Borden Ladner Gervais LLP
Lawyers • Patent & Trade-mark Agents
Scotia Plaza, 40 King Street West
Toronto, Ontario, Canada M5H 3Y4
tel.: (416) 367-6000 fax: (416) 367-6749
www.blgcanada.com

JAMES C. SIDLOFSKY
direct tel.: 416-367-6277
direct fax: 416-361-2751
e-mail: jsidlofsky@blgcanada.com

BORDEN LADNER GERVAIS

October 5, 2009

Delivered by Courier

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, Suite 2700
Toronto, Ontario
M4P 1E4

Dear Ms. Walli:

Re: OEB File No. EB-2009-0261
Chatham-Kent Hydro Inc. 2010 Electricity Distribution Rate Application

We are counsel to Chatham-Kent Hydro Inc. ("Chatham-Kent Hydro") in the above-captioned matter. Please find accompanying this letter two copies of Chatham-Kent Hydro's Application for its Electricity Distribution Rates and Charges effective May 1, 2010, together with an electronic version of same.

Please note that two items are being filed in confidence. The first is a copy of the 2008 audited financial statements of Chatham-Kent Utility Services Inc. ("CKUSI"), a competitive affiliate of Chatham-Kent Hydro, referred to in Exhibit 1, Tab 3, Schedule 1 of the Application. CKUSI is engaged in competitive business activities. Its financial information is consistently treated in a confidential manner. We submit that disclosure of CKUSI's financial information could reasonably be expected to prejudice the economic interest of, significantly prejudice the competitive position of, cause undue financial loss to, and be injurious to the financial interest of CKUSI. Chatham-Kent Hydro does not have CKUSI's consent to release this information.

The OEB's *Practice Direction on Confidential Filings* (the "Practice Direction") recognizes that these are among the factors that the Board will take into consideration when addressing the confidentiality of filings. They are also addressed in subsection 17(1) of the *Freedom of Information and Protection of Privacy Act* ("FIPPA"), and the Practice Direction notes (at Appendix C of the Practice Direction) that third party information as described in subsection 17(1) of FIPPA is among the types of information previously assessed or maintained by the OEB as confidential.

In keeping with the requirements of the Practice Direction, Chatham-Kent Hydro Inc. is filing a confidential unredacted version of the audited financial statements for 2008 for CKUSI. Chatham-Kent Hydro is prepared to provide unredacted copies of the financial statements to parties' counsel and experts or consultants provided that they have executed the OEB's form of Declaration and Undertaking with respect to confidentiality and that they comply with the Practice Direction, subject to Chatham-Kent Hydro's right to object

BORDEN
LADNER
GERVAIS

to the OEB's acceptance of a Declaration and Undertaking from any person. We note that financial statements relating to other members of the Chathem-Kent Hydro corporate family are provided at Exhibit 1, Tab 3, Schedule 1, Appendix F to the Application.

The second item being filed in confidence is a spreadsheet setting out detailed information with respect to costs related to smart meters (designated as Exhibit 9, Tab 2, Schedule 1, Appendix A to the Application). Chatham-Kent Hydro was a party to the OEB's combined proceeding costs associated with smart metering activities incurred by 13 utilities authorized by government regulation to undertake smart metering activities (EB-2007-0063). The OEB discussed the issue of confidentiality with respect to pricing information at pages 4 and 5 of its August 28, 2007 Decision. The OEB determined (at page 5) that:

> "…the competitive positions of the suppliers would be eroded if the prices charged to the thirteen utilities were disclosed. The Board accepts this position. It is important that the tendering and bidding processes continue to be competitive. The Board also recognized that none of the intervenors opposed maintaining confidentiality for the evidence and that intervenors representing four major consumer groups had access to all of the information. The Board finds that it is in the public interest that the prices charged to the applicants, including unit prices, installation costs and the contractual terms, be kept confidential. However, the aggregated per unit installed prices will be part of the Decision."

In keeping with that Decision, Appendix A is being filed in confidence in its entirety. Appendices B and C to Exhibit 9, Tab 2, Schedule 1 are being placed on the public record as they contain aggregated information. As with the CKUSI financial statements, Chatham-Kent Hydro is prepared to provide unredacted copies of Appendix A to parties' counsel and experts or consultants provided that they have executed the OEB's form of Declaration and Undertaking with respect to confidentiality and that they comply with the Practice Direction, subject to Chatham-Kent Hydro's right to object to the OEB's acceptance of a Declaration and Undertaking from any person.

Pursuant to the Practice Direction, copies of these two confidential items are being filed separately from the Application, in a sealed envelope. They are not to be placed on the public record.

We ask that copies of all correspondence and orders pertaining to this proceeding be delivered to the following:

Mr. Jim Hogan
Chief Executive Officer
Chatham-Kent Energy Inc.
PO Box 70
320 Queen Street
Chatham, ON
N7M 5K2

Tel: (519) 352-6300 ext.277
Fax: (519) 351-4059
E-mail: jimhogan@ckenergy.com

BORDEN
LADNER
GERVAIS

and to:

James C. Sidlofsky
Partner
Borden Ladner Gervais LLP
Scotia Plaza, 40 King Street West
Toronto, ON M5H 3Y4

Tel: 416-367-6277
Fax: 416-361-2751
E-mail: jsidlofsky@blgcanada.com

Should you have any questions or require further information, please do not hesitate to contact me.

Yours very truly,

BORDEN LADNER GERVAIS LLP

Original signed by James C. Sidlofsky

James C. Sidlofsky
JCS/dp
Encls.

cc: Jim Hogan, Chatham-Kent Hydro
Dave Kenney, Chatham-Kent Hydro
Cheryl Decaire, Chatham-Kent Hydro

EB-2009-0261

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

AND IN THE MATTER OF an Application by Chatham-Kent Hydro Inc. to the Ontario Energy Board for an Order or Orders approving or fixing just and reasonable rates and other service charges for the distribution of electricity as of May 1, 2010.

CHATHAM-KENT HYDRO INC.

2010 ELECTRICITY DISTRIBUTION RATE APPLICATION

FILED: OCTOBER 5, 2009

Applicant:
Chatham-Kent Hydro Inc.
PO Box 70
320 Queen Street
Chatham, Ontario
N7M 5K2

Jim Hogan
CEO
Tel: (519) 352-6300 ext 277
Fax: (519) 351-4059
jimhogan@ckenergy.com

Counsel to the Applicant:
Borden Ladner Gervais LLP
Suite 4100
40 King Street West
Toronto, Ontario
M5H 3Y4

James C. Sidlofsky
Tel: (416) 367-6277
Fax: (416) 361-2751
jsidlofsky@blgcanada.com

CHATHAM-KENT HYDRO INC.
APPLICATION FOR APPROVAL OF ELECTRICITY DISTRIBUTION RATES
EFFECTIVE MAY 1, 2010

INDEX

Exhibit	Tab	Schedule	Appendix	Contents
7 – Cost Allocation				
	1	1		Cost Allocation Overview
		2		Summary of Results and Proposed Changes
			A	Cost Allocation Model – Initial Filing
			B	Cost Allocation Model – Initial without Transformer Allowance
			C	Cost Allocation Model – Current without Transformer Allowance

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

AND IN THE MATTER OF an Application by Chatham-Kent Hydro Inc. to the Ontario Energy Board for an Order or Orders approving or fixing just and reasonable rates and other service charges for the distribution of electricity as of May 1, 2010.

