Chapleau Public Utilities Corporation (CPUC)
2008 Electricity Rate Application
Board File No. EB-2007-0755

VECC's Interrogatories

Question #1

Reference: i) Exhibit 1, page 14
ii) Appendix A, page 6 of 10

a) Does CPUC provide any services to or share any of its resources with the Affiliate? If so, please indicate what the they are and provide a schedule that sets out:

- The revenues received by CPUC for each service in 2006 (actual), 2007, and 2008,
- A description as to how the cost of each service is determined, and
- Where in the current Application these revenues are accounted for.

Response

Please refer to replies to Board Staff Interrogatories #4 – Purchase of Services or Products and #5 Shared Services. There are no revenues to account for.

Question #2

Reference: i) Exhibit 1, page 19

a) In its Application, CPUC states that allowing it to recover its required distribution revenue requirement will enable it to refund to customers the over-collection that has occurred in its RSVA accounts. Please explain this link further. Isn't the purpose of maintaining separate variance accounts for the RSVAs to allow them to be tracked and managed separately from the actual distribution rates?

Response

Please refer to replies to Board Staff Interrogatories # 31, 32, 34, and 40.

b) Please clarify the basis for the 2006 and 2008 average customer use data shown on page 19:

- Is the 2006 data the actual average use for 2006 or the average use for 2006 that was used in the 2006 EDR model?
- How were the 2008 average use figures developed?

Response

The 2006 data is the average use from the 2006 EDR model.
Please refer to replies to Board Staff Interrogatory # 24 for the development of the 2008 use figures.

Question #3

Reference: i) Appendix E, Exhibit 1 Schedules

a) Does CPUC pay proxy "Capital Taxes" and, if yes, where are they accounted for in the Application?

Response

CPUC does not pay proxy capital taxes.

b) Please revise Appendix E, Exhibit 1 (Revenue Sufficiency – Current Base Rates to Continue Schedule) to reflect/show for 2006 (approved) through 2008:

- Rate Base for each year
- Interest costs based on "deemed" debt for each year
- Net income after taxes for each year
- Return on equity achieved (based on deemed capital structure) for each year
- Allowed ROE for each year.

Response

Rate Base for each year can be seen in the amended excel schedule "Exhibit 2 Rate Base".
Interest costs based on "deemed" debt was only determined for Test Year 2008 (see amended excel schedule "Exhibit 2 Rate Base" G228).
CPUC has not paid taxes during this period.
Not able to determine Return on equity achieved (based on deemed capital structure) for each year.
Allowed ROE for each year is in the amended excel schedule "Exhibit 2 Rate Base" line 164.

c) With respect to Appendix E, Exhibit 1(Customer Class Impact Schedule) – please undertake the following:

- Confirm that there is no LV Cost recovery included in CPUC's 2006 or 2007 approved Distribution rates.
- Confirm that the LV Cost recovery is included in the Proposed Distribution Rates (as opposed to through a Rate Rider).
- Provide a schedule that set out 2008 revenue by customer class (fixed and variable) based on 2008 billing quantities and 2007 rates –

excluding approved 2007 Rate Riders and the Smart Meter Rate adder.

- Provide a schedule that set out 2008 revenue by customer class (fixed and variable) based on 2008 billing quantities and proposed 2008 rates – excluding proposed 2008 Rate Riders and the Smart Meter Rate adder.

Response

The table for comparison, has been prepared and is included in the excel schedule "Exhibit 1 (b) Customer Class Impact" at the bottom of the 2nd page.
Please note that the amended 2008 rates are inclusive of Low Voltage rates, revenue of $36,947 is included in revenue requirement and therefore unable to remove from base rates.

Question #4

Reference: i) Exhibit 2, pages 21-22
ii) Appendix D, page 9
iii) Appendix E, Exhibit 2 Schedules

a) Reference (i) suggests that the purpose of the 3 Regulators to be installed in 2008 is "to reduce distribution losses". However, the EnerSpectrum Group Report (Reference (ii)) states that the three regulators "are not attributable to reducing system losses". Please reconcile.

Response

Reference (i) should have read "to balance voltage levels".

b) Please explain why the average cost of a replacement pole increased from $310.20 in 2006 and $312.50 in 2007 to $400 in 2008 (almost 30%).

Response

The cost and quantity used is purely an estimate.

c) Were all capital expenditures for 2006, 2007 and 2008 placed in-service in the year spent? If not, please provide a table setting out the capital spending, capital additions and CWIP for each year.

Response

Yes, all capital expenditures for 2006, 2007 and 2008 were placed in-service in the year spent.

d) Please reconcile the reported $8,402 in 2007 total capital additions with the $9,402 sum of the individual projects (i.e. $6,902 + $2,500).

Response

Capital additions should have read $9,402.

e) Please provide a copy of CPUC's Smart Metering Plan, showing planned annual installation, capital costs and OM&A costs.

Response

Please refer to OEB Board staff Interrogatories, question # 2 and 43.

f) Does CPUC have government approval to proceed with Smart Meter installations? If yes, please provide a copy. If not, when is such approval anticipated?

Response

CPUC does not have government approval to proceed with Smart Meter installations. It is anticipated that approval will be in the current year. Please refer to OEB Board staff Interrogatories, question # 43 (a).

g) Please provide a detailed break down of the planned $29,291 spending on Smart Meters in 2008.

