Calculation

320,000 x [Days after Dec. 31, 2002 and before Jan. 1, 2004] 31 ______ ÷ ** 365 = + 46 ______

400,000 x [Days after Dec. 31, 2003] 34 365 ÷ ** 365 = + 47 400,000

Business Limit for Ontario purposes 46 + 47 = 44 400,000 x [Percentage of Federal Business limit (from T2 Schedule 23). Enter 100% if not associated.] 48 100.0000 % = 45 400,000

Income eligible for the IDSBC From 30 100.0000 % ***Ontario Allocation x 56 ______ (Least of 50 , 54 or 45) = 60 ______

* ***Note:*** *Modified by s.41(6) and (7) for corporations that are members of a partnership. (Refer to Guide.)*

** ***Note:*** *Adjust accordingly for a floating taxation year and use 366 for a leap year.*

*** ***Note:*** *Ontario Allocation for IDSBC purposes may differ from* 30 *if Taxable Income is allocated to foreign jurisdictions. See special rules (s.41(4)).*

continued on Page 5

Income Tax *continued from Page 4*

Calculation of IDSBC Rate

Number of Days in Taxation Year

	Rate		Days		Total Days		
Days after Dec. 31, 2002 and before Jan. 1, 2004	7 %	x	31	÷ 73	365	= + 89	.
Days after Dec. 31, 2003	8.5 %	x	34 365	÷ 73	365	= + 90	8.5000

IDSBC Rate for Taxation Year 89 + 90 = 78 8.5000

Claim From 60 x From 78 8.5000 % = 70

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 400,000 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

If you are a member of an associated group (X) 81 (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)
			+ 82	
			+ 83	
			+ 84	

Aggregate Taxable Income 80 + 82 + 83 + 84, etc. = 85

Number of Days in Taxation Year

		Days		Total Days		
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	365	÷ 73	365	= + 116	400,000

115 + 116 = 400,000 – 114 400,000

(If negative, enter nil) = 86

Calculation of Specified Rate for Surtax 4.6670 % x (Days after Dec. 31, 2002) 38 365 ÷ 73 (Total Days) 365 = + 97 4.6670

From 86 x From 97 4.6670 % = 87

From 87 x From 60 ÷ From 114 400,000 = 88

Surtax Lesser of 70 or 88 = 100

**** 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

DOLLARS ONLY

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

110 ____

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 ____

Add: Adjustment for Surtax on Canadian-controlled private corporations

From 100 ____ ÷ From 30 100.0000 % ÷ From 78 8.5000 % = 121 ____

*Ontario Allocation

Lesser of 56 or 121 + 122 ____

120 – 56 + 122 = 130 ____

Taxable Income + From 10 ____

Subtract: Income eligible for the Incentive Deduction for Small Business Corporations (IDSBC) – From 56 ____

Add: Adjustments for Surtax on Canadian-controlled private corporations + From 122 ____

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 ____

Claim

Number of Days in Taxation Year

143 ____ (Lesser of 130 or 142) x From 30 100.0000 % (Ontario Allocation) x 1.5 % x 33 ____ (Days after Dec. 31, 2002 and before Jan. 1, 2004) ÷ 73 365 (Total Days) = + 154 ____

143 ____ (Lesser of 130 or 142) x From 30 100.0000 % (Ontario Allocation) x 2 % x 34 365 (Days after Dec. 31, 2003) ÷ 73 365 (Total Days) = + 156 ____

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 ____

continued on Page 7

Income Tax *continued from Page 6*

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. 204 Name of Production

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

Eligible Credit From 5898 CT23 Schedule 114 (*Attach Schedule 114*) + 203

Other (specify) + 203.1

Total Specified Tax Credits 191 + 192 + 193 + 195 + 196 + 197 + 198 + 199 + 200 + 201 + 203 + 203.1 = 220

Specified Tax Credits ***Applied to reduce Income Tax*** = 225

Income Tax 190 – 225 **OR Enter NIL if reporting Non-Capital Loss** *(amount cannot be negative)* = 230

To 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.**

Corporate Minimum Tax (CMT)

DOLLARS ONLY

Total Assets of the corporation	+ 240	2,296,676
Total Revenue of the corporation	+ 241	2,727,614

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
			+ 243	+ 244
			+ 245	+ 246
			+ 247	+ 248

Aggregate Total Assets 240 + 243 + 245 + 247 , etc. = 249 2,296,676

Aggregate Total Revenue 241 + 244 + 246 + 248 , etc. = 250 2,727,614

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 Schedule 101 2136 [ ] (If negative, enter zero) X From 30 100.0000 % (Ontario Allocation) X 4 % = 276

Subtract: Foreign Tax Credit for CMT purposes *(Attach Schedule)* – 277

Subtract: Income Tax – From 190

Net CMT Payable (If negative, enter Nil on Page 17.) = 280

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

Gross CMT Payable + From 276

Subtract: Foreign Tax Credit for CMT purposes – From 277

If 276 – 277 is negative, enter NIL in 290 = – 290

Income Tax eligible for CMT Credit = 300

B. Income Tax (after deduction of specified credits) + From 230

Subtract: CMT credit used to reduce income taxes – 310

Income Tax = 320

Transfer to page 17

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 **.**

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

		Line	Amount
Paid-up capital stock (Int.B. 3012R and 3015R)	+	350	560,840
Retained earnings (if deficit, deduct) (Int.B. 3012R)	±	351	-743,510
Capital and other surpluses, excluding appraisal surplus (Int.B.3012R)	+	352	
Loans and advances *(Attach schedule)* (Int.B. 3013R)	+	353	
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	
Share of partnership(s) or joint venture(s) paid-up capital *(Attach schedule(s))* (Int.B. 3017R)	+	362	
Subtotal	=	370	-182,670
Subtract: Amounts deducted for income tax purposes in excess of amounts booked *(Retain calculations. Do not submit.)* (Int.B. 3012R)	–	371	
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	-182,670
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	-182,670

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.

		Line	Amount
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	
Loans and advances to unrelated corporations	+	405	
Eligible loans and advances to related corporations (certain restrictions apply) *(Refer to Guide)*	+	406	
Share of partnership(s) or joint venture(s) eligible investments *(Attach schedule)*	+	407	
Total Eligible Investments	=	410	

continued on Page 10

Total Assets (Int.B. 3015R)

DOLLARS ONLY

Total Assets per balance sheet	+	420	2,296,676
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	2,296,676
Amounts in 360 and 361 (if deducted from assets)	+	440	
Subtract: Amounts in 371, 372 and 381	–	441	
Subtract: Appraisal surplus if booked	–	442	
Add or Subtract: Other adjustments (specify on an attached schedule)	±	443	
Total Assets	=	450	2,296,676

Investment Allowance (410 ÷ 450) x 390 — **Not to exceed** 410	=	460	
Taxable Capital 390 – 460	=	470	

Gross Revenue (as adjusted to include the share of any partnership(s)/joint venture(s) Gross Revenue)	480	2,727,614
Total Assets (as adjusted)	From 430	2,296,676

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

				Total Days			
7,500,000	x	36 (Days after Dec. 31, 2004 and before Jan. 1, 2006)	÷ 73	365	= +	501	
10,000,000	x	37 (Days after Dec. 31, 2005 and before Jan. 1, 2007) 365	÷ 73	365	= +	502	10,000,000
12,500,000	x	38 (Days after Dec. 31, 2006 and before Jan. 1, 2008)	÷ 73	365	= +	504	
15,000,000	x	39 (Days after Dec. 31, 2007)	÷ 73	365	= +	505	

Taxable Capital Deduction (TCD) 501 + 502 + 504 + 505 = 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

				Total Days			
0.3 %	x	556 (Days before Jan. 1, 2007) 365	÷ 73	365	= +	511	0.3000 %
0.285 %	x	557 (Days after Dec. 31, 2006 and before Jan. 1, 2009)	÷ 73	365	= +	512	%

Capital Tax Rate 511 + 512 = 516 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 430 and 480 on page 10 are both $3,000,000 or less, enter NIL in 550 on page 12 and complete the return from that point.

C2. If Taxable Capital in 470 is **equal to or less than the TCD** in 503, enter NIL in 550 on page 12 and complete the return from that point.

C3. If Taxable Capital in 470 **exceeds the TCD** in 503, complete the following calculation and transfer the amount from 523 to 543 on page 12, and complete the return from that point.

+ From 470 ________
− From 503 ________
= 471 ________ x From 30 100.0000 % Ontario Allocation x From 516 0.3000 % Capital Tax Rate x Days in taxation year 555 365 / 365 (366 if leap year) = + 523 ________

If floating taxation year, refer to Guide.

Transfer to 543 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 509 or 524 and complete this section before you can calculate your Capital Tax Calculation under either Section E or Section F.

D1. ☐ 509 (X if applicable)

All corporations that you are associated with do **not** have a permanent establishment in Canada.

If Taxable Capital 470 on page 10 is equal to or less than the TCD 503 on page 10, enter NIL in 550 on page 12 and complete the return from that point.

If Taxable Capital 470 on page 10 exceeds the TCD 503 on page 10, proceed to **Section E**, enter the TCD amount in 542 in Section E, and complete Section E and the return from that point.

D2. ☐ 524 (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

continued on Page 12

Capital Tax Calculation *continued from Page 11*

DOLLARS ONLY

D2. Calculation
Do **not** complete this calculation if ss.69(2.1) election is filed

Taxable Capital From 470 on page 10 + From 470 ________ .

Determine aggregate taxable capital of an associated group (excluding financial institutions and corporations exempt from capital tax) and/or partnership having a permanent establishment in Canada

Names of associated corporations (excluding Financial Institutions and corporations exempt from Capital Tax) having a permanent establishment in Canada *(if insufficient space, attach schedule)*	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End		Taxable Capital
			+ 531	.
			+ 532	.
			+ 533	.

Aggregate Taxable Capital 470 + 531 + 532 + 533 , etc. = 540 ________ .

If 540 above is equal to or less than the TCD 503 on page 10, the corporation's Capital Tax for the taxation year, is NIL.

Enter NIL in 523 in section E below, as applicable.

If 540 above is greater than the TCD 503 on page 10, the corporation must compute its share of the TCD below in order to calculate its Capital Tax for the taxation year under Section E below.

From 470 ________ . ÷ From 540 ________ . x From 503 ________ . = 541 ________ .

Transfer to 542 *in Section E below*

Ss.69(2.1) Election Filed

☐ 591 (X if applicable) **Election filed**. *Attach a copy of Schedule 591 with this CT23 Return.* Proceed to **Section F** below.

SECTION E

This section applies if the corporation **is** a member of an associated group and/or partnership whose total **aggregate** Taxable Capital 540 above, exceeds the TCD 503 on page 10.

Complete the following calculation and transfer the amount from 523 to 543, and complete the return from that point.

+ From 470 ________ .
− 542 ________ .
= 471 ________ . x From 30 100.0000 % (Ontario Allocation) x From 516 0.3000 % (Capital Tax Rate) x 555 365 (Days in taxation year) / * 365 (366 if leap year) = + 523 ________ . (**Total Capital Tax for the taxation year**)

Transfer to 543 *and complete the return from that point*

SECTION F

This section applies if a corporation is a member of an associated group and the associated group has filed a ss.69(2.1) election

+ From 470 ________ . x From 30 100.0000 % (Ontario Allocation) x From 516 0.3000 % (Capital Tax Rate) = + 561 ________ .

− Capital tax deduction from 995 relating to **your corporation's** Capital Tax deduction, on Schedule 591 − From 995 ________ .

= 562 ________ .

Capital Tax 562 ________ . x 555 365 (Days in taxation year) / * 365 (366 if leap year) = 563 ________ . (**Total Capital Tax for the taxation year**)

Transfer to 543 *and complete the return from that point*

* *If floating taxation year, refer to Guide.*

Capital Tax before application of specified credits = 543 ________ .

Subtract: Specified Tax Credits applied to reduce capital tax payable *(Refer to Guide)* − 546 ________ .

Capital Tax 543 − 546 *(amount cannot be negative)* = 550 ________ .

Transfer to Page 17

continued on Page 13

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 550 on page 12, and complete the return from that point.

1.2 Other than Credit Unions

(Retain details of calculations for amounts in boxes 565 and 570. Do not submit with this tax return.)

565 ______ x 567 ______ % x From 30 100.0000 % x 555 365 (Days in taxation year) / 365* (366 if leap year) = + 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

570 ______ x 571 ______ % x From 30 100.0000 % x 555 365 (Days in taxation year) / 365* (366 if leap year) = + 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

Capital Tax for Financial Institutions – other than Credit Unions (before Section 2) 569 + 574 = 575 ______

** 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 – 585 ______

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

Capital Tax - Financial Institutions 575 – 585 = 586 ______

Transfer to 543 on Page 12

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

(1) Uninsured Benefits Arrangements 587 ______ x 2 % = 588 ______
Applies to Ontario-related uninsured benefits arrangements.

(2) Unlicensed Insurance (enter premium tax payable in 588 and attach a detailed schedule of calculations. If subject to tax under (1) above, add both taxes together and enter total tax in 588.)
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)* – 589 ______

Premium Tax 588 – 589 = 590 ______
Transfer to page 17

DOLLARS ONLY

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 ± 600 156,839

Transfer to Page 15

Add:

Federal capital cost allowance	+	601	
Federal cumulative eligible capital deduction	+	602	
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-arms' length non-residents

Number of Days in Taxation Year

				Days after Dec. 31, 2002 and before Jan. 1, 2004		Total Days		
612	x 5 / 12.5	x	33		÷ 73	365	=+ 633	

				Days after Dec. 31, 2003		Total Days		
612	x 5 / 14	x	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	
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 = 640

Transfer to Page 15

Deduct:

Ontario capital cost allowance (excludes amounts deducted under 675)	+	650	
Ontario cumulative eligible capital deduction	+	651	
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

Transfer to Page 15

continued on Page 15

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	156,839
Total of Additions on page 14	From = 640	
Sub Total of deductions on page 14	From = 681	

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:

Gross-up of CCA: [From 662 ______ x 100 / From 30 100.0000 (Ontario Allocation)] − From 662 ______ = 663 ______

Workplace Child Care Tax Incentive (WCCT)
(***Applies*** to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: [665 ______ x 30 % x 100 / From 30 100.0000 (Ontario allocation)] = 666 ______

Workplace Accessibility Tax Incentive (WATI)
(***Applies*** to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: [667 ______ x 100 % x 100 / From 30 100.0000 (Ontario allocation)] = 668 ______

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 / From 30 100.0000 (Ontario allocation)] = 671 ______

Educational Technology Tax Incentive (ETTI)
(***Applies*** to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: [672 ______ x 15 % x 100 / From 30 100.0000 (Ontario allocation)] = 673 ______

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

Total of Deductions 681 + 663 + 666 + 668 + 671 + 673 + 678 + 679 + 677 + 664 = ______ ▶ 680 ______

Net income (loss) for Ontario Purposes 600 + 640 − 680 = 690 156,839

Transfer to Page 4

DOLLARS ONLY

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) 884,573	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) 156,839	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		707 156,839	717	727	737	747	757
Balance at End of Year		709 (8) 727,734	719	729	739	749	759

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 1998-09-30	817 (9)	860 (9)		850	870
801 8th preceding taxation year 1999-09-30	818 (9)	861 (9)		851	871
802 7th preceding taxation year 2000-09-30	819 (9)	862 (9)		852	872
803 6th preceding taxation year 2001-09-30	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 92,324	833	843	856	876
807 2nd preceding taxation year 2004-12-31	824 296,896	834	844	857	877
808 1st preceding taxation year 2005-12-31	825 338,514	835	845	858	878
809 Current taxation year 2006-12-31	826	836	846	859	879
Total	829 727,734	839	849	869	889

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	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
CHAPLEAU PUBLIC UTILITIES CORPORATIO	6379730	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

	Predecessor Ontario Corporation's Tax Account No. (MOF)	Taxation Year Ending year month day	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						
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	
Corporate Minimum Tax	+ From 280	
Capital Tax	+ From 550	
Premium Tax	+ From 590	
Total Tax Payable	= 950	
Subtract: Payments	– 960	
Capital Gains Refund (s.48)	– 965	
Qualifying Environmental Trust Tax Credit *(Refer to Guide)*	– 985	
Specified Tax Credits *(Refer to Guide)*	– 955	
Other, specify ______	–	
Balance	= 970	
If payment due Enclosed *	990	
If overpayment: Refund *(Refer to Guide)*	= 975	
Apply to year month day	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)*: MARITA MORIN

Title: SECRETARY-TRESURER

Full Residence Address

Signature

Date: 2007-11-23

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
CHAPLEAU PUBLIC UTILITIES CORPORATION	6379730	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	119,469
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			
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	=		+ 2116	

Add/Subtract:

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

	Add		or Subtract	
** 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.s13(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	119,469
** 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	119,469
Deduct: * CMT losses: pre-1994 Loss	+ From 2210		
* CMT losses: other eligible losses	+ 2211 119,469		
	= 119,469	– 2135	119,469

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

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

CMT Base	= 2136	

Transfer to CMT Base on Page 8 of the CT23 or Page 6 of the CT8

Corporate Minimum Tax (CMT)
CT23 Schedule 101

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
CHAPLEAU PUBLIC UTILITIES CORPORATION	6379730	2006-12-31

Part 2: Continuity of CMT Losses Carried Forward

Balance at Beginning of year NOTES (1), (2)			+ 2201	769,307
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	769,307
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	119,469		
Losses expired during the year	+ 2212			
Subtotal	=	119,469	− 2213	119,469
Balances at End of Year NOTE (5) 2209 − 2213			= 2214	649,838

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 a 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	9th preceding taxation year 1998-09-30	2260	2280
2241	8th preceding taxation year 1999-09-30	2261	2281
2242	7th preceding taxation year 2000-09-30	2262	2282
2243	6th preceding taxation year 2001-09-30	2263	2283
2244	5th preceding taxation year 2001-12-31	2264	2284
2245	4th preceding taxation year 2002-12-31	2265	2285
2246	3rd preceding taxation year 2003-12-31	2266 87,080	2286
2247	2nd preceding taxation year 2004-12-31	2267 296,659	2287
2248	1st preceding taxation year 2005-12-31	2268 266,099	2288
2249	Current taxation year 2006-12-31	2269	2289
Totals		2270 649,838	2290

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

Corporate Minimum Tax (CMT)
CT23 Schedule 101

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
CHAPLEAU PUBLIC UTILITIES CORPORATION	6379730	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

Subtotal (If negative, enter NIL) . . . = ► − 2305

Current year's CMT credit (If negative, enter 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:

(1) Where acquisition of control of the corporation has occurred, the utilization of CMT credits can be restricted. (see s.43.1(5))

(2) The CMT credit of life insurance corporations can be restricted (see s.43.1(3)(b)).

(3) 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))

(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	9th preceding taxation year 1998-09-30	2360	2380
2341	8th preceding taxation year 1999-09-30	2361	2381
2342	7th preceding taxation year 2000-09-30	2362	2382
2343	6th preceding taxation year 2001-09-30	2363	2383
2344	5th preceding taxation year 2001-12-31	2364	2384
2345	4th preceding taxation year 2002-12-31	2365	2385
2346	3rd preceding taxation year 2003-12-31	2366	2386
2347	2nd preceding taxation year 2004-12-31	2367	2387
2348	1st preceding taxation year 2005-12-31	2368	2388
2349	Current taxation year 2006-12-31	2369	2389
Totals		2370	2390

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

Corporate Minimum Tax (CMT)
CT23 Schedule 101 – Supporting Schedule

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
CHAPLEAU PUBLIC UTILITIES CORPORATION	6379730	2006-12-31

CMT Losses Carried Forward Workchart

(i) Continuity of Pre-1994 CMT Losses

	Corporation's Pre-1994 Loss	Predecessors' Pre-1994 Loss Amalgamation	Predecessors' Pre-1994 Loss Wind-Up
Date of the last tax year end before the corp's 1st tax year commencing after 1993			
Pre-1994 Loss (per schedule)			
Less: Claimed in prior taxation years commencing after 1993			
Pre-1994 Loss available for the current year			
Less: Deducted in the current year (max. = adj. net income for the year)			
Expired after 10 years			
Pre-1994 Loss Carryforward			

(ii) Continuity of Other Eligible CMT Losses – Filing Corporation (for losses occurring in tax years commencing after 1993)

	Year of Origin YYYY/MM/DD	Opening Balance	Adjustment	Deduction	Expired	Closing Balance
10th Prior Year	1997-09-30					
9th Prior Year	1998-09-30					
8th Prior Year	1999-09-30					
7th Prior Year	2000-09-30					
6th Prior Year	2001-09-30					
5th Prior Year	2001-12-31	11,341		11,341		
4th Prior Year	2002-12-31	23,127		23,127		
3rd Prior Year	2003-12-31	172,081		85,001		87,080
2nd Prior Year	2004-12-31	296,659				296,659
1st Prior Year	2005-12-31	266,099				266,099
	Total	769,307		119,469		649,838

Predecessor Corporations Only – Amalgamation

Indicate the amounts of eligible CMT losses from predecessor corporations. **Do not include** these amounts in the 'opening balance' of the Filing Corporation.

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
1997-09-30						
1998-09-30						
1999-09-30						
2000-09-30						
2001-09-30						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
Total						

Corporate Minimum Tax (CMT)
CT23 Schedule 101 – Supporting Schedule

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
CHAPLEAU PUBLIC UTILITIES CORPORATION	6379730	2006-12-31

CMT Losses Carried Forward Workchart (continued)

Predecessor Corporations Only – Wind-Up

Indicate the amounts of eligible CMT losses from predecessor corporations. **Do not include** these amounts in the 'opening balance' of the Filing Corporation.

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
1997-09-30						
1998-09-30						
1999-09-30						
2000-09-30						
2001-09-30						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
Total						

Corporate Minimum Tax (CMT)
CT23 Schedule 101 – Supporting Schedule

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
CHAPLEAU PUBLIC UTILITIES CORPORATION	6379730	2006-12-31

CMT Credit Carryovers Workchart

Filing Corporation

	Year of Origin YYYY/MM/DD	Opening Balance	Adjustment	Deduction	Expired	Closing Balance
10th Prior Year	1997-09-30					
9th Prior Year	1998-09-30					
8th Prior Year	1999-09-30					
7th Prior Year	2000-09-30					
6th Prior Year	2001-09-30					
5th Prior Year	2001-12-31					
4th Prior Year	2002-12-31					
3rd Prior Year	2003-12-31					
2nd Prior Year	2004-12-31					
1st Prior Year	2005-12-31					
	Total					

Predecessor Corporations Only – Amalgamation

Indicate the amounts of CMT credit carryovers from predecessor corporations. **Do not include** these amounts in the 'opening balance' of the Filing Corporation.

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
1997-09-30						
1998-09-30						
1999-09-30						
2000-09-30						
2001-09-30						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
Total						

Predecessor Corporations Only – Wind-Up

Indicate the amounts of CMT credit carryovers from predecessor corporations. **Do not include** these amounts in the 'opening balance' of the Filing Corporation.

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
1997-09-30						
1998-09-30						
1999-09-30						
2000-09-30						
2001-09-30						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
Total						

Non-Capital Loss Continuity Workchart – Ontario

Non-capital losses

Year	Balance at beginning of year	Loss incurred in current year	Adjustments and transfers	Loss carried back Parts I & IV	Applied to reduce taxable income	Balance at end of year
Current	N/A				N/A	
2005	338,514	N/A		N/A		338,514
2004	296,896	N/A		N/A		296,896
2003	172,330	N/A		N/A	80,006	92,324
2002	23,143	N/A		N/A	23,143	
2001	53,690	N/A		N/A	53,690	
2001		N/A		N/A		
2000		N/A		N/A		*
Total	884,573				156,839	727,734

Farm losses

Year	Balance at beginning of year	Loss incurred in current year	Adjustments and transfers	Loss carried back Parts I & IV	Applied to reduce taxable income	Balance at end of year
Current	N/A				N/A	
2005		N/A		N/A		
2004		N/A		N/A		
2003		N/A		N/A		
2002		N/A		N/A		
2001		N/A		N/A		
2001		N/A		N/A		
2000		N/A		N/A		
1999		N/A		N/A		
1998		N/A		N/A		
1997		N/A		N/A		*
Total						

Restricted farm losses

Year	Balance at beginning of year	Loss incurred in current year	Adjustments and transfers	Loss carried back Parts I & IV	Applied to reduce taxable income	Balance at end of year
Current	N/A				N/A	
2005		N/A		N/A		
2004		N/A		N/A		
2003		N/A		N/A		
2002		N/A		N/A		
2001		N/A		N/A		
2001		N/A		N/A		
2000		N/A		N/A		
1999		N/A		N/A		
1998		N/A		N/A		
1997		N/A		N/A		*
Total						

* **This balance expires this year and will not be available next year.**

Ontario

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

Ontario Capital Cost Allowance
Schedule 8

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
CHAPLEAU PUBLIC UTILITIES CORPORATION	6379730	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)
1	979			0	979		979	4	0	0		979
1	926,598	24,293		0	950,891	12,147	938,744	4	0	0		950,891
Totals	927,577	24,293			951,870	12,147	939,723					951,870

Enter in boxes 650 . . . . 650 . . . . 650 on the CT23.

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.

Corporate Taxpayer Summary

Corporate information

Corporation's name: CHAPLEAU PUBLIC UTILITIES CORPORATION

Taxation Year: 2006-01-01 to 2006-12-31

Jurisdiction: Ontario

BC	AB	SK	MB	ON	QC	NB	NS	NO	PE	NL	XO	YT	NT	NU	OC
				X											

Corporation is associated: N Number of associated corporations:
Corporation is related: N Type of corporation: Canadian-Controlled Private Corporation

Total amount due (refund) federal and provincial*:

* The amounts displayed on lines "Total amount due (refund) federal and provincial" are all listed in the help. Press F1 to consult the context-sensative help.

Summary of federal information

Net income:	156,839
Taxable income:	
Donations:	
Part I tax (base amount)	
Surtax	

Calculation of income from an active business carried on in Canada:	156,839
Dividends paid:	
Balance of the low income rate pool at the end of the year:	
Balance of the general rate income pool at the end of the year:	

Credits against part I tax

Small business deduction	
M&P deduction	
Foreign tax credit	
Political contributions	
Investment tax credits	
Abatement/Other*	

Summary of tax

Part I	
Part I.3	
Part IV	
Part III.1	
Other*	
Provincial or territorial tax	

Refunds/credits

ITC refund	
Dividends refund	
Instalments	
Surtax credit	
Other*	

Balance due/refund (–)

* The amounts displayed on lines "Other" are all listed in the Help. Press F1 to consult the context-sensitive help.

Summary of federal carryforward/carryback information

Carryback amounts

Investment tax credits	
Non-capital loss	
Capital loss	
Farm loss	
Restricted farm loss	
Surtax credit	
Part I tax credit (Schedule 42)	
Federal foreign non-business income tax credit	

Carryforward balances

RDTOH	
Charitable donations	
Gifts to Canada, a province or a territory	
Gifts of certified cultural property	
Gifts of certified ecologically sensitive land	
Investment tax credits	
Non-capital losses	727,734
Capital/L.P.P. losses	
Farm losses	
Restricted farm losses	
Current year's balance of SR&ED expenditures (T661)	
Foreign business tax credit	
Unused surtax credit (Schedule 37)	
Capital dividend amount	
Part I tax credit (Schedule 42)	
Cumulative eligible capital	
Capital gains reserves	
Financial statement reserve	
Other reserves	
Balance of patronage dividends	
Continuity of exemption of accumulated income	

Summary of provincial information – provincial income tax payable

	Ontario (CT-23)	Québec (CO-17)	Alberta (AT1)
% Allocation	100.00		
Attributed taxable income			
Surtax		N.A.	N.A.
Tax payable before deduction*			
Deductions and credits			
Net tax payable			
Attributed taxable capital			N.A.
Capital tax payable**			N.A.
Total tax payable***			
Instalments and refundable credits			
Balance due/Refund (-)			

* For Québec, this includes special taxes.
** For Québec, this includes compensation tax and registration fee.
*** For Ontario, this includes corporate minimum tax and premium tax.

	British Columbia	Saskatchewan	Manitoba
% Allocation			
Attributed taxable income			
Tax payable before deduction			
Deductions and credits			
Tax payable or refundable credit			
Attributed taxable capital			
Capital tax payable			
Instalments and refundable credits			
Balance due/Refund (-)			

	Newfoundland and Labrador	Prince Edward Island	Nova Scotia	New Brunswick
% Allocation				
Attributed taxable income				
Tax payable before deduction				
Deductions and credits				
Tax payable or refundable credit				
Attributed taxable capital				
Capital tax payable				
Instalments and refundable credits				
Balance due/Refund (-)*				

* Only applies in the case of bank, a loan corporation or a trust corporation.

	Yukon	Northwest Territories	Nunavut
% Allocation			
Attributed taxable income			
Tax payable before deduction			
Deductions and credits			
Tax payable or refundable credit			

Summary of provincial carryforward amounts

	Ontario	Québec	Alberta
Non-capital losses	727,734		
Net capital/L.P.P. losses			
Farm losses			
Restricted farm losses			
Donations			
Capital gains reserves			
Financial statement reserves			
Other reserves			
Eligible capital			

Other carryforward amounts:

Scientific research and experimental development – Sch. 425	
Manufacturing and processing – Sch. 426	
Research and development – Sch. 380	
Manufacturing investment – Sch. 381	
Co-operative education – Sch. 384	
Odour control – Sch. 385	
Manufacturing and processing investment – Sch. 402	
Research and development – Sch. 403	
Direct equity tax – Sch. 303	
Investment – Sch. 321	
Energy efficiency tax credit – Sch. 342	
Manufacturing and processing investment – Sch. 344	
Research and development – Sch. 360	
Investment – Sch. 480	
R&D expenditures not deducted at the end of the year – RD – 222	
Foreign non-business income tax credits – CO-17S.39	
Development work expenses – FM220.3	
Excess development work expenses – FM220.3	
Unclaimed SR&ED expenditure pool deduction balance – A16	
Continuity of other eligible CMT losses – Filling Corporation – OCMT101	649,838
Predecessor corporations only – Amalgamation – OCMT101	
Predecessor corporations only – Wind-up – OCMT101	
CMT credit carryovers workchart - Filling Corporation – OCMT101	
CMT credit carryovers workchart - Predecessor corporations only – Amalgamation	
CMT credit carryovers workchart - Wind-up – OCMT101	
Ontario current taxation year closing balance in pool of deductible SR&ED expenditures – O161	
Continuity Schedule for Federal ITC relating to SR&ED Expenditures for the Preceding Taxation Year – O161	
Continuity Schedule for the Amount of Federal ITC from SR&ED Expenditures relating to QORD for the Preceding Taxation Year - O161	

Diagnostics : All

Type	Group	Jurisdiction	Diagnostic
Error	CCA	Federal	1 — Federal CCA claim has been overridden.
Error	CCA	Federal	1 — Federal CCA claim has been overridden.
Error	CCA	Federal	6 — Ontario CCA claim has been overridden.
Error	CCA	Federal	6 — Ontario CCA claim has been overridden.
Missing information	CCH	Ontario	M2 — CT23 - Electrical Generating Corporation may be eligible for deduction from paid-up capital.
Missing information	CCH	Ontario	M147 — CT23 - Ontario Net Income Reconciliation - Electrical Generating Corporation may be eligible for deduction from net income.
Possible input error	CCH	Federal	E102 — Schedule 4 - Non-capital loss balance on line 102 does not equal the lines above it.
Possible input error	CCH	Ontario	E158A — CT23 - Certain types of income must not be included in the corporation's revenue. Press F1 when the form is displayed and review 'Definition of sales figure'.
Possible input error	CCH	Federal	E431 — Schedule 7 - Income from goods has been reported in Schedule 125 of the GIFI, but Schedule 7, Calculation of aggregate investment income and active business income, has not been completed.
Forms with overridden cells	CCH	Federal	O103 — Overridden data - You can see the list by using the "Overridden data" filter in Xpress.
Filing	GIFI	Federal	F1 — Please attach a copy of the notes to the financial statements together with the RSI schedules to the federal income tax return.
Error	RSI	Federal	R130 — Schedule 125 - Describe the activity carried on only if you have multiple financial statements and the activity differs from that of the business.