Title of Proceeding:	An application by Chatham-Kent Hydro Inc. for an Order or Orders approving or fixing just and reasonable distribution rates and other charges, effective May 1, 2010.
Applicant's Name:	Chatham-Kent Hydro Inc.
Applicant's Address for Service:	PO Box 70 320 Queen Street Chatham Ontario N7M 5K2 Attention: Mr. Jim Hogan, CEO, Chatham-Kent Energy Inc. Telephone: 519-352-6300 ext 277 Fax: 519-351-4059 E-mail: jimhogan@ckenergy.com
Applicant's Counsel:	Borden Ladner Gervais LLP Suite 4100 40 King Street West Toronto ON M5H 3Y4 James C. Sidlofsky Telephone: (416) 367-6277 Fax: (416) 361-2751 E-mail jsidlofsky@blgcanada.com

APPLICATION

1. Introduction

(a) The Applicant is Chatham-Kent Hydro Inc. (referred to in this Application as the "Applicant" or "Chatham-Kent Hydro"). The Applicant is a corporation incorporated pursuant to the Ontario *Business Corporations Act* with its head office in the Municipality of Chatham-Kent. The Applicant carries on the business of distributing electricity within the Municipality of Chatham-Kent.

(b) The Applicant hereby applies to the Ontario Energy Board (the "OEB") pursuant to Section 78 of the *Ontario Energy Board Act, 1998* (the "OEB Act") for approval of its proposed distribution rates and other charges, effective May 1, 2010. A list of requested approvals is set out in Exhibit 1, Tab 1, Schedule 4.

(c) Except where specifically identified in the Application, the Applicant followed Chapter 2 of the OEB's *Filing Requirements for Transmission and Distribution Applications* dated May 27, 2009 (the "Filing Requirements") in order to prepare this application.

2. Proposed Distribution Rates and Other Charges

(a) The Schedule of Rates and Charges proposed in this Application is identified in Exhibit 1, Tab 1, Schedule 2, Appendix A attached to this schedule and Exhibit 8, Tab 1, Schedule 9, and the material being filed in support of this Application sets out Chatham-Kent Hydro's approach to its distribution rates and charges.

3. Proposed Effective Date of Rate Order

(a) The Applicant requests that the OEB make its Rate Order effective May 1, 2010.

4. The Proposed Distribution Rates and Other Charges are Just and Reasonable

(a) The Applicant submits the proposed distribution rates contained in this Application are just and reasonable on the following grounds:

i. the proposed rates for the distribution of electricity have been prepared in accordance with the Filing Requirements and reflect traditional rate making and cost of service principles;

ii. the proposed adjusted rates are necessary to meet the Applicant's Market Based Rate of Return ("MBRR") and Payments in Lieu of Taxes ("PILs") requirements;

iii. the Lost Revenue Adjustment Mechanism/Shared Savings Mechanism ("LRAM/SSM") and Smart Meter Disposition Riders fully meet the guidelines outlined by the OEB and should be recovered by the customers. The delays of the timing to begin recovery of LRAM/SSM until 2011 is a prudent and fair rate mitigation plan. Recovering the Smart Meter Disposition Rider over two years is also a prudent and fair mitigation plan. No further mitigation measures should be required;

iv. the other service charges proposed by the Applicant are the same as those previously approved by the OEB; and

v. such other grounds as may be set out in the material accompanying this Application Summary.

5. Relief Sought

(a) The Applicant applies for an Order or Orders approving the proposed distribution rates and other charges set out in Exhibit 1, Tab 1, Schedule 2, Appendix A to this Application as just and reasonable rates and charges pursuant to Section 78 of the OEB Act, to be effective May 1, 2010, or as soon as possible thereafter; and

6. Form of Hearing Requested

(a) The Applicant requests that this Application be disposed of by way of a written hearing.

DATED at Toronto, Ontario, this 5th day of October, 2009.

All of which is respectfully submitted,

BORDEN LADNER GERVAIS LLP

James C. Sidlofsky
Counsel to Chatham-Kent Hydro

APPENDIX A

SCHEDULE OF PROPOSED RATES AND CHARGES

SCHEDULE OF PROPOSED RATES AND CHARGES

Residential		
Service Charge	$	18.81
Smart Meter Disposition Rider - effective until April 30, 2012	$	0.45
Distribution Volumetric Rate	$/kWh	0.0085
Low Voltage Distribution Rate	$/kWh	0.0003
Deferral and Variance Account Rider	$/kWh	0.0002
LRAM/SSM Rider	$/kWh	0.0000
Retail Transmission Rate – Network Service Rate	$/kWh	0.0047
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0043
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.2500

General Service Less Than 50 kW		
Service Charge	$	33.74
Smart Meter Disposition Rider - effective until April 30, 2012	$	0.45
Distribution Volumetric Rate	$/kWh	0.0107
Low Voltage Distribution Rate	$/kWh	0.0003
Deferral and Variance Account Rider	$/kWh	(0.0007)
LRAM/SSM Rider	$/kWh	0.0000
Retail Transmission Rate – Network Service Rate	$/kWh	0.0042
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0039
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.2500

General Service 50 to 999 kW		
Service Charge	$	97.46
Smart Meter Disposition Rider - effective until April 30, 2012	$	0.45
Distribution Volumetric Rate	$/kW	4.7091
Low Voltage Distribution Rate	$/kW	0.1377
Deferral and Variance Account Rider	$/kWh	(0.6859)
LRAM/SSM Rider	$/kWh	0.0000
Retail Transmission Rate – Network Service Rate	$/kW	1.7495
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.5439
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	1.8642
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	1.6909
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.2500

General Service Intermediate - 1,000 to 4,999 kW		
Service Charge	$	795.83
Smart Meter Disposition Rider - effective until April 30, 2012	$	0.45
Distribution Volumetric Rate	$/kW	3.5829
Low Voltage Distribution Rate	$/kW	0.1505
Deferral and Variance Account Rider	$/kWh	(0.3825)
LRAM/SSM Rider	$/kWh	0.0000
Retail Transmission Rate – Network Service Rate	$/kW	1.8642
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.6909
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.2500

Standby Power

Service Charge	$	6,099.12
Smart Meter Disposition Rider - effective until April 30, 2012	$	0.45
Distribution Volumetric Rate	$/kW	3.8455
Low Voltage Distribution Rate	$/kW	0.1505
Deferral and Variance Account Rider	$/kWh	(0.6702)
LRAM/SSM Rider	$/kWh	0.0000
Retail Transmission Rate – Network Service Rate	$/kW	1.8642
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.6909
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.2500
Standby Charge – for a month where standby power is not provided. The charge is applied to the contracted amount (e.g. nameplate rating of generation facility).	$/kW	1.3500

Unmetered Scattered Load

Service Charge (per connection)	**$**	9.06
Distribution Volumetric Rate	$/kWh	0.0064
Low Voltage Distribution Rate	$/kWh	0.0003
Deferral and Variance Account Rider	$/kWh	(0.0015)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0042
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0039
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.2500

Sentinel Lighting

Service Charge (per connection)	**$**	7.88
Distribution Volumetric Rate	$/kW	5.7266
Low Voltage Distribution Rate	$/kW	0.0982
Deferral and Variance Account Rider	$/kW	0.3111
Retail Transmission Rate – Network Service Rate	$/kW	1.3289
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2171
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.2500

Street Lighting

Service Charge (per connection)	**$**	1.23
Distribution Volumetric Rate	$/kW	7.9163
Low Voltage Distribution Rate	$/kW	0.0454
Deferral and Variance Account Rider	$/kW	(0.8041)
Retail Transmission Rate – Network Service Rate	$/kW	1.3193
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.1926
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.2500

Specific Service Charges		
Customer Administration		
Arrears certificate	$	15.00
Statement of Account	$	15.00
Easement letter	$	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	$	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
Disconnect/Reconnect Charge – At Meter During Regular Hours	$	65.00
Temporary service install & remove – overhead – no transformer	$	500.00
Temporary service install & remove – overhead – with transformer	$	1,000.00
Specific charge for access to the power poles – per pole/year	$	22.35
Switching for company maintenance – Charge based on Time and Materials	$	
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)

Retail Service Charges (if applicable)	**Metric**	**Current**
Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity		
One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variance Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing credit, per customer, per retailer		0.30
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party		0.25
Processing fee, per request, applied to the requesting party		0.30
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year		no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0443
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0430
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0339
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0141

CONTACT INFORMATION:

CHATHAM-KENT HYDRO INC.