Response

Costs for Propagation Study	***$2,106***
Consulting Services	***$18,000***
Legal for AMI Contracts	***$5,714***
Legal for Installation Contracts	***$1,429***
Legal for old meter recycling contract	***$714***
Contingency	***$1,328***

h) Why are all of the 2008 Smart Meter cost considered to be capital?

Response

2008 Smart Meter costs are considered to be capital because there has been no official ruling yet.

i) Why are all of the Smart Meter costs being included in Rate Base as opposed to being recorded in Deferral/Variance Account #1555 (Smart Meter Capital and Recovery of Offset) which has been established by the OEB for this purpose?

Response

Smart Meter costs are being included in Rate Base because no approved template has been provided.

j) Please explain how CPUC established the Power Purchased, WMS, Network Charges and Connection Charges values for 2007 and 2008 used in the Allowance for Working Capital calculation.

Response

Please refer to OEB Board staff Interrogatories, question # 32.

k) Please reconcile the Low Voltage Expenses reported in Reference (i) for 2006, 2007 and 2008 as part of the Working Capital Allowance calculation with those reported in Appendix E, Exhibit 1.

Response

Please refer to OEB Board staff Interrogatories, question # 27.

l) Please explain why the 2008 Net Fixed Asset value used for Rate Base determination is the year-end value ($908,647) as opposed to the average annual value ($895,939).

Response

To achieve a higher rate base going forward to 2010.

m) Please provide the business case for the 3 Regulators CPUC plans to install in 2008. If the business case is contained in Appendix D, please indicate where in the Appendix the justification can be found.

Response

The 3 Regulators CPUC plans to install in 2008 are to improve year round voltage to within acceptable levels as per CSA standards.

n) Please confirm that CPUC does not own any buildings, computer equipment or software. If it does, where are the assets accounted for in Exhibit 2 (2008 Assets Schedule)?

Response

CPUC confirms that it does not own any buildings, computer equipment or software.

Question #5

Reference: i) Exhibit 3, pages 23-24
ii) Appendix E, Exhibit 3 Schedules

a) Please clarify the basis for the 2008 load forecast by reconciling the following:
- Reference (i) states that the volume forecast for 2008 is an average of the 2006 actual and the 2007 estimates.
- Reference (ii) {Exhibit 3 a – Customer Data Schedule) states that 2008 is an average of 2005, 2006 and 2007.
- Appendix E, Exhibit 9 a) suggests that the load forecast for 2008 is derived based on the projected number of customers for 2008 multiplied by an average use per customer value. The Exhibit also suggests that each customer class' average use per customer value is calculated by "averaging" per customer usage for 2006 and 2007.

Response

Please refer to OEB Board staff Interrogatories, question # 24 and 25.

b) Please explain basis for the Residential customer count (1,177) forecast for 2008.

Response

Please refer to OEB Board staff Interrogatories, question # 25.

c) Appendix D, Exhibit 3 c) {Distribution, Miscellaneous and Other Revenue) includes a line for Other Distribution Revenue – Retailer Charges with value of $1,736 for 2008. In Schedule Exhibit 1 {Revenue Deficiency} the $1,736 is attributed to Retailer Charges and SSS Administration. Please undertake the following:

- Clarify if the $1,736 includes SSS Administration Revenues
- If no, please indicate where these revenues are accounted for and what the values are for 2006 through 2008.
- If yes, please indicate the amount attributable to SSS Administration revenues.
- Please indicate the number of CPUC customers that are expected to pay the SSS Admin in 2008.

Response

The $1,736 does not include SSS Administration Revenues. It is retail service revenue. The $1,736 is included in Other Distribution Revenue – Retailer Charges. The retailer charges for 2006 are $1,381.60 and for 2008 they are estimated at the same as 2007 of $1,735.00. The SSS Administration Revenues are included in account 4080 Distribution Revenue. 2006 SSS amount is $4,918.93, 2007 amount is $4,713.70 and 2008 is estimated at $4,500.00. Approx. 1,310 PUC customers are expected to pay the SSS admin in 2008.

Question #6

Reference: i) Exhibit 4, pages 25-29
ii) Appendix E, Exhibit 4 Schedules

a) What are the major operating and maintenance activities that account the roughly $300,000 in costs annually?

Response

The major operation and maintenance activities that account for the roughly $300,000 in costs annually are: OH Distribution Lines – Labour approximately $100,000 and truck expense of approximately $68,000.

b) Why is 2007 included in the calculation of the loss adjustment factor as opposed to just using actual data?

Response

Please refer to OEB Board staff Interrogatories, question # 26.

Question #7

Reference: i) Exhibit 5, pages 30-32
ii) Appendix E, Exhibit 5 a), b) & c) Schedules

a) Why is there no reference to Account 1555? Where is CPUC recording the revenues it receives from the Smart Meter rate adder of $0.26 / customer / month?

Response

CPUC is recording revenues in account 1555.
Please refer to OEB Board staff Interrogatories, question # 34.

b) CPUC appears to be seeking to dispose of balances in its Regulatory Asset accounts as forecast to April 30, 2008. Why is CPUC seeking to dispose of forecast balances as opposed to using the 2006 actual balances?

Response

Please refer to OEB Board staff Interrogatories, question # 39.

c) Does CPUC pay Transmission charges directly to the IESO or does it pay Hydro One for these services based on Hydro One's retail transmission charges?