T2-RETURN AND SCHEDULE INFORMATION

Name: **CHAPLEAU PUBLIC UTILITIES CORPORATION**

BN: 89149 3322 RC 0001 **Taxation Year End: 2006-12-31**

For agency use
[055]

This page must be attached to your return and sent to the Canada Revenue Agency

Name: **CHAPLEAU PUBLIC UTILITIES CORPORATION**

BN: 89149 3322 RC 0001 **Taxation Year End: 2006-12-31**

For agency use
[055]

[001]	89149 3322 RC 0001
[060]	2006 01 01
[061]	2006 12 31
[099]	EP07
	XXXXXXXXXXX

B

[002]	CHAPLEAU PUBLIC UTILITIES CORPORATION
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	XXXXXXXXXXX
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[011]	
[012]	
[015]	
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[017]	
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[021]	
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[023]	
[025]	
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[027]	
[028]	

For agency use
[091] ______
[092] ______
[093] ______

For agency use
[094] ______
[095] ______
[096] ______
[100] ______

Name: CHAPLEAU PUBLIC UTILITIES CORPORATION

BN: 89149 3322 RC 0001 **Taxation Year End:** 2006-12-31

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[032]	
[035]	
[036]	
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[038]	
	XXXXXXXXXXXX

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Name: CHAPLEAU PUBLIC UTILITIES CORPORATION

BN: 89149 3322 RC 0001 **Taxation Year End: 2006-12-31**

[258]	______	**[284]**	ELECTRICITY DISTN
[259]	______	**[286]**	SERVICE WORK
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[262]	______	**[287]**	5
[263]	______	**[289]**	______
[264]	______	**[950]**	MORIN
[291]	2	**[951]**	MARITA
[292]	2	**[954]**	SECRETARY-TRESURER
[370]	______	**[955]**	2007 11 23
[435]	______	**[956]**	705 864 0111
[438]	______	**[957]**	1
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[646]	______	**[959]**	______
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[801]	______		
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[283]	1		

Name: **CHAPLEAU PUBLIC UTILITIES CORPORATION**

BN: 89149 3322 RC 0001 **Taxation Year End: 2006-12-31**

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		[644]			
		[648]			

Name: CHAPLEAU PUBLIC UTILITIES CORPORATION

BN: 89149 3322 RC 0001 Taxation Year End: 2006-12-31

Certification

I, MARITA MORIN 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 GIFI [line 200300]	156 839
Part I tax payable [line 200700]	0
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 territoral 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.

Date	Signature of an authorized signing officer of the corporation	Position, office or rank
2007-11-23		SECRETARY-TRESURER

Name: CHAPLEAU PUBLIC UTILITIES CORPORATION

BN: 89149 3322 RC 0001 **Taxation Year End: 2006-12-31**

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[106]		[123]		[208]	
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[108]		[125]		[210]	
[109]		[126]		[211]	
[110]		[127]		[212]	
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[116]		[201]		[218]	
[117]		[202]		[219]	

T2-RETURN AND SCHEDULE INFORMATION 001

Name: CHAPLEAU PUBLIC UTILITIES CORPORATION

BN: 89149 3322 RC 0001 **Taxation Year End:** 2006-12-31

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Name: CHAPLEAU PUBLIC UTILITIES CORPORATION

BN: 89149 3322 RC 0001 **Taxation Year End:** 2006-12-31

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		[951]		[942]	
[102]	884 573	[952]		[943]	
[105]		[953]			XXXXXXXXXXX
[110]			XXXXXXXXXXX		
[130]	156 839			[502]	
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[140]		[305]		[530]	
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[180]	727 734	[330]		[580]	
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[911]		[380]			XXXXXXXXXXX
[912]		[921]			
[913]		[922]			
	XXXXXXXXXXX	[923]			
		[931]			
		[932]			
		[933]			
			XXXXXXXXXXX		

Name: CHAPLEAU PUBLIC UTILITIES CORPORATION

BN: 89149 3322 RC 0001 **Taxation Year End: 2006-12-31**

[602] 1. ____________ *

[632] 1. ____________ *
XXXXXXXXXXXX

[600] 1. ____________ *

[630] 1. ____________ *

[660] 1. ____________ *
XXXXXXXXXXXX

Name: CHAPLEAU PUBLIC UTILITIES CORPORATION

BN: 89149 3322 RC 0001 **Taxation Year End:** 2006-12-31

[604] 1. ____________ *

[606] 1. ____________ *

[608] 1. ____________ *

[620] 1. ____________ *
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[634] 1. ____________ *

[636] 1. ____________ *

[638] 1. ____________ *

[650] 1. ____________ *
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[662] 1. ____________ *

[664] 1. ____________ *

[670] 1. ____________ *

[675] 1. ____________ *

[680] 1. ____________ *
XXXXXXXXXXXX

Name: CHAPLEAU PUBLIC UTILITIES CORPORATION

BN: 89149 3322 RC 0001 **Taxation Year End:** 2006-12-31

[101] 2

[200]
1. 1
2. 1 *

[211]
1. ______
2. 12 147 *

[212]
1. 4
2. 4 *

XXXXXXXXXXXX

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2. 926 598 *

[203]
1. ______
2. 24 293 *

[205]
1. ______
2. ______ *

[207]
1. ______
2. ______ *

[213]
1. ______
2. ______ *

[215]
1. ______
2. ______ *

[217]
1. ______
2. ______ *

[220]
1. 979
2. 950 891 *

XXXXXXXXXXXX

Name: **CHAPLEAU PUBLIC UTILITIES CORPORATION**

BN: 89149 3322 RC 0001 **Taxation Year End: 2006-12-31**

[100] 1. CORPORATION OF THE TOWNSHIP OF CHAPLEAU *

[200] 1. 10808 9400 RC 0001 *

[300] 1. ____________ *

[350] 1. ____________ *

[400] 1. 100 *

[500] 1. ____________ *

XXXXXXXXXXX

Name: CHAPLEAU PUBLIC UTILITIES CORPORATION

BN: 89149 3322 RC 0001 **Taxation Year End: 2006-12-31**

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[1062]	508 681	**[3849]**	# 743 510
[1122]	43 787		**XXXXXXXXXXXX**
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[2008]	2 175 939		
[2009]	# 1 266 778		
[2599]	2 296 676		
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[3140]	360 727		
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[3320]	509 527		
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[3499]	2 479 346		
	XXXXXXXXXXXX		
[3500]	560 840		
[3600]	# 743 510		

Name: **CHAPLEAU PUBLIC UTILITIES CORPORATION**

BN: 89149 3322 RC 0001 **Taxation Year End: 2006-12-31**

[0001]	CHAPLEAU PUBLIC UTILITES CORPORATION
[0002]	ELECTRICITY DISTRIBUTION COMPANY
	XXXXXXXXXXX
[0003]	______________
	XXXXXXXXXXX

[8519]	613 567	**[8670]**	37 370
[9369]	119 469	**[8710]**	36 114
[9899]	______________	**[9010]**	262 647
[9970]	119 469	**[9273]**	63 918
[9975]	______________	**[9284]**	164 663
[9976]	______________	**[9367]**	564 712
[9980]	______________	**[9368]**	2 608 145
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[8518]	2 043 433		

Name: **CHAPLEAU PUBLIC UTILITIES CORPORATION**

BN: 89149 3322 RC 0001 **Taxation Year End:** **2006-12-31**

[095]	1
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[198]	1
[099]	2
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[102]	2
[103]	2
[104]	2
[105]	2
[106]	1
[107]	1
[108]	2
	XXXXXXXXXXX

Canada Revenue Agency / Agence du revenu du Canada

Sudbury ON P3A 5C1

Date of mailing	December 14, 2007
Business Number	89149 3322 RC0001
Taxation year-end	December 31, 2006

CHAPLEAU PUBLIC UTILITIES
CORPORATION
PO BOX 670
CHAPLEAU ON P0M 1K0

0003110

CORPORATION NOTICE OF ASSESSMENT

RESULTS

For tax years ending in 2009 or later, corporations that have a permanent establishment in Ontario will need to file a harmonized "T2 Corporation Income Tax Return" with the Canada Revenue Agency (CRA). The harmonized return will include the following Ontario corporation taxes: corporate income tax, including refundable tax credits, corporate minimum tax, capital tax, and special additional tax on life insurance corporations.

Please send your combined Ontario and federal corporation tax instalment payments for tax years ending in 2009 or later to the CRA. For some corporations this may require making combined payments to the CRA as early as February 2008.

For information on how to calculate your instalment payments, please visit our Web site at: www.cra.gc.ca/t2return

This notice explains the results of our assessment of the T2 Corporation Income Tax Return for the taxation year indicated above. It also explains any changes we may have made to the return.

Result of this Assessment :	$	0.00
Prior balance:	$	0.00
		=================
Total balance:	$	0.00

Please refer to the Summary and Explanation for additional information.

Canada Revenue Agency | Agence du revenu du Canada

CHAPLEAU PUBLIC UTILITIES CORPORATION

Date of mailing	December 14, 2007
Business Number	89149 3322 RC0001
Taxation year-end	December 31, 2006

CORPORATION NOTICE OF ASSESSMENT

SUMMARY OF ASSESSMENT

	$ Reported	$ Assessed
Federal Tax:		
Part I	0.00	0.00
Part I.3	0.00	0.00
Part II	0.00	0.00
Part III.1	0.00	0.00
Part IV	0.00	0.00
Part IV.1	0.00	0.00
Part VI	0.00	0.00
Part VI.1	0.00	0.00
Part XIII.1	0.00	0.00
Part XIV	0.00	0.00
Total Federal Tax:		$ 0.00
Net balance:		$ 0.00
Result of this assessment:		$ 0.00
Prior balance:		$ 0.00
Total balance:		$ 0.00

William V. Baker
Commissioner of Revenue

EXPLANATION

We have revised the non-capital loss closing balance on Schedule 4, "Corporation Loss Continuity and Application," to $817,283.00, to agree with our records.

Please visit our Web site at www.cra.gc.ca/requests-business for information about online requests available to business clients. This service allows clients to electronically request certain financial actions, additional remittance vouchers and other communication products, as well as reproductions of previously issued correspondence.

The Canada Revenue Agency also offers the convenience of Direct Deposit. For information about this service, please visit our Web site at www.cra.gc.ca or contact the number provided below.

Did you know you may be eligible to file your return using our Corporation Internet Filing service? For information on eligibility criteria and the service in general, please visit www.cra.gc.ca/corporation-internet.

If you require additional information or wish to request an adjustment, contact:

Sudbury Tax Centre
1050 Notre Dame Ave
Sudbury ON P3A 5C1
Fax (705) 671-0490

Sudbury Tax Services Office
1050 Notre Dame Avenue
Sudbury ON P3A 5C1
Toll free number 1-800-959-5525

Detach and return this REMITTANCE FORM with your payment.

Ontario

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

Remittance Advice - Payment-in-Lieu (PIL)

Electricity Act, 1998
Corporations Tax Act, R.S.O. 1990

Account No.
1800066

35
PX5003

CHAPLEAU PUBLIC UTILITIES CORPORATION
C/O MARITA MORIN
P O BOX 670

CHAPLEAU ON
P0M 1K0

Taxation Year End: (YYYYMMDD)

Payment Amount: $

Taxation Year End: (YYYYMMDD) 2 0 0 6 1 2 3 1

Payment Amount: $

Total Payment Enclosed: $

Ontario

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

	Account No.	Assessment Date (year, month, day)	Page
CHAPLEAU PUBLIC UTILITIES CORPORATION	**1800066**	2008/01/23	1 of 1

ASSESSMENT NO. 44

Tax: Federal and Provincial PIL	0.00
Total Assessment Liability	0.00

SUMMARY OF 2006/12/31 TAXATION YEAR TRANSACTIONS

Sub-Total	0.00
TAXATION YEAR BALANCE	0.00

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

Financial Statements of

CHAPLEAU PUBLIC UTILITIES CORPORATION

Year ended December 31, 2006

KPMG

KPMG LLP
Chartered Accountants
Claridge Executive Centre
144 Pine Street PO Box 700
Sudbury ON P3E 4R6

Telephone (705) 675-8500
Fax (705) 675-7586
In Watts (1-800) 461-3551
Internet www.kpmg.ca

AUDITORS' REPORT

To the Shareholder of Chapleau Public Utilities Corporation

We have audited the balance sheet of **Chapleau Public Utilities Corporation** as at December 31, 2006 and the statements of earnings and deficit and cash flows for the year then ended. These financial statements are the responsibility of the Corporation'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 financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2006 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants, Licensed Public Accountants

Sudbury, Canada
April 25, 2007

CHAPLEAU PUBLIC UTILITIES CORPORATION
Balance Sheet

December 31, 2006, with comparative figures for 2005

		2006		2005
				(restated)
Assets				
Current assets:				
Cash	$	173,608	$	495,139
Term deposits and treasury bills		651,121		527,563
Trade receivables (note 2)		40,885		30,175
Plant materials and supplies - at cost		43,787		29,309
Prepaid expenses		10,318		9,200
Unbilled revenue - energy sales		424,856		449,301
Unbilled revenue - distribution		42,940		70,187
		1,387,515		1,610,874
Capital assets (note 3)		2,175,939		2,151,646
Less accumulated amortization		1,266,778		1,229,408
		909,161		922,238
	$	2,296,676	$	2,533,112
Liabilities and Shareholder's Deficiency				
Current liabilities:				
Accounts payable and accrued liabilities (note 4)	$	267,048	$	542,373
Accrued interest payable		-		203,905
Advances from related company (note 5)		20,551		121,903
		287,599		868,181
Other liabilities:				
Regulatory liabilities (note 6)		487,538		461,498
Customer deposits		21,989		27,259
Loan payable (notes 7 and 15)		360,727		717,560
Mortgage payable (notes 8 and 15)		1,321,493		1,321,493
Shareholder's deficiency:				
Share capital (note 9)		560,840		100
Deficit		(743,510)		(862,979)
		(182,670)		(862,879)
Commitments (note 12)				
Contingencies (note 13)				
Subsequent events (note 15)				
	$	2,296,676	$	2,533,112

See accompanying notes to financial statements.

On behalf of the Board:

______________________ Director

CHAPLEAU PUBLIC UTILITIES CORPORATION

Statement of Earnings and Deficit

Year ended December 31, 2006, with comparative figures for 2005

	2006	2005 (restated)
Revenue:		
Energy sales	$ 2,089,075	$ 2,143,133
Distribution	567,925	494,734
	2,657,000	2,637,867
Expenses:		
Power purchased	2,043,433	2,185,831
Operations and maintenance	262,647	291,278
Administration and general	164,663	181,879
Billing and collection	63,918	52,929
Amortization of capital assets	37,370	37,731
	2,572,031	2,749,648
Earnings (loss) before the undernoted	84,969	(111,781)
Other income (expenses):		
Interest earned	48,509	25,730
Late payment charges	4,684	5,091
Miscellaneous	17,421	8,459
Other interest	(36,114)	(51,351)
Chargebacks (note 11)	-	(46,540)
Interest on loans and mortgage payable (note 11)	-	(203,905)
	34,500	(262,516)
Net earnings (loss) for the year	119,469	(374,297)
Deficit, beginning of year	(862,979)	(488,682)
Deficit, end of year	$ (743,510)	$ (862,979)

See accompanying notes to financial statements.

CHAPLEAU PUBLIC UTILITIES CORPORATION
Statement of Cash Flows

Year ended December 31, 2006, with comparative figures for 2005

	2006	2005
		(restated)
Cash provided by (used in):		
Operations:		
Net earnings (loss) for the year	$ 119,469	$ (374,297)
Item not involving cash:		
Amortization of capital assets	37,370	37,731
	156,839	(336,566)
Change in non-cash operating working capital:		
Increase in trade receivables	(10,710)	(1,799)
Decrease (increase) in plant materials and supplies - at cost	(14,478)	2,242
Decrease (increase) in prepaid expenses	(1,118)	1,262
Decrease (increase) in unbilled revenue - energy sales	24,445	(12,692)
Decrease (increase) in unbilled revenue - distribution	27,247	(1,046)
Increase (decrease) in accounts payable and accrued liabilities	(275,325)	231,617
Increase (decrease) in accrued interest payable	(203,905)	18,537
Decrease in customer deposits	(5,270)	(8,210)
Decrease in payment in lieu of taxes	-	4,000
Increase in advances from related company	-	10,480
	(302,275)	(92,175)
Financing:		
Decrease in advances from related company	(101,352)	-
Increase (decrease) loan payable	(356,833)	185,368
Issue of share capital	560,740	-
	102,555	185,368
Investments:		
Addition to capital assets	(24,293)	(33,080)
Increase in regulatory liabilities	26,040	172,549
	1,747	139,469
Increase (decrease) in cash position	(197,973)	232,662
Cash position, beginning of year	1,022,702	790,040
Cash position, end of year	$ 824,729	$ 1,022,702
Cash and cash equivalents are represented by:		
Cash	$ 173,608	$ 495,139
Term deposits and treasury bills	651,121	527,563
	$ 824,729	$ 1,022,702
Supplemental cash flow information:		
Interest paid	$ 203,905	$ 185,368

See accompanying notes to financial statements.

Chapleau Public Utilities Corporation (the "Corporation") was incorporated August 18, 1999 to operate as an electricity distribution company.

1. Significant accounting policies:

(a) General:

These financial statements are the representation's of the Corporation's management and are prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and policies set forth in the Accounting Procedure Manual issued by the Ontario Energy Board ("OEB") under the authority of the Ontario Energy Board Act, 1998 ("OEBA"). The OEB is charged with the responsibility of approving or setting rates for the transmission and distribution of electricity and the responsibility for ensuring that distribution companies fulfill obligations to connect and service customers. In its capacity to set or approve rates, the OEB has the authority to specify regulatory treatments that may result in accounting treatments that differ from Canadian GAAP for enterprises operating in a non-rate regulated environment.

The Electricity Act, 1998 (Ontario) ("Electricity Act") provides for a competitive marketplace in the sale of electricity. The marketplace was deregulated effective May 1, 2002.

(b) Revenue recognition and power purchased:

Revenue is recorded in the accounts to various dates on the basis of monthly or bi-monthly meter readings. At the end of an accounting cycle, there is energy used by consumers for which meter readings are not available. The unbilled revenue is estimated and recorded in the accounts at the end of each fiscal year. The related cost of energy is recorded on the basis of energy used.

(c) Effects of rate regulation:

The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have been applied in a non rate-regulated company. Such change in timing involves the application of rate regulated accounting, giving rise to the recognition of regulatory assets and liabilities. Regulatory assets represent future revenues associated with certain costs, incurred in the current period or in prior periods, that are expected to be recovered from customers in future periods through the rate-setting and approval process. Regulatory liabilities represent future reductions or limitations of increases in revenues associated with amounts that are expected to be refunded to customers as a result of the rate-setting and approval process.

1. Significant accounting policies (continued):

(d) Capital assets:

Capital assets are stated at cost. Amortization is provided using the following methods and annual rates:

Asset	Basis	Rate
Transmission and distribution systems	Declining-balance	25 - 40 years

(e) Payment in lieu of taxes:

Effective October 1, 2001 and pursuant to the Electricity Act, the Corporation is required to compute taxes under the Income Tax Act (Canada) and Ontario Corporations Tax Act and remit such amounts computed thereunder to the Ontario Electricity Financial Corporation ("OEFC"). These amounts, referred to as payments in lieu of taxes ("PILs") under the Electricity Act, are applied to reduce certain debt obligations of the former Ontario Hydro now owed by the OEFC.

The Corporation provides for amounts in lieu of income taxes 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 amounts for accounting purposes. When unrecorded future income taxes become payable, it is expected that they will be included in rates approved by the OEB and recovered from customers at that time.

(f) Asset retirement obligations:

During 2004, the Corporation adopted the Canadian Institute of Chartered Accountants (CICA) Handbook Section 3110, Asset Retirement Obligations. This accounting standard requires the Corporation to determine the fair value of the future expenditures required to settle legal obligations to remove capital assets. If reasonably estimable, a liability is recognized equal to the present value of the estimated future removal expenditures. An equivalent amount is capitalized as an inherent cost of the associated capital asset.

Some of the Corporation's transmission and distribution assets may have asset retirement obligations. As the Corporation expects to use the majority of its installed assets for an indefinite period, no removal date can be determined and consequently a reasonable estimate of the fair value of any related asset retirement obligation cannot be made at this time. If, at some future date, it becomes possible to estimate the fair value cost of removing assets that the Corporation is legally required to remove, an asset retirement obligation will be recognized at that time.

1. Significant accounting policies (continued):

(g) Use of estimates:

The preparation of financial statements 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 year. Actual results could differ from those estimates.

2. Trade receivables:

	2006	2005
Electrical	$ 50,785	$ 36,175
Provision for doubtful accounts	(9,900)	(6,000)
	$ 40,885	$ 30,175

3. Capital assets:

			2006	2005
	Cost	Accumulated amortization	Net book value	Net book value
Land	$ 141	$ -	$ 141	$ 141
Transmission and distribution systems	2,175,798	1,266,778	909,020	922,097
	$ 2,175,939	$ 1,266,778	$ 909,161	$ 922,238

4. Accounts payable and accrued liabilities:

	2006	2005
Power purchased	$ 224,317	$ 303,889
Miscellaneous	42,731	238,484
	$ 267,048	$ 542,373

5. Advances from related company:

The amounts advanced from related company are non-interest bearing, unsecured and have no specified terms of repayment. The Corporation is related by virtue of common ownership.

6. Regulatory liabilities:

Net regulatory liabilities represent costs incurred by the Corporation less amounts billed to the consumer at OEB approved rates less recoveries. These amounts have been accumulated pursuant to the Electricity Act and deferred in anticipation of their future recovery in electricity distribution rates. Management assesses the future uncertainty with respect to the final regulatory disposition of those amounts and the extent required, makes accounting provisions to reduce the deferred balances accumulated or to increase the recorded liabilities. Upon rendering of the final regulatory decision adjusting distribution rates, the provisions are adjusted to reflect the final impact of that decision, and such adjustment is reflected in net earnings for the period.

	2006	2005
Deferred transition costs (a)	$ 33,943	$ 54,718
Retail settlement variances (b)	(518,187)	(454,121)
Pre-market opening energy variances (c)	-	(42,085)
Deferred payments in lieu of taxes (d)	(3,294)	(20,010)
	$ (487,538)	$ (461,498)

(a) Deferred transition costs - the OEB established a process for the recording of costs incurred by the Corporation to be market ready, including related carrying costs, as deferred transition costs to be recovered in the future through the regulatory rate-setting process. In the absence of rate regulation, Canadian GAAP would require that the costs be recognized as an expense or capital asset, as applicable, when incurred. The Corporation filed for recovery of these costs in March 2005 and were granted final approval for recovery of these costs over a three year period.

(b) Retail settlement variances - represent the difference between the amount paid by the Corporation to the Independent Market System Operator ("IESO") for the cost of energy and the amount billed by the Corporation to its customers as energy sales, and related carrying costs which are recorded on the balance sheet as retail settlement variances until their final disposition is decided by the OEB. The Corporation recognizes retail settlement variances as as an asset or liability based on the expectation these amounts will be approved by the OEB for future collection from, or refund to, customers through the rate setting and approval process. The retail settlement variance liability represents the deficiency of amounts billed by the IESO for the cost of energy compared to the amounts charged to customers as energy sales. In the absence of rate regulation, Canadian GAAP would require that the total cost of energy be charged to operations when incurred and the total amount of energy sales be credited to operations when earned.

6. Regulatory liabilities (continued):

(c) Pre-market opening energy variances - represent the difference between the cost of energy purchased and the amounts billed to customers prior to Market Opening. The Corporation filed for recovery of these costs in March 2005 and were granted final approval for recovery of these costs in 2006.

(d) Deferred payments in lieu of taxes - represent variances that result from the difference between OEB approved PILs recoverable in electricity distribution service charges and the actual amount of these charges to customers that relates to the recovery of PILs.

The continuing restructuring of Ontario's electricity industry and other regulatory developments, including current and possible future consultations between the OEB and interested stakeholders, may affect the distribution rates that the Corporation may charge and the costs that the Corporation may recover, including the balance of its regulatory assets.

In the absence of rate regulation, Canadian GAAP would require the Corporation to record the costs and recoveries described above in the operating results of the year in which they are incurred and reported earnings before income taxes would be $16,716 (2005 - ($20,010)) lower than reported.

For certain of the regulatory assets and liabilities identified above, the expected recovery or settlement period, or likelihood of recovery or settlement, is affected by risks and uncertainties relating to the ultimate authority of the OEB in determining the item's treatment for rate-setting purposes. The Corporation continually assesses the likelihood of recovery of each of its regulatory assets and refund each of its regulatory liabilities and continues to believe that it is probable that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If at some future date the Corporation determines that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be charged to operations in the period the determination is made.

7. Loan payable:

The loan is repayable to the Corporation of the Township of Chapleau (the "Township"). The loan bears interest at 7.25%, is unsecured and has no specified terms of repayment. Payment of interest has been postponed indefinitely and the Township has indicated they will not demand repayment within the next twelve months.

During the year, the Corporation converted $560,740 of the loan payable into common shares of the Corporation.

8. Mortgage payable:

The mortgage payable is repayable to the Township, is secured by a general security agreement and specific assets of the Corporation, bears interest at 7.25% and has no specified terms of repayment. Payment of interest has been postponed indefinitely and the Township has indicated they will not demand repayment within the next twelve months.

9. Share capital:

	2006	2005
Authorized:		
Unlimited common shares		
Issued:		
560,840 common shares (2005 - 100 common shares) (note 7)	$ 560,840	$ 100

10. Payment in lieu of taxes:

For payment in lieu of tax purposes, the Corporation has losses of $728,423 carried forward which can be applied to reduce future years' taxable income. These losses will expire as follows:

2010	$ 128,130
2011	296,896
2012	303,397

11. Related party transactions:

The Corporation is related to the Township by virtue of the fact that the Township is the sole shareholder of the Corporation. The Corporation is related to Chapleau Energy Services Corporation by virtue of common ownership.

During the year, the Corporation was charged $Nil (2005 - $203,905) of interest by the Township and billed the Township $286,995 (2005 - $272,606) for power purchased.

Also, the Corporation was charged $Nil (2005 - $46,540) by Chapleau Energy Services Corporation, for the Corporation's portion of certain shared costs.

During the year, the Corporation paid $1,181 (2005 - $1,240) to the Township on account of municipal taxes.

12. Commitments:

The Corporation has issued a $300,205 Letter of Credit to the IMO for market opening on May 1, 2002. At December 31, 2006, no amounts have been drawn on this financing arrangement.

13. Contingencies:

A class action lawsuit claiming $500 million in restitutionary payments plus interest was served on the former Toronto Hydro Electric Commission, continuing as Toronto Hydro Corporation, on November 8, 1998. This 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 after April 1, 1981.

The claim is that late payment penalties result in 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 Electricity Distributors Association has undertaken the defence of this class action. At this time it is not possible to quantify the effect, if any, on the financial statements.

Accordingly, no provision has been made in these financial statements with respect to any possible losses that may arise as a result of this matter.

14. Financial instruments:

Fair value of financial assets and financial liabilities

The carrying value of cash, trade receivable, unbilled revenue, term deposits and treasury bills, accounts payable and accrued liabilities, accrued interest payable, advances from related company and customer deposits approximate their fair value due to the relatively short periods to maturity of these items.

It was not practicable to estimate the fair value of the loan payable and mortgage payable as there are no principal repayment terms.

15. Subsequent events:

Subsequent to year-end, the Corporation passed a resolution authorizing the conversion of $360,727 of the loan payable and $199,813 of the mortgage payable owing to the Township into common shares of the Corporation.

Appendix F

Informational Filing

Sheets I3 to I8 and 01and 02

2006 Cost Allocation Information Filing

Chapleau Public Utilities Corporation

EB-2005-0349 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)

Step 10: Enter Total Rate Base from approved EDR (Sheet 3-1, cell F21)

Step 11: Enter Directly Allocated amounts into column G.