PO Box 70
320 Queen Street
Chatham ON
N7M 5K2

PRESIDENT:

Mr. Dave Kenney
Telephone: (519) 352-6300 ext. 261
Facsimile: (519) 351-4059
E-mail: davekenney@ckenergy.com

CHIEF EXECUTIVE OFFICER,
Chatham-Kent Energy Inc.

Mr. Jim Hogan
Telephone: (519) 352-6300 ext.277
Facsimile: (519) 351-4059
E-mail: jimhogan@ckenergy.com

APPLICANT'S COUNSEL:

Borden Ladner Gervais LLP
Suite 4100
40 King Street West
Toronto ON
M5H 3Y4

James C. Sidlofsky
Telephone: (416) 367-6277
Facsimile: (416) 361-2751
E-mail: jsidlofsky@blgcanada.com

LIST OF SPECIFIC APPROVALS REQUESTED:

In this proceeding, Chatham-Kent Hydro is requesting the following approvals:

- Approval of revised distribution rates for the period May 1, 2010 to April 30, 2011 (Exhibit 1, Tab 1, Schedule 2, Appendix A)

- Approval of a change in the proposed loss factor from the current factor of 1.047 to a proposed factor of 1.0443 (Exhibit 8, Tab 1, Schedule 6)

- Approval to revise the Retail Transmission-Network Service, Retail Transmission-Connection Charges (Exhibit 8, Tab 1, Schedule 3)

- Approval to recover an amount for the Lost Revenue Adjustment Mechanism (“LRAM”) and Shared Savings Mechanism (“SSM”) for Conservation and Demand Management Programs implemented for the periods 2006 to 2009 (Exhibit 10, Tab 1, Schedule 3 & 4) and to begin the recovery of these costs in May 1, 2011.

- Approval to dispose of the following Deferral and Variance Account Balances of December 31 2008 with an adjustment for interest to April 30, 2010 over a one-year period using the method of recovery described in Exhibit 9, Tab 1, Schedule 3. The accounts include:

    i. Retail Settlement Variance Account – Wholesale Market Service Charge - 1580
    ii. Retail Settlement Variance Account – One-Time Wholesale Market Service - 1582
    iii. Retail Settlement Variance Account – Retail Transmission Network Charge - 1584
    iv. Retail Settlement Variance Account – Retail Transmission Connection Charge - 1586
    v. Retail Settlement Variance Account – Power - 1588

vi. Retail Cost Variance Account – Retail - 1518

vii. Retail Cost Variance Account – STR - 1548

viii. Other Regulatory Assets – Sub-account OEB cost assessments - 1508

ix. Other Regulatory Assets – Sub-account Pension Cost - 1508

x. Miscellaneous Deferred Debits - 1525

xi. Low Voltage Variance Account - 1550

xii. Qualifying Transition Cost - 1570

xiii. Extraordinary Event Losses - 1572

xiv. Recovery of Regulatory Asset Balances - 1590

- Approval of a proposed Smart Meter Disposition Rider, Smart Meter Adder and Smart Meter Permanent Rate for the installations of Residential and General Service Smart Meters. The Disposition Rider and Adder relate to costs for investments made up to December 31, 2008 (Exhibit 9, Tab 2) while the Adder is to fund investments to be made in 2009 and 2010.

- Approval of the proposed Low Voltage Distribution Rate. (Exhibit 8, Tab 1, Schedule 4).

DRAFT ISSUES LIST:

The Applicant would expect, based on previous regulatory experience and other hearings, that the following matters pertaining to the 2010 Test Year may constitute issues in this Application:

- The amount of Chatham-Kent Hydro's proposed revenue requirement;
- The reasonableness of the proposed electricity distribution rates;
- The reasonableness of the 2010 capital program and the operating, maintenance and administrative budget; and
- The reasonableness of the 2010 weather normalized forecast.

PROCEDURAL ORDERS/MOTIONS/NOTICES:

On March 12, 2007, the OEB issued a Report titled "LDC Screening Methodology to Establish a Rebasing Schedule for Electricity LDCs". The purpose of that Report was "to describe the criteria to be considered in determining which electricity distributors to engage in proceedings before the Board for rebasing to establish rates for each of the years 2009 and 2010 and to establish the next steps and timelines for filing." Section 3.3 of that Report provided an opportunity for LDCs to "self-nominate" to be rebased in a particular year.

On March 21, 2007, Chatham-Kent Hydro filed a self-nomination request for rebasing in 2010. Subsequently, in Board File No. EB-2006-0330, the OEB issued its list of distributors that will be rebased in 2010. Chatham-Kent Hydro was included on that list.

On January 29, 2009, the OEB again provided a list of LDCs that would file cost of service applications for 2010 and 2011 (EB-2009-0028). Chatham-Kent Hydro filed a letter dated February 4, 2009 requesting to file a cost of service application for the 2010 Test Year. On March 5, 2009 the OEB's final list for 2010 cost of service filings included Chatham-Kent Hydro.

ACCOUNTING ORDERS REQUESTED:

As part of this proceeding, Chatham-Kent Hydro is requesting the following accounting orders:

- The continuation of regulatory deferral and variance accounts

COMPLIANCE WITH UNIFORM SYSTEM OF ACCOUNTS:

Chatham-Kent Hydro has followed the accounting principles and main categories of accounts as stated in the OEB's Accounting Procedures Handbook (the "APH") and the Uniform System of Accounts ("USoA") in the preparation of this Application.

DISTRIBUTION SERVICE TERRITORY AND DISTRIBUTION SYSTEM:

Description of Distributor:

COMMUNITIES SERVED:	Blenheim, Bothwell, Chatham, Dresden, Erieau, Merlin, Ridgetown, Thamesville, Tilbury, Wallaceburg, Wheatley and the Bloomfield Business Park
TOTAL SERVICE AREA:	76.9 sq km
RURAL SERVICE AREA:	0 sq km
DISTRIBUTION TYPE:	Electricity distribution
SERVICE AREA POPULATION:	74,761
MUNICIPAL POPULATION:	107,341

A map of Chatham-Kent Hydro’s Distribution Service Territory accompanies this Schedule as Appendix B.