Response

As an embedded distributor, CPUC pays both IESO and Hydro One transmission charges. CPUC pays Hydro One directly for Distribution-sub-transmission charges for embedded Wholesale Market Participant.

d) Please indicate how the 12% figure used to adjust the Transmission Network and Connection rates was established. Are the CPUC monthly billing volumes for Line Connection and Transformation Connection the same? If not, what are their relative values?

Response

Please refer to OEB Board staff Interrogatories, question # 31.

Question #8

Reference: i) Exhibit 6, page 33

ii) Appendix E, Exhibit 6 Schedules

a) Why has CPUC not included a short-term debt component in its deemed capital structure, as directed by the OEB in its December 20, 2006 Report of the Board o Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors?

Response

Please refer to OEB Board staff Interrogatories, question # 19 and 22.

b) What is the basis for the proposed 9% ROE?

Response

Please refer to OEB Board staff Interrogatories, question # 22 and 23.

c) Does CPUC acknowledge that the ROE will be updated in January 2008 based on the Board's ROE formula?

Response

Please refer to OEB Board staff Interrogatories, question # 22 and 23.

Question #9

Reference: i) Exhibit 7, page 34

a) Please provide a schedule that sets out the derivation of the $749,633 in revenue shown on page 34.

Response

Please refer to OEB Board staff Interrogatories, question # 23 and new excel worksheets.

b) Throughout the Application there are a number of different values given for 2008 Base Distribution revenues at Proposed Base Rates. Please explain and reconcile the differences between the following values:

- Appendix E, Exhibit 1 (Revenue Sufficiency @ Proposed Base Rates) $680,023
- Appendix E, Exhibit 1 (Customer Class Data) $729,656

(calculated as sum of Base volumetric and fixed revenues plus LV/Wheeling)

- Appendix E, Exhibit 2 $678,911 (Base Revenue Requirement)
- Appendix E, Exhibit 3 c) $723,168 (2008 Distribution Revenues)

Response

The $680,023 is the estimated expected revenue for the 2008, using the old rates from January to April and the new rates from May to December to determine pro forma statements. The distribution revenue of $723,158 is the total revenue before determination of the pro forma revenue (as above).

The Base Revenue Requirement from Exhibit 2 (Appendix E) of $678,911 plus the Transformer Allowance becomes the revenue requirement to determine the new rates as shown in "Exhibit 9 (b) CA Rate Design".

Unable to identify the amount $729,656.

c) Please reconcile the $617,239 in reported in Appendix E, Exhibit 2 as Distribution expense other than PILs and interest with the $617,411 figure reported in Reference (i).

Response

Unable to identify the amounts in question.

d) What are the expected LV costs for 2008? Reference (i) cites a value of $24,631. However, Appendix E, Exhibit 1 (Customer Class Data) cites a value of $36,903.

Response

The Low voltage amount of $24,631 is only for 8 months while the $36,903 is for 12 months.

e) Please confirm whether to following Table correctly sets out CPUC's 2008 proposed Revenue Requirement and revise as necessary explaining any changes.

2008 Revenue Requirement		Source
Operations/Maintenance	$366,697	App. E, Exh 4

and Billing & Collecting		
Depreciation	$36,563	App. E, Exh 2
Administration	$189,520	App. E, Exh 4
LV Charges	$36,903	App. E, Exh 5 a)
Return on Rate Base	$105,863	Exh 7, page 34
Total	$735,546	
Less Other Revenues	$44,981	App. E, Exh 3 c)
Base Distribution Revenue Requirement	$690,565	

Response

The above table has been changed as follows due to board staff interrogatory responses.

2008 Revenue Requirement		***Source***
Operations/Maintenance and Billing & Collecting	***$366,697***	***App. E, Exh 4***
Depreciation	***$36,563***	***App. E, Exh 2***
Administration 1	***$201,125***	***App. E, Exh 4***
LV Charges	***$36,903***	***App. E, Exh 5 a)***
Return on Rate Base 2	***$95,280***	***Exh 7, page 34***
Total	***$736,568***	
Less Other Revenues	***$44,981***	***App. E, Exh 3 c)***
Base Distribution Revenue Requirement	***$691,588***	

1. ***See board staff interrogatory response # 3.***
2. ***See board staff interrogatory response # 23.***

f) Please clarify what overall return on capital CPUC is requesting for 2008 – 8.07% or 10.8%. If the later, what is the basis for this departure from the calculated cost of capital?

Response

Please refer to OEB Board staff Interrogatories, question # 23.

Question #10

Reference: i) Exhibit 8, pages 35-36
ii) Appendix E, Exhibit 8 and 9 Schedules

a) Please provide a copy of Run 2 of CPUC's Cost Allocation informational filing.

Response

Copy of Run 2 of CPUC's Cost Allocation informational Filing is attached.

b) Please explain the source of the $688,519 Test Year Revenue Requirement set out on page 36 of Reference (i). Please provide a schedule that sets out the derivation of this value and provide cross references to where in the Application each of the values used in the derivation can be found.

Response

Due to a typographical error the $688,519 should be $688,521 and is derived from Exhibit 9 (b) CA Rate Design (cellsL31 to L36) which in turn is derived from Exhibit 2 Rate Base cell G245, this being the base revenue requirement plus the transformer credit of $9,610.

c) Reference (i) states that CPUC is proposing to address some of the cross subsidization in the current cost allocation. How did CPUC determine the adjustment that would be made to each class' Revenue Requirement?