		From this Sheet
Approved Target Net Income ($)	$60,149	
Approved PILs ($)	$0	
Approved Interest ($)	$48,454	
Approved Specific Service Charges ($)	$16,737	
Approved Transformer Ownership Allowance ($)	$11,559	
Approved Low Voltage Wheeling Adjustment ($)	$0	
Approved Revenue Requirement ($)	$632,826	
Revenue Requirement to be Used in this model ($)	$644,385	**$644,385**
Approved Rate Base ($)	$1,336,649	
Rate Base to be Used in this model ($)	$1,338,383	**$1,338,383**

Uniform System of Accounts - Detail Accounts

USoA Account #	Accounts		Financial Statement (EDR Sheet 2.4, Column P)	Model Adjustments	Reclassify accounts	Direct Allocation
1005	Cash					
1010	Cash Advances and Working Funds					
1020	Interest Special Deposits					
1030	Dividend Special Deposits					
1040	Other Special Deposits					
1060	Term Deposits					
1070	Current Investments					
1100	Customer Accounts Receivable					
1102	Accounts Receivable - Services					
1104	Accounts Receivable - Recoverable Work					
1105	Accounts Receivable - Merchandise, Jobbing, etc.					
1110	Other Accounts Receivable					
1120	Accrued Utility Revenues					
1130	Accumulated Provision for Uncollectible Accounts--Credit					
1140	Interest and Dividends Receivable					
1150	Rents Receivable					

1170	Notes Receivable		
1180	Prepayments		
1190	Miscellaneous Current and Accrued Assets		
1200	Accounts Receivable from Associated Companies		
1210	Notes Receivable from Associated Companies		
1305	Fuel Stock		
1330	Plant Materials and Operating Supplies		
1340	Merchandise		
1350	Other Materials and Supplies		
1405	Long Term Investments in Non-Associated Companies		
1408	Long Term Receivable - Street Lighting Transfer		
1410	Other Special or Collateral Funds		
1415	Sinking Funds		
1425	Unamortized Debt Expense		
1445	Unamortized Discount on Long-Term Debt--Debit		
1455	Unamortized Deferred Foreign Currency Translation Gains and Losses		
1460	Other Non-Current Assets		
1465	O.M.E.R.S. Past Service Costs		
1470	Past Service Costs - Employee Future Benefits		
1475	Past Service Costs - Other Pension Plans		
1480	Portfolio Investments - Associated Companies		
1485	Investment in Associated Companies - Significant Influence		
1490	Investment in Subsidiary Companies		
1505	Unrecovered Plant and Regulatory Study Costs		
1508	Other Regulatory Assets		
1510	Preliminary Survey and Investigation Charges		
1515	Emission Allowance Inventory		
1516	Emission Allowances Withheld		
1518	RCVARetail		
1520	Power Purchase Variance Account		
1525	Miscellaneous Deferred Debits		
1530	Deferred Losses from Disposition of Utility Plant		
1540	Unamortized Loss on Reacquired Debt		
1545	Development Charge Deposits/ Receivables		
1548	RCVASTR		
1560	Deferred Development Costs		
1562	Deferred Payments in Lieu of Taxes		
1563	Account 1563 - Deferred PILs Contra Account		
1565	Conservation and Demand Management Expenditures and Recoveries		
1570	Qualifying Transition Costs		
1571	Pre-market Opening Energy Variance		
1572	Extraordinary Event Costs		
1574	Deferred Rate Impact Amounts		
1580	RSVAWMS		
1582	RSVAONE-TIME		
1584	RSVANW		
1586	RSVACN		
1588	RSVAPOWER		
1590	Recovery of Regulatory Asset Balances		
1605	Electric Plant in Service - Control Account		
1606	Organization		
1608	Franchises and Consents		
1610	Miscellaneous Intangible Plant		
1615	Land		
1616	Land Rights		
1620	Buildings and Fixtures		
1630	Leasehold Improvements		
1635	Boiler Plant Equipment		
1640	Engines and Engine-Driven Generators		
1645	Turbogenerator Units		
1650	Reservoirs, Dams and Waterways		
1655	Water Wheels, Turbines and Generators		
1660	Roads, Railroads and Bridges		
1665	Fuel Holders, Producers and Accessories		
1670	Prime Movers		
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		
1965	Water Heater Rental Units		
1970	Load Management Controls - Customer Premises		
1975	Load Management Controls - Utility Premises		
1980	System Supervisory Equipment		
1985	Sentinel Lighting Rental Units		
1990	Other Tangible Property		
1995	Contributions and Grants - Credit		
2005	Property Under Capital Leases		
2010	Electric Plant Purchased or Sold		
2020	Experimental Electric Plant Unclassified		
2030	Electric Plant and Equipment Leased to Others		
2040	Electric Plant Held for Future Use		
2050	Completed Construction Not Classified--Electric		
2055	Construction Work in Progress--Electric		
2060	Electric Plant Acquisition Adjustment		
2065	Other Electric Plant Adjustment		
2070	Other Utility Plant		
2075	Non-Utility Property Owned or Under Capital Leases		
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment		
2120	Accumulated Amortization of Electric Utility Plant - Intangibles		
2140	Accumulated Amortization of Electric Plant Acquisition Adjustment		
2160	Accumulated Amortization of Other Utility Plant		
2180	Accumulated Amortization of Non-Utility Property		
2205	Accounts Payable		
2208	Customer Credit Balances		
2210	Current Portion of Customer Deposits		
2215	Dividends Declared		
2220	Miscellaneous Current and Accrued Liabilities		
2225	Notes and Loans Payable		
2240	Accounts Payable to Associated Companies		
2242	Notes Payable to Associated Companies		
2250	Debt Retirement Charges(DRC) Payable		
2252	Transmission Charges Payable		
2254	Electrical Safety Authority Fees Payable		
2256	Independent Market Operator Fees and Penalties Payable		
2260	Current Portion of Long Term Debt		
2262	Ontario Hydro Debt - Current Portion		
2264	Pensions and Employee Benefits - Current Portion		
2268	Accrued Interest on Long Term Debt		
2270	Matured Long Term Debt		

2272	Matured Interest on Long Term Debt		
2285	Obligations Under Capital Leases--Current		
2290	Commodity Taxes		
2292	Payroll Deductions / Expenses Payable		
2294	Accrual for Taxes, Payments in Lieu of Taxes, Etc.		
2296	Future Income Taxes - Current		
2305	Accumulated Provision for Injuries and Damages		
2306	Employee Future Benefits		
2308	Other Pensions - Past Service Liability		
2310	Vested Sick Leave Liability		
2315	Accumulated Provision for Rate Refunds		
2320	Other Miscellaneous Non-Current Liabilities		
2325	Obligations Under Capital Lease--Non-Current		
2330	Development Charge Fund		
2335	Long Term Customer Deposits		
2340	Collateral Funds Liability		
2345	Unamortized Premium on Long Term Debt		
2348	O.M.E.R.S. - Past Service Liability - Long Term Portion		
2350	Future Income Tax - Non-Current		
2405	Other Regulatory Liabilities		
2410	Deferred Gains from Disposition of Utility Plant		
2415	Unamortized Gain on Reacquired Debt		
2425	Other Deferred Credits		
2435	Accrued Rate-Payer Benefit		
2505	Debentures Outstanding - Long Term Portion		
2510	Debenture Advances		
2515	Reacquired Bonds		
2520	Other Long Term Debt		
2525	Term Bank Loans - Long Term Portion		
2530	Ontario Hydro Debt Outstanding - Long Term Portion		
2550	Advances from Associated Companies		
3005	Common Shares Issued		
3008	Preference Shares Issued		
3010	Contributed Surplus		
3020	Donations Received		
3022	Development Charges Transferred to Equity		
3026	Capital Stock Held in Treasury		
3030	Miscellaneous Paid-In Capital		
3035	Installments Received on Capital Stock		
3040	Appropriated Retained Earnings		
3045	Unappropriated Retained Earnings		
3046	Balance Transferred From Income	$0	$0
3047	Appropriations of Retained Earnings - Current Period		
3048	Dividends Payable-Preference Shares		
3049	Dividends Payable-Common Shares		
3055	Adjustment to Retained Earnings		
3065	Unappropriated Undistributed Subsidiary Earnings		
4006	Residential Energy Sales		
4010	Commercial Energy Sales		
4015	Industrial Energy Sales		
4020	Energy Sales to Large Users		
4025	Street Lighting Energy Sales		
4030	Sentinel Lighting Energy Sales		
4035	General Energy Sales		
4040	Other Energy Sales to Public Authorities		
4045	Energy Sales to Railroads and Railways		
4050	Revenue Adjustment		
4055	Energy Sales for Resale		
4060	Interdepartmental Energy Sales		
4062	Billed WMS		
4064	Billed-One-Time		
4066	Billed NW		
4068	Billed CN		
4080	Distribution Services Revenue	$88,124	
4082	Retail Services Revenues		
4084	Service Transaction Requests (STR) Revenues		
4090	Electric Services Incidental to Energy Sales		
4105	Transmission Charges Revenue		
4110	Transmission Services Revenue		
4205	Interdepartmental Rents		
4210	Rent from Electric Property		
4215	Other Utility Operating Income		
4220	Other Electric Revenues		
4225	Late Payment Charges		
4230	Sales of Water and Water Power		
4235	Miscellaneous Service Revenues	($93,139)	
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
4375	Revenues from Non-Utility Operations
4380	Expenses of Non-Utility Operations
4385	Non-Utility Rental Income
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
4505	Operation Supervision and Engineering
4510	Fuel
4515	Steam Expense
4520	Steam From Other Sources
4525	Steam Transferred--Credit
4530	Electric Expense
4535	Water For Power
4540	Water Power Taxes
4545	Hydraulic Expenses
4550	Generation Expense
4555	Miscellaneous Power Generation Expenses
4560	Rents
4565	Allowances for Emissions
4605	Maintenance Supervision and Engineering
4610	Maintenance of Structures
4615	Maintenance of Boiler Plant
4620	Maintenance of Electric Plant
4625	Maintenance of Reservoirs, Dams and Waterways
4630	Maintenance of Water Wheels, Turbines and Generators
4635	Maintenance of Generating and Electric Plant
4640	Maintenance of Miscellaneous Power Generation Plant
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
4720	Other Expenses
4725	Competition Transition Expense
4730	Rural Rate Assistance Expense
4805	Operation Supervision and Engineering
4810	Load Dispatching
4815	Station Buildings and Fixtures Expenses
4820	Transformer Station Equipment - Operating Labour
4825	Transformer Station Equipment - Operating Supplies and Expense
4830	Overhead Line Expenses
4835	Underground Line Expenses
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		$0
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		$11,559
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		
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		$0
5165	Maintenance of Street Lighting and Signal Systems		
5170	Sentinel Lights - Labour		
5172	Sentinel Lights - Materials and Expenses		
5175	Maintenance of Meters		
5178	Customer Installations Expenses- Leased Property		
5185	Water Heater Rentals - Labour		
5186	Water Heater Rentals - Materials and Expenses		
5190	Water Heater Controls - Labour		
5192	Water Heater Controls - Materials and Expenses		
5195	Maintenance of Other Installations on Customer Premises		
5205	Purchase of Transmission and System Services		
5210	Transmission Charges		
5215	Transmission Charges Recovered		
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		$0	
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			
5725	Miscellaneous Amortization			
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		$0	$0
6010	Amortization of Debt Discount and Expense			
6015	Amortization of Premium on Debt Credit			
6020	Amortization of Loss on Reacquired Debt			
6025	Amortization of Gain on Reacquired Debt--Credit			
6030	Interest on Debt to Associated Companies			
6035	Other Interest Expense			
6040	Allowance for Borrowed Funds Used During Construction--Credit			
6042	Allowance For Other Funds Used During Construction			
6045	Interest Expense on Capital Lease Obligations			
6105	Taxes Other Than Income Taxes			
6110	Income Taxes		$0	$0
6115	Provision for Future Income Taxes			
6205	Donations			
6210	Life Insurance			
6215	Penalties			
6225	Other Deductions			
6305	Extraordinary Income			
6310	Extraordinary Deductions			
6315	Income Taxes, Extraordinary Items			
6405	Discontinues Operations - Income/ Gains			
6410	Discontinued Operations - Deductions/ Losses			
6415	Income Taxes, Discontinued Operations			

$0

Reclassification Equals to Zero.
O.K. to Proceed.

Asset Accounts Directly Allocated	$0

Differences?

Rev Req Matches

Rate Base Matches

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2006 Cost Allocation Information Filing

Chapleau Public Utilities Corporation

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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 approved EDR, Sheet 3-1, cell F12	$943,844

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**	**Accumulated Depreciation - 2120**	**Asset net of Accumulated Depreciation and Contributed Capital**
1565	Conservation and Demand Management	$0		-	-					-
1805	Land	$141		($141)	-					
1805-1	Land Station >50 kV			$0	-					-
1805-2	Land Station <50 kV		100.00%	$141	141					141
1806	Land Rights	$0		$0	-					
1806-1	Land Rights Station >50 kV			$0	-					-
1806-2	Land Rights Station <50 kV		100.00%	$0	-					-
1808	Buildings and Fixtures	$0		$0	-					
1808-1	Buildings and Fixtures > 50 kV			$0	-					-
1808-2	Buildings and Fixtures < 50 KV		100.00%	$0	-					-
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	$442,547		($442,547)	-					-
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)		0.00%	$0	-					-
1820-2	Distribution Station Equipment - Normally Primary below 50 kV Primary)		100.00%	$442,547	442,547			$ (129,011)		313,536
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	$1,103,872		($1,103,872)	-					
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery		0.00%	$0	-					-
1830-4	Poles, Towers and Fixtures - Primary		59.45%	$656,252	656,252			$ (424,647)		231,605

2006 Cost Allocation Information Filing
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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 approved EDR, Sheet 3-1, cell F12	**$943,844**

RATE BASE AND DISTRIBUTION ASSETS

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	Accumulated Depreciation - 2120	Asset net of Accumulated Depreciation and Contributed Capital
					BALANCE SHEET ITEMS					
1830-5	Poles, Towers and Fixtures - Secondary		40.55%	$447,620	447,620			$ (289,646)		157,974
1835	Overhead Conductors and Devices	$0		$0	-					
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery			$0	-					-
1835-4	Overhead Conductors and Devices - Primary			$0	-					-
1835-5	Overhead Conductors and Devices - Secondary		100.00%	$0	-					-
1840	Underground Conduit	$77,300		($77,300)	-					
1840-3	Underground Conduit - Bulk Delivery		0.00%	$0	-					-
1840-4	Underground Conduit - Primary		10.14%	$7,838	7,838			$ (4,285)		3,554
1840-5	Underground Conduit - Secondary		89.86%	$69,462	69,462			$ (37,970)		31,491
1845	Underground Conductors and Devices	$0		$0	-					
1845-3	Underground Conductors and Devices - Bulk Delivery			$0	-					-
1845-4	Underground Conductors and Devices - Primary			$0	-					-
1845-5	Underground Conductors and Devices - Secondary		100.00%	$0	-					-
1850	Line Transformers	$339,041		$0	339,041			$ (212,082)		126,959
1855	Services	$0		$0	-					-
1860	Meters	$153,675		$0	153,675			$ (75,091)		78,584
	Total	**$2,116,575**		**$0**	**$2,116,575**	**$0**	**$0**	**($1,172,732)**	**$0**	**943,843**
	SUB TOTAL from I3	**$2,116,575**								

2006 Cost Allocation Information Filing

Chapleau Public Utilities Corporation

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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 approved EDR, Sheet 3-1, cell F12	$943,844

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	Accumulated Depreciation - 2120	Asset net of Accumulated Depreciation and Contributed Capital
General Plant		Break out Functions				Contributed Capital - 1995	Accumulated Depreciation - 2105 Capital Contribution	Accumulated Depreciation - 2105 Fixed Assets Only	Accumulated Depreciation - 2120	Net Asset
1905	Land	$0			-					$ -
1906	Land Rights	$0			-					$ -
1908	Buildings and Fixtures	$0			-					$ -
1910	Leasehold Improvements	$0			-					$ -
1915	Office Furniture and Equipment	$0			-					$ -
1920	Computer Equipment - Hardware	$0			-					$ -
1925	Computer Software	$0			-					$ -
1930	Transportation Equipment	$0			-					$ -
1935	Stores Equipment	$0			-					$ -
1940	Tools, Shop and Garage Equipment	$0			-					$ -
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	$0			-					$ -
1990	Other Tangible Property	$0			-					$ -
2005	Property Under Capital Leases	$0			-					$ -
2010	Electric Plant Purchased or Sold	$0			-					$ -
	Total	$0		$0	$0	$0	$0	$0	$0	$0
	SUB TOTAL from I3	$0								
	I3 Directly Allocated	$0								
	Grand Total	$2,116,575		$0	$2,116,575	$0	$0	($1,172,732)	$0	$943,843

2006 Cost Allocation Information Filing
Chapleau Public Utilities Corporation
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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 approved EDR, Sheet 3-1, cell F12	**$943,844**

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**	**Accumulated Depreciation - 2120**	**Asset net of Accumulated Depreciation and Contributed Capital**
To be Prorated										
1995	Contributed Capital - 1995	$0				$0	Balanced			
2105	Accumulated Depreciation - 2105	($1,172,732)						$1,172,732	Balanced	
2120	Accumulated Depreciation - 2120	$0							$0	Balanced
	Total	**($1,172,732)**								
	Net Assets	**$943,843**	**Net Fixed Assets Match EDR**							

Amortization Expenses

5705	Amortization Expense - Property, Plant, and Equipment	$37,890
5710	Amortization of Limited Term Electric Plant	$0
5715	Amortization of Intangibles and Other Electric Plant	$0
5720	Amortization of Electric Plant Acquisition Adjustments	$0
	Total Amortization Expense	**$37,890**

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Sheet I4 Brea

Instructions:
This is an input sheet for the Break Out o
*****Please see Handbook for detailed instr***

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**	**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				
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)	$12,797			
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	$9,454			

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Sheet I4 Brea

Instructions:
This is an input sheet for the Break Out
*****Please see Handbook for detailed instr***

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	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	$6,448			
1835	Overhead Conductors and Devices				
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery				
1835-4	Overhead Conductors and Devices - Primary				
1835-5	Overhead Conductors and Devices - Secondary				
1840	Underground Conduit				
1840-3	Underground Conduit - Bulk Delivery				
1840-4	Underground Conduit - Primary	$145			
1840-5	Underground Conduit - Secondary	$1,285			
1845	Underground Conductors and Devices				
1845-3	Underground Conductors and Devices - Bulk Delivery				
1845-4	Underground Conductors and Devices - Primary				
1845-5	Underground Conductors and Devices - Secondary				
1850	Line Transformers	$5,182			
1855	Services				
1860	Meters	$2,579			
	Total	**$37,890**	**$0**	**$0**	**$0**
	SUB TOTAL from I3				
		5705	5710	5715	5720

2006 Cost All
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Sheet I4 Brea

Instructions:
This is an input sheet for the Break Out
***Please see Handbook for detailed instr*

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	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
General Plant		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
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				
2005	Property Under Capital Leases				
2010	Electric Plant Purchased or Sold				

Total	$0	$0	$0	$0
SUB TOTAL from I3 I3 Directly Allocated				
Grand Total	$37,890	$0	$0	$0

2006 Cost All
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Sheet I4 Brea

Instructions:
This is an input sheet for the Break Out
*****Please see Handbook for detailed instr***

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**	**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					
2120	Accumulated Depreciation - 2120					
	Total					
	Net Assets					
Amortization Expenses						
5705	Amortization Expense - Property, Plant, and Equipment	($37,890)	**Balanced**			
5710	Amortization of Limited Term Electric Plant		$0	**Balanced**		
5715	Amortization of Intangibles and Other Electric Plant			$0	**Balanced**	
5720	Amortization of Electric Plant Acquisition Adjustments				$0	**Balanced**
	Total Amortization Expense					

Sheet I5 Miscellaneous Data Worksheet - Second Run

kMs of Roads in Service Area Where Distribution Lines Exist	27
Deemed Equity Component of Rate Base (%)	50%

	1	2	3	7	8	9
	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
Step 3: Insert Approved Monthly Service Charge (Please refer to Approved EDR Sheet 8-5 column W)	19.74	30.89	151.53	0.79	2.63	15.32
Step 4: Insert Smart Meter Adder Included in Approved Monthly Service Charge (Please refer to Approved EDR Sheet 8-5 column T)	0.26	0.26	0.26			

Instructions (Cont'd):

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Sheet I6 Customer Data Worksheet - Second Run

Total kWhs	31,492,664
Total kWs	23,216
Total Approved Distribution Revenue ($)	$601,704

			1	2	3	7	8	9
	ID	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
Billing Data								
kWh from approved EDR model, Sheet 7-1, Col M	**CEN**	31,492,664	16,417,968	5,887,927	8,934,168	220,460	24,929	7,212
kW from approved EDR model, Sheet 7-1, Col S	**CDEM**	23,216			22,409	736	71	
kW, included in CDEM, from customers with line transformer allowance from approved EDR model, Sheet 6-3, Col P		19,266			19,266			
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**	31,492,664	16,417,968	5,887,927	8,934,168	220,460	24,929	7,212
kWh - 30 year weather normalized amount		31,162,261	15,922,454	6,057,716	8,846,651	303,797	24,237	7,407
Approved Distribution Rev from approved EDR, Sheet 7-1, Col AK + Sheet 7-3 Col H	**CREV**	$601,704	$434,694	$109,314	$50,448	$5,022	$1,021	$1,205
Bad Debt 3 Year Historical Average from Approved EDR Model	**BDHA**	$4,624	$4,388	$236	$0	$0	$0	$0
Late Payment 3 Year Historical Average	**LPHA**	$7,154	$4,739	$1,219	$1,196			
Weighting Factor - Services			1.0	2.0	10.0	1.0	1.0	1.0
Weighting Factor - Billings			1.0	2.0	7.0	1.0	0.1	5.0
Number of Bills	**CNB**	13,714	11,205	1,968	169	12	288	72
Number of Connections (Unmetered)	**CCON**	371				341	24	6
Total Number of Customer from Approved EDR, Sheet 7-1, Col H excluding connections	**CCA**	1,359	1,166	163	13	1	10	6
Bulk Customer Base	**CCB**	1,359	1,166	163	13	1	10	6
Primary Customer Base	**CCP**	1,359	1,166	163	13	1	10	6
Line Transformer Customer Base	**CCLT**	1,351	1,166	163	5	1	10	6
Secondary Customer Base	**CCS**	1,351	1,166	163	5	1	10	6
Weighted - Services	**CWCS**	1,913	1,166	326	50	341	24	6
Weighted Meter -Capital	**CWMC**	93,810	62,325	22,185	9,300	-	-	-
Weighted Meter Reading	**CWMR**	16,680	12,504	3,816	360	-	-	-
Weighted Bills	**CWNB**	16,725	11,205	3,936	1,183	12	29	360
Data Mismatch Analysis								
Revenue with 30 year weather normalized kWh		593,145	421,574	112,466	49,954	6,920	993	1,238

Weather Normalized Data from Hydro

	Total	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
kWh - 30 year weather normalized amount	32,564,563	16,638,965	6,330,313	9,244,750	317,468	25,328	7,740
2006 EDR Distribution Loss Factor		**1.0450**	1.0450	1.0450	1.0450	1.0450	1.0450

Bad Debt Data from EDR 2006

Sheet ADJ5 rows 26 - 32, column E	-	-	-	-			
Sheet ADJ5 rows 26 - 32, column F	8,456	8,456	-	-			
Sheet ADJ5 rows 26 - 32, column G	5,416	4,709	707				
Three-year average	**4,624**	**4,388**	**236**	**-**		**-**	**-**

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Sheet I7.1 Meter Capital Worksheet - Secor

		Residential	
		1	2
		Number of Meters	Weighted Metering Costs
	Allocation Percentage Weighted Factor		
	Cost Relative to Residential Average Cost		
	Total	1187	62325
Meter Types	**Cost per Meter (Installed)**		
Single Phase 200 Amp - Urban	50	1,170	58500
Single Phase 200 Amp - Rural	150		0
Central Meter	250		0
Network Meter (Costs to be updated)	225	17	3825
Three-phase - No demand	210		0
Smart Meters	300		0
Demand without IT (usually three-phase)	500		0
Demand with IT	2,100		0
Demand with IT and Interval Capability - Secondary	2,300		0
Demand with IT and Interval Capability - Primary	10,000		0
Demand with IT and Interval Capability -Special (WMP)	40,000		0
LDC Specific 1			0
LDC Specific 2			0
LDC Specific 3			0

nd Run

	GS <50			
3	1	2	3	1
Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters
66.44%			24%	
1.00			2.66	
52.50631845	159	22185	139.5283019	15

	104	5200		
		0		
	23	5750		
	11	2475		
	6	1260		
		0		
	15	7500		14
		0		
		0		1
		0		
		0		
		0		
		0		
		0		

GS>50-Regular		Street Light		
2	3	1	2	3
Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs
	10%			0%
	11.81			-
9300	620	0	0	-

0			0	
0			0	
0			0	
0			0	
0			0	
0			0	
7000			0	
0			0	
2300			0	
0			0	
0			0	
0			0	
0			0	
0			0	

Sentinel			Unmetered Scattered L	
1	2	3	1	2
Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs
		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

.oad	TOTAL		
3	1	2	3
Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs
0%			100%
-			1.31
-	1361	93810	68.92725937
	1,274	63700	
	0	0	
	23	5750	
	28	6300	
	6	1260	
	0	0	
	29	14500	
	0	0	
	1	2300	
	0	0	
	0	0	
	0	0	
	0	0	
	0	0	

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Sheet I7.2 Meter Reading Worksheet - Second Run

Weighting Factors based on Contractor Pricing

Description		1			2			3			7			8			9					
		Residential			GS <50			GS>50-Regular			Street Light			Sentinel			Unmetered Scattered Load			TOTAL		
		Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs
	Allocation Percentage Weighted Factor			74.96%			22.88%			2.16%			0.00%			0.00%			0.00%			100.00%
	Cost Relative to Residential Average Cost			1.00			1.78			1.78			0.00			0.00			0.00			4.56
	Total	11,142	12,504	1.12	1,908	3,816	2.00	180	360	2.00	-	-	0	-	-	0	-	-	0	13,230	16,680	5
	Factor																					
Residential - Urban - Outside	1.00	9,780	9,780			0			0			0			0			0		9,780	9,780	
Residential - Urban - Outside with other services	1.00		0			0			0			0			0			0		-	-	
Residential - Urban - Inside	2.00	1,362	2,724			0			0			0			0			0		1,362	2,724	
Residential - Urban - Inside - with other services	1.00		0			0			0			0			0			0		-	-	
Residential - Rural - Outside	3.00		0			0			0			0			0			0		-	-	
Residential - Rural - Outside with other services	2.00		0			0			0			0			0			0		-	-	
LDC Specific 1			0			0			0			0			0			0		-	-	
LDC Specific 2			0			0			0			0			0			0		-	-	
GS - Walking	2.00		0		1,908	3,816		180	360			0			0			0		2,088	4,176	
GS - Walking - with other services	3.00		0			0			0			0			0			0		-	-	
GS - Vehicle with other services --- TOU Read	3.00		0			0			0			0			0			0		-	-	
GS - Vehicle with other services	3.00		0			0			0			0			0			0		-	-	
LDC Specific 3			0			0			0			0			0			0		-	-	
LDC Specific 4	0.00		0			0			0			0			0			0		-	-	
Interval	49.00		0			0			0			0			0			0		-	-	
LDC Specific 5			0			0			0			0			0			0		-	-	
LDC Specific 6			0			0			0			0			0			0		-	-	

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Sheet I8 Demand Data Worksheet - Second Run

This is an input sheet for demand allocators.

CP TEST RESULTS	4 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

Row	Customer Classes		Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
35	**CO-INCIDENT PEAK**								
37	**1 CP**								
38	Transformation CP	TCP1	7,694	4,248	1,585	1,833	25	2	1
39	Bulk Delivery CP	BCP1	7,694	4,248	1,585	1,833	25	2	1
40	Total Sytem CP	DCP1	7,694	4,248	1,585	1,833	25	2	1
42	**4 CP**								
43	Transformation CP	TCP4	28,559	15,759	6,059	6,554	172	11	4
44	Bulk Delivery CP	BCP4	28,559	15,759	6,059	6,554	172	11	4
45	Total Sytem CP	DCP4	28,559	15,759	6,059	6,554	172	11	4
47	**12 CP**								
48	Transformation CP	TCP12	63,765	33,923	13,761	15,780	271	18	11
49	Bulk Delivery CP	BCP12	63,765	33,923	13,761	15,780	271	18	11
50	Total Sytem CP	DCP12	63,765	33,923	13,761	15,780	271	18	11
52	**NON CO_INCIDENT PEAK**								
54	**1 NCP**								
55	Classification NCP from Load Data Provider	DNCP1	8,490	4,669	1,768	1,969	74	9	1
56	Primary NCP	PNCP1	8,490	4,669	1,768	1,969	74	9	1
57	Line Transformer NCP	LTNCP1	6,796	4,669	1,768	276	74	9	1
58	Secondary NCP	SNCP1	6,796	4,669	1,768	276	74	9	1
60	**4 NCP**								
61	Classification NCP from Load Data Provider	DNCP4	31,029	16,928	6,638	7,132	295	32	4
62	Primary NCP	PNCP4	31,029	16,928	6,638	7,132	295	32	4
63	Line Transformer NCP	LTNCP4	24,896	16,928	6,638	998	295	32	4
64	Secondary NCP	SNCP4	24,896	16,928	6,638	998	295	32	4
66	**12 NCP**								
67	Classification NCP from Load Data Provider	DNCP12	69,790	36,203	15,314	17,303	886	75	11
68	Primary NCP	PNCP12	69,790	36,203	15,314	17,303	886	75	11
69	Line Transformer NCP	LTNCP12	54,910	36,203	15,314	2,422	886	75	11
70	Secondary NCP	SNCP12	54,910	36,203	15,314	2,422	886	75	11

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Sheet O1 Revenue to Cost Summary Worksheet - Second Run

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
crev	Distribution Revenue (sale)	$601,704	$434,694	$109,314	$50,448	$5,022	$1,021	$1,205
mi	Miscellaneous Revenue (mi)	$42,681	$27,575	$9,239	$4,589	$707	$86	$485
	Total Revenue	**$644,385**	**$462,269**	**$118,553**	**$55,037**	**$5,729**	**$1,107**	**$1,690**
	Expenses							
di	Distribution Costs (di)	$203,991	$125,920	$39,140	$23,028	$14,617	$1,029	$257
cu	Customer Related Costs (cu)	$74,245	$52,640	$16,366	$4,221	$30	$73	$914
ad	General and Administration (ad)	$219,656	$140,209	$43,967	$22,325	$11,443	$856	$856
dep	Depreciation and Amortization (dep)	$37,890	$22,853	$7,817	$5,264	$1,798	$127	$32
INPUT	PILs (INPUT)	$0	$0	$0	$0	$0	$0	$0
INT	Interest	$48,454	$29,273	$10,021	$6,700	$2,261	$159	$40
	Total Expenses	**$584,236**	**$370,895**	**$117,312**	**$61,538**	**$30,149**	**$2,244**	**$2,099**
	Direct Allocation	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
NI	Allocated Net Income (NI)	$60,149	$36,338	$12,440	$8,318	$2,807	$198	$49
	Revenue Requirement (includes NI)	$644,385	$407,233	$129,751	$69,856	$32,955	$2,441	$2,148
		Revenue Requirement Input equals Output						
	Rate Base Calculation							
	Net Assets							
dp	Distribution Plant - Gross	$2,116,575	$1,305,806	$428,298	$250,424	$121,370	$8,542	$2,136
gp	General Plant - Gross	$0	$0	$0	$0	$0	$0	$0
accum dep	Accumulated Depreciation	($1,172,732)	($735,595)	($233,099)	($119,905)	($77,330)	($5,443)	($1,361)
co	Capital Contribution	$0	$0	$0	$0	$0	$0	$0
	Total Net Plant	**$943,843**	**$570,211**	**$195,199**	**$130,519**	**$44,040**	**$3,100**	**$775**
	Directly Allocated Net Fixed Assets	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
COP	Cost of Power (COP)	$2,132,367	$1,111,660	$398,671	$604,932	$14,927	$1,688	$488
	OM&A Expenses	$497,892	$318,769	$99,474	$49,574	$26,090	$1,958	$2,027
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0
	Subtotal	***$2,630,260***	***$1,430,429***	***$498,145***	***$654,507***	***$41,017***	***$3,646***	***$2,516***
	Working Capital	**$394,539**	**$214,564**	**$74,722**	**$98,176**	**$6,153**	**$547**	**$377**
	Total Rate Base	**$1,338,382**	**$784,775**	**$269,921**	**$228,695**	**$50,192**	**$3,646**	**$1,152**
		Rate Base Input equals Output						
	Equity Component of Rate Base	**$669,191**	**$392,388**	**$134,961**	**$114,348**	**$25,096**	**$1,823**	**$576**
	Net Income on Allocated Assets	**$60,149**	**$91,374**	**$1,241**	**($6,501)**	**($24,419)**	**($1,136)**	**($409)**
	Net Income on Direct Allocation Assets	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
	Net Income	**$60,149**	**$91,374**	**$1,241**	**($6,501)**	**($24,419)**	**($1,136)**	**($409)**
	RATIOS ANALYSIS							
	REVENUE TO EXPENSES %	100.00%	113.51%	91.37%	78.79%	17.39%	45.37%	78.67%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($0)	$55,035	($11,199)	($14,819)	($27,226)	($1,334)	($458)
	RETURN ON EQUITY COMPONENT OF RATE BASE	8.99%	23.29%	0.92%	-5.69%	-97.30%	-62.32%	-70.98%

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Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - Second Run

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1	2	3	7	8	9
	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
Customer Unit Cost per month - Avoided Cost	$3.68	$8.75	$26.01	$0.01	$0.22	$11.13
Customer Unit Cost per month - Directly Related	$6.34	$15.26	$48.18	$0.01	$0.42	$20.41
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$12.99	$20.32	$45.13	$8.05	$8.35	$23.27
Fixed Charge per approved 2006 EDR	$19.74	$30.89	$151.53	$0.79	$2.63	$15.32

Information to be Used to Allocate PILs, ROD, ROE and A&G

		1	2	3	7	8	9
	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
General Plant - Gross Assets	$0	$0	$0	$0	$0	$0	$0
General Plant - Accumulated Depreciation	$0	$0	$0	$0	$0	$0	$0
General Plant - Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0
General Plant - Depreciation	$0	$0	$0	$0	$0	$0	$0
Total Net Fixed Assets Excluding General Plant	$943,843	$570,211	$195,199	$130,519	$44,040	$3,100	$775
Total Administration and General Expense	$219,656	$140,209	$43,967	$22,325	$11,443	$856	$856
Total O&M	$278,236	$178,560	$55,506	$27,249	$14,647	$1,102	$1,171

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

			1	2	3	7	8	9
USoA Account #	Accounts	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
	Distribution Plant							
1860	Meters							
	Accumulated Amortization							
	Accum. Amortization of Electric Utility Plant - Meters only							
	Meter Net Fixed Assets							
	Misc Revenue							
4082	Retail Services Revenues							
4084	Service Transaction Requests (STR) Revenues							
4090	Electric Services Incidental to Energy Sales							
4220	Other Electric Revenues							
4225	Late Payment Charges							
	Sub-total							
	Operation							
5065	Meter Expense							
5070	Customer Premises - Operation Labour							
5075	Customer Premises - Materials and Expenses							
	Sub-total							
	Maintenance							
5175	Maintenance of Meters							
	Billing and Collection							
5310	Meter Reading Expense							
5315	Customer Billing							
5320	Collecting							
5325	Collecting- Cash Over and Short							
5330	Collection Charges							
	Sub-total							
	Total Operation, Maintenance and Billing							
	Amortization Expense - Meters							
	Allocated PILs							
	Allocated Debt Return							
	Allocated Equity Return							
	Total							

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

USoA Account #	Accounts							
	Distribution Plant							
1860	Meters							
	Accumulated Amortization							
	Accum. Amortization of Electric Utility Plant - Meters only							
	Meter Net Fixed Assets							
	Allocated General Plant Net Fixed Assets							
	Meter Net Fixed Assets Including General Plant							
	Misc Revenue							
4082	Retail Services Revenues							
4084	Service Transaction Requests (STR) Revenues							
4090	Electric Services Incidental to Energy Sales							
4220	Other Electric Revenues							
4225	Late Payment Charges							
	Sub-total							
	Operation							
5065	Meter Expense							
5070	Customer Premises - Operation Labour							
5075	Customer Premises - Materials and Expenses							
	Sub-total							
	Maintenance							
5175	Maintenance of Meters							
	Billing and Collection							
5310	Meter Reading Expense							
5315	Customer Billing							
5320	Collecting							
5325	Collecting- Cash Over and Short							
5330	Collection Charges							
	Sub-total							
	Total Operation, Maintenance and Billing							
	Amortization Expense - Meters							
	Amortization Expense - General Plant assigned to Meters							
	Admin and General							
	Allocated PILs							
	Allocated Debt Return							
	Allocated Equity Return							
	Total							