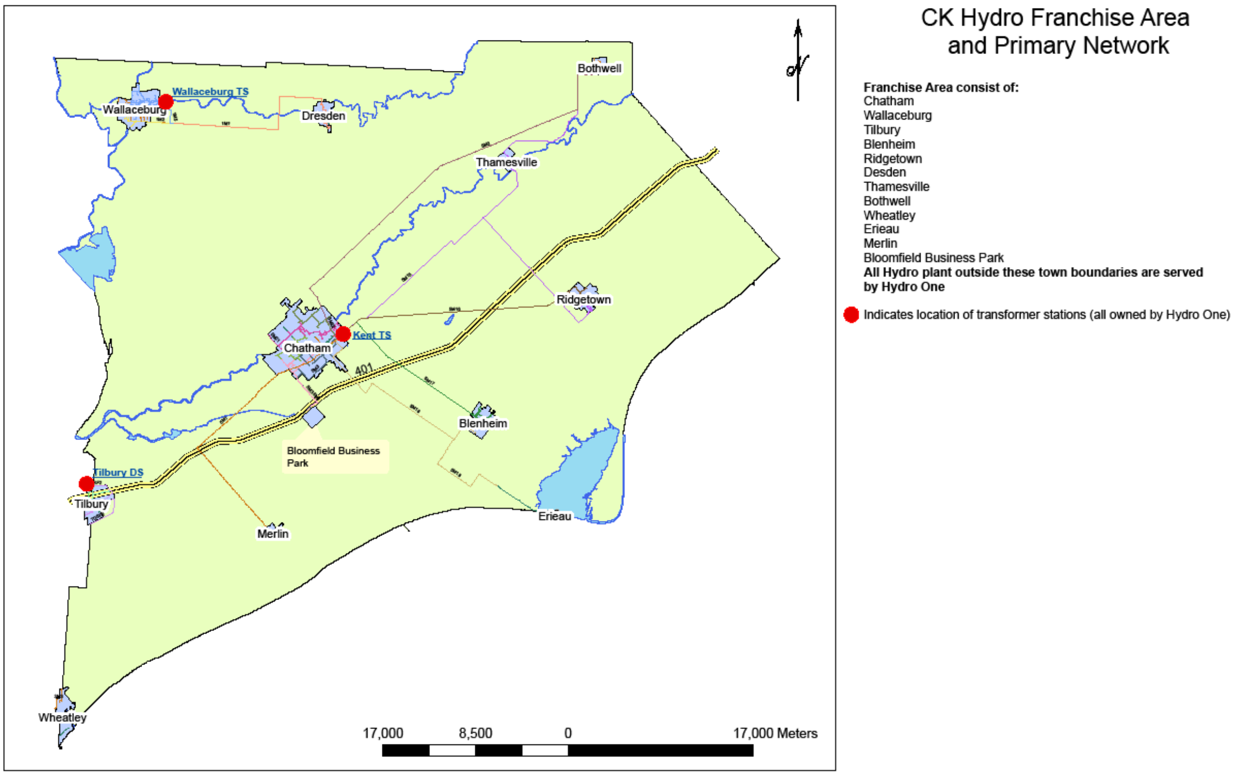
Individual schematic diagram of Chatham-Kent Hydro’s communities served by the Distribution System is attached in Appendix C.