Response

Please refer to OEB Board staff Interrogatories, question # 29.

d) Please confirm whether the rates used in Reference (ii), Exhibit 9 a) to determine the allocation to customer classes prior to any adjustment for to address cross subsidization concerns included the Smart Meter rate adder.

Response

The rates used in Reference (ii), Exhibit 9 a) Rate Design to determine the allocation to customer classes prior to any adjustment, does include the Smart Meter Rate. This will be corrected upon resubmission.

e) Please confirm if the rates used to determine the fixed-variable split by customer class in Exhibits 9 a) and 9 c) included the Smart Meter rate adder.

Response

The rates used to determine the fixed-variable split by customer class included the Smart Meter rate adder. This will be corrected upon resubmission.

f) If the responses to parts (d) and/or (e) are yes, please recalculate the cost allocation and base rates with the Smart Meter rate adder excluded from the 2007 rates used in the analysis.

Response

This is being corrected in the resubmission.

Question #11

Reference: i) Customer Impacts

a) Based on a recent 12 consecutive months of actual billing data, please indicate the percentage of total residential customers that:

- Consume less than 100 kWh per month
- Consume 100 -> 250 kWh per month
- Consume 250 -> 500 kWh per month
- Consume 500 -> 750 kWh per month

Response:

Based on a recent 12 consecutive months of actual billing data, percentage of total residential customers that:

- ***Consume less than 100 kWh per month is 2.0% (23 customers – 15 premises are empty)***
- ***Consume 100 - 250 kWh per month is 2.0% (24 customers – 11 premises are empty)***
- ***Consume 250 - 500 kWh per month is 3.5% (41 customers)***
- ***Consume 500 - 750 kWh is 5.8% (67 customers)***

Question #12

Reference: i) General

a) Please provide copies of all Board Decisions pertaining to CPUC's rates issued since December 31, 2004.

<u>Response:</u>

Copies as requested are attached as Appendix G.

Appendix G

Approved Rate Schedules

Ontario Energy Board

Commission de l'Énergie de l'Ontario

Ontario

RP-2005-0013
EB-2005-0016

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15 (Schedule B);

AND IN THE MATTER OF an Application by **Chapleau Public Utilities Corporation** for an order or orders approving or fixing just and reasonable rates.

BEFORE: Gordon Kaiser
Vice Chair and Presiding Member

Paul Vlahos
Member

Pamela Nowina
Member

DECISION AND ORDER

Background and Application

In November 2003 the Ontario government announced that it would permit local distribution companies to apply to the Board for the next installment of their allowable return on equity beginning March 1, 2005. The Government also indicated that the Board's approval would be conditional on a financial commitment to reinvest in conservation and demand management initiatives, an amount equal to one year's incremental returns.

Also in November 2003, the Government announced, in conjunction with the introduction of Bill 4, the *Ontario Energy Board Amendment Act, (Electricity Pricing), 2003*, that electricity distributors could start recovering Regulatory Assets in their rates, beginning March 1, 2004, over a four year period.

In February and March, 2004, the Board approved the applications of distributors to recover 25% of their December 31, 2002 Regulatory Asset balances (or additional amounts for rate stability) in their distribution rates on an interim basis effective March 1, 2004 and implemented on April 1, 2004.

On December 20, 2004 the Board issued filing guidelines to all electricity distribution utilities for the April 1, 2005 distribution rate adjustments. The guidelines allowed the applicants to recover three types of costs. These costs concern (i) the rate recovery of the third tranche of the allowable return on equity (Market Adjusted Revenue Requirement or “MARR”), (ii) the 2005 proxy allowance for payments in lieu of taxes (“PILs”) and (iii) a second installment of the recovery of Regulatory Assets.

A generic Notice of the proceeding was published on January 25, 2005 in major newspapers in the province, which provided a 14 day period for submissions from interested parties. On February 4, 2005, the Board issued Procedural Order No. 1, providing for an extension for submissions until February 16, 2005 and also providing for reply submissions from applicants and other parties.

The Applicant filed an application for adjustments to their rates for the following amounts:

MARR: $ 43,807

2005 PILs Proxy: $ 23,712

Regulatory Assets Second Tranche: -$ 2,191

The Applicant also applied for an item outside of the guidelines. Specifically, the Applicant requested an amount of PILs Proxy in excess of the guidelines.

Submissions

The Board received one submission which addressed the 2005 rate setting process in general. This submission was made by School Energy Coalition (SEC). SEC objected to the guideline which caused the recovery of the 2005 PILs proxy to be reflected only on the variable charge. SEC was also concerned that monthly service charges and overall distribution charges varied significantly between utilities across the province. SEC also raised concerns regarding the consistency of, and access to, information on the applications as filed by the utilities.

Reply submissions to SEC's general submissions were received from the Coalition of Large Distributors, the Electricity Distributors Association, Hydro One Networks, and the LDC Coalition (a group of 7 distributors). These parties generally argued against the recommendations put forward by SEC, by and large indicating that the Board's existing processes for 2006 and 2007 have been planned to address these issues going forward and that these issues should not be added to the 2005 rates adjustment process.

The Applicant was not specifically named in any of these submissions.

The full record of the proceeding is available for review at the Board's offices.