Scenario 3

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

USoA Account #	Accounts							
	Distribution Plant							
1565	Conservation and Demand Management Expenditures and Recoveries							
1830	Poles, Towers and Fixtures							
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery							
1830-4	Poles, Towers and Fixtures - Primary							
1830-5	Poles, Towers and Fixtures - Secondary							
1835	Overhead Conductors and Devices							
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery							
1835-4	Overhead Conductors and Devices - Primary							
1835-5	Overhead Conductors and Devices - 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							
1845-3	Underground Conductors and Devices - Bulk Delivery							
1845-4	Underground Conductors and Devices - Primary							
1845-5	Underground Conductors and Devices - Secondary							
1850	Line Transformers							
1855	Services							
1860	Meters							
	Sub-total							
	Accumulated Amortization							
	Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters							
	Customer Related Net Fixed Assets							
	Allocated General Plant Net Fixed Assets							

Customer Related NFA Including General Plant

	Misc Revenue
4082	Retail Services Revenues
4084	Service Transaction Requests (STR) Revenues
4090	Electric Services Incidental to Energy Sales
4220	Other Electric Revenues
4225	Late Payment Charges
4235	Miscellaneous Service Revenues
	Sub-total
	Operating and Maintenance
5005	Operation Supervision and Engineering
5010	Load Dispatching
5020	Overhead Distribution Lines and Feeders - Operation Labour
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses
5035	Overhead Distribution Transformers- Operation
5040	Underground Distribution Lines and Feeders - Operation Labour
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses
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
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
	Sub-total
	Billing and Collection
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
	Sub-total
	Sub Total Operating, Maintenance and Biling
	Amortization Expense - Customer Related
	Amortization Expense - General Plant assigned to Meters
	Admin and General
	Allocated PILs
	Allocated Debt Return
	Allocated Equity Return
	PLCC Adjustment for Line Transformer
	PLCC Adjustment for Primary Costs
	PLCC Adjustment for Secondary Costs
	Total

Below: Grouping to avoid disclosure

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

Accounts	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
Distribution Plant							
CWMC	$ 153,675	$ 102,098	$ 36,342	$ 15,235	$ -	$ -	$ -
Accumulated Amortization							
Accum. Amortization of Electric Utility Plant - Meters only	$ (75,091)	$ (49,889)	$ (17,758)	$ (7,444)	$ -	$ -	$ -
Meter Net Fixed Assets	$ 78,584	$ 52,210	$ 18,584	$ 7,791	$ -	$ -	$ -
Misc Revenue							

CWNB	$ (5,222)	$ (3,498)	$ (1,229)	$ (369)	$ (4)	$ (9)	$ (112)
NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ (5,900)	$ (3,908)	$ (1,005)	$ (986)	$ -	$ -	$ -
Sub-total	$ (11,122)	$ (7,407)	$ (2,234)	$ (1,356)	$ (4)	$ (9)	$ (112)
Operation							
CWMC	$ 8,366	$ 5,558	$ 1,979	$ 829	$ -	$ -	$ -
CCA	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-total	$ 8,366	$ 5,558	$ 1,979	$ 829	$ -	$ -	$ -
Maintenance							
1860	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Billing and Collection							
CWMR	$ 18,005	$ 13,497	$ 4,119	$ 389	$ -	$ -	$ -
CWNB	$ 42,458	$ 28,445	$ 9,992	$ 3,003	$ 30	$ 73	$ 914
Sub-total	$ 60,463	$ 41,942	$ 14,111	$ 3,392	$ 30	$ 73	$ 914
Total Operation, Maintenance and Billing	$ 68,829	$ 47,501	$ 16,090	$ 4,221	$ 30	$ 73	$ 914
Amortization Expense - Meters	$ 2,579	$ 1,713	$ 610	$ 256	$ -	$ -	$ -
Allocated PILs	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Allocated Debt Return	$ 4,034	$ 2,680	$ 954	$ 400	$ -	$ -	$ -
Allocated Equity Return	$ 5,008	$ 3,327	$ 1,184	$ 496	$ -	$ -	$ -
Total	**$ 69,328**	**$ 47,815**	**$ 16,604**	**$ 4,018**	**$ 27**	**$ 64**	**$ 801**

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

Accounts	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
Distribution Plant							
CWMC	$ 153,675	$ 102,098	$ 36,342	$ 15,235	$ -	$ -	$ -
Accumulated Amortization							
Accum. Amortization of Electric Utility Plant - Meters only	$ (75,091)	$ (49,889)	$ (17,758)	$ (7,444)	$ -	$ -	$ -
Meter Net Fixed Assets	$ 78,584	$ 52,210	$ 18,584	$ 7,791	$ -	$ -	$ -
Allocated General Plant Net Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Meter Net Fixed Assets Including General Plant	$ 78,584	$ 52,210	$ 18,584	$ 7,791	$ -	$ -	$ -
Misc Revenue							
CWNB	$ (5,222)	$ (3,498)	$ (1,229)	$ (369)	$ (4)	$ (9)	$ (112)
NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ (5,900)	$ (3,908)	$ (1,005)	$ (986)	$ -	$ -	$ -
Sub-total	*$ (11,122)*	*$ (7,407)*	*$ (2,234)*	*$ (1,356)*	*$ (4)*	*$ (9)*	*$ (112)*
Operation							
CWMC	$ 8,366	$ 5,558	$ 1,979	$ 829	$ -	$ -	$ -
CCA	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-total	*$ 8,366*	*$ 5,558*	*$ 1,979*	*$ 829*	*$ -*	*$ -*	*$ -*
Maintenance							
1860	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Billing and Collection							
CWMR	$ 18,005	$ 13,497	$ 4,119	$ 389	$ -	$ -	$ -
CWNB	$ 42,458	$ 28,445	$ 9,992	$ 3,003	$ 30	$ 73	$ 914
Sub-total	*$ 60,463*	*$ 41,942*	*$ 14,111*	*$ 3,392*	*$ 30*	*$ 73*	*$ 914*
Total Operation, Maintenance and Billing	$ 68,829	$ 47,501	$ 16,090	$ 4,221	$ 30	$ 73	$ 914
Amortization Expense - Meters	$ 2,579	$ 1,713	$ 610	$ 256	$ -	$ -	$ -
Amortization Expense - General Plant assigned to Meters	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Admin and General	$ 54,250	$ 37,298	$ 12,745	$ 3,458	$ 24	$ 57	$ 668
Allocated PILs	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Allocated Debt Return	$ 4,034	$ 2,680	$ 954	$ 400	$ -	$ -	$ -
Allocated Equity Return	$ 5,008	$ 3,327	$ 1,184	$ 496	$ -	$ -	$ -
Total	**$ 123,579**	**$ 85,113**	**$ 29,349**	**$ 7,476**	**$ 51**	**$ 121**	**$ 1,470**

Scenario 3

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

USoA Account #	Accounts	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
	Distribution Plant							
	CDMPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Poles, Towers and Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	PNCP	$ 265,636	$ 180,812	$ 25,277	$ 2,016	$ 52,879	$ 3,722	$ 930
	SNCP	$ 206,833	$ 141,447	$ 19,773	$ 607	$ 41,367	$ 2,911	$ 728
	Overhead Conductors and Devices	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	LTNCP	$ 135,616	$ 92,744	$ 12,965	$ 398	$ 27,123	$ 1,909	$ 477
	CWCS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	CWMC	$ 153,675	$ 102,098	$ 36,342	$ 15,235	$ -	$ -	$ -
	Sub-total	*$ 761,760*	*$ 517,101*	*$ 94,358*	*$ 18,255*	*$ 121,369*	*$ 8,542*	*$ 2,136*

Accumulated Amortization							
Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	$ (462,543)	$ (314,308)	$ (54,722)	$ (9,379)	$ (77,330)	$ (5,443)	$ (1,361)
Customer Related Net Fixed Assets	$ 299,217	$ 202,794	$ 39,635	$ 8,876	$ 44,039	$ 3,100	$ 775
Allocated General Plant Net Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Related NFA Including General Plant	$ 299,217	$ 202,794	$ 39,635	$ 8,876	$ 44,039	$ 3,100	$ 775
Misc Revenue							
CWNB	$ (21,959)	$ (14,712)	$ (5,168)	$ (1,553)	$ (16)	$ (38)	$ (473)
NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ (5,900)	$ (3,908)	$ (1,005)	$ (986)	$ -	$ -	$ -
Sub-total	*$ (27,859)*	*$ (18,620)*	*$ (6,173)*	*$ (2,540)*	*$ (16)*	*$ (38)*	*$ (473)*
Operating and Maintenance							
1815-1855	$ 5,839	$ 3,985	$ 557	$ 29	$ 1,165	$ 82	$ 21
1830 & 1835	$ 62,808	$ 42,833	$ 5,988	$ 358	$ 12,527	$ 882	$ 220
1850	$ 4,624	$ 3,162	$ 442	$ 14	$ 925	$ 65	$ 16
1840 & 1845	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWMC	$ 8,366	$ 5,558	$ 1,979	$ 829	$ -	$ -	$ -
CCA	$ -	$ -	$ -	$ -	$ -	$ -	$ -
O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1830	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1835	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1855	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1840	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1845	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1860	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-total	*$ 81,637*	*$ 55,538*	*$ 8,965*	*$ 1,230*	*$ 14,617*	*$ 1,029*	*$ 257*
Billing and Collection							
CWNB	$ 42,458	$ 28,445	$ 9,992	$ 3,003	$ 30	$ 73	$ 914
CWMR	$ 18,005	$ 13,497	$ 4,119	$ 389	$ -	$ -	$ -
BDHA	$ 5,416	$ 5,140	$ 276	$ -	$ -	$ -	$ -
Sub-total	*$ 65,879*	*$ 47,082*	*$ 14,387*	*$ 3,392*	*$ 30*	*$ 73*	*$ 914*
Sub Total Operating, Maintenance and Biling	*$ 147,515*	*$ 102,621*	*$ 23,353*	*$ 4,622*	*$ 14,647*	*$ 1,102*	*$ 1,171*
Amortization Expense - Customer Related	$ 11,585	$ 7,860	$ 1,469	$ 300	$ 1,798	$ 127	$ 32
Amortization Expense - General Plant assigned to Meters	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Admin and General	$ 116,019	$ 80,579	$ 18,498	$ 3,787	$ 11,443	$ 856	$ 856
Allocated PILs	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Allocated Debt Return	$ 15,361	$ 10,411	$ 2,035	$ 456	$ 2,261	$ 159	$ 40
Allocated Equity Return	$ 19,069	$ 12,924	$ 2,526	$ 566	$ 2,806	$ 198	$ 49
PLCC Adjustment for Line Transformer	$ 2,434	$ 2,127	$ 298	$ 9	$ -	$ -	$ -
PLCC Adjustment for Primary Costs	$ 8,912	$ 7,736	$ 1,085	$ 91	$ -	$ -	$ -
PLCC Adjustment for Secondary Costs	$ 8,935	$ 7,760	$ 1,084	$ 91	$ -	$ -	$ -
Total	**$ 261,409**	**$ 178,151**	**$ 39,241**	**$ 6,999**	**$ 32,939**	**$ 2,403**	**$ 1,675**

Appendix H

Excel Worksheets

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170

EDR File Number: EB-2005-0349

Cost Allocation File Number: EB-2007-0001

EXHIBIT 1

Pro Forma Operating Statements

Balance Sheet

	2006 Historical Actual	Bridge Year 2007	Test Year 2008
Assets			
Current Assets:			
Cash	173,608	174,637	176,298
Term Deposits and Treasury Bills	651,121	803,000	790,000
Trade Receivable	40,885	40,885	40,885
Plant Material and Supplies	43,787	43,787	43,787
Prepaid Expenses	10,318	10,318	10,318
Unbilled revenue - Energy sales	424,856	424,856	424,856
Unbilled revenue - Distribution	42,940	42,940	42,940
	1,387,515	1,540,423	1,529,084
Capital Assets	2,175,939	2,185,341	2,249,202
Accumulated Dipreciation	1,266,778	1,303,051	1,339,614
	909,161	882,290	909,588
	2,296,676	2,422,713	2,438,672
Liabilities and Shareholder's Equity			
Current Liabilities			
Accounts Payable and accrued Liabilities	267,048	270,548	266,874
Advanses from Related Companies	20,551	20,551	20,551
	287,599	291,099	287,425
Other Liabilities			
Regulatory Liabilities	487,538	601,613	572,678
Customer Deposits	21,989	21,989	21,989
Loan Payable	360,727	360,727	-
Mortgage Payable	1,321,493	1,321,493	1,195,551
Shareholders Deficiency			
Share Capital	560,840	560,840	1,047,509
Deficit	(743,510)	(735,048)	(686,480)
	(182,670)	(174,208)	361,029
	2,296,676	2,422,713	2,438,672

Chapleau Public Utilities Corporation

Appendix C

License Number: ED-2002-0528

EXHIBIT 1
Revenue Sufficiency (Proposed Base Rates)

Pro Forma Operating Statements

	2006 Historical Board Approved	2006 Historical Actual	Bridge Year 2007	Test Year 2008	Forecast 2009
Revenue					
Distribution Revenue	$ 605,891	$ 566,543	$ 592,434	$ 668,215	$ 705,447
SSS Admin. and Retailer Charges	$ -	$ 1,382	$ 1,735	$ 1,735	$ 1,735
Miscellaneous Revenue	$ 42,681	$ 42,657	$ 52,304	$ 43,244	$ 36,800
Low Voltage Revenue (8 Moths Only)	0	$ -	$ -	$ -	$ -
Revenue	$ 648,572	$ 610,582	$ 646,473	$ 713,194	$ 743,982
Operations and Maintenance	$ 263,311	$ 262,647	$ 296,913	$ 302,585	$ 308,637
Billing & Collecting	$ 65,879	$ 63,918	$ 66,539	$ 64,112	$ 66,035
Depreciation	$ 37,890	$ 37,370	$ 36,273	$ 36,563	$ 42,977
Administrative and General Expenses					
Community Relations	$ 2,607	$ 1,707	$ 1,063	$ 1,200	$ 1,200
Executive Salaries and Expense	$ 59,881	$ 59,331	$ 62,672	$ 64,552	$ 66,489
Office Supplies and Expense	$ 22,176	$ 19,574	$ 21,661	$ 22,248	$ 22,915
Outside Services Employed	$ 38,352	$ 47,795	$ 104,368	$ 60,820	$ 60,000
Recovery of one time costs				$ 11,605	
Property Insurance	$ 13,601	$ 12,119	$ 13,000	$ 13,500	$ 18,000
Regulatory Expenses	$ 5,734	$ 4,584	$ 5,769	$ 6,000	$ 12,000
Misc. General Expenses	$ 6,546	$ 10,612	$ 15,000	$ 12,000	$ 12,000
Bank Charges	$ 8,247	$ 8,941	$ 9,883	$ 9,200	$ 10,000
Low Voltage Charges (8 Moths Only)	$ -	$ -	$ -	$ 24,631	$ 36,947
Total Expenses	$ 524,224	$ 528,598	$ 633,141	$ 629,016	$ 657,200
Income (Loss)	$ 124,348	$ 81,984	$ 13,332	$ 84,178	$ 86,782
Interest Payable to Township of Chapleau	$ 48,454	$ -	$ -	$ 87,328	92207
Net Income (Loss)	$ 75,894	$ 81,984	$ 13,332	$ (3,150)	$ (5,425)

Cash Flow Forecast 2008 to 2012	2007	2008	2009	2010	2011	2012
Cash Biginning of the Year	$ 824,729	$ 982,507	$ 930,413	$ 407,611	$ 374,522	$ 437,153
Net Income (Loss)	$ 13,332	$ (3,150)	$ 49,000	$ 45,000	$ 45,000	$ 45,000
Adjustments For Cash Flow						
Depreciation	$ 36,273	$ 36,563	$ 42,977	$ 52,885	$ 51,910	$ 50,123
Purchase of Capital Assets	$ (9,402)	$ (63,861)	$ (533,639)	$ (49,834)	$ (7,232)	$ (7,232)
Net Ovecollection/(Refund) of Regulatory Assets	$ 114,075	$ (21,646)	$ (81,140)	$ (81,140)	$ (27,047)	$ (33,674)
Change in Accounts Reaceivable	$ 3,500	$ -	$ -	$ -	$ -	$ -
Cash End of the Year	$ 982,507	$ 930,413	$ 407,611	$ 374,522	$ 437,153	$ 491,369

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

EXHIBIT 1

Revenue Deficiency (Current Base Rates to Continue)

	Historical Actual 2006	(Forecast - Current Rates) Bridge Year 2007	Test Year 2008	2009
Revenue				
Distribution Revenue	$ 558,385	$ 592,434	$ 612,102	$ 619,631
SSS Admin. and Retailer Charges	$ 1,382	$ 1,735	$ 1,735	$ 1,735
Miscellaneous Revenue	$ 42,657	$ 52,304	$ 43,244	$ 36,800
Low Voltage Revenue (8 Moths Only)	$ -	$ -	$ 24,631	$ 36,947
	$ 602,424	$ 646,473	$ 681,713	$ 695,113
Expenses				
Operations and Maintenance	$ 262,647	$ 296,913	$ 302,585	311,663
Administrative and General Expenses	$ 164,663	$ 233,416	$ 214,151	239,551
Billing & Collecting	$ 63,918	$ 66,539	$ 64,112	66,035
Depreciation	$ 37,370	$ 36,273	$ 36,563	42,977
Profit (Loss)	$ 73,826	$ 13,332	$ 64,301	$ 34,887
Interest Payable to Township of Chapleau	$ -	$ -	$ 87,328	92207
Profit (Loss)	$ 73,826	$ 13,332	$ (23,027)	$ (57,320)

Cash Flow Forecast 2008 to 2012

	2007	2008	2009	2010	2011	2012
Cash Biginning of the Year	$ 824,729	$ 982,507	$ 910,536	$ 383,485	$ 243,466	$ 199,097
Net Income (Loss)	$ 13,332	$ (23,027)	$ (57,320)	$ (62,000)	$ (62,000)	$ (62,000)
Adjustments For Cash Flow						
Depreciation	$ 36,273	$ 36,563	$ 42,977	$ 52,885	$ 51,910	$ 50,123
Purchase of Capital Assets	$ (9,402)	$ (63,861)	$ (431,568)	$ (49,764)	$ (7,232)	$ (7,232)
Net Ovecollection/(Refund) of Regulatory Assets	$ 114,075	$ (21,646)	$ (81,140)	$ (81,140)	$ (27,047)	$ (33,674)
Change in Accounts Reaceivable & other.	$ 3,500	$ -	$ -	$ -	$ -	$ -
Cash End of the Year	$ 982,507	$ 910,536	$ 383,485	$ 243,466	$ 199,097	$ 146,314

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

EXHIBIT 1

CUSTOMER CLASS IMPACT

	2008 TEST YEAR DATA				2008 Proposed Rates ($) — Volumetric Rate per kWh/kW							Fixed Service Charge	
	Number of Customers (Connections)	kWh	kW	Volumetric Rate Type	Base Rates (From Exhib. 8(b))	LV/ Wheeling (From Exhib. 5(a))	WMS & Rural per kWh (From Exhib. 5(b))	Trans. Rates CN & NW (From Exhib. 5(b))	Reg. Assets (From Exhib. 5(b))	Total Volumetric Rates kWh	Total Volumetric Rates kW	**Base Rates**	**Total Revenue $**
RESIDENTIAL													
Regular	1,164	14,611,894		kWh	0.0112		0.0051	0.0054	(0.0029)	**0.0189**		**22.27**	**587,239.78**
GENERAL SERVICE													
Less than 50 kW	166	5,492,773		kWh	0.0111		0.0051	0.0050	(0.0029)	**0.0183**		**40.57**	**181,366.13**
Greater than 50 kW (to 3000 kW)	14	7,770,248	21,079	kW	1.7988		0.0051	2.0060	(1.0606)	**0.0051**	**2.7442**	**227.03**	**135,822.50**
Unmetered Scattered Load	6	6,991		kWh	0.0111		0.0051	0.0050	(0.0029)	**0.0183**		**20.17**	**1,580.01**
Sentinel Lighting	24	23,871	66	kW	6.2544		0.0051	1.5414	(1.0406)	**0.0051**	**6.7552**	**4.42**	**1,841.66**
Street Lighting	341	295,064	780	kW	4.5435		0.0051	1.5255	(1.0884)	**0.0051**	**4.9806**	**1.50**	**11,521.95**
TOTALS	**1,715**	**28,200,840**	**21,925**		266,457	0	144,573	150,548	(81,140)	418,260	62,177	438,935	**919,372.02**

	2008 TEST YEAR DATA				2007 Currently Approved Rates ($) — Volumetric Rate per kWh/kW							Fixed Service Charge	
	Number of Customers (Connections)	kWh	kW	Volumetric Rate Type	Base Rate	LV/ Wheeling	WMS & Rural	Trans. Rates CN & NW	Reg. Assets	Total Volumetric Rates kWh	Total Volumetric Rates kW	**Base Rates**	**Total Revenue $**
RESIDENTIAL													
Regular	1,164	14,611,894		kWh	0.0100	0.0	0.0062	0.0099	0.0007	**0.0268**		**19.92**	**669,841**
GENERAL SERVICE													
Less than 50 kW	166	5,492,773		kWh	0.0085	0.0	0.0062	0.0090	(0.0001)	**0.0236**		**31.17**	**191,720**
Greater than 50 kW (to 3000 kW)	14	7,770,248	21,079	kW	1.2099	0.0	0.0062	3.6186	(0.2732)	**0.0062**	**4.5553**	**152.82**	**169,872**
Unmetered Scattered Load	6	6,991		kWh	0.0085	0.0	0.0062	0.0090	(0.0001)	**0.0236**		**15.46**	**1,278**
Sentinel Lighting	24	23,871	66	kW	3.7484	0.0	0.0062	2.7987	3.0482	**0.0062**	**9.5953**	**2.65**	**1,544**
Street Lighting	341	295,064	780	kW	2.4286	0.0	0.0062	2.7628	0.0178	**0.0062**	**5.2092**	**0.80**	**9,166**
TOTALS	**1,715**	**28,200,840**	**21,925**		220,513	0.0000	174,845	272,773	4,135	571,546	100,719	371,157	**1,043,422**

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

EXHIBIT 1

CUSTOMER CLASS IMPACT

	2008 Total Revenue $	2007Total Revenue $	Class Impact Variance $	Class Impact Variance %
RESIDENTIAL				
Regular	587,239.78	669,841.32	(82,601.54)	-12.33%
GENERAL SERVICE				
Less than 50 kW	181,366.13	191,720.07	(10,353.95)	-5.40%
Greater than 50 kW (to 3000 kW)	135,822.50	169,871.99	(34,049.49)	-20.04%
Unmetered Scattered Load	1,580.01	1,278.11	301.90	23.62%
Sentinel Lighting	1,841.66	1,544.49	297.17	19.24%
Street Lighting	11,521.95	9,166.17	2,355.78	25.70%
TOTALS	919,372.02	1,043,422.15	(124,050.13)	-11.89%

	2008 Test Year Total Revenue $	2007 Bridge Year Total Revenue$	Revenue Change $
Rate Base - Volumetric charge	266,457	220,513	45,944
Rate Base - Service charge	434,741	366,964	67,778
- Smart Meter Rate	4193	4193	-
Low Voltage Rate	-	0.00	-
Wholesale Market Rate and Rural Rate	144,573	174,845	(30,272)
Transmission Rates (Connection and Network)	150,548	272,773	(122,225)
Regulatory Assets	(81,140)	4,135	(85,275)
Total Revenue	919,372	1,043,422	(124,050)

	2008 TEST YEAR DATA			
	Number of Customers (Connections)	*kWh*	*kW*	*Volumetric Rate Type*
RESIDENTIAL				
Regular	*1,164*	*14,611,894*		*kWh*
GENERAL SERVICE				
Less than 50 kW	*166*	*5,492,773*		*kWh*
Greater than 50 kW (to 3000 kW)	*14*	*7,770,248*	*21,079*	*kW*
Unmetered Scattered Load	*6*	*6,991*		*kWh*
Sentinel Lighting	*24*	*23,871*	*66*	*kW*
Street Lighting	*341*	*295,064*	*780*	*kW*
TOTALS	*1,715*	*28,200,840*	*21,925*	

Revenue based on 2007 Rates			Revenue based on 2008 Rates		
Volumetric Revenue	*Fixed Revenue*	*Total Revenue*	*Volumetric Revenue*	*Fixed Revenue*	*Total Revenue*
146,119	*274,611*	*420,730*	*163,615*	*307,493*	*471,108*
46,689	*61,573*	*108,261*	*60,890*	*80,301*	*141,191*
25,504	*25,630*	*51,134*	*37,917*	*38,098*	*76,015*
59	*1,094*	*1,154*	*78*	*1,433*	*1,511*
247	*688*	*936*	*413*	*1,199*	*1,611*
1,894	*2,210*	*4,104*	*3,544*	*5,060*	*8,604*
220,513	*365,806*	*586,319*	*266,457*	*433,584*	*700,040*

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

EXHIBIT 2

Assets and Depreciation

Assets 2006	**Opening Balance at Jan. 1, 2006**		**Actual Purchases to Dec. 31, 2006**	**Closing Balance at Dec. 31, 2006**
Land	$ 140.50		$ -	$ 140.50
Distribution Station Equip. Below 50kV	$ 457,507.56		$ -	$ 457,507.56
Poles Towers and Fixtures	$ 1,110,648.07		$ 1,550.88	$ 1,112,198.95
Underground Conduit	$ 77,299.99		$ -	$ 77,299.99
Line Transformers	$ 339,040.90		$ 21,899.21	$ 360,940.11
Meters	$ 167,009.20		$ 842.40	$ 167,851.60
	$ 2,151,646.22		$ 24,292.49	**$ 2,175,938.71**
2006 Average of Opening and Closing Year Balance of Gross Assets				**$ 2,163,792.47**
Depreciation 2006				
Land	$ -		$ -	$ -
Distribution Station Equip. Below 50kV	$ (148,293.56)	4%	$ (12,369.00)	$ (160,662.56)
Poles Towers and Fixtures	$ (737,693.07)	4%	$ (14,948.88)	$ (752,641.95)
Underground conduit	$ (44,342.99)	4%	$ (1,318.00)	$ (45,660.99)
Line Transformers	$ (219,647.90)	4%	$ (5,214.21)	$ (224,862.11)
Meters	$ (79,430.20)	4%	$ (3,520.40)	$ (82,950.60)
	$ (1,229,407.72)		$ (37,370.49)	**$ (1,266,778.21)**

2006 Capital Expenditures
1 - 5 Poles $1,551 in-service in Sept. 2006 to replace old existing Poles.
2 - 8 Line Transformers $21,899 in-service throuout 2006 to replace old existing Line Transformers
3 - 3 GS and 5 Res. Meters $842 in service at various times during 2006 to replace old Meters.

2006 Average of Opening and Closing Year Balance for Depreciation	**$ (1,248,092.97)**
2006 Average of Opening and Closing Year Balance for Net Assets	**$ 915,699.50**
2006 Net Fixed Assets	**$ 909,160.50**
Materiality Threshold of 1%	**$ 9,091.61**

Assets 2007	**Opening Balance at Jan. 1, 2007**	**Actual Purchases to Jun. 30, 2007**	**Forecast Purchases to Dec. 31, 2007**	**Forecast to Dec. 31, 2007**
Land	$ 140.50	$ -	$ -	$ 140.50
Distribution Station Equip. Below 50kV	$ 457,507.56	$ -	$ -	$ 457,507.56
Poles Towers and Fixtures	$ 1,112,198.95	$ -	$ 2,500.00	$ 1,114,698.95
Underground Conduit	$ 77,299.99	$ -	$ -	$ 77,299.99
Line Transformers	$ 360,940.11	$ 6,901.83	$ -	$ 367,841.94
Meters	$ 167,851.60	$ -	$ -	$ 167,851.60
	$ 2,175,938.71	**$ 6,901.83**	**$ 2,500.00**	**$ 2,185,340.54**
2007 Average of Opening and Closing Year Balance of Gross Assets				**$ 2,180,639.63**
Depreciation 2007				
Land	$ -		$ -	$ -
Distribution Station Equip. Below 50kV	$ (160,662.56)	4%	$ (11,873.80)	$ (172,536.36)
Poles Towers and Fixtures	$ (752,641.95)	4%	$ (14,432.28)	$ (767,074.23)
Underground conduit	$ (45,660.99)	4%	$ (1,265.56)	$ (46,926.55)
Line Transformers	$ (224,862.11)	4%	$ (5,305.08)	$ (230,167.19)
Meters	$ (82,950.60)	4%	$ (3,396.04)	$ (86,346.64)
	$ (1,266,778.21)		**$ (36,272.76)**	**$ (1,303,050.97)**

2007 Capital Expenditures
1 - 8 Poles $2,500 in-service in Sept/Oct. 2007 to replace old existing Poles.
2 - 2 Line Transformers & 1 Padmount transformer $6,902 in-service during 2076 to replace old existing Transformers.

2007 Average of Opening and Closing Year Balance of Depreciation	**$ (1,284,914.59)**
2007 Average of Opening and Closing Year Balance of Net Assets	**$ 895,725.03**
2007 Net Fixed Assets	**$ 882,289.57**
Materiality Threshold of 1%	**$ 8,822.90**

Chapleau Public Utilities Corporation

Board File Number: EB-2006-0170
License Number: ED-2002-0528 EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

EXHIBIT 2

Assets 2008	**Opening Balance at Jan. 1, 2008**		**Budget Purchases to Dec. 31, 2008**	**Budget to Dec. 31, 2008**
Land	$ 140.50		$ -	$ 140.50
Distribution Station Equip. Below 50kV	$ 457,507.56		$ -	$ 457,507.56
Poles Towers and Fixtures	$ 1,114,698.95		$ 4,000.00	$ 1,118,698.95
Overhead Conductors and Devices	$ -		$ 23,500.00	$ 23,500.00
Underground conduit	$ 77,299.99		$ -	$ 77,299.99
Line Transformers	$ 367,841.94		$ 7,000.00	$ 374,841.94
Meters	$ 167,851.60		$ 29,361.30	$ 197,212.90
	$ 2,185,340.54		**$ 63,861.30**	**$ 2,249,201.84**
2008 Average of Opening and Closing Year Balance of Gross Assets				**$ 2,217,271.19**
Depreciation 2008				
Land	$ -		$ -	$ -
Distribution Station Equip. Below 50kV	$ (172,536.36)	4%	$ (11,398.85)	$ (183,935.17)
Poles Towers and Fixtures	$ (767,074.23)	4%	$ (13,984.99)	$ (781,059.18)
Overhead Conductors and Devices	$ -	4%	$ (470.00)	$ (469.96)
Underground conduit	$ (46,926.55)	4%	$ (1,214.94)	$ (48,141.45)
Line Transformers	$ (230,167.19)	4%	$ (5,646.99)	$ (235,814.14)
Meters	$ (86,346.64)	4%	$ (3,847.42)	$ (90,194.02)
	$ (1,303,050.97)		**$ (36,563.19)**	**$ (1,339,613.92)**

<u>2008 Capital Expenditures</u>

1 - 10 Poles $4,000 in-service during 2008 to replace old existing Poles.
2 - 3 Regulators $23,500 in-service during 2008 to help reduce line losses
3 - 3 Line Transformers $7,000 in-service during 2008 to replace old existing Line Transformers
4 - Start-up cost for Smart Meters $29,361 (Legal, Consulting, etc.) during 2008.