APPENDIX B

MAP OF DISTRIBUTION SERVICE TERRITORY

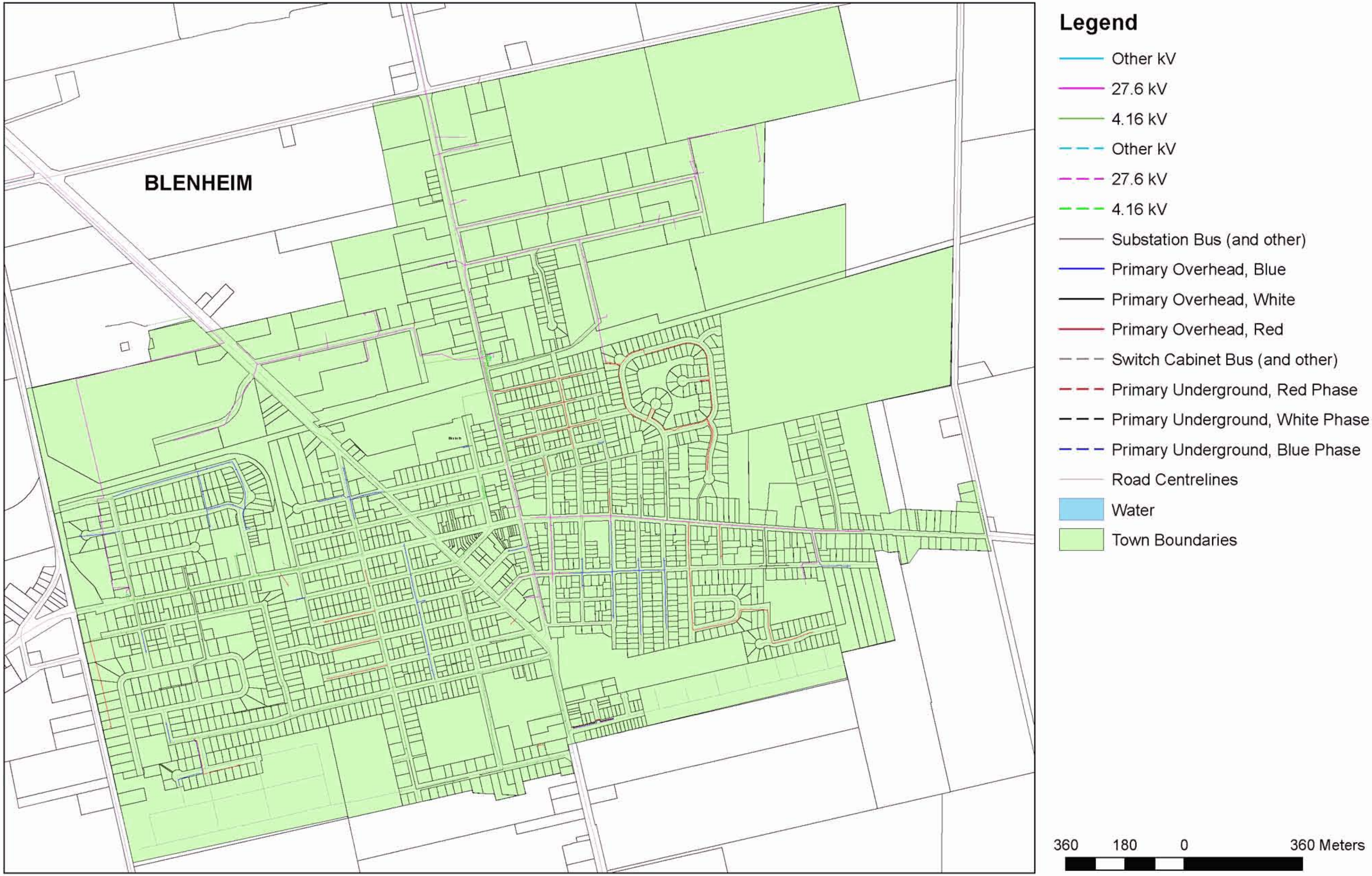
MAP OF DISTRIBUTION SERVICE TERRITORY

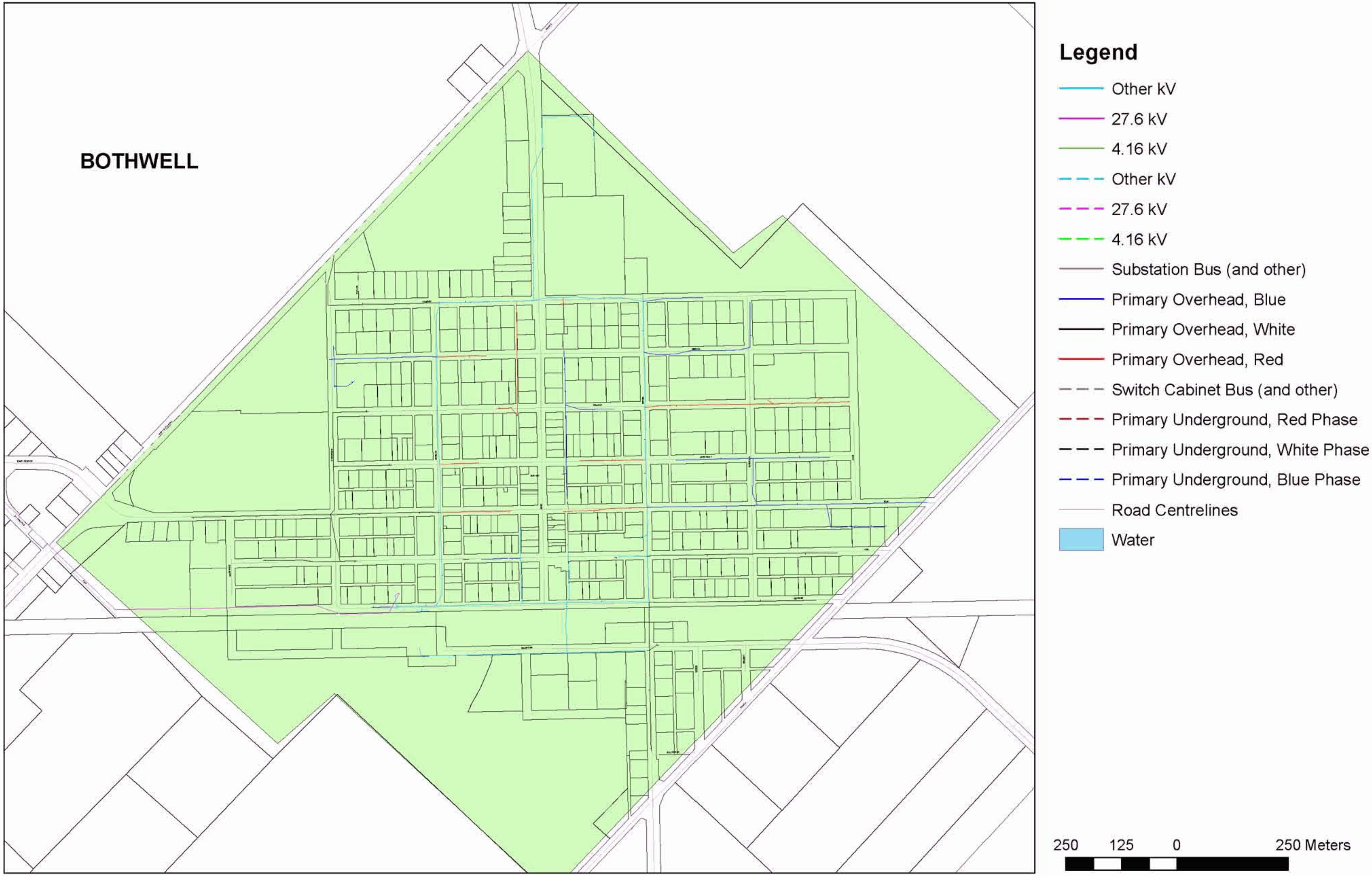
The outlined area represents the Chatham-Kent Hydro Service Area