Board Findings

The Board first addresses the general submission of SEC. While SEC raises important issues regarding electricity distribution rates, the Board has put in place a process which will address most of the issues raised by SEC on a comprehensive basis with coordinated cost of service, cost allocation and cost of capital studies for all distributors in 2006, 2007 and 2008. The Board does agree that unless there are compelling reasons to diverge from the Board's original filing guidelines for the 2005 distribution rate adjustment process, distributors should follow the guidelines in their applications.

At this time, the Board will approve only the portion of the application that conforms to the guidelines as the generic notice published informed customers and the public of only the changes contemplated in the guidelines. The Applicant may wish to apply for other specific changes to rates in a separate application.

The Board adjusted the application for the recovery of PILs and also adjusted the non-RSVA regulatory assets as the applied-for recovery was in excess of the non-RSVA total reported by the applicant.

As a result, the Board has made adjustments to the amounts applied for resulting in the following approved amounts:

MARR: $ 43,807
2005 PILs Proxy: $ 22,891
Regulatory Assets Second Tranche: -$ 13,711

Subject to these adjustments, the Board finds that the application conforms with earlier decisions of the Board (including approval for the Applicant's Conservation and Demand Management plan), directives and guidelines.

The Board will issue a separate decision on cost awards.

THE BOARD ORDERS THAT:

1) The rate schedule attached as Appendix "A" is approved effective March 1, 2005, to be implemented on April 1, 2005. All other rates currently in effect that are not shown on the attached schedule remain in force. If the Applicant's billing system is not capable of prorating to accommodate the April 1, 2005 implementation date, the new rates shall be implemented with the first billing cycle for electricity consumed or estimated to have been consumed after April 1, 2005.

2) The Applicant shall notify its customers of the rate changes, no later than with the first bill reflecting the new rates and include the brochure provided by the Board.

DATED at Toronto, March 23, 2005
ONTARIO ENERGY BOARD

Peter H. O'Dell
Assistant Board Secretary

Appendix "A"

RP-2005-0013
EB-2005-0016

March 23, 2005

ONTARIO ENERGY BOARD

Ontario Energy Board

Commission de l'Énergie de l'Ontario

Ontario

RP-2005-0020
EB-2005-0349

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15 (Schedule B);

AND IN THE MATTER OF an Application by Chapleau Public Utilities Corporation for an order or orders approving or fixing just and reasonable distribution rates and other charges, effective May 1, 2006.

BEFORE: Paul Vlahos
Presiding Member

Bob Betts
Member

DECISION AND ORDER

Chapleau Public Utilities Corporation ("Chapleau PUC" or the "Applicant") is a licensed distributor providing electrical service to consumers within its defined service area. Chapleau PUC filed an Application (the "Application") with the Ontario Energy Board (the "Board") for an order or orders approving or fixing just and reasonable rates for the distribution of electricity and other matters, to be effective May 1, 2006.

Chapleau PUC is one of over 90 electricity distributors in Ontario that are regulated by the Board. To streamline the process for the approval of distribution rates and charges for these distributors, the Board developed and issued the 2006 Electricity Distribution Rate Handbook (the "Handbook") and complementary spreadsheet-based models. These materials were developed after extensive public consultation with distributors, customer groups, public and environmental interest groups, and other interested parties. The Handbook contains requirements and guidelines for filing an application.

The models determine the amounts to be included for the payments in lieu of taxes ("PILs") and calculate rates based on historical financial and other information entered by the distributor.

Also included in this process was a methodology and model for the final recovery of regulatory assets flowing from the Board's decision dated December 9, 2004 on the Review and Recovery of Regulatory Assets – Phase 2 for Toronto Hydro, London Hydro, Enersource Hydro Mississauga and Hydro One Networks Inc. In Chapter 10 of the decision, the Board outlined a Phase 2 process for the remaining distributors. By letter of July 12, 2005, the Board provided guidance and a spreadsheet-based model to the distributors for the inclusion of this recovery as part of their 2006 distribution rate applications.

As a distributor that is embedded in Hydro One Network's low voltage system, the Applicant has included the recovery of certain Regulatory Assets that have been allocated by Hydro One Networks. The amount claimed by the Applicant was provided by Hydro One Networks as a reasonable approximation of the actual amount that Hydro One Networks will assess the Applicant. To the degree that the amount differs from the actual amount approved for Hydro One Networks in another proceeding (RP-2005-0020/EB-2005-0378), this difference will be reconciled at the end of the Regulatory Asset recovery period, as set out in the Phase II regulatory assets decision issued on December 9, 2004 (RP-2004-0064/RP-2004-0069/RP-2004-0100/RP-2004-0117/RP-2004-0118).

In its preliminary review of the 2006 rate applications received from the distributors, the Board identified several issues that appeared to be common to many or all of the distributors. As a result, the Board held a hearing (EB-2005-0529) to consider these issues (the "Generic Issues Proceeding") and released its decision (the "Generic Decision") on March 21, 2006. The rulings flowing from that Generic Decision apply to this Application, except to the extent noted in this Decision. The Board notes that pursuant to ss. 21 (6.1) of the *Ontario Energy Board Act, 1998*, and to the extent that it is pertinent to this Application, the evidentiary record of the Generic Issues Proceeding is part of the evidentiary record upon which the Board is basing this Decision.