2008 Average of Opening and Closing Year Balance of Depreciation	**$ (1,321,332.45)**
2008 Average of Opening and Closing Year Balance of Net Assets	**$ 895,938.74**
2008 Net Fixed Assets	**$ 909,587.92**
Materiality Threshold of 1%	**$ 9,095.88**

Chapleau Public Utilities Corporation

Board File Number: EB-2006-0170
License Number: ED-2002-0528 EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

EXHIBIT 2

Rate Base Calculation	Board Approved 2006		Historical Actual 2006		Bridge Year 2007		Test Year 2008	
Net Fixed Assets - at December 31		**$ 943,844**		**$ 909,161**		**$ 882,290**		**$ 909,588**
Materiality Level (1% of net assets)	**$ 9,438**		**$ 9,092**		**$ 8,823**		**$ 9,096**	
Working Capital Allowance								
Power Purchased			$ 1,721,671		$ 1,782,162		$ 1,751,917	
WMS charges			$ 154,628		$ 152,308		$ 153,468	
Network charges			$ 153,524		$ 147,202		$ 133,613	
Connection charges			$ 59,948		$ 51,081		$ 49,458	
Low Voltage charges			$ 13,195		$ 36,947		$ 36,947	
Power adjustment			$ -		$ -		$ -	
			$ 2,102,966		$ 2,169,700		$ 2,125,403	
Expenses - Net of Depreciation less Low Voltage Charges			$ 491,228		$ 596,868		$ 567,822	
Working Capital	$ 2,618,701		$ 2,594,194		$ 2,766,568		$ 2,693,225	
Working Capital Allowance @15%		**392,805.15**		**389,129.10**		**414,985.20**		**$ 403,983.75**
Rate Base		**$ 1,336,649**		**$ 1,298,290**		**$ 1,297,275**		**$ 1,313,572**
Fixed Assets for Energy Conservation (Smart Meters)								
Smart Meter purchases 2008							$ 29,361	
Smart Meter purchases 2009 to 2010							$ 573,473	
Service Revenue Requirement								
Rate Base	**$ 1,336,649**		**$ 1,298,290**		**$ 1,297,275**		**$ 1,313,572**	
Cost of Capital	**8.13%**		**8.13%**		**8.13%**		**7.25%**	
Return on Ratebase		$ 108,603		$ 105,551		$ 105,468		$ 95,280
Distribution Expenses		$ 524,223		$ 528,456		$ 638,011		$ 641,288
Revenue Requirement Before Income Taxes		**$ 632,826**		**$ 634,007**		**$ 743,479**		**$ 736,568**
Income Taxes - from PILS Model				$ -		$ -		$ -
Service Revenue Requirement		**$ 632,826**		**$ 634,007**		**$ 743,479**		**$ 736,568**

3 Variance Analysis for Rate Base

Board Approved vs Historical Actual — **Board Approved net fixed assets were ovestated to Historical Actual by $34,683 caused by an understatement in both Gross Assets and Accumulated Depreciation of $59,364 and $94,046 respectively. Net Impact to Board Approved Rate Base is $$38,381 (overstated). Net impact to Service Revenue Requirement is below materiality level.**

Historical Actual vs Bridge Year. — **Bridge Year is $10,131 higher than Historical Year due to Lower Capital Expenditures that reduced Net Assets by $27,851 and an increase in Working Capital Allowance of $37,982, this is mainly due to an increase in the Cost of Power of $95,979, an increase (full year) in Low Voltage charges of $23,493 and higher than expected Distribution Expenses (Outside Servises employed of $77,545 and Operations and Maintenanse of $37,353)**

Bridge Year vs Test Year. — **Test Year is higher than Bridge Year by $12,995 due to an increase in Capital Expenditures of $27,337and is a reduction in Working Capital Allowance of $14,343, this is manly due to a reduction in the Cost of Power of $47,990 and a reduction in Distribution Expenses of $48,560 (Redused spending in Outside Servises employed of $65,340 and increased spending in Operation and Maintanance of $6,400 and inflationary increases in other areas of $10,380)**

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
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EXHIBIT 2

Cost of Capital

Rate Base: (from above *Ratebase Calc.*)	**$**	**1,313,572**		
Size of LDC (based on Rate Base)		**small**		
Debt Rate (based on Size)		**6.10%**		
Deemed Debt (based on Size)		**53.3%**		
Deemed Equity (based on Size)		**46.7%**		
ROE as advised by The Board on March 7, 2008		**8.57%**		
Cost of Capital		**7.25%**	**$**	**95,280**
Revenue Requirement other than PILS			**$**	**736,568**
Distribution Expenses other than PILS and interest			**$**	**641,288**
			$	**95,280**
Calculated Interest				
Rate Base	**$**	**1,313,572**		
Debt Component		**53.3%**		
Debt Rate reflected in Revenue Requirement		**6.10%**		**42,708**
Target Net Income (for PILs)			**$**	**52,572**
Service Revenue Requirement			**$**	**736,568**
Board Approved Charges				
Specific Service Charges	$	17,728		
Late Payment Charges	$	4,665		
Other Distribution Revenue	$	1,735		
Other Income & Deductions	$	20,852		
	$	44,980	**$**	**44,980**
Base Revenue Requirement			**$**	**691,588**

Chapleau Public Utilities Corporation

License Number: ED-2002-0528
EXHIBIT 3 (a)
CUSTOMER DATA

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

Year Month	Wholesale purchase kWh		Resident kWh	GS<50kW kWh	GS>50kW kWh	GS>50kW kW	USL kWh	Sentinel Lights kWh	Sentinel Lights kW	Street Lights kWh	Street Lights kW	Total KWh	Total KW
2005 Jan	4,114,085		2,075,699	720,780	919,963	2,335	603	1992	7	32798	75	3,751,835	2,417
2005 Feb	3,275,429		1,784,654	624,726	808,068	2,416	603	1917	7	26726	75	3,246,694	2,498
2005 Mar	3,236,656		1,533,173	567,873	736,474	2,321	603	1928	6	26024	70	2,866,075	2,397
2005 Apr	2,386,028		1,127,220	458,349	614,989	2,001	603	1881	6	21390	70	2,224,432	2,077
2005 May	2,131,198		937,262	400,057	573,698	1,839	603	1929	5	18716	60	1,932,265	1,903
2005 Jun	1,758,000		772,380	355,015	519,014	1,604	603	1933	5	15870	55	1,664,815	1,663
2005 Jul	1,681,638		723,513	365,980	503,146	1,553	603	1988	4	17469	55	1,612,699	1,612
2005 Aug	1,681,674		719,897	351,866	517,144	1,457	603	1874	5	20499	55	1,611,883	1,516
2005 Sept	1,779,924		787,517	343,299	558,804	1,452	603	1909	5	23460	60	1,715,592	1,516
2005 Oct	2,294,542		1,106,552	422,670	690,677	1,670	603	2498	6	28163	65	2,251,163	1,741
2005 Nov	3,029,797		1,467,052	532,427	815,577	2,061	603	1979	6	30705	70	2,848,343	2,137
2005 Dec	3,689,681		1,778,206	621,704	852,391	2,232	603	2003	6	33867	70	3,288,774	2,308
TOTALS	31,058,652		14,813,125	5,764,746	8,109,945	22,939	7236	23831	66	295687	780	29,014,570	23,785
2006 Jan	3,371,350		1,832,027	644,101	849,594	2,482	603	1922	7	31740	75	3,359,987	2,564
2006 Feb	3,384,486		1,631,657	582,176	809,941	2,297	603	1829	7	26726	75	3,052,932	2,379
2006 Mar	3,170,628		1,581,749	564,919	836,060	2,026	603	2123	6	26024	70	3,011,478	2,102
2006 Apr	2,363,723		1,172,907	425,432	589,581	1,952	603	1946	6	21390	70	2,211,859	2,028
2006 May	2,001,924		954,508	378,171	544,763	1,528	451	1907	5	18716	60	1,898,516	1,592
2006 Jun	1,697,230		768,369	338,149	493,188	1,310	451	1897	5	15870	55	1,617,924	1,369
2006 Jul	1,663,765		725,730	353,593	467,853	1,268	451	1900	4	17468	55	1,566,995	1,327
2006 Aug	1,600,280		735,225	344,233	451,826	1,231	601	1928	5	20499	55	1,554,312	1,290
2006 Sept	1,818,043		857,734	337,367	511,801	1,336	601	1977	4.5	23460	60	1,732,940	1,400
2006 Oct	2,466,157		1,165,113	429,726	666,461	1,692	601	1965	6	28037	65	2,291,903	1,763
2006 Nov	2,765,361		1,402,127	505,312	738,317	1,892	601	2019	6	30705	70	2,679,081	1,968
2006 Dec	3,266,327		1,631,376	554,463	763,778	1,882	601	1984	6	33868	70	2,986,070	1,958
TOTALS	29,569,274		14,458,522	5,457,642	7,723,163	20,894	6770	23397	66	294503	780	27,963,997	21,740
2007 Jan	3,618,490 A	A	1,876,237	654,759	828,146	1,906	601	2108	7	32798	75	3,394,649	1,988
2007 Feb	3,629,416 A	A	1,775,994	635,459	803,081	2,069	601	2046	7	26726	75	3,243,907	2,151
2007 Mar	3,152,119 A	A	1,663,322	579,362	789,176	2,041	601	2148	6	26024	70	3,060,633	2,117
2007 Apr	2,500,401 A	A	1,219,276	424,026	572,381	1,879	601	1960	6	21390	70	2,239,634	1,955
2007 May	1,871,049 A	A	910,041	369,435	486,521	1,693	601	2155	5	18716	60	1,787,469	1,757
2007 Jun	1,676,726 A	E	770375	346582	506101	1,457	601	1915	5	15870	55	1,641,444	1516
2007 Jul	1,672,702	E	724622	359787	485500	1,411	601	1944	4	17469	55	1,589,921	1470
2007 Aug	1,640,977	E	727561	348050	484485	1,344	601	1901	5	20499	55	1,583,097	1403
2007 Sept	1,798,984	E	822626	340333	535303	1,394	601	1943	5	23460	60	1,724,265	1458
2007 Oct	2,380,350	E	1135833	426198	678569	1,681	601	2232	6	28100	65	2,271,532	1752
2007 Nov	2,897,579	E	1434590	518870	776947	1,977	601	1999	6	30705	70	2,763,711	2053
2007 Dec	3,478,004	E	1704791	588084	808085	2,057	601	1994	6	33868	70	3,137,421	2133
Adjustments				-47280	47280	269						0	269
	30,316,796		14,765,266	5,543,663	7,801,574	21,175	7,212	24,344	66	295,624	780	28,437,682	22,021
2008 estimates are the average of 2005/6/7												28,437,682	
2008 Jan	3,494,920	E	1,854,132	649,430	838,870	2,194	602	2,015	7	32,269	75	3377318	2,276
2008 Feb	3,506,951	E	1,703,826	608,818	806,511	2,183	602	1,938	7	26,726	75	3148420	2,265
2008 Mar	3,161,374	E	1,622,536	572,141	812,618	2,034	602	2,136	6	26,024	70	3036056	2,110
2008 Apr	2,432,062	E	1,196,092	424,729	580,981	1,916	602	1,953	6	21,390	70	2225747	1,992
2008 May	1,936,487	E	932,275	373,803	515,642	1,610	526	2,031	5	18,716	60	1842993	1,675
2008 Jun	1,686,978	E	769,372	342,366	499,645	1,383	526	1,906	5	15,870	55	1629684	1,443
2008 Jul	1,668,233	E	725,176	356,690	476,676	1,339	526	1,922	4	17,468	55	1578458	1,398
2008 Aug	1,620,629	E	731,393	346,141	468,156	1,287	601	1,915	5	20,499	55	1568704	1,347
2008 Sept	1,808,513	E	840,180	338,850	523,552	1,365	601	1,960	5	23,460	60	1728603	1,429
2008 Oct	2,423,253	E	1,150,473	427,962	672,515	1,687	601	2,098	6	28,069	65	2281718	1,758
2008 Nov	2,831,470	E	1,418,358	512,091	757,632	1,934	601	2,009	6	30,705	70	2721396	2,010
2008 Dec	3,372,166	E	1,668,084	571,273	785,931	1,970	601	1,989	6	33,868	70	3061746	2,046
Adjustments				-47280	47280	269							269
	29,943,035		14,611,894	5,477,013	7,786,008	21,169	6,991	23,871	66	295,064	780	28,200,840	22,015

Chapleau Public Utilities Corporation

License Number: ED-2002-0528
EXHIBIT 3 (a)

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
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CUSTOMER DATA

Year	Wholesale Purchases	Customer Data by Class															Total		
		Residential		GS <50kW		GS >50kW			USL		Sentinel Lights			Street Lights					
	kWh	# of Cust	kWh	# of Cust	kWh	# of Cust	kWh	kW	# of Cust	kWh	# of Cust	kWh	kW	# of Cust	kWh	kW	# of Cust	kWh	kW
2002	34,764,471	1,175	16,842,271	175	6,062,613	15	10,415,498	22,852	6	7,212	30	33,333	98	341	220,459	650	1,742	33,581,386	23,600
2003	33,611,224	1,164	16,533,903	162	6,027,452	14	9,668,139	25,121	6	7,212	27	27,506	76	341	219,856	771	1,714	32,484,068	25,968
2004	32,654,946	1,166	15,978,327	163	5,952,232	13	8,798,182	24,094	6	7,212	24	23,670	66	341	221,064	789	1,713	30,980,687	24,949
2005	31,058,652	1,171	14,813,125	167	5,764,746	13	8,109,945	22,939	6	7,236	24	23,831	66	341	295,687	780	1,722	29,014,570	23,785
2006	29,569,274	1,190	14,458,522	165	5,457,642	14	7,723,163	20,894	6	6,770	24	23,397	66	341	294,503	780	1,740	27,963,997	21,740
2007	30,316,796	1,164	14,765,266	166	5,543,663	14	7,801,574	21,175	6	7,212	24	24,344	66	341	295,624	780	1,715	28,437,682	22,021
2008	29,943,035	1,164	14,611,894	166	5,477,013	14	7,786,008	21,169	6	6,991	24	23,871	66	341	295,064	780	1,715	28,200,840	22,015

Loss Factor Calculation

Year	Wholesale Purchases kWh	Distribution kWh	Loss Factor %
2002	34,764,471	33,581,386	1.0352
2003	33,611,224	32,484,068	1.0347
2004	32,654,946	30,980,687	1.0540
2005	31,058,652	29,014,570	1.0705
2006	29,569,274	27,963,997	1.0574
2007	30,316,796	28,437,682	1.0661
2008	29,943,035	28,200,840	1.0618
Average Loss Factor 2003 to 2007 (5 Years)			**1.0565**

Notes To this Page

1 2007 Forecast of Data is actual data to May, and from June to December is forecasted to be the average consumption for the previous two years (2005/2006).

2 2008 Forecast of Data is the average consumption level for 2006 and 2007 for all classes.

3 Data supplied from 2002 to 2006 is to show the reduced consumption levels by 16.7% (and therefore reduced distribution revenue) for all classes caused mainly throughrecent economic conditions and reduced population levels.

4 The increase in loss factors is due the age of Chapleau's infrastructure in certain parts of the town. A study has been undertaken to address this. Chapleau PUC will invest $23,500 in the replacement of conductors during 2007 in an efford to reduce line losses.

5 Customer transfers: 1 from GS <50kW to GS >50kW and 1 from GS >50kW to GS <50kW - Data adjusted for 2007 and 2008.

Average Consumptions by customer

Year	Purchases	Residential		Ave. kWh Consump	GS <50kW		Ave. kWh Consump	GS >50kW			Ave kWh Consump	Ave. kW Consump
	kWh	# of Cust	kWh		# of Cust	kWh		# of Cust	kWh	kW		
2002	34,764,471	1,175	16,842,271	14,334	175	6,062,613	34,644	15	10,415,498	22,852	694,367	1,523.5
2003	33,611,224	1,164	16,533,903	14,204	162	6,027,452	37,206	14	9,668,139	25,121	690,581	1,794.4
2004	32,654,946	1,166	15,978,327	13,704	163	5,952,232	36,517	15	8,798,182	24,094	586,545	1,606.3
2005	31,058,652	1,171	14,813,125	12,650	167	5,764,746	34,519	13	8,109,945	22,939	623,842	1,764.5
2006	29,569,274	1,190	14,458,522	12,150	165	5,457,642	33,077	14	7,723,163	20,894	551,655	1,492.4
2007	30,316,796	1,164	14,765,266	12,685	166	5,543,663	33,396	14	7,801,574	21,175	557,255	1,512.5
2008	29,943,035	1,164	14,611,894	12,553	166	5,477,013	32,994	14	7,786,008	21,169	556,143	1,512.1

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

EXHIBIT 3 (b)

CONSUMPTION DATA

	Number of Customers (Connections)			Demand Data - kWh			Demand Data - kW			2007 Approved Rates		
	2006	2007	2008	2006	2007	2008	2006	2007	2008	Distribution Rate kWh	Distribution Rate kW	Mthly Service Chrg (Per Cust. or Connection)
	#	#	#	kWh	kWh	kWh	kW	kW	kW	$	$	$
RESIDENTIAL												
Regular	1,190	1,164	1,164	14,458,522	14,765,266	14,611,894	0	0	0	0.0100		19.92
GENERAL SERVICE												
Less than 50 kW	165	166	166	5,457,642	5,543,663	5,477,013	0	0	0	0.0085		31.17
Greater than 50 kW (to 3000 kW)	14	14	14	7,723,163	7,801,574	7,786,008	20,894	21,175	21,169		1.2099	152.82
Unmetered Scattered Load	6	6	6	6,770	7,212	6,991	0	0	0	0.0085		15.46
Sentinel Lighting	24	24	24	23,397	24,344	23,871	66	66	66		3.7484	2.65
Street Lighting	341	341	341	294,503	295,624	295,064	780	780	780		2.4286	0.80
TOTALS	1,740	1,715	1,715	27,963,997	28,437,682	28,200,840	21,740	22,021	22,015			

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

EXHIBIT 3 (b)

TRANSFORMER CREDIT

	2006			2007			2008		
	kW	$/kW	$	kW	$/kW	$	kW	$/kW	$
RESIDENTIAL									
Regular			0.00			0.00			0.00
GENERAL SERVICE									
Less than 50 kW			0.00			0.00			0.00
Greater than 50 kW (to 3000 kW)	16,462	0.60	9,877.06	15,572	0.60	9,343.00	16,017	0.60	9,610.03
Unmetered Scattered Load			0.00			0.00			0.00
Sentinel Lighting	0	0.60	0.00		0.60	0.00	0	0.60	0.00
Street Lighting	0	0.60	0.00		0.60	0.00	0	0.60	0.00
TOTALS	16,462		9,877.06	15,572		9,343.00	16,017		**9,610.03**

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

EXHIBIT 3 (c)

2006 Board Approved (DISTRIBUTION REVENUE)

2006 Data by Class (From Cust. Data Sheet)	kW	kWh	Number of Customers (Connections)	Distribution Revenues	APPROVED RATES EFFECTIVE MAY 1, 2006 Fixed	Variable
Residential Class		16,417,968	1,166	$438,740	$ 19.74	$ 0.0099
General Service Less than 50 kW		5,887,927	163	$109,879	$ 30.89	$ 0.0084
General Service 50 to 4,999 kW	22,409	8,934,168	13	$50,489	$ 151.43	$ 1.1989
Unmetered Scattered Load		7,212	6	$1,164	$ 15.32	$ 0.0084
Sentinel Lighting	71	24,929	24	$1,021	$ 2.63	$ 3.7142
Street Lighting	737	220,460	341	$5,006	$ 0.79	$ 2.4065
TOTALS	23,217	31,492,664	1,713	$605,891		

Actual Distribution Revenue as per 2006 Financial Statements $ 567,925

2006 Actual (DISTRIBUTION REVENUE)

2006 Data by Class (From Exhibit 3(a))	kW	kWh	Number of Customers (Connections)	Distribution Revenues	APPROVED RATES EFFECTIVE MAY 1, 2006 Fixed	Variable
Residential Class		14,458,522	1,190	$425,027	$ 19.74	$ 0.0099
General Service Less than 50 kW		5,457,642	165	$107,006	$ 30.89	$ 0.0084
General Service 50 to 4,999 kW	20,894	7,723,163	14	$50,490	$ 151.43	$ 1.1989
Unmetered Scattered Load		6,770	6	$1,160	$ 15.32	$ 0.0084
Sentinel Lighting	66	23,397	24	$1,003	$ 2.63	$ 3.7142
Street Lighting	780	294,503	341	$5,110	$ 0.79	$ 2.4065
TOTALS	21,740	27,963,997	1,740	$589,795		

Less Revenue Jan to April @ old Rates. $ 23,252
Actual Distribution Revenue as per Financial Statements $ 566,543

2007 Bridge Year (DISTRIBUTION REVENUE)

2007 Data by Class (From Exhibit 3(a))	kW	kWh	Number of Customers (Connections)	Distribution Revenues	APPROVED RATES EFFECTIVE MAY 1, 2007 Fixed	Variable
Residential Class		14,765,266	1,164	$425,895	$ 19.92	$ 0.0100
General Service Less than 50 kW		5,543,663	166	$109,212	$ 31.17	$ 0.0085
General Service 50 to 4,999 kW	21,175	7,801,574	14	$51,293	$ 152.82	$ 1.2099
Unmetered Scattered Load		7,212	6	$1,174	$ 15.46	$ 0.0085
Sentinel Lighting	66	24,344	24	$1,011	$ 2.65	$ 3.7484
Street Lighting	780	295,624	341	$5,168	$ 0.80	$ 2.4286
TOTALS	22,021	28,437,683	1,715	$593,753		

Less Revenue Jan to April @ old Rates = 1/3 of ($593,753 - $589,795) = $3,958/3 = $1,319 $ 1,319
$592,434

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

2008 Test Year (DISTRIBUTION REVENUE)

2008 Data by Class (From Exhibit 3(a))	kW	kWh	Number of Customers (Connections)	Distribution Revenues	PROPOSED RATES 2008 Fixed	Variable
Residential Class		14,611,894	1,164	$474,721	$ 22.27	$ 0.0112
General Service Less than 50 kW		5,477,013	166	$141,610	$ 40.57	$ 0.0111
General Service 50 to 4,999 kW	21,169	7,786,008	14	$76,219	$ 227.05	$ 1.7986
Unmetered Scattered Load		6,991	6	$1,530	$ 20.17	$ 0.0111
Sentinel Lighting	66	23,871	24	$1,686	$ 4.42	$ 6.2544
Street Lighting	780	295,064	341	$9,682	$ 1.50	$ 4.5435
TOTALS	22,015	28,200,841	1,715	$705,447		

Less Revenue Jan to April @ old Rates = 1/3 of ($705,447 - $593,753) = $111,694/3 = $37,232 $ 37,232
$668,215

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

EXHIBIT 3 (c)

SPECIFIC SERVICE CHARGES

Description	Standard Amount (Rate) $	2006 Revenue	2007 Revenue
Returned cheque charge (plus bank charges)	15.00	$ -	$ 330.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	30.00	$ 1,132.50	$ 5,062.50
Disconnect/Reconnect at meter - during regular hours	65.00	$ 1,200.00	$ 1,675.00
Specific Charge for Access to the Power Poles $/pole/year	22.35	$ 1,471.87	$ 4,498.54
TOTAL REVENUE - SPECIFIC SERVICE CHARGES		$ 3,804.37	$11,566.04

OTHER REVENUE SOURCES	2006	2007	2008
Interest Earned	$ 12,395.10	$ 16,087.12	$ 15,575.00
Meter Exit Rebate from Hydro One	$ 14,126.90	$ 17,100.00	$ -
Sale of Material	$ 7,286.84	$ 2,206.70	$ 4,747.00
Miscellaneous	$ 360.44	$ 698.77	$ 530.00
TOTAL OTHER REVENUE	**$ 34,169.28**	**$ 36,092.59**	**$ 20,852.00**

Description	Standard Amount (Rate) $	2005 Volume	2006 Volume	2007 Volume	2008 Test Year Volume (3 yr. avg.)	Calc'd. Amt. Std. Formula $
Arrears certificate	15.00	44	35	0	0	**0.00**
Credit reference/credit check (plus credit agency costs)	15.00	2	12	10	8	**120.00**
Returned cheque charge (plus bank charges)	15.00	34	28	22	28	**420.00**
Charge to certify cheque	15.00	0	0	0	0	**0.00**
Legal letter charge	15.00	0	0	0	0	**0.00**
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	30.00	274	286	262	274	**8,220.00**
Special meter reads	30.00	0	0	0	0	**0.00**
Collection of account charge - no disconnection	30.00	0	0	0	0	**0.00**
Collection of account charge - no disconnection - after regular hours	165.00				0	**0.00**
Disconnect/Reconnect at meter - during regular hours	65.00	12	60	50	41	**2,643.00**
Install/Remove load control device - during regular hours	65.00				0	**0.00**
Meter dispute charge plus Measurement Canada fees (if meter found correct)	30.00	0	0	0	0	**0.00**
Specific Charge for Access to the Power Poles $/pole/year	22.35	283	283	283	283	**6,325.05**
TOTAL REVENUE - SPECIFIC SERVICE CHARGES						**17,728.05**

DISTRIBUTION, MISCELLANEOUS AND OTHER REVENUE

	Board Approved 2006	Historical Yr 2006	Bridge Yr 2007 (est)	Test Year 2008 (est)
Distribution Revenue	**$ 605,891**	**$ 566,543**	**$592,434**	**$668,215**
Late Payment Charges	**$ 5,900**	**$ 4,683.71**	**$ 4,645.83**	**$ 4,664.77**
Specific Service Charges	**$ 16,737**	**$ 3,804.37**	**$ 11,566.04**	**$ 17,728.05**
Other Revenue Sources	**$ 14,822**	**$ 34,169.28**	**$ 36,092.59**	**$ 20,852.00**
Total Miscellaneous Revenue	**$ 37,459.00**	**$ 42,657.36**	**$ 52,304.46**	**$ 43,244.82**
Other Distribution Revenue - Retailer Charges	**$ 5,222**	**$ 1,381.60**	**$ 1,735.00**	**$ 1,735.00**
TOTAL REVENUE	**$ 648,572**	**$ 610,582**	**$ 646,474**	**$ 713,195**

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

EXHIBIT 4

OPERATING COSTS

Oparating and Maintenance	2006 Board Approved	2006 Historical Yr.	2007 Bridge Year	2008 Test Year
1 Operations and Maintenance	$ 263,311	$ 274,181	$ 296,913	$ 302,585
2 Billing & Collecting	$ 65,879	$ 60,018	$ 66,539	$ 64,112
3 Depreciation	$ 37,890	$ 37,370	$ 36,273	$ 36,563
Administrative and General Expenses				
4 Community Relations	$ 2,607	$ 1,707	$ 1,063	$ 1,200
5 Executive Salaries and Expense	$ 59,881	$ 59,331	$ 62,672	$ 64,552
6 Office Supplies and Expense	$ 22,176	$ 19,432	$ 21,661	$ 22,248
7 Outside Services Employed	$ 38,352	$ 47,795	$ 104,368	$ 60,820
Recovery of one time costs				$ 11,605
8 Property Insurance	$ 13,601	$ 12,119	$ 13,000	$ 13,500
9 Regulatory Expenses	$ 5,734	$ 4,584	$ 5,769	$ 6,000
10 Misc. General Expenses	$ 6,546	$ 10,612	$ 15,000	$ 12,000
11 Bank Charges	$ 8,247	$ 8,941	$ 9,883	$ 9,200
12 Low Voltage Charges (8 Moths Only)	$ -	$ -	$ -	$ 36,903
TOTAL OPERATING COSTS	$ 524,224	$ 536,090	$ 633,141	$ 641,288
Variance Analysis Threshold 1%	$ 389,071	$ 5,361	$ 6,331	$ 6,413

Variance Analysis

Board Approved - Historical Year.
Historical Year Billing and Collections lower due mainly to lower write offs/Bad Debt Expense.
Historical Year Office Supplies and Expense lower due to the timing of perchasing supplies.
Historical Year - Customer billing clerk in 2006 was off on LTD and lower rate paid to temp. replacement by approx. $3,000
Historical Year Misc. Gen. Expenses higher due to additional travel expenses for Board members and Management to attend industry meetings.

Historical Year - Bridge Year
Bridge Year Billing and Collections higher due mainly to write offs/Bad Debt Expense.
Bridge Year - Customer billing clerk in 2006 was off on LTD and lower rate paid to temp. replacement by approx. $3,000
Bridge Year Misc. General Expense higher due to higher travel expenses required for Smart Meter Program.

Operations and Maintenance	2006 Board Approved	2006 Historical Yr.	2007 Bridge Year	2008 Test Year
Dist. Station Equipment Labour		$ 1,829	$ 1,572	$ 1,619
OH Dist. Lines Labour		$ 95,936	$ 108,056	$ 111,298
Group Insurance		$ 27,260	$ 28,428	$ 29,281
Holidays and Sick Time		$ 18,788	$ 22,238	$ 20,513
OH Dist. Lines Supplies		$ 18,580	$ 15,120	$ 15,574
OH Dist. Transformer Supplies		$ -	$ 709	$ 700
Meter Expense Labour		$ 1,789	$ 1,534	$ 1,500
Meter Expense Supplies		$ 1,074	$ 1,470	$ 1,450
Truck Expense		$ 65,063	$ 68,292	$ 70,332
On Call Expense		$ 7,800	$ 7,800	$ 8,034
WSIB		$ 2,242	$ 2,483	$ 2,500
Taxes Other Than Income Taxes		$ 7,678	$ 7,688	$ 7,700
CPP Expense		$ 7,253	$ 7,982	$ 8,000
EI Expense		$ 3,961	$ 4,039	$ 4,050
EHT Expense		$ 3,394	$ 3,400	$ 3,450
Pension (OMERS)		$ 11,534	$ 16,102	$ 16,585
	$ 263,311	**$ 274,181**	**$ 296,913**	**$ 302,585**

Variance Analysis

* 2006-2007 - Operations and Maintenance for 2007, (Bridge Year) is expected to be higher than 2006 (Historical Year) actual by $22,732 due to additional repairs and maintenance to Chapleau's distribution system over 2006 but compares well with 2005 actual of $291,278 which was a normal year. Salaries and Wages increased by 3% January 1, 2007.

* 2007-2008 - Expectation is to do the same volume work (repairs and maintenance) in 2008. Salaries and Wages will increase by 3% effective January 1, 2008. Material costs and insurance to increase by 3%. Overall incease from 2007 is 1.9% ($5,672)

Billing & Collecting	2006 Board Approved	2006 Historical Yr.	2007 Bridge Year	2008 Test Year
Meter Reading		$ 16,933	$ 16,618	$ 17,279
Customer Billing		$ 37,715	$ 39,421	$ 39,725
Collections Overdue Accounts		$ -	$ 823	$ 412
Collection Charges		$ (270)	$ (205)	$ (238)
Bad Debt Expense		$ 9,540	$ 6,950	$ 8,245
Sub Total		$ 63,918	$ 63,607	$ 65,423
Less Bad Debt Expense		$ (9,540)	$ (6,950)	$ (8,245)
Add Write Offs		$ 5,640	$ 9,882	$ 6,934
	$ 65,879	**$ 60,018**	**$ 66,539**	**$ 64,112**

Variance Analysis

2006-2007 - Customer billing clerk in 2006 was off on LTD and lower rate paid to temp. replacement by approx. $3,000

2007-2008 - 2008 costs determined to be the average of 2006/07 plus 3% for increase in payroll as of January 1, 2008.

	2005 Historical Yr	2006 Historical Yr	2007 Bridge Year	2008 Test Year
Write Offs by Class				
Residential	$ 4,572.85	$ 4,476.48	$ 6,023.18	$ 5,024.17
General Service <50kW	$ 706.61	$ 1,163.52	$ 3,858.69	$ 1,909.61
Total Write Offs	**$ 5,279.46**	**$ 5,640.00**	**$ 9,881.87**	**$ 6,933.78**

Outside Services Employed		2006 Historical Yr	2007 Bridge Year	2008 Test Year
Regulatory Compliance Services	Rates Applications, Cost of Service, Dist. Rates Rebasing and interrogatories	$ 3,878	$ 39,675	$ 18,000
KPMG	Annual Audit, PILs Submission, Review for OEB, 3 Year Bus. Plan	$ 16,672	$ 33,677	$ 15,000
Spi Group	EBT License, Maintenance and Monthly Support	$ 6,120	$ 3,960	$ 4,120
Peterborough Utilities	MDMA & MSP Wholesale Meters	$ 17,718	$ 17,754	$ 17,800
MacGillivray Janitorial	Janitorial Services	$ 2,700	$ 2,700	$ 2,700
Valentine Farms Snow Removal	Snow Removal	$ 707	$ 800	$ 800
Hydro One	Weather Normalization	$ -	$ 3,500	$ -
Sudbury Control	Infra Red Scan	$ -	$ 600	$ 600
AESI	ESA Audit	$ -	$ 1,702	$ 1,800
		$ 47,795	**$ 104,368**	**$ 60,820**

Variance Analysis

Historical Year - Bridge Year	Bridge Year increase of $61,443 is maily due to prepararion of CA Model and Rebasing Rates for 2008 by RCS, (increase of $35,797), costs incurred for the OEB review and 3 year business plan pepared by KPMG ($21,715) and the weather normalization data prepared by Hydro One ($3,500).
Bridge Year - Test Year	Test Year expectation is for expenditures to be lower by $48,418. Expected expenditures beyond standard is for RCS to assist with rate rebasing interrogatories in 2008.