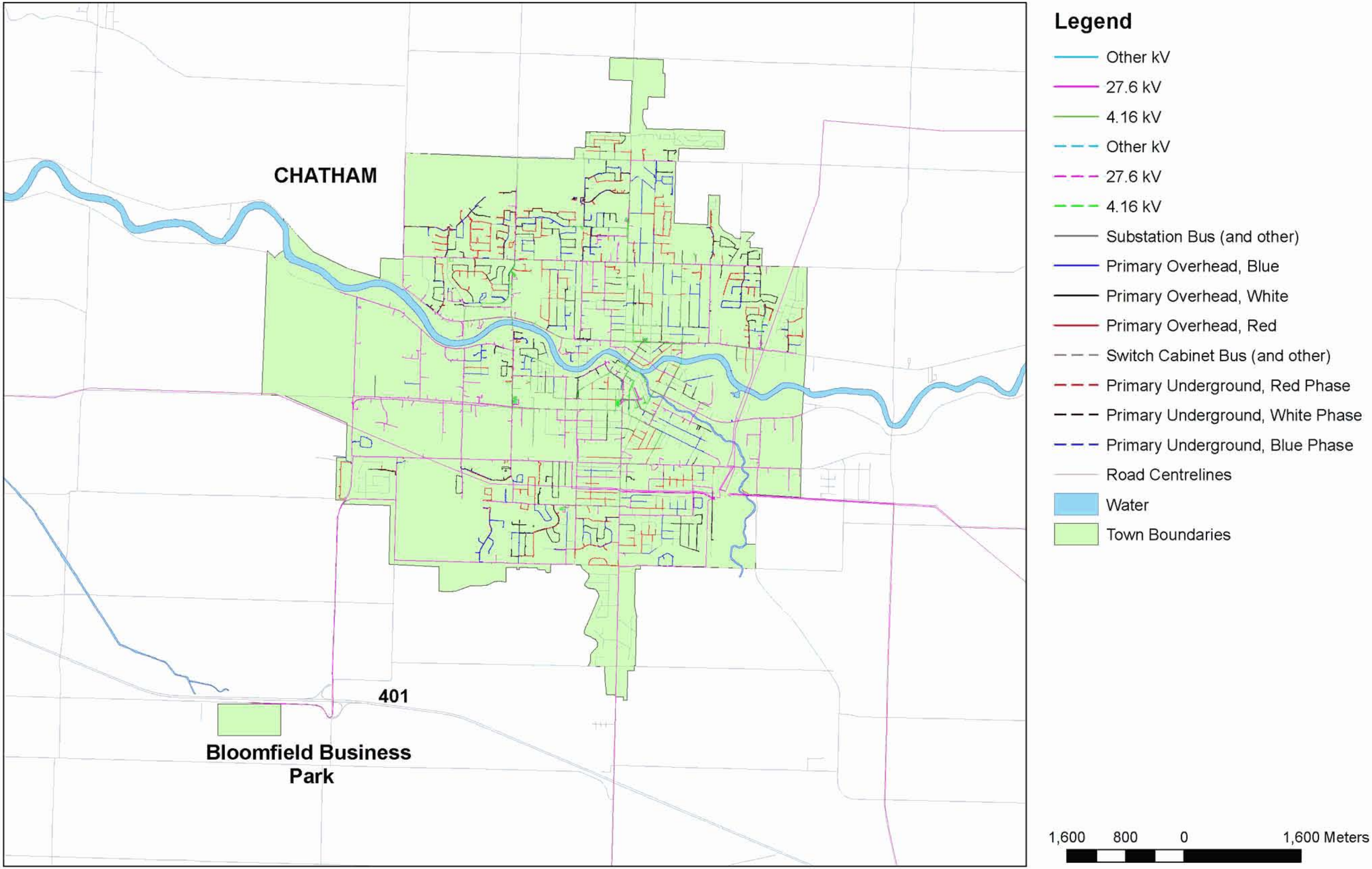


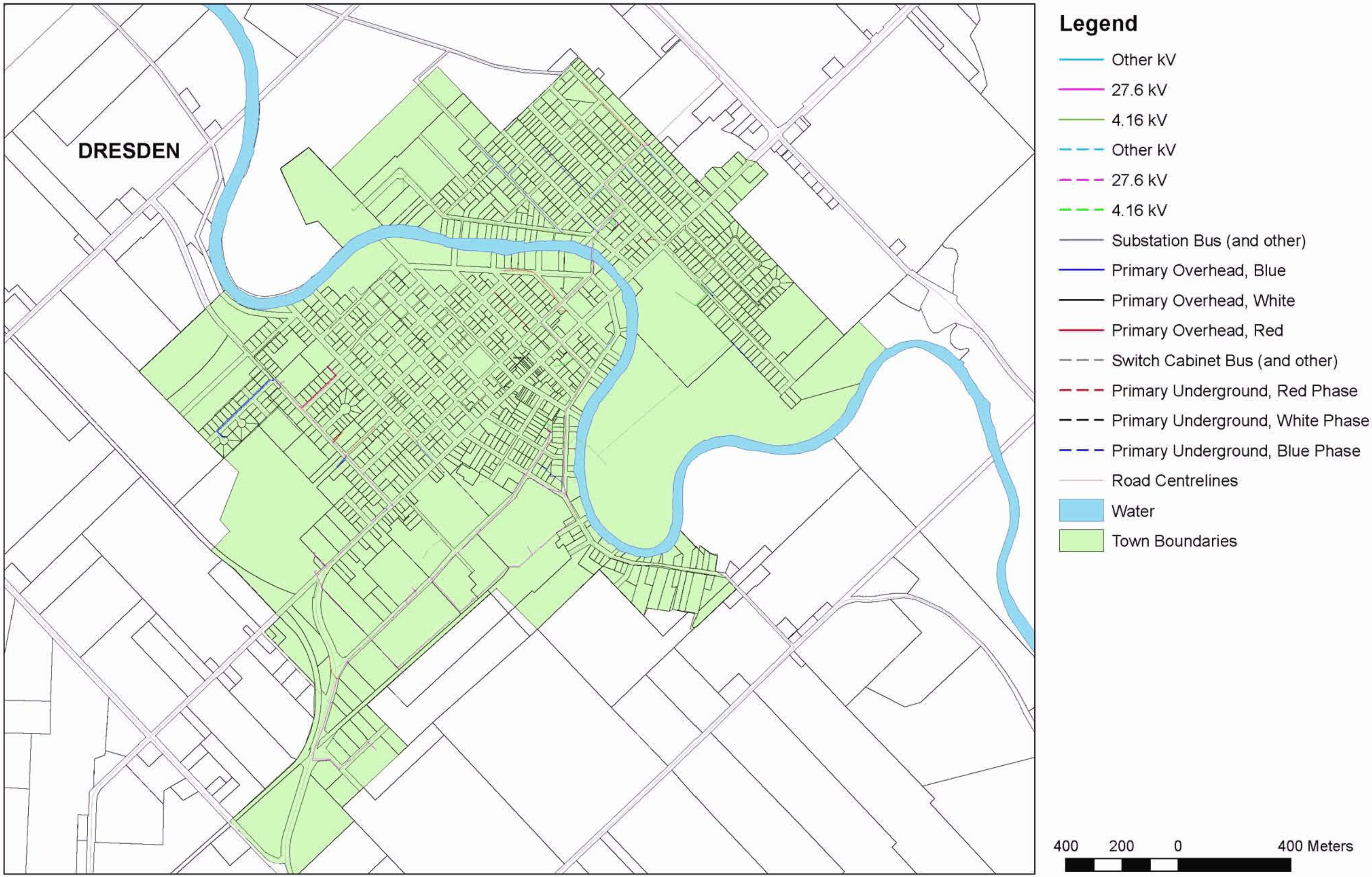
APPENDIX C

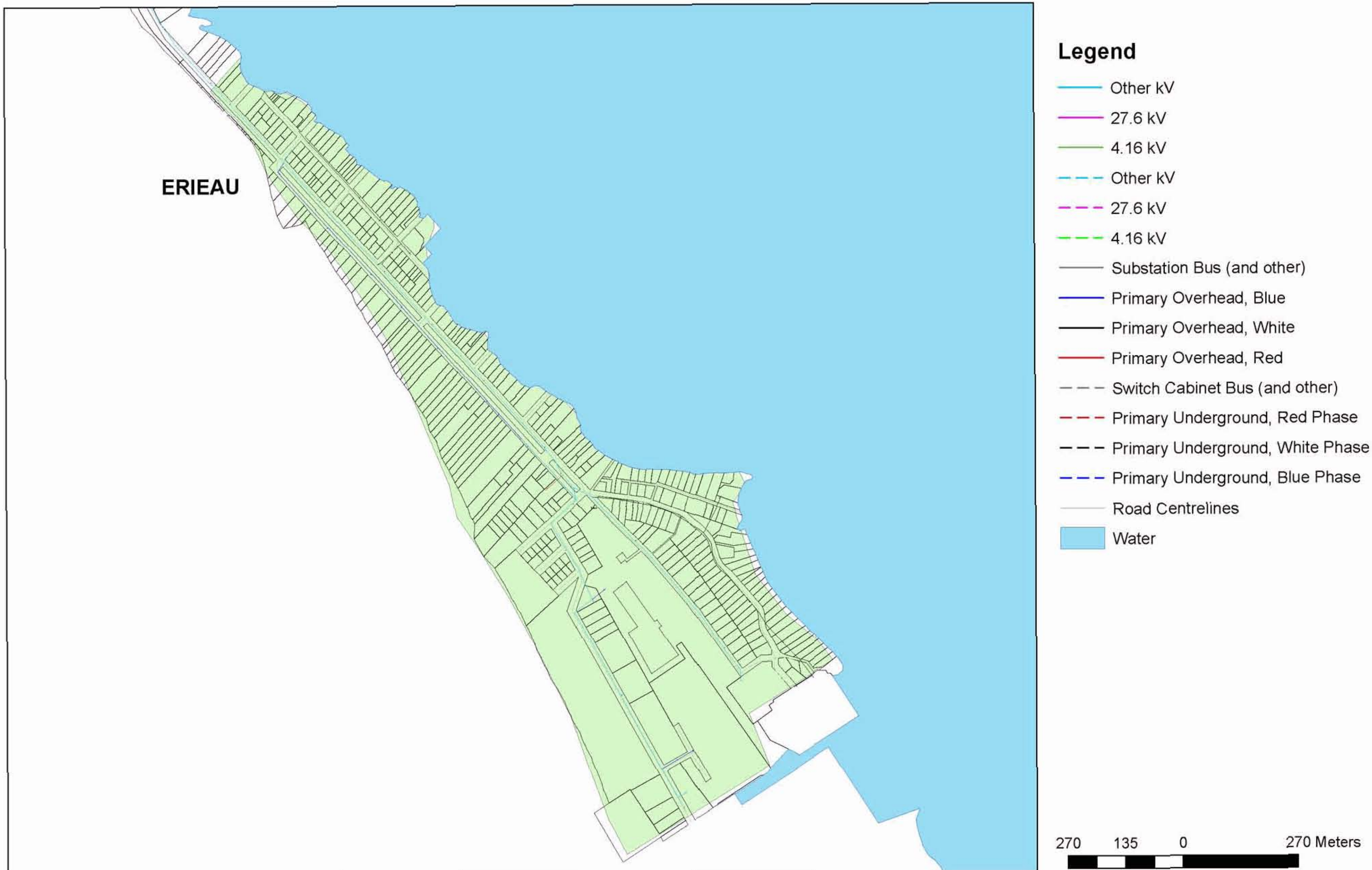
MAPS OF DISTRIBUTION SYSTEM

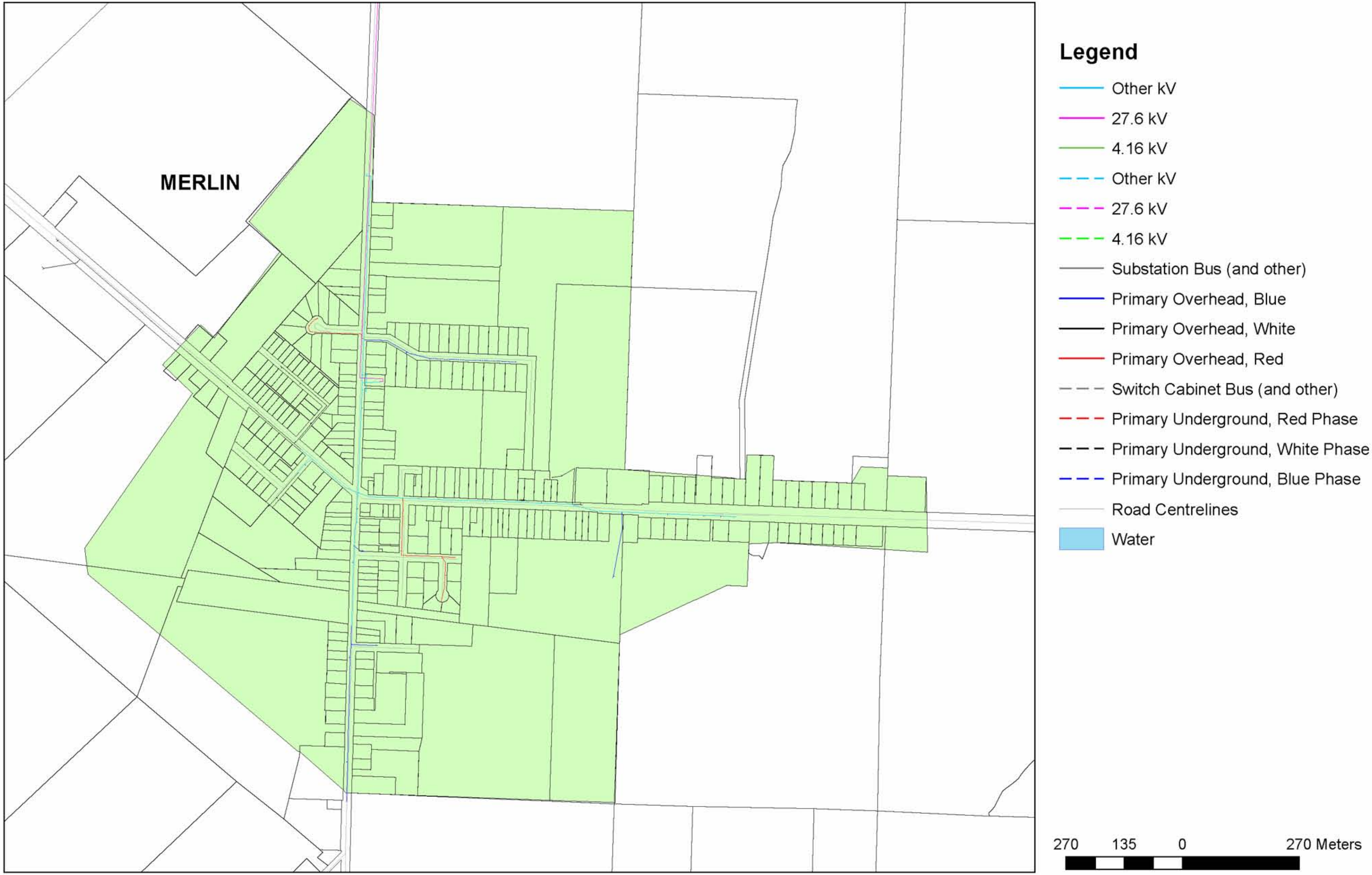

BLENHEIM
Legend
Other kV
27.6 kV
4.16 kV
Other kV
27.6 kV
4.16 kV
Substation Bus (and other)
Primary Overhead, Blue
Primary Overhead, White
Primary Overhead, Red
Switch Cabinet Bus (and other)
Primary Underground, Red Phase
Primary Underground, White Phase