In December 2001, the Board authorized the establishment of deferral accounts by the distributors related to the payments that the distributors make to the Ministry of Finance in lieu of taxes. The Board is required, under its enabling legislation, to make an order with respect to non-commodity deferral accounts once every twelve months. The Board has considered the information available with respect to these accounts and orders that the amounts recorded in the accounts will not be reflected in rates as part of the Rate Order that will result from this Decision. The Board will continue to monitor the accounts with a view to clearing them when appropriate.

Public notice of the rate Application made by Chapleau PUC was given through newspaper publication in its service area. The evidence filed was made available to the public. Interested parties intervened in the proceeding. The evidence in the Application was tested through written interrogatories from Board staff and intervenors, and intervenors and Chapleau PUC had the opportunity to file written argument. While the Board has considered the entire record in this proceeding, it has made reference in this Decision only to such evidence and argument as is necessary to provide context to its findings.

Chapleau PUC has requested an amount of $648,657 as revenue to be recovered through distribution rates and charges. Included in this amount is a debit of $4,272 for the recovery of regulatory assets. Except where noted in this Decision, the Board finds that Chapleau PUC has filed its Application in accordance with the Handbook and the guidelines for the recovery of regulatory assets.

Notwithstanding Chapleau PUC's general compliance with the Handbook and associated models, in considering this Application the Board reviewed the following matters in detail:

- Capital Structure;
- Retail Transmission Connection Rate; and
- Consequences of the Generic Decision (EB-2005-0529).

Capital Structure

Chapleau PUC reported in its Application that its capital structure is currently 100% debt and 0% equity. This deviates significantly from the 50:50 deemed capital structure for the Applicant, and the Handbook requires a report to be filed by the distributor where the difference exceeds 10 percentage points. The debt, which is held by the shareholder, consists of mortgage payable and loan payable components, both of which feature a 10% interest rate, the basis of which is not stated in the Application. Chapleau PUC states that the debt is held by the municipal shareholder and does not pose a financial risk to it. Chapleau PUC notes that the capital structure was created to achieve two objectives: to permit the securitization of 100% of the Township's investment in the PUC and to minimize the amount of taxable income at the PUC level.

The Board is concerned about the potential risk to the utility's financial viability arising from this highly leveraged capital structure. It is not clear to what extent Chapleau PUC can avoid interest payments if its financial circumstances warrant. Nor is it clear what the consequences are of not making these debt payments to the municipal shareholder. For the purposes of the rates arising out of this Decision, the Board will not deem a different capital structure. However, the Board will inform the Chief Regulatory Auditor of this situation, who will then make a determination of how to proceed.

Retail Transmission Connection Rate

In an attempt to minimize the level of the associated variance account going forward, the 2006 EDR model performs an update of the retail transmission line and transformation connection service rate, based on data submitted by the distributor. In the case of Chapleau PUC, this automatic calculation produces an anomalous result; the rate would go from being a charge to a credit (for example for residential customers from a charge of $0.0050/kWh to a credit of $0.0057/kWh) This is a result not intended when the model was designed, and is not an appropriate change to the rate. The Board will not accept the new calculated rate, and the existing rate shall prevail.

Consequences of the Generic Decision on this Application

The Generic Decision contains findings relevant to funding for smart meters for electricity distributors. The Applicant did not file a specific smart meter investment plan or request approval of any associated amount in revenue requirement. Absent a specific plan or discrete revenue requirement, the Generic Decision provides that $0.30 per residential customer per month be reflected in the Applicant's revenue requirement. The Board finds that this increase in the revenue requirement amount will be allocated equally to all metered customers and recovered through their monthly service charge. This increment is reflected in the approved monthly service charges contained in the Tariff of Rates and Charges appended to this Decision. Pursuant to the Generic

Decision, a variance account will be established, the details of which will be communicated in due course.

Resulting Revenue Requirement

As a result of the Board's determinations on these issues, the Board has adjusted the revenue requirement to be recovered through distribution rates and charges to $652,855 including a credit amount of $4,272 for the recovery of Regulatory Assets.

In its letter of December 20, 2004 to electricity distributors, the Board indicated that it would consider the disposition of the 2005 OEB dues recorded in Account 1508 in this proceeding. However, given that the final 2005 OEB dues are not available because of the difference in fiscal years for the Board and the distributors, and given that the model used to develop the Application does not incorporate this provision, the Board will review and dispose of the 2005 OEB dues at a later time.

Cost Awards

This Application is one of a number of applications before the Board dealing with 2006 rates chargeable by distributors. Intervenors may be parties to multiple applications and, if eligible, their costs associated with a specific distributor may not be separable. Therefore, for these applications, the matter of intervenor cost awards will be addressed by the Board at a later date, upon the conclusion of the current rate applications. If an intervenor that is eligible to recover its costs is able to uniquely identify its costs associated with this Application, it must file its cost claim within 10 days from the receipt of this Decision.

THE BOARD ORDERS THAT:

1) The Tariff of Rates and Charges set out in Appendix "A" of this Order is approved, effective May 1, 2006, for electricity consumed or estimated to have been consumed on and after May 1, 2006. The application of the revised distribution rates shall be prorated to May 1, 2006. If Chapleau Public Utilities Corporation's billing system is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors shall be implemented upon the first subsequent billing for each billing cycle.