Bank Charges	2006 Historical Yr.	2007 Bridge Year	2008 Test Year
Bank processing fees	$ 3,537	$ 4,420	$ 4,350
Letter of Credit fee	$ 5,403	$ 5,462	$ 4,850
	$ 8,940	**$ 9,882**	**$ 9,200**

Variance Analysis

2006-2007 - Increase in processing and letter of credit fees in 2007. Letter of credit reduced August 2007 by approx. $100,000 and fee also reduced by $1,160.

2007-2008 - Lower fees in 2008 is due to letter of credit.

Employee Benefit Programs.	2006 Historical Yr.	2007 Bridge Year	2008 Test Year
Holidays And Sick Time	$ 18,788	$ 22,238	$ 21,128
Group Insurance	$ 27,260	$ 28,428	$ 29,281
WSIB	$ 2,242	$ 2,483	$ 2,500
CPP Expense	$ 7,253	$ 7,982	$ 8,000
EI Expense	$ 3,961	$ 4,039	$ 4,050
EHT Expense	$ 3,394	$ 3,400	$ 3,450
Pension (OMERS)	$ 11,534	$ 16,102	$ 16,585
	$ 74,432	**$ 84,672**	**$ 84,994**

Variance Analysis

2006-2007 - 2007 Holiday and Sick Time, increase is due to additional 1 week vacation for 2 employees, increase sick time and increase in salaries and wages of 3%.

- 2006 OMERS Pension is only for May to December. Pension for January to April is in Deferral account number 1508.

2007-2008 - 2008 Holiday and Sick Time is average for 2006 and 2007 plus increase in salaries and wages of 3%.

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

EXHIBIT 5 (a)

REGULATORY ASSETS and VARIANCES

Retail Settlement Variance Accounts - for 2006

	WMS				NW				CN				Energy				Low Voltage		
	Charge Accounts	Billed Accounts	Cumulative Variance	Interest	Charge Accounts	Billed Accounts	Cumulative Variance	Interest	Charge Accounts	Billed Accounts	Cumulative Variance	Interest	Charge Accounts	Billed Accounts	Cumulative Variance	Interest	Charge Accounts	Cumulative Variance	Interest
Opening Balance			**30663.40**	**5546.68**			**-64326.35**	**-6390.98**			**-230732.66**	**-40267.08**			**-27743.25**	**8330.99**		**0**	**0**
Iterest Rate %																			
Jan. '06	**0.006042**				**0.006042**				**0.006042**				**0.006042**				**0.006042**		
May '06	**0.003450**				**0.003450**				**0.003450**				**0.003450**				**0.003450**		
July '06	**0.003825**				**0.003825**				**0.003825**				**0.003825**				**0.003825**		
January	22719.65	19354.65	34028.40	185.27	17323.64	17345.13	-64347.84	-388.66	9193.28	15014.92	-236554.3	-1394.09	233734.53	178160.82	27830.46	-167.62			
February	16494.5	22501.03	28021.87	205.60	19356.07	20551.43	-65543.20	-388.79	10237.1	17804.34	-244121.54	-1429.26	170645.17	206613.48	-8137.85	168.15			
March	11541.86	22374.1	17189.63	169.31	19847.46	19707.15	-65402.89	-396.01	10176.76	17076.56	-251021.34	-1474.98	181245.06	199475.06	-26367.85	-49.17			
Adjustment			-21747.00	-4168.01			39106.12	7789.63			153615.28	-1326.66			8568.00	2500.00			
April	20533.4	20542.16	-4566.13	103.86	16636.52	17709.05	-27369.30	-395.16	5069.38	15347.39	-107684.07	-1516.67	177095.23	180490.16	-21194.78	-159.31			
May	13133.76	16890.77	-8323.14	-15.75	13937.09	15084.91	-28517.12	-94.42	4265.16	13060.01	-116478.92	-371.51	123563.44	147389.51	-45020.85	-73.12			
June	13749.11	13821.06	-8395.09	-28.71	11073.62	11907.58	-29351.08	-98.38	3585.02	10884.05	-123777.95	-401.85	115295.05	125107.28	-54833.08	-155.32			
July	8098.27	11679.97	-11976.79	-32.11	8772.46	8817.43	-29396.05	-112.27	2723.58	8775.84	-129830.21	-473.45	104968.18	113332.07	-63196.97	-209.74	2387.08	2387.08	0
Aug	8636.6	10210.76	-13550.95	-45.81	8080.65	7700.02	-29015.42	-112.44	2542.18	7723.92	-135011.95	-496.60	107748.29	99307.95	-54756.63	-241.73	1967.65	4354.73	9.13
Sept	8420.14	10622.63	-15753.44	-51.83	7480.14	8046.9	-29582.18	-110.98	2306.98	8074.77	-140779.74	-516.42	88765.12	109375.27	-75366.78	-209.44	1812.61	6167.34	16.66
Oct	7287.15	9850.83	-18317.12	-60.26	7857.06	7736.28	-29461.40	-113.15	2570.26	7757.15	-145966.63	-538.48	106796.14	95585.72	-64156.36	-288.28	1695.14	7862.48	23.59
Nov	9959.89	12474.1	-20831.33	-70.06	10560.7	9918.95	-28819.65	-112.69	3423.52	9954.3	-152497.41	-558.32	152526.93	121597.42	-33226.85	-245.40	2434.68	10297.16	30.07
Dec	14053.45	16481.01	-23258.89	-79.68	12599.08	12227.44	-28448.01	-110.24	3854.94	12280.88	-160923.35	-583.30	159288.13	165391.65	-39330.37	-127.09	2897.74	13194.9	39.39
	154627.78	186803.07			153524.49	156752.27			59948.16	143754.13			1721671.27	1741826.39			13194.90		
		-32175.29	**-23258.89**	**1658.49**		**-3227.78**	**-28448.01**	**-1034.55**		**-83805.97**	**-160923.35**	**-51348.68**		**-20155.12**	**-39330.37**	**9072.91**	**13194.90**	**13194.90**	**118.84**
Adjustment posted to recovery				**-4168.00**				3714.00				17967.00				-3693.00			
				-2509.51				**2679.45**				**-33381.68**				**5379.91**			

Retail Settlement Variance Accounts - for 2007

	WMS				NW				CN				Energy				Low Voltage		
	Charge Accounts	Billed Accounts	Cumulative Variance	Interest	Charge Accounts	Billed Accounts	Cumulative Variance	Interest	Charge Accounts	Billed Accounts	Cumulative Variance	Interest	Charge Accounts	Billed Accounts	Cumulative Variance	Interest	Charge Accounts	Cumulative Variance	Interest
Opening Balance			**-23258.89**	**-2509.51**			**-28448.01**	**2679.45**			**-160923.35**	**-33381.68**			**-39330.37**	**5379.91**		**13194.9**	**118.84**
Iterest Rate	**0.003825**				**0.003825**				**0.003825**				**0.003825**				**0.003825**		
January	14237.76	16966.19	-25987.32	-88.97	15355.84	12982.65	-26074.82	-108.81	4525.44	13048.89	-169446.8	-615.53	178488.68	169115.75	-29957.44	-150.44	3194.99	16389.89	50.47
February	21479.41	21626.31	-26134.22	-99.40	16726.07	15703.13	-25051.88	-99.74	5231.54	15814.29	-180029.55	-648.13	241429.08	209848.63	1623.01	-114.59	3728.88	20118.77	62.69
March	20143.55	22620.45	-28611.12	-99.96	18024.23	17106.74	-24134.39	-95.82	5577.96	17224.99	-191676.58	-688.61	211466.62	230338.58	-17248.95	6.21	4218.14	24336.91	76.95
April	14781.42	21276.25	-35105.95	-109.44	17987.86	15877.91	-22024.44	-92.31	5691.92	15977.67	-201962.33	-733.16	168005.4	215035.68	-64279.23	-65.98	4601.43	28938.34	93.09
May	8837.93	19047	-45315.02	-134.28	14708.56	14389.82	-21705.7	-84.24	4707.76	14484.19	-211738.76	-772.51	144630.2	184597.17	-104246.2	-245.87	4284.31	33222.65	110.69
June	9204.53	13109.28	-49219.77	-173.33	10550.72	10316.13	-21471.11	-83.02	3325.26	10354.9	-218768.4	-809.90	96160.46	121971.78	-130057.52	-398.74	3496.26	36718.91	127.08
July	8745.18	10061.89	-50536.48	-188.27	8913.98	8184.04	-20741.17	-82.13	2597.24	8205.51	-224376.67	-836.79	111159.6	94136.43	-113034.35	-497.47	2356.57	39075.48	140.45
Aug	7375.44	10103.78	-53264.82	-193.30	8105.2	7782.99	-20418.96	-79.33	2422.94	7804.14	-229757.87	-858.24	91379.66	96031.66	-117686.35	-432.36	2116.55	41192.03	149.46
Sept *	8469.34	9977.89	-54773.37	-203.74	7326.74	7461.06	-20553.28	-78.10	2326.6	7483.79	-234915.06	-878.82	93095.72	95981.6	-120572.23	-450.15	1921.87	43113.9	157.56
Oct	10424.13	10439.14	-54788.38	-209.51	7948.17	8789.88	-21394.99	-78.62	4556.32	8126.98	-238485.72	-898.55	131012.07	101134.54	-90694.7	-461.19	1695.14	44809.04	164.91
Nov **	13019.33	12143.09	-53912.14	-209.57	10385.53	10308.9	-21318.36	-81.84	5338.39	9598	-242745.33	-912.21	151838.51	118241.06	-57097.25	-346.91	2434.68	47243.72	171.39
Dec	15589.74	17030.37	-55352.77	-206.21	14108.49	13658.34	-20868.21	-81.54	6158.82	12668.4	-249254.91	-928.50	163496.17	162095.51	-55696.59	-218.40	2897.74	50141.46	180.71
	152307.76	**184401.64**			**150141.39**	**142561.59**			**52460.19**	**140791.75**			1782162.17	1798528.39			36946.56		
Variance		**-32093.88**	**-55352.77**	**-4425.48**		**7579.8**	**-20868.21**	**1633.94**		**-88331.56**	**-249254.91**	**-42962.64**		-16366.22	**-55696.59**	**2004.04**	**36946.56**	**50141.46**	**1604.30**

Retail Settlement Variance Accounts - January to April 30, 2008

	WMS Charge Accounts	WMS Billed Accounts	WMS Cumulative Variance	WMS Interest	NW Charge Accounts	NW Billed Accounts	NW Cumulative Variance	NW Interest	CN Charge Accounts	CN Billed Accounts	CN Cumulative Variance	CN Interest	Energy Charge Accounts	Energy Billed Accounts	Energy Cumulative Variance	Energy Interest	Low Voltage Charge Accounts	Low Voltage Cumulative Variance	Low Voltage Interest
January	18478.71	18160.42	-55034.48	-211.72	16339.74	15163.89	-19692.36	-79.82	6857.36	14031.91	-256429.46	-953.40	206111.61	173638.29	-23223.27	-213.04	3194.99	53336.45	191.79
February	18986.96	22063.67	-58111.19	-210.51	18041.07	18127.28	-19778.57	-75.32	7734.32	16809.32	-265504.46	-980.84	206037.13	208231.06	-25417.2	-88.83	3728.88	57065.33	204.01
March	15842.71	22497.2	-64765.68	-222.28	18935.85	18406.95	-19249.67	-75.65	7877.36	17150.78	-274777.88	-1015.55	196355.84	214906.82	-43968.18	-97.22	4218.14	61283.47	218.27
April	17657.41	20909.21	-68017.48	-247.73	17312.19	16793.48	-18730.96	-73.63	5380.65	15662.53	-285059.76	-1051.03	172550.32	197762.92	-69180.78	-168.18	4601.43	65884.90	234.41
	70965.79	**83630.50**			**70628.85**	**68491.60**			**27849.69**	**63654.54**			**781054.90**	**794539.09**			**15743.44**		
		-12664.71	**-68017.48**	**-5317.72**		**2137.25**	**-18730.96**	**1329.51**		**-35804.85**	**-285059.76**	**-46963.46**		**-13484.19**	**-69180.78**	**1436.77**	**15743.44**	**65884.90**	**2452.78**

***Actuals to September 2007 - October to December 2007 (est) used average 2005 and 2006 data.**
- January to April 2008 (est) used average 2006 and 2007 data.
- Transmission rates effective November 1, 2007 to April 30, 2008 have been redused by 12% to minimize variance.

**** Charge accounts for Transmission Network and Connection adjusted to reflect the 12 % reduction as per OEB advice.**

Deferral Accounts

	Pension			Regulatory Costs		
	Charge Accounts	Cumulative Variance	Interest	Charge Accounts	Cumulative Variance	Interest
Opening Balance		**0**	**0**		**0**	**0**
Iterest Rate %						
Jan. '04				**0.0048**		
Jan. '05	**0.003233**					
May '06	**0.003450**			**0.003450**		
July '06	**0.003825**			**0.003825**		
2004						
July				338	338	
Aug				0	338	1.62
Sept				338	676	1.62
Oct				0	676	3.24
Nov				338	1014	3.24
Dec				0	1014	4.87
2005						
January	995.12	995.12	0.00	0	1014	4.87
February	995.12	1990.24	3.22	0	1014	4.87
March	995.12	2985.36	6.43	0	1014	4.87
April	995.12	3980.48	9.65	898.25	1912.25	4.87
May	995.12	4975.6	12.87	0	1912.25	9.18
June	1492.79	6468.39	16.09	898.25	2810.5	9.18
July	995.12	7463.51	20.91	0	2810.5	13.49
Aug	995.12	8458.63	24.13	0	2810.5	13.49
Sept *	995.12	9453.75	27.35	508.25	3318.75	13.49
Oct	995.12	10448.87	30.56	0	3318.75	15.93
Nov	995.12	11443.99	33.78	0	3318.75	15.93
Dec	1492.79	12936.78	37.00	508.25	3827	15.93
2006						
January	1032.95	13969.73	41.82	0	3827	18.37
February	1071.65	15041.38	45.16	0	3827	18.37
March	1117.71	16159.09	48.63	695.5	4522.5	18.37
April	1163.77	17322.86	52.24	0	4522.5	21.71
May	0	17322.86	59.76	0	4522.5	15.60
June	0	17322.86	59.76	0	4522.5	15.60
July	0	17322.86	66.26	0	4522.5	17.30
Aug	0	17322.86	66.26	0	4522.5	17.30
Sept	0	17322.86	66.26	0	4522.5	17.30
Oct	0	17322.86	66.26	0	4522.5	17.30
Nov	0	17322.86	66.26	0	4522.5	17.30
Dec	0	17322.86	66.26	-1014	3508.5	17.30
2007				**Posted to Recovery**		-123.20
January	0	17322.86	66.26	0	3508.5	13.42
February	0	17322.86	66.26	0	3508.5	13.42
March	0	17322.86	66.26	0	3508.5	13.42
April	0	17322.86	66.26	0	3508.5	13.42
May	0	17322.86	66.26	0	3508.5	13.42
June	0	17322.86	66.26	0	3508.5	13.42
July	0	17322.86	66.26	0	3508.5	13.42
Aug	0	17322.86	66.26	0	3508.5	13.42
Sept	0	17322.86	66.26	0.00	3508.5	13.42
Oct	0	17322.86	66.26	0	3508.5	13.42
Nov	0	17322.86	66.26	0	3508.5	13.42
Dec	0	17322.86	66.26	0	3508.5	13.42
2008						
January	0	17322.86	66.26	0	3508.5	13.42
February	0	17322.86	66.26	0	3508.5	13.42
March	0	17322.86	66.26	0	3508.5	13.42
April	0	17322.86	66.26	0	3508.50	13.42
	Adj.		-241	Adj.		-76.78
	$ 17,322.86		**$ 1,746.10**	**$ 3,508.50**		**$ 367.24**

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

EXHIBIT 5 (b)

REGULATORY ASSETS and VARIANCES

Year		WMS	NW ***	CN ***	Low Voltage	Energy	Total
2003	**Cost**	$ 212,355.10	$ 175,998.88	$ 55,134.73		$ 1,520,327.01	$ 1,963,815.72
	Revenue	$ 215,545.34	$ 189,711.40	$ 164,175.43		$ 1,611,478.99	$ 2,180,911.16
	Variance	$ (3,190.24)	$ (13,712.52)	$ (109,040.70)		$ (91,151.98)	$ (217,095.44)
2004	**Cost**	$ 202,551.32	$ 160,793.35	$ 50,313.08		$ 1,552,785.53	$ 1,966,443.28
	Revenue	$ 205,570.31	$ 183,106.60	$ 158,481.90		$ 1,570,632.14	$ 2,117,790.95
	Variance	$ (3,018.99)	$ (22,313.25)	$ (108,168.82)		$ (17,846.61)	$ (151,347.67)
2005	**Cost**	$ 205,779.62	$ 152,107.86	$ 59,596.96		$ 1,851,442.13	$ 2,268,926.57
	Revenue	$ 195,348.49	$ 175,395.57	$ 151,806.76		$ 1,737,263.21	$ 2,259,814.03
	Variance	$ 10,431.13	$ (23,287.71)	$ (92,209.80)		$ 114,178.92	$ 9,112.54
2006	**Cost**	$ 154,627.78	$ 153,524.49	$ 59,948.16	$ 13,194.90	$ 1,721,671.27	$ 2,102,966.60
	Revenue	$ 186,803.07	$ 156,752.27	$ 143,754.13	$ -	$ 1,741,826.39	$ 2,229,135.86
	Variance	$ (32,175.29)	$ (3,227.78)	$ (83,805.97)	$ 13,194.90	$ (20,155.12)	$ (126,169.26)
2007 *	**Cost**	$ 152,307.76	$ 150,141.39	$ 52,460.19	$ 36,946.56	$ 1,782,162.17	$ 2,174,018.07
	Revenue	$ 184,401.64	$ 142,561.59	$ 140,791.75	$ -	$ 1,798,528.39	$ 2,266,283.37
	Variance	$ (32,093.88)	$ 7,579.80	$ (88,331.56)	$ 36,946.56	$ (16,366.22)	$ (92,265.30)
2008**	**Cost**	$ 153,467.77	$ 151,832.94	$ 56,204.18	$ 36,946.56	$ 1,751,916.72	$ 2,150,368.17
	Revenue	$ 185,602.36	$ 149,656.93	$ 142,272.94	$ -	$ 1,770,177.39	$ 2,247,709.62
	Variance	$ (32,134.59)	$ 2,176.01	$ (86,068.77)	$ 36,946.56	$ (18,260.67)	$ (97,341.45)

* **Years 2003 to 2006 are actuals. 2007 is actual to May 31 and estimated From June 1 to December 31.**
** **Year 2008 is the average of 2006 and 2007**
*** **Transmission Rates Cost reduced by 12% from November 2007.**

Average (2006/07/08)	**Cost**	**$ 153,467.77**	**$ 151,832.94**	**$ 56,204.18**	**$ 36,946.56**			**$ 398,451.45**
	Revenue	**$ 185,602.36**	**$ 149,656.93**	**$ 142,272.94**	**$ -**			**$ 477,532.23**
	Variance	**$ (32,134.59)**	**$ 2,176.01**	**$ (86,068.77)**	**$ 36,946.56**			**$ (79,080.78)**

Customer Class	**Unit of measure**	**Current Rates**			**Calculated Rates Rates**			
		WMS& Rural kWh	**Network**	**Connection**	**WMS& Rural kWh**	**Network**	**Connection**	**Low Voltage**
Residential	**kWh**	**$ 0.0062**	**$ 0.0049**	**$ 0.0050**	**$ 0.0051**	**$ 0.0036**	**$ 0.0019**	**$ 0.0013**
GS <50kW	**kWh**	**$ 0.0062**	**$ 0.0045**	**$ 0.0045**	**$ 0.0051**	**$ 0.0033**	**$ 0.0017**	**$ 0.0013**
GS >50kW	**kW**	**$ 0.0062**	**$ 1.8304**	**$ 1.7882**	**$ 0.0051**	**$ 1.3371**	**$ 0.6690**	**$ 0.4809**
USL	**kWh**	**$ 0.0062**	**$ 0.0045**	**$ 0.0045**	**$ 0.0051**	**$ 0.0033**	**$ 0.0017**	**$ 0.0013**
Sentinel Lights	**kW**	**$ 0.0062**	**$ 1.3874**	**$ 1.4113**	**$ 0.0051**	**$ 1.0135**	**$ 0.5280**	**$ 0.4738**
Street Lights	**kW**	**$ 0.0062**	**$ 1.3804**	**$ 1.3824**	**$ 0.0051**	**$ 1.0083**	**$ 0.5172**	**$ 0.4956**

Calculated rates for Network, Connection and Wholesale were calculated by using the average of 3 years 2006, 2007 and 2008.
For Network and Connection rates, current rates are reduced by 28% and 5% respectively to reflect lower rates in effect November 1, 2007.
Calculated rates for Low Voltage charges were calculated using the 12 months actual cost from August 2006 to July 2007 of $36,946.56 and the average consumptions of 2006, 2007 and 2008 (see below).

Low Voltage Rate Calculation

	Total	**Residential**	**GS <50kW**	**GS >50kW**	**USL**	**Sent. Lights**	**Street Lights**
Estimated Consumpion 2008. (From Sheet '1- Customer Data")							
kWh	28,200,840	14,611,894	5,492,773	7,770,248	6,991	23,871	295,064
Customer class Allocation	100%	51.81%	19.48%	27.55%	0.02%	0.08%	1.05%
kW	22,015	-	-	21,169	-	66	780
Low Voltage Cost Allocation	**$ 36,946.56**	$ 19,143.22	$ 7,196.15	$ 10,179.90	$ 9.16	$ 31.27	$ 386.57
Proposed Low Voltage Rate		**$ 0.0013**	**$ 0.0013**	**$ 0.4809**	**$ 0.0013**	**$ 0.4738**	**$ 0.4956**

PROPOSAL.

Based on the above comparison of current to calculated rates it's recomented that Chapleau PUC adopt the following rates :

- **Current WMS and Rural rate of $0.0052 and $0.0010 to be reduced to the calculated rate of $0.0051 being WMS $0.0041 and Rural $0.0010.**
- **Transmission Network and Connection rates to be reduced to the calculated rates.**
- **Low Voltage rates to be adopted as calculated above.**

Customer Class	**Unit of measure**	**Proposed Rates**				
		WMS/kWh	**Rural/kWh**	**Network**	**Connection**	**Low Voltage**
Residential	**kWh**	**$ 0.0041**	**$ 0.0010**	**$ 0.0036**	**$ 0.0019**	**$ 0.0013**
GS <50kW	**kWh**	**$ 0.0041**	**$ 0.0010**	**$ 0.0033**	**$ 0.0017**	**$ 0.0013**
GS >50kW	**kW**	**$ 0.0041**	**$ 0.0010**	**$ 1.3371**	**$ 0.6690**	**$ 0.4809**
USL	**kWh**	**$ 0.0041**	**$ 0.0010**	**$ 0.0033**	**$ 0.0017**	**$ 0.0013**
Sentinel Lights	**kW**	**$ 0.0041**	**$ 0.0010**	**$ 1.0135**	**$ 0.5280**	**$ 0.4738**
Street Lights	**kW**	**$ 0.0041**	**$ 0.0010**	**$ 1.0083**	**$ 0.5172**	**$ 0.4956**

Please note that Low Voltage rates are no longer applied as an add'n to variable rates. Total L/V cost of $36,947 has been included in revenue requirement

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

EXHIBIT 5 (c)

REGULATORY ASSETS

	Account Number	Total Amount for disposition as per (#34) response to interrogatories
RSVA - Wholesale Market Service Charge	1580	$ (27,372.00)
RSVA - One-time Wholesale Market Service	1582	$ -
RSVA - Retail Transmission Network Charge	1584	$ (27,480.00)
RSVA - Retail Transmission Connection Charge	1586	$ (207,193.00)
RSVA - Power	1588	$ (36,389.00)
Low Voltage Charges	1550	$ 14,121.00
Other Reg. Assets - OEB Assessment	1508	$ 3,896.00
Other Reg. Assets - Pension contributions	1508	$ 19,069.00
Recovery of regulatory balances	1590	$ 17,928.00
TOTAL		$ (243,420.00)

Rate Rider Calculation		**Total**	**Residential**	**GS <50kW**	**GS >50kW**	**USL**	**Sent. Lights**	**Street Lights**	
Estimated Consumption 2008. (From "Exhibit 3(a) Op. Rev. (Data 1)")									
kWh		28,200,840	14,611,894	5,492,773	7,770,248	6,991	23,871	295,064	
Customer class Allocation		100%	51.8137%	19.4773%	27.5533%	0.0248%	0.0846%	1.0463%	
kW		21,925	-	-	21,079	-	66	780	
RSVA - Wholesale Market Service Charge	1580	$ (27,372.00)	$ (14,182.44)	$ (5,331.34)	$ (7,541.88)	$ (6.79)	$ (23.17)	$ (286.39)	
RSVA - One-time Wholesale Market Service	1582	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
RSVA - Retail Transmission Network Charge	1584	$ (27,480.00)	$ (14,238.40)	$ (5,352.37)	$ (7,571.63)	$ (6.81)	$ (23.26)	$ (287.52)	
RSVA - Retail Transmission Connection Charge	1586	$ (207,193.00)	$ (107,354.33)	$ (40,355.68)	$ (57,088.41)	$ (51.36)	$ (175.38)	$ (2,167.85)	
RSVA - Power	1588	$ (36,389.00)	$ (18,854.48)	$ (7,087.61)	$ (10,026.35)	$ (9.02)	$ (30.80)	$ (380.74)	
Low Voltage Charges	1550	$ 14,121.00	$ 7,316.61	$ 2,750.39	$ 3,890.79	$ 3.50	$ 11.95	$ 147.75	
Other Reg. Assets - OEB Assessment	1508	$ 3,896.00	$ 2,018.66	$ 758.84	$ 1,073.47	$ 0.97	$ 3.30	$ 40.76	
Other Reg. Assets - Pension contributions	1508	$ 19,069.00	$ 9,880.35	$ 3,714.13	$ 5,254.13	$ 4.73	$ 16.14	$ 199.52	
Recovery of regulatory balances	1590	$ 17,928.00	$ 9,289.16	$ 3,491.90	$ 4,939.75	$ 4.44	$ 15.18	$ 187.58	
TOTAL		$ (243,420.00)	$ (126,124.87)	$ (47,411.73)	$ (67,070.12)	$ (60.34)	$ (206.04)	$ (2,546.89)	$ (243,420.00)
Balance to be collected/refunded		$ (243,420.00)	$ (126,124.87)	$ (47,411.73)	$ (67,070.12)	$ (60.34)	$ (206.04)	$ (2,546.89)	
Rate per kWh/kW - Over 1 Year		$ (243,420.00)	$ (0.0086)	$ (0.0086)	$ (3.1818)	$ (0.0086)	$ (3.1219)	$ (3.2652)	
Rate per kWh/kW - Over 2 Years		$ (121,710.00)	$ (0.0043)	$ (0.0043)	$ (1.5909)	$ (0.0043)	$ (1.5609)	$ (1.6326)	
Rate per kWh/kW - Over 3 Years	*	**$ (81,140.00)**	**$ (0.0029)**	**$ (0.0029)**	**$ (1.0606)**	**$ (0.0029)**	**$ (1.0406)**	**$ (1.0884)**	
Rate per kWh/kW - Over 4 Years		$ (60,855.00)	$ (0.0022)	$ (0.0022)	$ (0.7954)	$ (0.0022)	$ (0.7805)	$ (0.8163)	

*** The recommended option by CPUC is to refund the over collection of regulatory assets over a 3 year period**

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170

EDR File Number: EB-2005-0349

Cost Allocation File Number: EB-2007-0001

EXHIBIT 6

COST OF CAPITAL AND RATE OF RETURN

Capital Structure	Board Approved 2006					Historical Year 2006					Test Year 2008			
		Amount	Ratio %	Rate	Rate x Ratio %		Amount	Ratio %	Rate	Rate x Ratio %		Amount	Ratio %	Rate	Rate x Ratio %
Long-Term Debt	$	1,853,685	99.99%	7.25%	7.25%	$	1,321,493	58.9%	7.3%	4.27%	$	1,183,970	49.3%	6.10%	3.01%
Short-Term Debt/Unfunded Debt	$	-				$	360,727	16.1%	7.3%	1.17%	$	96,062	4.0%	4.47%	0.18%
Total Debt	$	1,853,685	99.99%			$	1,682,220	75.0%		5.44%	$	1,280,032	53.3%		3.19%
Preference Shares	$	-	0.00%			$	-	0.0%			$	-	0.0%		0.00%
Common Equity	$	100	0.01%	9.00%	0.00%	$	560,840	25.0%	9.0%	2.25%	$	1,121,529	46.7%	8.57%	4.00%
Total Equity	$	100	0.01%			$	560,840	25.0%		2.25%	$	1,121,529	46.7%		4.00%
Total Rate Base	$	1,853,785	100.0%		7.25%	$	2,243,060	100.0%		7.69%	$	2,401,561	100.0%		7.19%

Long Term Debt is payable to the Township of Chapleau for an unspecified term at a debt rate cost of 7.25%

Chapleau Public Utilities Corporation
License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

EXHIBIT 1

Pro Forma Operating Statements

	2006 Historical Actual	Bridge Year 2007	Test Year 2008
Assets			
Current Assets:			
Cash	173,608	174,637	176,298
Term Deposits and Treasury Bills	651,121	803,000	790,000
Trade Receivable	40,885	40,885	40,885
Plant Material and Supplies	43,787	43,787	43,787
Prepaid Expenses	10,318	10,318	10,318
Unbilled revenue - Energy sales	424,856	424,856	424,856
Unbilled revenue - Distribution	42,940	42,940	42,940
	1,387,515	1,540,423	1,529,084
Capital Assets	2,175,939	2,185,341	2,249,202
Accumulated Dipreciation	1,266,778	1,303,051	1,339,614
	909,161	882,290	909,588
	2,296,676	2,422,713	2,438,672
Liabilities and Shareholder's Equity			
Current Liabilities			
Accounts Payable and accrued Liabilities	267,048	270,548	266,874
Advanses from Related Companies	20,551	20,551	20,551
	287,599	291,099	287,425
Other Liabilities			
Regulatory Liabilities	487,538	601,613	572,678
Customer Deposits	21,989	21,989	21,989
Loan Payable	360,727	360,727	-
Mortgage Payable	1,321,493	1,321,493	1,195,551
Shareholders Deficiency			
Share Capital	560,840	560,840	1,047,509
Deficit	(743,510)	(735,048)	(686,480)
	(182,670)	(174,208)	361,029
	2,296,676	2,422,713	2,438,672

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

	EB-2006-0170
EDR File Number:	EB-2005-0349
Cost Allocation File Number:	EB-2007-0001

EXHIBIT 1
Revenue Sufficiency (Proposed Base Rates)