Primary Underground, Blue Phase
Road Centrelines
Water
Town Boundaries
360 180 0 360 Meters

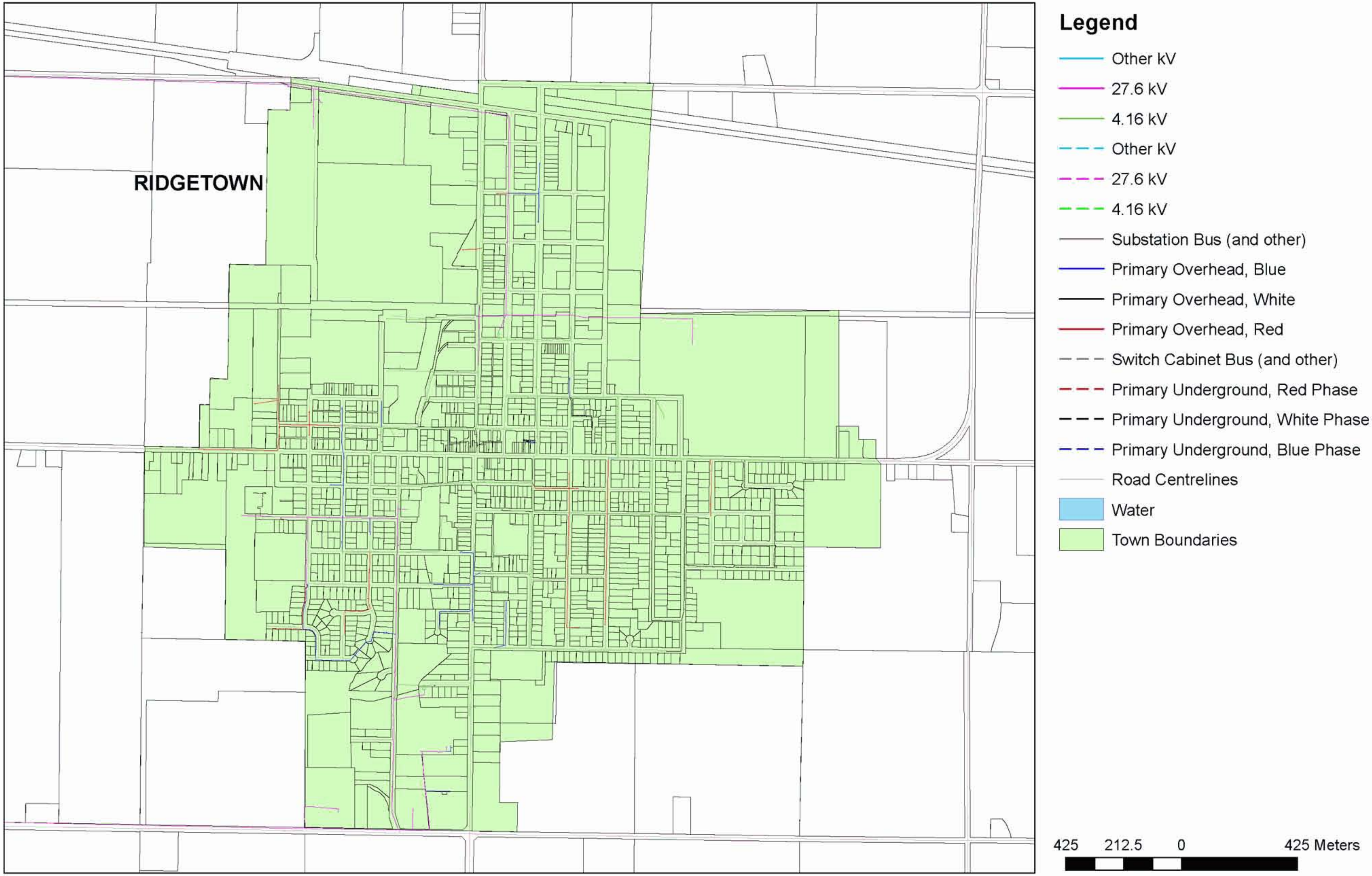

BOTHWELL
Legend
Other kV
27.6 kV
4.16 kV
Other kV
27.6 kV
4.16 kV
Substation Bus (and other)
Primary Overhead, Blue
Primary Overhead, White
Primary Overhead, Red
Switch Cabinet Bus (and other)
Primary Underground, Red Phase
Primary Underground, White Phase
Primary Underground, Blue Phase
Road Centrelines
Water
250 125 0 250 Meters