2) The Tariff of Rates and Charges set out in Appendix “A” of this Order supersedes all previous distribution rate schedules approved by the Ontario Energy Board for Chapleau Public Utilities Corporation., and the rates and charges are final in all respects.

3) Chapleau Public Utilities Corporation shall notify its customers of the rate changes no later than with the first bill reflecting the new rates.

DATED at Toronto, April 12, 2006.

ONTARIO ENERGY BOARD

John Zych
Board Secretary

Appendix “A”

RP-2005-0020
EB-2005-0349

April 12, 2006

ONTARIO ENERGY BOARD

Chapleau Public Utilities Corporation
TARIFF OF RATES AND CHARGES
Effective May 1, 2006

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

RP-2005-0020
EB-2005-0349

APPLICATION

- The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Codes, Guidelines or Orders of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.
- No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
- This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2006 for all consumption or deemed consumption services used on or after that date.
SPECIFIC SERVICE CHARGES - May 1, 2006 for all charges incurred by customers on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2006 unless the distributor is not capable of prorating changed loss factors jointly with distribution rates. In that case, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

SERVICE CLASSIFICATIONS

Residential
This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively by a single family unit, non-commercial. This can be a separately metered living accommodation, town house, apartment, semi-detached, duplex, triplex or quadruplex with residential zoning.

General Service Less Than 50 kW
This classification refers to a non residential account taking electricity at 750 volts or less whose average monthly average peak demand is less than, or is forecast to be less than, 50 kW.

General Service 50 to 4,999 kW
This classification refers to a non residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW.

Unmetered Scattered Load
This classification refers to an account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information/ documentation with regard to electrical demand/consumption of the proposed unmetered load.

Sentinel Lighting
This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light.

Street Lighting
This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of transportation and private roadway lighting operation, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template.

Chapleau Public Utilities Corporation
TARIFF OF RATES AND CHARGES
Effective May 1, 2006

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

RP-2005-0020
EB-2005-0349

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	19.74
Distribution Volumetric Rate	$/kWh	0.0099
Regulatory Asset Recovery	$/kWh	0.0007
Retail Transmission Rate – Network Service Rate	$/kWh	0.0049
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0050
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge	$	0.25

General Service Less Than 50 kW

Service Charge	$	30.89
Distribution Volumetric Rate	$/kWh	0.0084
Regulatory Asset Recovery	$/kWh	(0.0001)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0045
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge	$	0.25

General Service 50 to 4,999 kW

Service Charge	$	151.43
Distribution Volumetric Rate	$/kW	1.1989
Regulatory Asset Recovery	$/kW	(0.2732)
Retail Transmission Rate – Network Service Rate	$/kW	1.8304
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.7882
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge (per connection)	$	15.32
Distribution Volumetric Rate	$/kWh	0.0084
Regulatory Asset Recovery	$/kWh	(0.0001)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0045
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	$	0.25

Sentinel Lighting

Service Charge (per connection)	$	2.63
Distribution Volumetric Rate	$/kW	3.7142
Regulatory Asset Recovery	$/kW	3.0482
Retail Transmission Rate – Network Service Rate	$/kW	1.3874
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.4113
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	$	0.25

Chapleau Public Utilities Corporation
TARIFF OF RATES AND CHARGES
Effective May 1, 2006

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

RP-2005-0020
EB-2005-0349

Street Lighting

Service Charge (per connection)	$	0.79
Distribution Volumetric Rate	$/kW	2.4065
Regulatory Asset Recovery	$/kW	0.0178
Retail Transmission Rate – Network Service Rate	$/kW	1.3804
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3824
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	$	0.25

Specific Service Charges

Customer Administration		
Arrears certificate	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned Cheque (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
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
Install/Remove load control device – during regular hours	$	65.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35
Allowances		
Transformer Allowance for Ownership - per kW of billing demand/month	$	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0497
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0145
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0392
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0045

Ontario Energy Board **Commission de l'énergie de l'Ontario**

Ontario

EB-2007-0515

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15 (Schedule B);

AND IN THE MATTER OF an application by Chapleau Public Utilities Corporation for an order or orders approving or fixing just and reasonable distribution rates and other charges, to be effective May 1, 2007.

BEFORE: Paul Sommerville
Presiding Member

Paul Vlahos
Member

Ken Quesnelle
Member

DECISION AND ORDER

Chapleau Public Utilities Corporation ("Chapleau PUC") is a licensed distributor providing electrical service to consumers within its licensed service area. Chapleau PUC filed an application with the Ontario Energy Board (the "Board") for an order or orders approving or fixing just and reasonable rates for the distribution of electricity and other charges, to be effective May 1, 2007.

Chapleau PUC is one of 85 electricity distributors in Ontario that are regulated by the Board. To streamline the process for the approval of distribution rates and charges for these distributors, the Board issued its *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* (the "Report") on December 20, 2006. The Report contained the relevant guidelines for 2007 rate adjustments ("the guidelines") for distributors applying for rates only on the basis of the cost of capital and 2nd generation incentive regulation mechanism policies set out in the Report.

Public notice of Chapleau PUC’s rate application was given through newspaper publication in Chapleau PUC’s service area. The evidence filed as part of the rate application was made available to the public. Both Chapleau PUC and interested parties had the opportunity to file written submissions in relation to the rate application. The Board received no submissions. While the Board has considered the entire record in this rate application, it has made reference only to such evidence as is necessary to provide context to its findings.