Pro Forma Operating Statements

	2006 Historical Board Approved	2006 Historical Actual	2007 Budget	YTD to July Budget	Aug. - Dec. Forecast	YTD Actual Jul. 2007	Bridge Year 2007	Test Year 2008	Forecast 2009
Revenue									
Distribution Revenue	$ 605,891	$ 566,543	$ 555,545	$ 372,720	$ 202,280	$ 392,265	$ 592,434	$ 668,215	$ 705,447
SSS Admin. and Retailer Charges	$ -	$ 1,382	$ 1,735	$ 1,012	$ 723	$ 1,012	$ 1,735	$ 1,735	$ 1,735
Miscellaneous Revenue	$ 42,681	$ 42,657	$ 36,804	$ 21,469	$ 7,835	$ 33,389	$ 52,304	$ 43,244	$ 36,800
Low Voltage Revenue (8 months only)									
Revenue	$ 648,572	$ 610,582	$ 594,084	$ 395,201	$ 210,838	$ 426,666	$ 646,473	$ 713,194	$ 743,982
Cost of Energy Revenue	0	$ 2,089,075	$ 2,322,000	$ 1,550,000	$ 666,311	$ 1,151,339	$ 1,782,162	$ 1,751,917	$ 1,767,040
Cost of Energy Expense	0	$ 2,089,075	$ 2,322,000	$ 1,550,000	$ 666,311	$ 1,151,339	$ 1,782,162	$ 1,751,917	$ 1,767,040
Cost of Power	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Operations and Maintenance	$ 263,311	$ 262,647	$ 300,000	$ 175,000	$ 131,528	$ 168,472	$ 296,913	$ 302,585	$ 308,637
Billing & Collecting	$ 65,879	$ 63,918	$ 60,000	$ 35,000	$ 34,103	$ 25,897	$ 66,539	$ 64,112	$ 66,035
Depreciation	$ 37,890	$ 37,370	$ 36,000	$ 21,000	$ 15,125	$ 21,148	$ 36,273	$ 36,563	$ 42,977
Administrative and General Expenses									
Community Relations	$ 2,607	$ 1,707	$ 2,400	$ 1,400	$ 1,000	$ 63	$ 1,063	$ 1,200	$ 1,200
Executive Salaries and Expense	$ 59,881	$ 59,331	$ 60,000	$ 35,000	$ 25,000	$ 37,672	$ 62,672	$ 64,552	$ 66,489
Office Supplies and Expense	$ 22,176	$ 19,574	$ 21,000	$ 12,250	$ 8,750	$ 12,911	$ 21,661	$ 22,248	$ 22,915
Outside Services Employed	$ 38,352	$ 47,795	$ 57,000	$ 33,250	$ 43,078	$ 61,290	$ 104,368	$ 72,425	$ 60,000
Property Insurance	$ 13,601	$ 12,119	$ 18,000	$ 10,500	$ 9,657	$ 8,343	$ 13,000	$ 13,500	$ 18,000
Regulatory Expenses	$ 5,734	$ 4,584	$ 12,000	$ 7,000	$ 8,551	$ 3,449	$ 5,769	$ 6,000	$ 12,000
Misc. General Expenses	$ 6,546	$ 10,612	$ 12,000	$ 7,000	$ 8,901	$ 6,099	$ 15,000	$ 12,000	$ 12,000
Bank Charges	$ 8,247	$ 8,941	$ 11,100	$ 9,000	$ 2,100	$ 9,395	$ 9,883	$ 9,200	$ 10,000
Low Voltage Charges (8 Moths Only)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 24,631	$ 36,947
Total Expenses	$ 524,224	$ 528,598	$ 589,500	$ 346,400	$ 287,793	$ 354,739	$ 633,141	$ 629,016	$ 657,200
Income (Loss)	$ 124,348	$ 81,984	$ 4,584	$ 48,801	$ (76,956)	$ 71,927	$ 13,332	$ 84,178	$ 86,782
Interest Payable to Township of Chapleau	$ 48,454	$ -	$ 45,000	$ 26,250	$ 45,000	$ -	$ -	$ -	45000
Net Income (Loss)	$ 75,894	$ 81,984	$ (40,416)	$ 22,551	$ (121,956)	$ 71,927	$ 13,332	$ 84,178	$ 41,782
Adjustments For Cash Flow									
Depreciation			$ 36,000	$ 21,000	$ 15,105	$ 21,148	$ 36,273	$ 36,563	
Purchase of Capital assets					$ (1,500)	$ (6,902)	$ (9,402)	$ (63,861)	
Ovecollection/(Refund) of Regulatory Assets					$ 36,439	$ 51,015	$ 114,075	$ (21,646)	
Change in Accounts Reaceivable			$ 3,500	$ 13,000	$ 3,500	$ -	$ 3,500	$ -	
Net Cash Flow			$ (916)	$ 56,551	$ (103,351)	$ 93,075	$ 157,778	$ 35,234	
Cash Biginning of the Year			$ 172,400	$ 172,400	$ 228,951	$ 172,400	$ 824,729	$ 982,507	
Cash End of the Year			$ 171,484	$ 228,951	$ 125,601	$ 265,475	$ 982,507	$ 1,017,740	

Cash Flow Forecast 2008 to 2012

	2007	2008	2009	2010	2011	2012
Cash Biginning of the Year	$ 824,729	$ 982,507	$ 1,017,740	$ 487,938	$ 451,849	$ 511,480
Net Income (Loss)	$ 13,332	$ 84,178	$ 42,000	$ 42,000	$ 42,000	$ 42,000
Adjustments For Cash Flow						
Depreciation	$ 36,273	$ 36,563	$ 42,977	$ 52,885	$ 51,910	$ 50,123
Purchase of Capital Assets	$ (9,402)	$ (63,861)	$ (533,639)	$ (49,834)	$ (7,232)	$ (7,232)
Net Ovecollection/(Refund) of Regulatory Assets	$ 114,075	$ (21,646)	$ (81,140)	$ (81,140)	$ (27,047)	$ (33,674)
Change in Accounts Reaceivable	$ 3,500	$ -	$ -	$ -	$ -	$ -
Cash End of the Year	$ 982,507	$ 1,017,740	$ 487,938	$ 451,849	$ 511,480	$ 562,697

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

EXHIBIT 1

Revenue Deficiency (Current Base Rates to Continue)

	Historical Actual 2006	(Forecast - Current Rates) Bridge Year 2007	Test Year 2008	2009
Revenue				
Distribution Revenue	$ 558,385	$ 592,434	$ 612,102	$ 619,631
SSS Admin. and Retailer Charges	$ 1,382	$ 1,735	$ 1,735	$ 1,735
Miscellaneous Revenue	$ 42,657	$ 52,304	$ 43,244	$ 36,800
	$ 602,424	$ 646,473	$ 657,081	$ 658,166
Expenses				
Operations and Maintenance	$ 262,647	$ 296,913	$ 302,585	311,663
Administrative and General Expenses	$ 164,663	$ 233,416	$ 225,756	239,551
Billing & Collecting	$ 63,918	$ 66,539	$ 64,112	66,035
Depreciation	$ 37,370	$ 36,273	$ 36,563	42,977
Profit (Loss)	$ 73,826	$ 13,332	$ 28,065	$ (2,060)
Interest Payable to Township of Chapleau	$ -	$ -	$ -	$ 45,000
Profit (Loss)	$ 73,826	$ 13,332	$ 28,065	$ (47,060)

Cash Flow Forecast 2008 to 2012

	2006	2007	2008	2009	2010	2011	2012
Cash Biginning of the Year	$ 1,022,702	$ 824,729	$ 982,507	$ 961,628	$ 342,766	$ 204,677	$ 162,308
Net Income (Loss)	$ 119,469	$ 13,332	$ 28,065	$ (47,060)	$ (60,000)	$ (60,000)	$ (60,000)
Adjustments For Cash Flow							
Depreciation	$ 37,370	$ 36,273	$ 36,563	$ 42,977	$ 52,885	$ 51,910	$ 50,123
Purchase of Capital Assets	$ 24,292	$ (9,402)	$ (63,861)	$ (533,639)	$ (49,834)	$ (7,232)	$ (7,232)
Net Ovecollection/(Refund) of Regulatory Assets	$ (126,169)	$ 114,075	$ (21,646)	$ (81,140)	$ (81,140)	$ (27,047)	$ (33,674)
Change in Accounts Reaceivable & other.	$ (252,935)	$ 3,500	$ -	$ -	$ -	$ -	$ -
Cash End of the Year	$ 824,729	$ 982,507	$ 961,628	$ 342,766	$ 204,677	$ 162,308	$ 111,525

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

EXHIBIT 8 (a)

COST ALLOCATION TO BASE REVENUE REQUIREMENT

Results from the 2006 Cost Allocation Information Filing	Total Current Revenue (From 2006 EDR Model)	Revenue Requirement (From CA Model)	Adjustment Required to Total Current Revenue	% Revenue Requirement (Per CA Model)
RESIDENTIAL				
Regular	462,269	407,234	(55,035)	63.20%
GENERAL SERVICE				
Less than 50 kW	118,553	129,751	11,198	20.14%
Greater than 50 kW (to 3000 kW)	55,037	69,856	14,819	10.84%
Unmetered Scattered Load	1,690	2,148	458	0.33%
Sentinel Lighting	1,107	2,441	1,334	0.38%
Street Lighting	5,729	32,955	27,226	5.11%
TOTALS	**644,385**	**644,385**	**0**	**100.00%**

Cost Allocation to 2008 Revenue Requirement	Total Revenue as Calculated Exhibit9(a) L31-L36	Cost Allocated Revenue Requirement	Adjustment Required to Revenue as Calculated	Proposed Adjustment to Revenue as Calculated	Proposed Cost Allocated Revenue Requirement
RESIDENTIAL					
Regular	502,178	443,138	(59,039)	$ (31,069)	$ 471,108
GENERAL SERVICE					
Less than 50 kW	129,219	141,191	11,971	$ 11,971	$ 141,191
Greater than 50 kW (to 3000 kW)	61,027	76,015	14,988	$ 14,988	$ 76,015
Unmetered Scattered Load	1,400	2,337	938	$ 130	$ 1,530
Sentinel Lighting	1,206	2,656	1,450	$ 480	$ 1,686
Street Lighting	6,168	35,861	29,692	$ 3,500	$ 9,668
TOTALS	**701,198**	**701,198**	**0**	**$ -**	**$ 701,198**

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

EXHIBIT 9 (a)

Allocation - Base Revenue Requirement

	Number of Customers (Connections)	kWh per Customer			Calculated kWh per Customer	Calculated kWh	kW per Customer			Calculated kW per Customer	Calculated kW
	2008 Customer count	2006	2007	2008	3 yr average per customer	2008 cust. count x 3 yr average per cust.	2006	2007	2008	3 yr average per customer	2008 cust. count x 3 yr average per cust.
RESIDENTIAL											
Regular	1,164	12,421.4	12,684.9	12,553.2	12,553.2	14,611,894	0.0	0.0	0.0	0.0	0.0
Less than 50 kW	166	32,877.4	33,395.6	32,994.1	33,089.0	5,492,773	0.0	0.0	0.0	0.0	0.0
Greater than 50 kW (to 3000 kW)	14	551,654.5	557,255.3	556,143.4	555,017.7	7,770,248	1,492.4	1,512.5	1,512.1	1,505.7	21,079.3
Unmetered Scattered Load	6	1,128.3	1,202.0	1,165.2	1,165.2	6,991	0.0	0.0	0.0	0.0	0.0
Sentinel Lighting	24	974.9	1,014.3	994.6	994.6	23,871	2.8	2.8	2.8	2.8	66.0
Street Lighting	341	863.6	866.9	865.3	865.3	295,064	2.3	2.3	2.3	2.3	780.0
TOTALS	1,715					28,200,840					21,925.3

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

EXHIBIT 9 (a)

Allocation - Base Revenue Requirement

	Calculated Revenue for Allocation to Customer Classes: 2008 Consumption determinants x Existing Rates for 2007 Exluding Smart Meter Rates				Allocation to Customer Classes	Allocation between Fixed and Variable %			Base Revenue Requirement Allocated (adjusted for Transformer Credit)		
RESIDENTIAL	Volumetric kWh ($)	Volumetric kW ($)	Monthly Fixed Charges ($)	Total ($)	Total for customer class as % of Total for all classes	Volumetric as percent of Total for customer class	Fixed charges as percent of total for customer		Overall Allocation to Classes	Variable Component	Fixed Component
Regular	146,119	0	274,611	420,730	71.62%	34.73%	65.27%	100.00%	502,178	174,406	327,772
Less than 50 kW	46,689	0	61,573	108,261	18.43%	43.13%	56.87%	100.00%	129,219	55,727	73,492
Greater than 50 kW (to 3000 kW)	0	25,504	25,625	51,129	8.70%	49.88%	50.12%	100.00%	61,027	30,441	30,586
Unmetered Scattered Load	59	0	1,113	1,173	0.20%	5.07%	94.93%	100.00%	1,400	71	1,329
Sentinel Lighting	0	247	763	1,011	0.17%	24.48%	75.52%	100.00%	1,206	295	911
Street Lighting	0	1,894	3,274	5,168	0.88%	36.66%	63.34%	100.00%	6,168	2,261	3,907
TOTALS	192,867	27,646	366,959	587,471	100.00%	37.54%	62.46%	100.00%	**701,198**	**263,201**	**437,997**
									9,610	<< Less Transformer Credit	
									691,588	<< Base Revenue Req. B.R.R.#	

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

EXHIBIT 9 (a)

Rates - Base Revenue Requirement

	Number of Customers (Connections)	**kWh**	**kW**	**Base Revenue Requirement Allocated**	
	2008 Customer count	**2008 cust. count x 3 yr per cust. avg. kWh**	**2008 cust. count x 3 yr per cust. avg. kW**	Variable Component	Fixed Component
RESIDENTIAL					
Regular	1,164	14,611,894	0	174,406	327,772
GENERAL SERVICE					
Less than 50 kW	166	5,492,773	0	55,727	73,492
Greater than 50 kW (to 3000 kW)	14	7,770,248	21,079	30,441	30,586
Unmetered Scattered Load	6	6,991	0	71	1,329
Sentinel Lighting	24	23,871	66	295	911
Street Lighting	341	295,064	780	2,261	3,907
TOTALS	1,715	28,200,840	21,925	**263,201**	**437,997**

	Base Rates - Revenue Requirement *divided by consumption* for 2008.			
	Volumetric Rate Type	Rate per kWh $	Rate per kW $	Fixed service charge $
Regular	kWh	0.0119		23.47
Less than 50 kW	kWh	0.0101		36.89
Greater than 50 kW (to 3000 kW)	kW		1.4441	182.06
Unmetered Scattered Load	kWh	0.0101		18.45
Sentinel Lighting	kW		4.4740	3.16
Street Lighting	kW		2.8987	0.95

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

EXHIBIT 8 (b)

Cost Allocation - Base Revenue Requirement / Proposed Rates

	Cost Allocated Base Revenue Requirement Between Fixed and Variable and Adjusted for Transformer Credit			Number of Customers (Connections)	kWh	kW	Base Rates - Revenue Requirement for 2008 test yr. + Meter Charge $0.26 for Metered Cusomers..			
	Cost Allocation to Classes from Exhibit 8 F25 - F31	Variable Component	Fixed Component	2008 Customer count	2008 cust. count x 3 yr per cust. avg. kWh	2008 cust. count x 3 yr per cust. avg. kW	Volumetric Rate Type	Rate per kWh $	Rate per kW $	Fixed service charge $
RESIDENTIAL										
Regular	471,108	163,615	307,493	1,164	14,611,894	0	kWh	0.0112		22.27
GENERAL SERVICE										
Less than 50 kW	141,191	60,890	80,301	166	5,492,773	0	kWh	0.0111		40.57
Greater than 50 kW (to 3000 kW)	76,015	37,917	38,098	14	7,770,248	21,079	kW		1.7988	227.03
Unmetered Scattered Load	1,530	78	1,452	6	6,991	0	kWh	0.0111		20.17
Sentinel Lighting	1,686	413	1,273	24	23,871	66	kW		6.2544	4.42
Street Lighting	9,668	3,544	6,124	341	295,064	780	kW		4.5435	1.50
TOTALS	**701,198**	266,457	434,741	1,715	28,200,840	21,925				
	9,610	<< Less Transformer Credit								
	691,588	<< Base Rev. Req. B.R.R.#1								

Chapleau Public Utilities Corporation

Tariff OF RATES AND CHARGES

Effective May 1, 2008

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	22.27
Distribution Volumetric Rate	$/kWh	0.0112
Rate Rider 1 (if applicable)	$/kWh	0.0000
Rate Rider 2 (if applicable)	$/kWh	0.0000
Regulatory Asset Recovery	$/kWh	(0.0029)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0036
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0019
Retail Transmission Rate – Network Service Rate (if applicable)	$/kWh	0.0000
Retail Transmission Rate – Line and Transformation Connection Service Rate (if applicable)	$/kWh	0.0000
Retail Transmission Rate – Network Service Rate (if applicable)	$/kWh	0.0000
Retail Transmission Rate – Line and Transformation Connection Service Rate (if applicable)	$/kWh	0.0000
Wholesale Market Service Rate	$/kWh	0.0041
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge	$	0.25

General Service Less Than 50 kW

Service Charge	$	40.57
Distribution Volumetric Rate	$/kWh	0.0111
Rate Rider 1 (if applicable)	$/kWh	0.0000
Rate Rider 2 (if applicable)	$/kWh	0.0000
Regulatory Asset Recovery	$/kWh	(0.0029)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0033
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0017
Retail Transmission Rate – Network Service Rate (if applicable)	$/kWh	0.0000
Retail Transmission Rate – Line and Transformation Connection Service Rate (if applicable)	$/kWh	0.0000
Retail Transmission Rate – Network Service Rate (if applicable)	$/kWh	0.0000
Retail Transmission Rate – Line and Transformation Connection Service Rate (if applicable)	$/kWh	0.0000
Wholesale Market Service Rate	$/kWh	0.0041
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge	$	0.25

General Service 50 to 4,999 kW

Service Charge	$	227.03
Distribution Volumetric Rate	$/kW	1.7988
Rate Rider 1 (if applicable)	$/kW	0.0000
Rate Rider 2 (if applicable)	$/kW	0.0000
Regulatory Asset Recovery	$/kW	(1.0606)
Retail Transmission Rate – Network Service Rate	$/kW	1.3371
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.6690
Retail Transmission Rate – Network Service Rate (if applicable)	$/kW	0.0000
Retail Transmission Rate – Line and Transformation Connection Service Rate (if applicable)	$/kW	0.0000
Retail Transmission Rate – Network Service Rate (if applicable)	$/kW	0.0000
Retail Transmission Rate – Line and Transformation Connection Service Rate (if applicable)	$/kW	0.0000
Wholesale Market Service Rate	$/kWh	0.0041
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge	$	0.25

Unmetered Scattered Load

Service Charge	$	20.17
Distribution Volumetric Rate	$/kWh	0.0111
Rate Rider 1 (if applicable)	$/kWh	0.0000
Rate Rider 2 (if applicable)	$/kWh	0.0000
Regulatory Asset Recovery	$/kWh	(0.0029)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0033
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0017
Retail Transmission Rate – Network Service Rate (if applicable)	$/kWh	0.0000
Retail Transmission Rate – Line and Transformation Connection Service Rate (if applicable)	$/kWh	0.0000
Retail Transmission Rate – Network Service Rate (if applicable)	$/kWh	0.0000
Retail Transmission Rate – Line and Transformation Connection Service Rate (if applicable)	$/kWh	0.0000
Wholesale Market Service Rate	$/kWh	0.0041
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge	$	0.25

Sentinel Lighting

Service Charge	$	**4.42**
Distribution Volumetric Rate	$/kW	**6.2544**
Rate Rider 1 (if applicable)	$/kW	0.0000
Rate Rider 2 (if applicable)	$/kW	0.0000
Regulatory Asset Recovery	$/kW	**(1.0406)**
Retail Transmission Rate – Network Service Rate	$/kW	**1.0135**
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	**0.5280**
Retail Transmission Rate – Network Service Rate (if applicable)	$/kW	0.0000
Retail Transmission Rate – Line and Transformation Connection Service Rate (if applicable)	$/kW	0.0000
Retail Transmission Rate – Network Service Rate (if applicable)	$/kW	0.0000
Retail Transmission Rate – Line and Transformation Connection Service Rate (if applicable)	$/kW	0.0000
Wholesale Market Service Rate	$/kWh	**0.0041**
Rural Rate Protection Charge	$/kWh	**0.0010**
Regulated Price Plan – Administration Charge	$	**0.25**

Street Lighting

Service Charge	$	**1.50**
Distribution Volumetric Rate	$/kW	**4.5435**
Rate Rider 1 (if applicable)	$/kW	0.0000
Rate Rider 2 (if applicable)	$/kW	0.0000
Regulatory Asset Recovery	$/kW	**(1.0884)**
Retail Transmission Rate – Network Service Rate	$/kW	**1.0083**
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	**0.5172**
Retail Transmission Rate – Network Service Rate (if applicable)	$/kW	0.0000
Retail Transmission Rate – Line and Transformation Connection Service Rate (if applicable)	$/kW	0.0000
Retail Transmission Rate – Network Service Rate (if applicable)	$/kW	0.0000
Retail Transmission Rate – Line and Transformation Connection Service Rate (if applicable)	$/kW	0.0000
Wholesale Market Service Rate	$/kWh	**0.0041**
Rural Rate Protection Charge	$/kWh	**0.0010**
Regulated Price Plan – Administration Charge	$	**0.25**

Specific Service Charges

Customer Administration

Arrears certificate	$	**15.00**
Credit reference/credit check (plus credit agency costs)	$	**15.00**
Returned cheque charge (plus bank charges)	$	**15.00**
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	**30.00**
Special meter reads	$	**30.00**
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	**30.00**
	$	0.00

Non-Payment of Account

Late Payment - per month	%	**1.50**
Late Payment - per annum	%	**19.56**
Collection of account charge - no disconnection	$	**30.00**
Disconnect/Reconnect at meter - during regular hours	$	**65.00**
	$	0.00

Install/Remove load control device - during regular hours	$	**65.00**
Specific Charge for Access to the Power Poles $/pole/year	$	**22.35**
	$	0.00

Allowances

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	**-0.60**
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	**-1.00**
	$/kW	0.00

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	**1.0654**
Total Loss Factor – Secondary Metered Customer > 5,000 kW	**1.0145**
Total Loss Factor – Primary Metered Customer < 5,000 kW	**1.0506**
Total Loss Factor – Primary Metered Customer > 5,000 kW	**1.0045**

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

EXHIBIT

Customer Impacts - Annualized Average

Residential

Consumption 100 kWh, 0 kW — **Loss Factor 1.0606**

	2007 BILL			2008 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			$ 19.92			$ 22.27	$ 2.35	11.80%	71.57%
Distribution (kWh)	100	$ 0.0100	$ 1.00	100	$ 0.0112	$ 1.12	$ 0.1200	12.00%	3.60%
Distribution (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Regulatory Assets (kWh)	100	$ 0.0007	$ 0.07	100	-$ 0.0029	-$ 0.29	$ (0.36)	-514.29%	-0.93%
Regulatory Assets (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Sub-Total			**$ 20.99**			**$ 23.10**	**$ 2.11**	**10.05%**	**74.23%**
Other Charges (kWh)	106	$ 0.0231	$ 2.45	106	$ 0.0176	$ 1.87	$ (0.58)	-23.81%	6.00%
Other Charges (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Cost of Power Commodity (kWh)	106	$ 0.0580	$ 6.15	106	$ 0.0580	$ 6.15	$ -	0.00%	19.77%
Cost of Power Commodity (kWh)	0	$ 0.0670	$ -	0	$ 0.0670	$ -	$ -	0.00%	0.00%
Total Bill before Taxes			**$ 29.59**			**$ 31.12**	**$ 1.53**	**5.16%**	**100%**
GST (6%)			**$ 1.78**			**$ 1.87**	**$ 0.09**	**5.16%**	
Total Bill after Taxes			**$ 31.37**			**$ 32.99**	**$ 1.62**	**5.16%**	

Residential

Consumption 250 kWh, 0 kW — **Loss Factor 1.0606**

	2007 BILL			2008 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			$ 19.92			$ 22.27	$ 2.35	11.80%	50.17%
Distribution (kWh)	250	$ 0.0100	$ 2.50	250	$ 0.0112	$ 2.80	$ 0.3000	12.00%	6.31%
Distribution (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Regulatory Assets (kWh)	250	$ 0.0007	$ 0.18	250	-$ 0.0029	-$ 0.73	$ (0.90)	-514.29%	-1.63%
Regulatory Assets (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Sub-Total			**$ 22.60**			**$ 24.35**	**$ 1.75**	**7.75%**	**54.84%**
Other Charges (kWh)	265	$ 0.0231	$ 6.12	265	$ 0.0176	$ 4.67	$ (1.46)	-23.81%	10.51%
Other Charges (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Cost of Power Commodity (kWh)	265	$ 0.0580	$ 15.38	265	$ 0.0580	$ 15.38	$ -	0.00%	34.64%
Cost of Power Commodity (kWh)	0	$ 0.0670	$ -	0	$ 0.0670	$ -	$ -	0.00%	0.00%
Total Bill before Taxes			**$ 44.10**			**$ 44.39**	**$ 0.29**	**0.66%**	**100%**
GST (6%)			**$ 2.65**			**$ 2.66**	**$ 0.02**	**0.66%**	
Total Bill after Taxes			**$ 46.74**			**$ 47.05**	**$ 0.31**	**0.66%**	

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

Residential

Consumption 500 kWh 0 kW **Loss Factor 1.0606**

	2007 BILL			2008 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			$ 19.92			$ 22.27	$ 2.35	11.80%	33.48%
Distribution (kWh)	500	$ 0.0100	$ 5.00	500	$ 0.0112	$ 5.60	$ 0.6000	12.00%	8.42%
Distribution (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Regulatory Assets (kWh)	500	$ 0.0007	$ 0.35	500	-$ 0.0029	-$ 1.45	$ (1.80)	-514.29%	-2.18%
Regulatory Assets (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Sub-Total			**$ 25.27**			**$ 26.42**	**$ 1.15**	**4.55%**	**39.72%**
Other Charges (kWh)	530	$ 0.0231	$ 12.25	530	$ 0.0176	$ 9.33	$ (2.92)	-23.81%	14.03%
Other Charges (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Cost of Power Commodity (kWh)	530	$ 0.0580	$ 30.76	530	$ 0.0580	$ 30.76	$ -	0.00%	46.24%
Cost of Power Commodity (kWh)	0	$ 0.0670	$ -	0	$ 0.0670	$ -	$ -	0.00%	0.00%
Total Bill before Taxes			**$ 68.28**			**$ 66.51**	**$ (1.77)**	**-2.59%**	**100%**
GST (6%)			**$ 4.10**			**$ 3.99**	**$ (0.11)**	**-2.59%**	
Total Bill after Taxes			**$ 72.37**			**$ 70.50**	**$ (1.87)**	**-2.59%**	

Residential

Consumption 1,000 kWh 0 kW **Loss Factor 1.0606**

	2007 BILL			2008 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			$ 19.92			$ 22.27	$ 2.35	11.80%	19.69%
Distribution (kWh)	1,000	$ 0.0100	$ 10.00	1,000	$ 0.0112	$ 11.20	$ 1.2000	12.00%	9.90%
Distribution (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Regulatory Assets (kWh)	1,000	$ 0.0007	$ 0.70	1,000	-$ 0.0029	-$ 2.90	$ (3.60)	-514.29%	-2.56%
Regulatory Assets (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Sub-Total			**$ 30.62**			**$ 30.57**	**-$ 0.05**	**-0.16%**	**27.03%**
Other Charges (kWh)	1061	$ 0.0231	$ 24.50	1061	$ 0.0176	$ 18.67	$ (5.83)	-23.81%	16.50%
Other Charges (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Cost of Power Commodity (kWh)	800	$ 0.0580	$ 46.40	800	$ 0.0580	$ 46.40	$ -	0.00%	41.03%
Cost of Power Commodity (kWh)	261	$ 0.0670	$ 17.46	261	$ 0.0670	$ 17.46	$ -	0.00%	15.44%
Total Bill before Taxes			**$ 118.98**			**$ 113.10**	**$ (5.88)**	**-4.94%**	**100%**
GST (6%)			**$ 7.14**			**$ 6.79**	**$ (0.35)**	**-4.94%**	
Total Bill after Taxes			**$ 126.12**			**$ 119.88**	**$ (6.24)**	**-4.94%**	

Residential

Consumption 2,000 kWh 0 kW **Loss Factor 1.0606**

	2007 BILL			2008 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			$ 19.92			$ 22.27	$ 2.35	11.80%	10.55%
Distribution (kWh)	2,000	$ 0.0100	$ 20.00	2,000	$ 0.0112	$ 22.40	$ 2.4000	12.00%	10.61%
Distribution (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Regulatory Assets (kWh)	2,000	$ 0.0007	$ 1.40	2,000	-$ 0.0029	-$ 5.80	$ (7.20)	-514.29%	-2.75%
Regulatory Assets (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Sub-Total			**$ 41.32**			**$ 38.87**	**-$ 2.45**	**-5.93%**	**18.41%**
Other Charges (kWh)	2121	$ 0.0231	$ 49.00	2121	$ 0.0176	$ 37.33	$ (11.67)	-23.81%	17.68%
Other Charges (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Cost of Power Commodity (kWh)	800	$ 0.0580	$ 46.40	800	$ 0.0580	$ 46.40	$ -	0.00%	21.98%
Cost of Power Commodity (kWh)	1,321	$ 0.0670	$ 88.52	1,321	$ 0.0670	$ 88.52	$ -	0.00%	41.93%
Total Bill before Taxes			**$ 225.24**			**$ 211.12**	**$ (14.12)**	**-6.27%**	**100%**
GST (6%)			**$ 13.51**			**$ 12.67**	**$ (0.85)**	**-6.27%**	
Total Bill after Taxes			**$ 238.75**			**$ 223.79**	**$ (14.96)**	**-6.27%**	

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

General Service Less Than 50 kW

Consumption 1,000 kWh 0 kW **Loss Factor 1.0606**

	2007 BILL			2008 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			$ 31.17			$ 40.57	$ 9.40	30.16%	31.59%
Distribution (kWh)	1,000	$ 0.0085	$ 8.50	1,000	$ 0.0111	$ 11.10	$ 2.6000	30.59%	8.64%
Distribution (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Regulatory Assets (kWh)	1,000	-$ 0.0001	-$ 0.10	1,000	-$ 0.0029	-$ 2.90	$ (2.80)	2800.00%	-2.26%
Regulatory Assets (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Sub-Total			**$ 39.57**			**$ 48.77**	**$ 9.20**	**23.25%**	**37.98%**
Other Charges (kWh)	1061	$ 0.0222	$ 23.55	1061	$ 0.0171	$ 18.14	$ (5.41)	-22.97%	14.12%
Other Charges (kW)	0	$ -	$ -	0		$ -	$ -	0.00%	0.00%
Cost of Power Commodity (kWh)	1,061	$ 0.0580	$ 61.51	1,061	$ 0.0580	$ 61.51	$ -	0.00%	47.90%
Cost of Power Commodity (kWh)	0	$ 0.0670	$ -	0	$ 0.0670	$ -	$ -	0.00%	0.00%
Total Bill before Taxes			**$ 124.63**			**$ 128.42**	**$ 3.79**	**3.04%**	**100%**
GST (6%)			**$ 7.48**			**$ 7.71**	**$ 0.23**	**3.04%**	
Total Bill after Taxes			**$ 132.11**			**$ 136.13**	**$ 4.02**	**3.04%**	

General Service Less Than 50 kW

Consumption 2,000 kWh 0 kW **Loss Factor 1.0606**

	2007 BILL			2008 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			$ 31.17			$ 40.57	$ 9.40	30.16%	17.63%
Distribution (kWh)	2,000	$ 0.0085	$ 17.00	2,000	$ 0.0111	$ 22.20	$ 5.2000	30.59%	9.65%
Distribution (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Regulatory Assets (kWh)	2,000	-$ 0.0001	-$ 0.20	2,000	-$ 0.0029	-$ 5.80	$ (5.60)	2800.00%	-2.52%
Regulatory Assets (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Sub-Total			**$ 47.97**			**$ 56.97**	**$ 9.00**	**18.76%**	**24.76%**
Other Charges (kWh)	2121	$ 0.0222	$ 47.09	2121	$ 0.0178	$ 37.76	$ (9.33)	-19.82%	16.41%
Other Charges (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Cost of Power Commodity (kWh)	750	$ 0.0580	$ 43.50	750	$ 0.0580	$ 43.50	$ -	0.00%	18.91%
Cost of Power Commodity (kWh)	1,371	$ 0.0670	$ 91.87	1,371	$ 0.0670	$ 91.87	$ -	0.00%	39.93%
Total Bill before Taxes			**$ 230.43**			**$ 230.10**	**$ (0.33)**	**-0.14%**	**100%**
GST (6%)			**$ 13.83**			**$ 13.81**	**$ (0.02)**	**-0.14%**	
Total Bill after Taxes			**$ 244.26**			**$ 243.90**	**$ (0.35)**	**-0.14%**	

General Service Less Than 50 kW

Consumption 10,000 kWh 0 kW **Loss Factor 1.0606**

	2007 BILL			2008 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			$ 31.17			$ 40.57	$ 9.40	30.16%	4.00%
Distribution (kWh)	10,000	$ 0.0085	$ 85.00	10,000	$ 0.0111	$ 111.00	$ 26.0000	30.59%	10.93%
Distribution (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Regulatory Assets (kWh)	10,000	-$ 0.0001	-$ 1.00	10,000	-$ 0.0029	-$ 29.00	$ (28.00)	2800.00%	-2.86%
Regulatory Assets (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Sub-Total			**$ 115.17**			**$ 122.57**	**$ 7.40**	**6.43%**	**12.07%**
Other Charges (kWh)	10606	$ 0.0222	$ 235.45	10606	$ 0.0178	$ 188.79	$ (46.67)	-19.82%	18.60%
Other Charges (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Cost of Power Commodity (kWh)	750	$ 0.0580	$ 43.50	750	$ 0.0580	$ 43.50	$ -	0.00%	4.28%
Cost of Power Commodity (kWh)	9,856	$ 0.0670	$ 660.35	9,856	$ 0.0670	$ 660.35	$ -	0.00%	65.05%
Total Bill before Taxes			**$ 1,054.48**			**$ 1,015.21**	**$ (39.27)**	**-3.72%**	**100%**
GST (6%)			**$ 63.27**			**$ 60.91**	**$ (2.36)**	**-3.72%**	
Total Bill after Taxes			**$ 1,117.74**			**$ 1,076.12**	**$ (41.62)**	**-3.72%**	

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

General Service 50 to 4,999 kW

Consumption 5,000 kWh 50 kW ***Loss Factor 1.0606***

	2007 BILL			2008 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			$ 152.82			$ 227.03	$ 74.21	48.56%	28.99%
Distribution (kWh)	5,000	$ -	$ -	5,000	$ -	$ -	$ -	0.00%	0.00%
Distribution (kW)	50	**$ 1.2099**	$ 60.50	50	$ 1.7988	$ 89.94	$ 29.45	48.67%	11.49%
Regulatory Assets (kWh)	5,000	$ -	$ -	5,000	$ -	$ -	$ -	0.00%	0.00%
Regulatory Assets (kW)	50	-$ 0.2732	-$ 13.66	50	-$ 1.0606	-$ 53.03	$ (39.37)	288.21%	-6.77%
Sub-Total			**$ 199.66**			**$ 263.94**	**$ 64.29**	**32.20%**	**33.71%**
Other Charges (kWh)	5303	$ 0.0132	$ 70.00	5303	$ 0.0121	$ 64.17	$ (5.83)	-8.33%	8.19%
Other Charges (kW)	53	$ 3.6186	$ 191.89	53	$ 2.0061	$ 106.38	$ (85.51)	-44.56%	13.59%
Cost of Power Commodity (kWh)	750	$ 0.0580	$ 43.50	750	$ 0.0580	$ 43.50	$ -	0.00%	5.56%
Cost of Power Commodity (kWh)	4,553	$ 0.0670	$ 305.05	4,553	$ 0.0670	$ 305.05	$ -	0.00%	38.96%
Total Bill before Taxes			**$ 810.10**			**$ 783.04**	**$ (27.06)**	**-3.34%**	**100%**
GST (6%)			**$ 48.61**			**$ 46.98**	**$ (1.62)**	**-3.34%**	
Total Bill after Taxes			**$ 858.71**			**$ 830.02**	**$ (28.68)**	**-3.34%**	

General Service 50 to 4,999 kW

Consumption 210 kWh 65 kW ***Loss Factor 1.0606***

	2007 BILL			2008 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			$ 152.82			$ 227.03	$ 74.21	48.56%	53.52%
Distribution (kWh)	210	$ -	$ -	210	$ -	$ -	$ -	0.00%	0.00%
Distribution (kW)	65	**$ 1.2099**	$ 78.64	65	$ 1.7988	$ 116.92	$ 38.28	48.67%	27.56%
Regulatory Assets (kWh)	210	$ -	$ -	210	$ -	$ -	$ -	0.00%	0.00%
Regulatory Assets (kW)	65	-$ 0.2732	-$ 17.76	65	-$ 1.0606	-$ 68.94	$ (51.18)	288.21%	-16.25%
Sub-Total			**$ 213.71**			**$ 275.01**	**$ 61.31**	**28.69%**	**64.83%**
Other Charges (kWh)	223	$ 0.0132	$ 2.94	223	$ 0.0121	$ 2.69	$ (0.24)	-8.33%	0.64%
Other Charges (kW)	69	$ 3.6186	$ 249.46	69	$ 2.0061	$ 138.30	$ (111.16)	-44.56%	32.60%
Cost of Power Commodity (kWh)	750	$ 0.0580	$ 43.50	750	$ 0.0580	$ 43.50	$ -	0.00%	10.26%
Cost of Power Commodity (kWh)	-527	$ 0.0670	-$ 35.33	-527	$ 0.0670	-$ 35.33	$ -	0.00%	-8.33%
Total Bill before Taxes			**$ 474.28**			**$ 424.18**	**$ (50.10)**	**-10.56%**	**100%**
GST (6%)			**$ 28.46**			**$ 25.45**	**$ (3.01)**	**-10.56%**	
Total Bill after Taxes			**$ 502.74**			**$ 449.63**	**$ (53.11)**	**-10.56%**	

General Service 50 to 4,999 kW

Consumption 100,000 kWh 500 kW ***Loss Factor 1.0606***

	2007 BILL			2008 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			$ 152.82			$ 227.03	$ 74.21	48.56%	2.26%
Distribution (kWh)	100,000	$ -	$ -	100,000	$ -	$ -	$ -	0.00%	0.00%
Distribution (kW)	500	**$ 1.2099**	$ 604.95	500	$ 1.7988	$ 899.40	$ 294.45	48.67%	8.96%
Regulatory Assets (kWh)	100,000	$ -	$ -	100,000	$ -	$ -	$ -	0.00%	0.00%
Regulatory Assets (kW)	500	-$ 0.2732	-$ 136.60	500	-$ 1.0606	-$ 530.30	$ (393.70)	288.21%	-5.28%
Sub-Total			**$ 621.17**			**$ 596.13**	**-$ 25.04**	**-4.03%**	**5.94%**
Other Charges (kWh)	106060	$ 0.0132	$ 1,399.99	106060	$ 0.0121	$ 1,283.33	$ (116.67)	-8.33%	12.78%
Other Charges (kW)	530	$ 3.6186	$ 1,918.94	530	$ 2.0061	$ 1,063.83	$ (855.11)	-44.56%	10.59%
Cost of Power Commodity (kWh)	750	$ 0.0580	$ 43.50	750	$ 0.0580	$ 43.50	$ -	0.00%	0.43%
Cost of Power Commodity (kWh)	105,310	$ 0.0670	$ 7,055.77	105,310	$ 0.0670	$ 7,055.77	$ -	0.00%	70.26%
Total Bill before Taxes			**$ 11,039.38**			**$ 10,042.56**	**$ (996.81)**	**-9.03%**	**100%**
GST (6%)			**$ 662.36**			**$ 602.55**	**$ (59.81)**	**-9.03%**	
Total Bill after Taxes			**$ 11,701.74**			**$ 10,645.11**	**$ (1,056.62)**	**-9.03%**	

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

General Service 50 to 4,999 kW

Consumption 400,000 kWh / 500 kW **Loss Factor 1.0606**

	2007 BILL			2008 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			$ 152.82			$ 227.03	$ 74.21	48.56%	0.64%
Distribution (kWh)	400,000	$ -	$ -	400,000	$ -	$ -	$ -	0.00%	0.00%
Distribution (kW)	500	**$ 1.2099**	$ 604.95	500	$ 1.7988	$ 899.40	$ 294.45	48.67%	2.55%
Regulatory Assets (kWh)	400,000	$ -	$ -	400,000	$ -	$ -	$ -	0.00%	0.00%
Regulatory Assets (kW)	500	-$ 0.2732	-$ 136.60	500	-$ 1.0606	-$ 530.30	$ (393.70)	288.21%	-1.51%
Sub-Total			**$ 621.17**			**$ 596.13**	**-$ 25.04**	**-4.03%**	**1.69%**
Other Charges (kWh)	424240	$ 0.0132	$ 5,599.97	424240	$ 0.0121	$ 5,133.30	$ (466.66)	-8.33%	14.58%
Other Charges (kW)	530	$ 3.6186	$ 1,918.94	530	$ 2.0061	$ 1,063.83	$ (855.11)	-44.56%	3.02%
Cost of Power Commodity (kWh)	750	$ 0.0580	$ 43.50	750	$ 0.0580	$ 43.50	$ -	0.00%	0.12%
Cost of Power Commodity (kWh)	423,490	$ 0.0670	$ 28,373.83	423,490	$ 0.0670	$ 28,373.83	$ -	0.00%	80.58%
Total Bill before Taxes			**$ 36,557.41**			**$ 35,210.60**	**$ (1,346.81)**	**-3.68%**	**100%**
GST (6%)			**$ 2,193.44**			**$ 2,112.64**	**$ (80.81)**	**-3.68%**	
Total Bill after Taxes			**$ 38,750.86**			**$ 37,323.23**	**$ (1,427.62)**	**-3.68%**	

Unmetered Scattered Load

Consumption 100 kWh / kW **Loss Factor 1.0606**

	2007 BILL			2008 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			$ 15.46			$ 20.17	$ 4.71	30.47%	69.66%
Distribution (kWh)	100	$ 0.0085	$ 0.85	100	$ 0.0111	$ 1.11	$ 0.2600	30.59%	3.83%
Distribution (kW)	0	**$ -**	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Regulatory Assets (kWh)	100	-$ 0.0001	-$ 0.01	100	-$ 0.0029	-$ 0.29	$ (0.28)	2800.00%	-1.00%
Regulatory Assets (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Sub-Total			**$ 16.30**			**$ 20.99**	**$ 4.69**	**28.77%**	**72.49%**
Other Charges (kWh)	106	$ 0.0222	$ 2.35	106	$ 0.0171	$ 1.81	$ (0.54)	-22.97%	6.26%
Other Charges (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Cost of Power Commodity (kWh)	106	$ 0.0580	$ 6.15	106	$ 0.0580	$ 6.15	$ -	0.00%	21.24%
Cost of Power Commodity (kWh)	0	$ 0.0670	$ -	0	$ 0.0670	$ -	$ -	0.00%	0.00%
Total Bill before Taxes			**$ 24.81**			**$ 28.96**	**$ 4.15**	**16.73%**	**100%**
GST (6%)			**$ 1.49**			**$ 1.74**	**$ 0.25**	**16.73%**	
Total Bill after Taxes			**$ 26.29**			**$ 30.69**	**$ 4.40**	**16.73%**	

Unmetered Scattered Load

Consumption 200 kWh / 0 kW **Loss Factor 1.0606**

	2007 BILL			2008 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			$ 15.46			$ 20.17	$ 4.71	30.47%	53.44%
Distribution (kWh)	200	$ 0.0085	$ 1.70	200	$ 0.0111	$ 2.22	$ 0.5200	30.59%	5.88%
Distribution (kW)	0	**$ -**	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Regulatory Assets (kWh)	200	-$ 0.0001	-$ 0.02	200	-$ 0.0029	-$ 0.58	$ (0.56)	2800.00%	-1.54%
Regulatory Assets (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Sub-Total			**$ 17.14**			**$ 21.81**	**$ 4.67**	**27.25%**	**57.79%**
Other Charges (kWh)	212	$ 0.0222	$ 4.71	212	$ 0.0171	$ 3.63	$ (1.08)	-22.97%	9.61%
Other Charges (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Cost of Power Commodity (kWh)	212	$ 0.0580	$ 12.30	212	$ 0.0580	$ 12.30	$ -	0.00%	32.60%
Cost of Power Commodity (kWh)	0	$ 0.0670	$ -	0	$ 0.0670	$ -	$ -	0.00%	0.00%
Total Bill before Taxes			**$ 34.15**			**$ 37.74**	**$ 3.59**	**10.51%**	**100%**
GST (6%)			**$ 2.05**			**$ 2.26**	**$ 0.22**	**10.51%**	
Total Bill after Taxes			**$ 36.20**			**$ 40.00**	**$ 3.80**	**10.51%**	

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

Unmetered Scattered Load

Consumption 1,000 kWh / 0 kW ***Loss Factor 1.0606***

	2007 BILL			2008 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			$ 15.46			$ 20.17	$ 4.71	30.47%	18.20%
Distribution (kWh)	1,000	$ 0.0085	$ 8.50	1,000	$ 0.0111	$ 11.10	$ 2.6000	30.59%	10.02%
Distribution (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Regulatory Assets (kWh)	1,000	-$ 0.0001	-$ 0.10	1,000	-$ 0.0029	-$ 2.90	$ (2.80)	2800.00%	-2.62%
Regulatory Assets (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Sub-Total			**$ 23.86**			**$ 28.37**	**$ 4.51**	**18.90%**	**25.60%**
Other Charges (kWh)	1061	$ 0.0222	$ 23.55	1061	$ 0.0171	$ 18.14	$ (5.41)	-22.97%	16.37%
Other Charges (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Cost of Power Commodity (kWh)	750	$ 0.0580	$ 43.50	750	$ 0.0580	$ 43.50	$ -	0.00%	39.25%
Cost of Power Commodity (kWh)	311	$ 0.0670	$ 20.81	311	$ 0.0670	$ 20.81	$ -	0.00%	18.78%
Total Bill before Taxes			**$ 111.72**			**$ 110.82**	**$ (0.90)**	**-0.80%**	**100%**
GST (6%)			**$ 6.70**			**$ 6.65**	**$ (0.05)**	**-0.80%**	
Total Bill after Taxes			**$ 118.42**			**$ 117.47**	**$ (0.95)**	**-0.80%**	

Sentinel Lighting

Consumption 222 kWh / 0.6 kW ***Loss Factor 1.0606***

	2007 BILL			2008 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			$ 2.65			$ 4.42	$ 1.77	66.79%	17.66%
Distribution (kWh)	222	$ -	$ -	222	$ -	$ -	$ -	0.00%	0.00%
Distribution (kW)	0.6	**$ 3.7484**	$ 2.25	0.6	$ 6.2544	$ 3.75	$ 1.50	66.86%	14.99%
Regulatory Assets (kWh)	222	$ -	$ -	222	$ -	$ -	$ -	0.00%	0.00%
Regulatory Assets (kW)	0.6	$ 3.0482	$ 1.83	0.6	-$ 1.0406	-$ 0.62	$ (2.45)	-134.14%	-2.49%
Sub-Total			**$ 6.73**			**$ 7.55**	**$ 0.82**	**12.19%**	**30.15%**
Other Charges (kWh)	235	$ 0.0132	$ 3.11	235	$ 0.0121	$ 2.85	$ (0.26)	-8.33%	11.38%
Other Charges (kW)	1	$ 2.7987	$ 1.78	1	$ 1.5415	$ 0.98	$ (0.80)	-44.92%	3.92%
Cost of Power Commodity (kWh)	235	$ 0.0580	$ 13.66	235	$ 0.0580	$ 13.66	$ -	0.00%	54.55%
Cost of Power Commodity (kWh)	0	$ 0.0670	$ -	0	$ 0.0670	$ -	$ -	0.00%	0.00%
Total Bill before Taxes			**$ 25.27**			**$ 25.03**	**$ (0.24)**	**-0.94%**	**100%**
GST (6%)			**$ 1.52**			**$ 1.50**	**$ (0.01)**	**-0.94%**	
Total Bill after Taxes			**$ 26.79**			**$ 26.54**	**$ (0.25)**	**-0.94%**	

Sentinel Lighting

Consumption 865 kWh / 2.3 kW ***Loss Factor 1.0606***

	2007 BILL			2008 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			$ 2.65			$ 4.42	$ 1.77	66.79%	5.14%
Distribution (kWh)	865	$ -	$ -	865	$ -	$ -	$ -	0.00%	0.00%
Distribution (kW)	2.3	**$ 3.7484**	$ 8.62	2.3	$ 6.2544	$ 14.39	$ 5.76	66.86%	16.73%
Regulatory Assets (kWh)	865	$ -	$ -	865	$ -	$ -	$ -	0.00%	0.00%
Regulatory Assets (kW)	2.3	$ 3.0482	$ 7.01	2.3	-$ 1.0406	-$ 2.39	$ (9.40)	-134.14%	-2.78%
Sub-Total			**$ 18.28**			**$ 16.41**	**-$ 1.87**	**-10.23%**	**19.09%**
Other Charges (kWh)	917	$ 0.0132	$ 12.11	917	$ 0.0121	$ 11.10	$ (1.01)	-8.33%	12.91%
Other Charges (kW)	2	$ 2.7987	$ 6.83	2	$ 1.5415	$ 3.76	$ (3.07)	-44.92%	4.37%
Cost of Power Commodity (kWh)	750	$ 0.0580	$ 43.50	750	$ 0.0580	$ 43.50	$ -	0.00%	50.59%
Cost of Power Commodity (kWh)	167	$ 0.0670	$ 11.22	167	$ 0.0670	$ 11.22	$ -	0.00%	13.04%
Total Bill before Taxes			**$ 91.94**			**$ 85.99**	**$ (5.95)**	**-6.47%**	**100%**
GST (6%)			**$ 5.52**			**$ 5.16**	**$ (0.36)**	**-6.47%**	

Total Bill after Taxes	**$ 97.45**		**$ 91.15**	**$ (6.30)**	**-6.47%**	

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170

EDR File Number: EB-2005-0349

Cost Allocation File Number: EB-2007-0001

Sentinel Lighting

Consumption 2,000 kWh / 5 kW — **Loss Factor 1.0606**

	2007 BILL			2008 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			$ 2.65			$ 4.42	$ 1.77	66.79%	2.21%
Distribution (kWh)	2,000	$ -	$ -	2,000	$ -	$ -	$ -	0.00%	0.00%
Distribution (kW)	5	**$ 3.7484**	$ 18.74	5	$ 6.2544	$ 31.27	$ 12.53	66.86%	15.66%
Regulatory Assets (kWh)	2,000	$ -	$ -	2,000	$ -	$ -	$ -	0.00%	0.00%
Regulatory Assets (kW)	5	$ 3.0482	$ 15.24	5	-$ 1.0406	-$ 5.20	$ (20.44)	-134.14%	-2.61%
Sub-Total			**$ 36.63**			**$ 30.49**	**-$ 6.14**	**-16.77%**	**15.27%**
Other Charges (kWh)	2121	$ 0.0132	$ 28.00	2121	$ 0.0121	$ 25.67	$ (2.33)	-8.33%	12.85%
Other Charges (kW)	5	$ 2.7987	$ 14.84	5	$ 1.5415	$ 8.17	$ (6.67)	-44.92%	4.09%
Cost of Power Commodity (kWh)	750	$ 0.0580	$ 43.50	750	$ 0.0580	$ 43.50	$ -	0.00%	21.78%
Cost of Power Commodity (kWh)	1,371	$ 0.0670	$ 91.87	1,371	$ 0.0670	$ 91.87	$ -	0.00%	46.00%
Total Bill before Taxes			**$ 214.84**			**$ 199.70**	**$ (15.14)**	**-7.05%**	**100%**
GST (6%)			**$ 12.89**			**$ 11.98**	**$ (0.91)**	**-7.05%**	
Total Bill after Taxes			**$ 227.74**			**$ 211.68**	**$ (16.05)**	**-7.05%**	

Street Lighting

Consumption 865 kWh / 2.3 kW — **Loss Factor 1.0606**

	2007 BILL			2008 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			$ 0.80			$ 1.50	$ 1.50	187.50%	1.90%
Distribution (kWh)	865	$ -	$ -	865	$ -	$ -	$ -	0.00%	0.00%
Distribution (kW)	2	**$ 2.4286**	$ 5.59	2	$ 4.5435	$ 10.45	$ 4.86	87.08%	13.23%
Regulatory Assets (kWh)	865	$ -	$ -	865	$ -	$ -	$ -	0.00%	0.00%
Regulatory Assets (kW)	2	$ 0.0178	$ 0.04	2	-$ 1.0884	-$ 2.50	$ (2.54)	-6214.61%	-3.17%
Sub-Total			**$ 6.43**			**$ 9.45**	**$ 3.82**	**59.44%**	**11.96%**
Other Charges (kWh)	917	$ 0.0132	$ 12.11	917	$ 0.0121	$ 11.10	$ (1.01)	-8.33%	14.05%
Other Charges (kW)	2	$ 2.7628	$ 6.74	2	$ 1.5255	$ 3.72	$ (3.02)	-44.78%	4.71%
Cost of Power Commodity (kWh)	750	$ 0.0580	$ 43.50	750	$ 0.0580	$ 43.50	$ -	0.00%	55.07%
Cost of Power Commodity (kWh)	167	$ 0.0670	$ 11.22	167	$ 0.0670	$ 11.22	$ -	0.00%	14.20%
Total Bill before Taxes			**$ 79.99**			**$ 78.99**	**$ (0.21)**	**-0.26%**	**100%**
GST (6%)			**$ 4.80**			**$ 4.74**	**$ (0.06)**	**-1.26%**	
Total Bill after Taxes			**$ 84.79**			**$ 83.72**	**$ (1.07)**	**-1.26%**	

Street Lighting

Consumption 24,500 kWh / 65 kW — **Loss Factor 1.0606**

	2007 BILL			2008 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			$ 272.80			$ 511.50	$ 238.70	87.50%	17.70%
Distribution (kWh)	24,500	$ -	$ -	24,500	$ -	$ -	$ -	0.00%	0.00%
Distribution (kW)	65	**$ 2.4286**	$ 157.86	65	$ 4.5435	$ 295.33	$ 137.47	87.08%	10.22%
Regulatory Assets (kWh)	24,500	$ -	$ -	24,500	$ -	$ -	$ -	0.00%	0.00%
Regulatory Assets (kW)	65	$ 0.0178	$ 1.16	65	-$ 1.0884	-$ 70.75	$ (71.90)	-6214.61%	-2.45%
Sub-Total			**$ 431.82**			**$ 736.08**	**$ 304.27**	**70.46%**	**25.47%**
Other Charges (kWh)	25985	$ 0.0132	$ 343.00	25985	$ 0.0121	$ 314.41	$ (28.58)	-8.33%	10.88%
Other Charges (kW)	69	$ 2.7628	$ 190.46	69	$ 1.5255	$ 105.17	$ (85.30)	-44.78%	3.64%
Cost of Power Commodity (kWh)	750	$ 0.0580	$ 43.50	750	$ 0.0580	$ 43.50	$ -	0.00%	1.51%
Cost of Power Commodity (kWh)	25,235	$ 0.0670	$ 1,690.72	25,235	$ 0.0670	$ 1,690.72	$ -	0.00%	58.50%
Total Bill before Taxes			**$ 2,699.50**			**$ 2,889.89**	**$ 190.38**	**7.05%**	**100%**
GST (6%)			**$ 161.97**			**$ 173.39**	**$ 11.42**	**7.05%**	
Total Bill after Taxes			**$ 2,861.47**			**$ 3,063.28**	**$ 201.81**	**7.05%**	

Appendix I

Informational Filing

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Chapleau Public Utilities Corporation	**LICENCE NUMBER**	ED-2002-0528
NAME OF CONTACT	Marita Morin	**DOCID NUMBER**	EB-2007-0755
E-mail Address	chec@onlink.net		
VERSION NUMBER	v3.0	**PHONE NUMBER**	705-864-0111
Date	14-Feb-08	**(extension)**	

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	$ 21,747	$ 8,917				$ 30,663	$ 2,069	$ 72	$ 2,140
RSVA - One-time Wholesale Market Service	1582						$ -			$ -
RSVA - Retail Transmission Network Charge	1584	$ (37,073)	$ (25,220)		$ (2,614)		$ (64,907)	$ 68	$ (149)	$ (81)
RSVA - Retail Transmission Connection Charge	1586	$ (262,237)	$ (77,117)		$ 139,661		$ (199,693)	$ (3,555)	$ (487)	$ (4,042)
Sub-Totals		$ (277,564)	$ (93,421)		$ 137,047	$ -	$ (233,937)	$ (1,419)	$ (564)	$ (1,982)
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 1,014	$ 2,813				$ 3,827	$ 15	$ 126	$ 141
Other Regulatory Assets - Sub-Account - Pension Contributions	1508		$ 25,873				$ 25,873			$ -
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						$ -			$ -
Retail Cost Variance Account - STR	1548						$ -			$ -
Misc. Deferred Debits	1525		$ 5,553				$ 5,553		$ 12	$ 12
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 Me	1555						$ -			$ -
Smart Meter OM&A Variance	1556						$ -			$ -
Conservation and Demand Management Expenditures and Recoveries	1565		$ 1,738				$ 1,738		$ 49	$ 49
CDM Contra	1566						$ -			$ -
Qualifying Transition Costs [5]	1570	$ 54,717	n/a	n/a			$ 54,717		$ 3,967	$ 3,967
Pre-Market Opening Energy Variances Total [5]	1571	$ (42,084)	n/a	n/a			$ (42,084)	$ (6,119)	$ (3,051)	$ (9,170)
Extra-Ordinary Event Costs	1572						$ -			$ -
Deferred Rate Impact Amounts	1574						$ -			$ -
Other Deferred Credits	2425						$ -			$ -
Sub-Totals		$ 13,647	$ 35,978	$ -	$ -	$ -	$ 49,625	$ (6,104)	$ 1,103	$ (5,002)
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		$ (263,917)	$ (57,443)	$ -	$ 137,047	$ -	$ (184,312)	$ (7,523)	$ 539	$ (6,984)
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	$ (8,568)	$ (19,175)				$ (27,743)	$ 4,520	$ 695	$ 5,215
RSVA - Power - Sub-Account - Global Adjustment [4]	1588	$ -	$ (4,923)				$ (4,923)	$ -	$ (654)	$ (654)
Recovery of Regulatory Asset Balances	1590	$ (13,197)	$ (32,805)				$ (46,002)	$ (262)	$ (2,066)	$ (2,328)

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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	Chapleau Public Utilities Corporation
NAME OF CONTACT	Marita Morin
E-mail Address	chec@onlink.net
VERSION NUMBER	v3.0
Date	14-Feb-08

		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	$ 30,663	$ (32,175)				$ (21,747)	$ (23,259)	$ 2,140	$ (662)	$ (4,168)	$ (2,690)
RSVA - One-time Wholesale Market Service	1582	$ -	$ -		$ -			$ -	$ -	$ -	$ -	$ -
RSVA - Retail Transmission Network Charge	1584	$ (64,907)	$ (3,228)				$ 39,687	$ (28,448)	$ (81)	$ (925)	$ 3,714	$ 2,709
RSVA - Retail Transmission Connection Charge	1586	$ (199,693)	$ (83,807)				$ 122,576	$ (160,924)	$ (4,042)	$ (50,345)	$ 17,967	$ (36,420)
Sub-Totals		$ (233,937)	$ (119,210)		$ -	$ -	$ 140,516	$ (212,631)	$ (1,982)	$ (51,931)	$ 17,513	$ (36,401)
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 3,827	$ 2,355			$ (1,660)	$ (1,014)	$ 3,508	$ 141	$ 125	$ (15)	$ 251
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ 25,873	$ 18,113			$ (26,664)		$ 17,323	$ -	$ 927		$ 927
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	$ -						$ -	$ -			$ -
Retail Cost Variance Account - STR	1548	$ -						$ -	$ -			$ -
Misc. Deferred Debits	1525	$ 5,553				$ (904)	$ (4,649)	$ -	$ 12	$ 351	$ (363)	$ -
LV Variance Account	1550	$ -	$ 13,195		$ -			$ 13,195	$ -	$ 119	$ -	$ 119
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555	$ -						$ -	$ -			$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555	$ -	$ (2,419)					$ (2,419)	$ -	$ (51)		$ (51)
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Me	1555	$ -						$ -	$ -			$ -
Smart Meter OM&A Variance	1556	$ -						$ -	$ -			$ -
Conservation and Demand Management Expenditures and Recoveries	1565	$ 1,738	$ 2,221					$ 3,960	$ 49	$ 140		$ 189
CDM Contra	1566	$ -						$ -	$ -			$ -
Qualifying Transition Costs [5]	1570	$ 54,717	n/a	n/a			$ (54,717)	$ -	$ 3,967	$ 1,317	$ (5,284)	$ 0
Pre-Market Opening Energy Variances Total [5]	1571	$ (42,084)	n/a	n/a			$ 42,084	$ -	$ (9,170)	$ 3,051	$ 6,119	$ -
Extra-Ordinary Event Costs	1572	$ -						$ -	$ -			$ -
Deferred Rate Impact Amounts	1574	$ -						$ -	$ -			$ -
Other Deferred Credits	2425	$ -						$ -	$ -			$ -
Sub-Totals		$ 49,625	$ 33,465	$ -	$ -	$ (29,227)	$ (18,296)	$ 35,567	$ (5,002)	$ 5,979	$ 457	$ 1,434
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		$ (184,312)	$ (85,745)	$ -	$ -	$ (29,227)	$ 122,220	$ (177,065)	$ (6,984)	$ (45,952)	$ 17,970	$ (34,967)
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	$ (27,743)	$ (20,155)				$ 8,568	$ (39,330)	$ 5,215	$ 3,827	$ (3,693)	$ 5,349
RSVA - Power - Sub-Account - Global Adjustment [4]	1588	$ (4,923)	$ 20,722					$ 15,799	$ (654)	$ (15)		$ (669)
Recovery of Regulatory Asset Balances	1590	$ (46,002)	$ (17,500)				$ 52,886	$ (10,617)	$ (2,328)	$ (6,343)	$ (18,943)	$ (27,614)

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Chapleau Public Utilities Corporation
NAME OF CONTACT	Marita Morin
E-mail Address	chec@onlink.net
VERSION NUMBER	v3.0
Date	14-Feb-08

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	$ (1,068)	$ (356)	$ (27,372)	$ (32,094)	$ (12,665)	$ (1,339)	$ (45)	$ (73,515)
RSVA - One-time Wholesale Market Service	1582	$ -	$ -	$ -	$ -	$ -	$ -		$ -
RSVA - Retail Transmission Network Charge	1584	$ (1,306)	$ (435)	$ (27,480)	$ 4,641	$ (6,338)	$ 255	$ (33)	$ (28,956)
RSVA - Retail Transmission Connection Charge	1586	$ (7,386)	$ (2,462)	$ (207,193)	$ (89,711)	$ (39,147)	$ (3,570)	$ (207)	$ (339,828)
Sub-Totals		$ (9,760)	$ (3,253)	$ (262,045)	$ (117,165)	$ (58,150)	$ (4,654)	$ (286)	$ (442,299)
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 161	$ 54	$ 3,973	$ -	$ -	$ (77)		$ 3,896
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ 795	$ 265	$ 19,310	$ -	$ -	$ (241)		$ 19,069
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			$ -					$ -
Retail Cost Variance Account - STR	1548			$ -					$ -
Misc. Deferred Debits	1525			$ -					$ -
LV Variance Account	1550	$ 606	$ 202	$ 14,121	$ 36,947	$ 15,743	$ 1,445	$ 81	$ 68,338
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555			$ -					$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555	$ (111)	$ (37)	$ (2,618)	$ (4,187)	$ (1,396)	$ (221)	$ (13)	$ (8,436)
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Me	1555			$ -					$ -
Smart Meter OM&A Variance	1556			$ -					$ -
Conservation and Demand Management Expenditures and Recoveries	1565	$ 182	$ 61	$ 4,391	$ (25,819)	$ 10,000	$ (4,326)	$ -	$ (15,754)
CDM Contra	1566			$ -					$ -
Qualifying Transition Costs [5]	1570			$ 0					$ 0
Pre-Market Opening Energy Variances Total [5]	1571			$ -					$ -
Extra-Ordinary Event Costs	1572			$ -					$ -
Deferred Rate Impact Amounts	1574			$ -					$ -
Other Deferred Credits	2425			$ -					$ -
Sub-Totals		$ 1,633	$ 544	$ 39,177	$ 6,940	$ 24,347	$ (3,419)	$ 68	$ 67,114
Deferred Payments in Lieu of Taxes	1562								
2006 PILs & Taxes Variance	1592								
Sub-Totals				$ -					$ -
Total		$ (8,127)	$ (2,709)	$ (222,868)	$ (110,224)	$ (33,802)	$ (8,073)	$ (218)	$ (375,185)
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	$ (1,805)	$ (602)	$ (36,389)	$ (16,366)	$ (13,484)	$ (1,821)	$ 285	$ (67,775)
RSVA - Power - Sub-Account - Global Adjustment [4]	1588	$ 725	$ 242	$ 16,097					$ 16,097
Recovery of Regulatory Asset Balances	1590	$ 2,807	$ (162)	$ (35,586)	$ 44,538	$ (1,350)	$ 4,874	$ (14)	$ 12,462

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