Chapleau PUC’s rate application was filed on the basis of the guidelines. In fixing new rates and charges for Chapleau PUC, the Board has applied the policies described in the Report.

After confirming the accuracy of the 2006 rate tariff and accompanying materials submitted in the rate application, the Board applied its approved price cap index adjustment to distribution rates (fixed and variable) uniformly across all customer classes. The price cap index is calculated as a price escalator less an X-factor of 1.0%, intended to represent input price and productivity trends. Based on the final 2006 data published by Statistics Canada, the Board has established the price escalator to be 1.9%. The resulting price cap index adjustment is therefore 0.9%.

The price cap index adjustment was not applied to the following components of the rates:

- the specific service charges;
- the regulatory asset recovery rate rider; and
- the smart meter rate adder (an amount in the fixed components of the rates associated with smart meter cost recovery).

Chapleau PUC requested an amount for smart meter costs. The Board has approved an amount of $0.26 per month per metered customer. Chapleau PUC’s variance accounts for smart meter program implementation costs, previously authorized by the Board, are continued. It is the Board’s understanding that Chapleau PUC will not be undertaking any smart metering activity (i.e. discretionary metering activity) in 2007. The amount collected through the smart meter rate adder will be booked into the existing variance accounts, and retained in those accounts, to help fund future smart meter activity. As the notice of this application indicated, the Board will be holding a combined proceeding to consider, among other things, appropriate recovery of smart meter costs.

The Board has made the necessary adjustments to Chapleau PUC's filed 2006 Tariff of Rates and Charges to produce a new Tariff of Rates and Charges to be effective May 1, 2007. The Board finds the rates and charges in the Tariff of Rates and Charges attached as Appendix A to this decision to be just and reasonable.

THE BOARD ORDERS THAT:

1. The Tariff of Rates and Charges set out in Appendix A of this order is approved, effective May 1, 2007, for electricity consumed or estimated to have been consumed on and after May 1, 2007.

2. The Tariff of Rates and Charges set out in Appendix A of this order supersedes all previous distribution rate schedules approved by the Ontario Energy Board for Chapleau PUC, and is final in all respects.

3. Chapleau PUC shall notify its customers of the rate changes no later than with the first bill reflecting the new rates.

DATED at Toronto, April 12, 2007.

ONTARIO ENERGY BOARD

Original signed by

Peter H. O'Dell
Assistant Board Secretary

Appendix A

EB-2007-0515

April 12, 2007

ONTARIO ENERGY BOARD

Chapleau Public Utilities Corporation
TARIFF OF RATES AND CHARGES
Effective May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2007-0515

APPLICATION

- The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Codes, Guidelines or Orders of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.
- No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
- This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
SPECIFIC SERVICE CHARGES - May 1, 2007 for all charges incurred by customers on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007 unless the distributor is not capable of prorating changed loss factors jointly with distribution rates. In that case, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

SERVICE CLASSIFICATIONS

Residential
This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively by a single family unit, non-commercial. This can be a separately metered living accommodation, town house, apartment, semi-detached, duplex, triplex or quadruplex with residential zoning.

General Service Less Than 50 kW
This classification refers to a non residential account taking electricity at 750 volts or less whose average monthly average peak demand is less than, or is forecast to be less than, 50 kW.

General Service 50 to 4,999 kW
This classification refers to a non residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW.

Unmetered Scattered Load
This classification refers to an account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information/ documentation with regard to electrical demand/consumption of the proposed unmetered load.

Sentinel Lighting
This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light.

Street Lighting
This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template.

Chapleau Public Utilities Corporation
TARIFF OF RATES AND CHARGES
Effective May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2007-0515

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	19.92
Distribution Volumetric Rate	$/kWh	0.0100
Regulatory Asset Recovery	$/kWh	0.0007
Retail Transmission Rate – Network Service Rate	$/kWh	0.0049
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0050
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service Less Than 50 kW

Service Charge	$	31.17
Distribution Volumetric Rate	$/kWh	0.0085
Regulatory Asset Recovery	$/kWh	(0.0001)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0045
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 50 to 4,999 kW

Service Charge	$	152.79
Distribution Volumetric Rate	$/kW	1.2097
Regulatory Asset Recovery	$/kW	(0.2732)
Retail Transmission Rate – Network Service Rate	$/kW	1.8304
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.7882
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge (per connection)	$	15.46
Distribution Volumetric Rate	$/kWh	0.0085
Regulatory Asset Recovery	$/kWh	(0.0001)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0045
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Sentinel Lighting

Service Charge (per connection)	$	2.65
Distribution Volumetric Rate	$/kW	3.7476
Regulatory Asset Recovery	$/kW	3.0482
Retail Transmission Rate – Network Service Rate	$/kW	1.3874
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.4113
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Chapleau Public Utilities Corporation
TARIFF OF RATES AND CHARGES
Effective May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2007-0515

Street Lighting

Service Charge (per connection)	$	0.80
Distribution Volumetric Rate	$/kW	2.4282
Regulatory Asset Recovery	$/kW	0.0178
Retail Transmission Rate – Network Service Rate	$/kW	1.3804
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3824
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Specific Service Charges

Customer Administration		
Arrears certificate	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned Cheque (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
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
Install/Remove load control device – during regular hours	$	65.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35
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)

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0497
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0392
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A