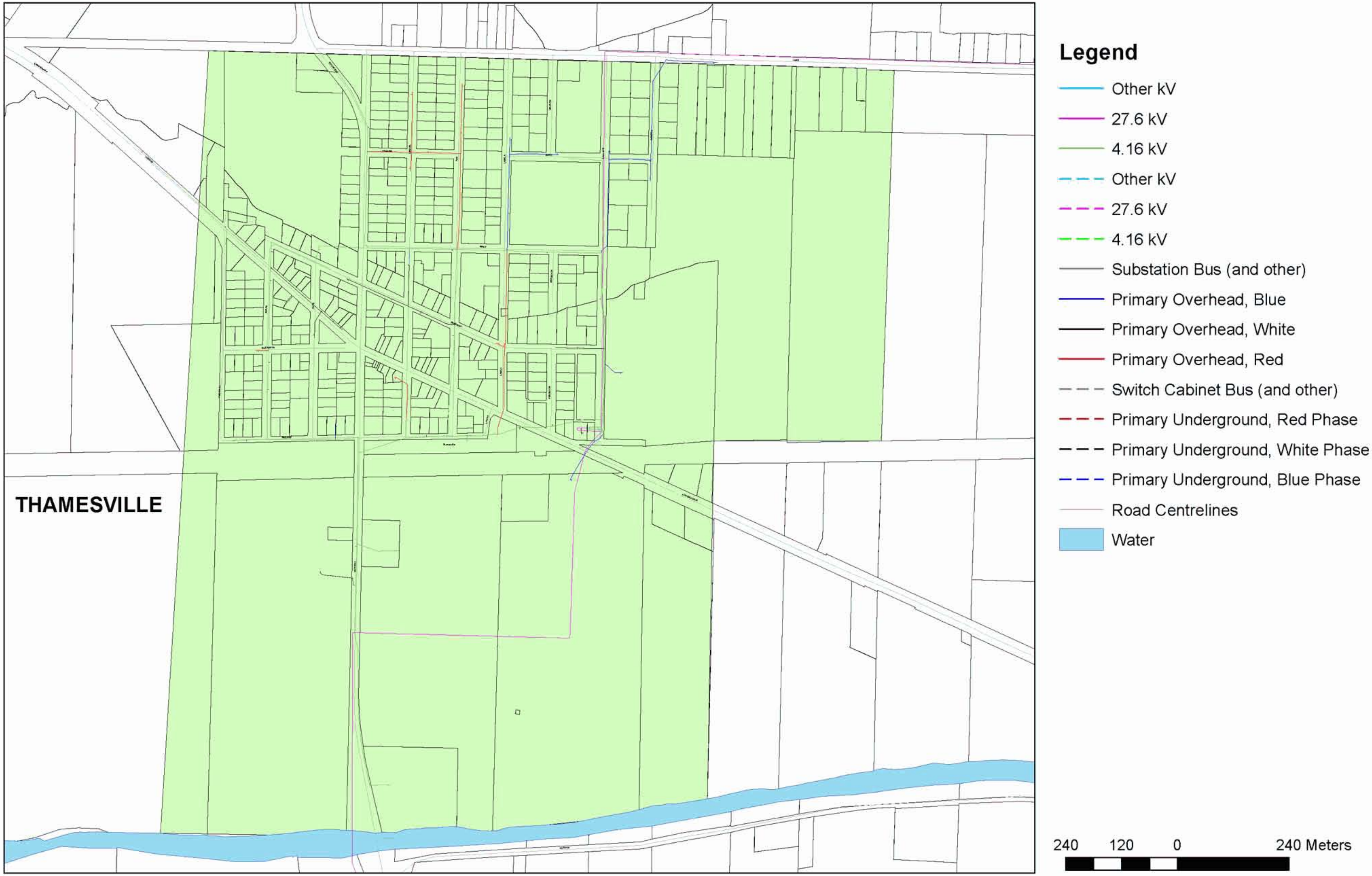

CHATHAM
401
Bloomfield Business Park
Legend
Other kV
27.6 kV
4.16 kV
Other kV
27.6 kV
4.16 kV
Substation Bus (and other)
Primary Overhead, Blue
Primary Overhead, White
Primary Overhead, Red
Switch Cabinet Bus (and other)
Primary Underground, Red Phase
Primary Underground, White Phase
Primary Underground, Blue Phase
Road Centrelines
Water
Town Boundaries
1,600 800 0 1,600 Meters

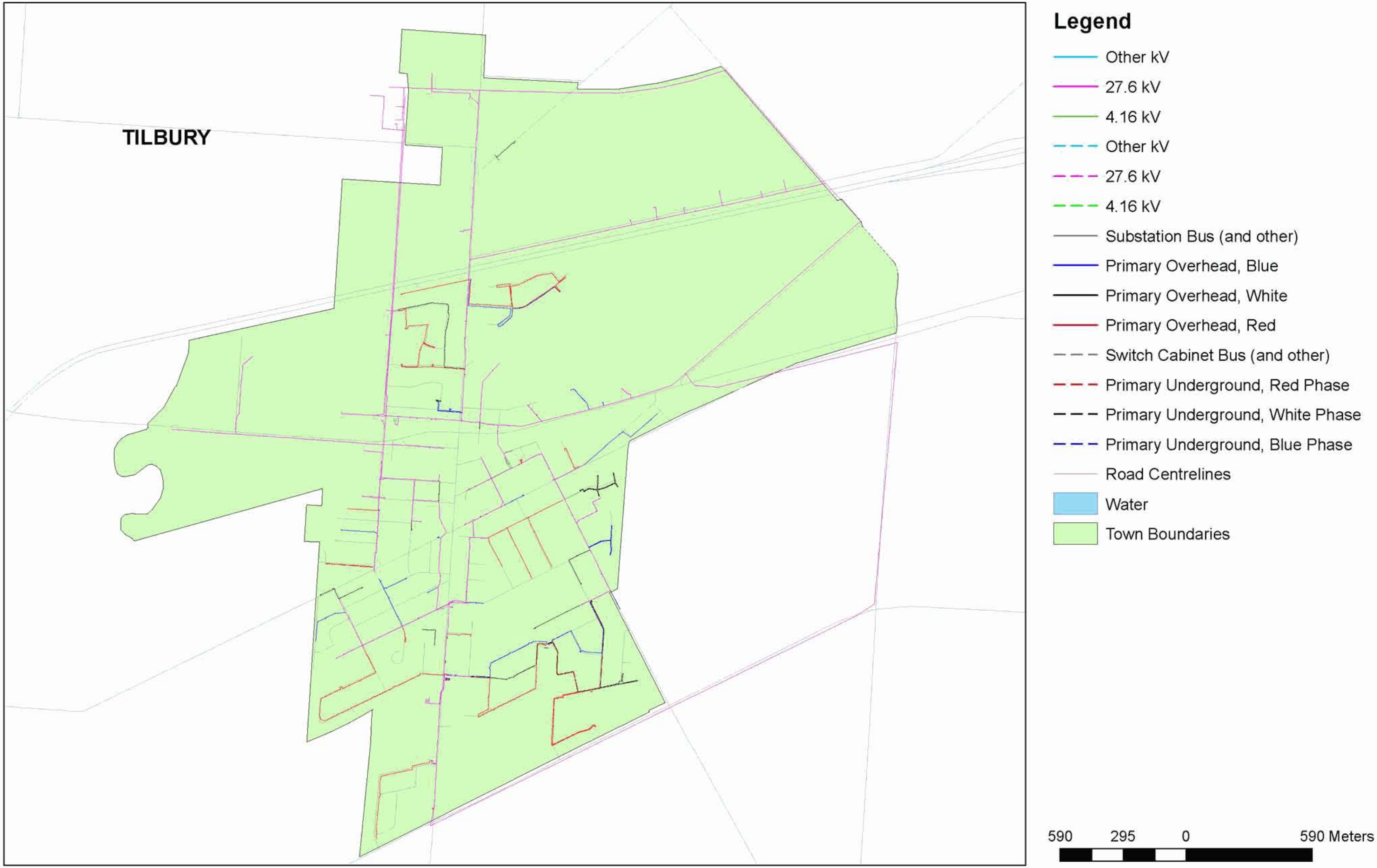

DRESDEN
Legend
Other kV
27.6 kV
4.16 kV
Other kV
27.6 kV
4.16 kV
Substation Bus (and other)
Primary Overhead, Blue
Primary Overhead, White
Primary Overhead, Red
Switch Cabinet Bus (and other)
Primary Underground, Red Phase
Primary Underground, White Phase
Primary Underground, Blue Phase
Road Centrelines
Water
Town Boundaries
400 200 0 400 Meters

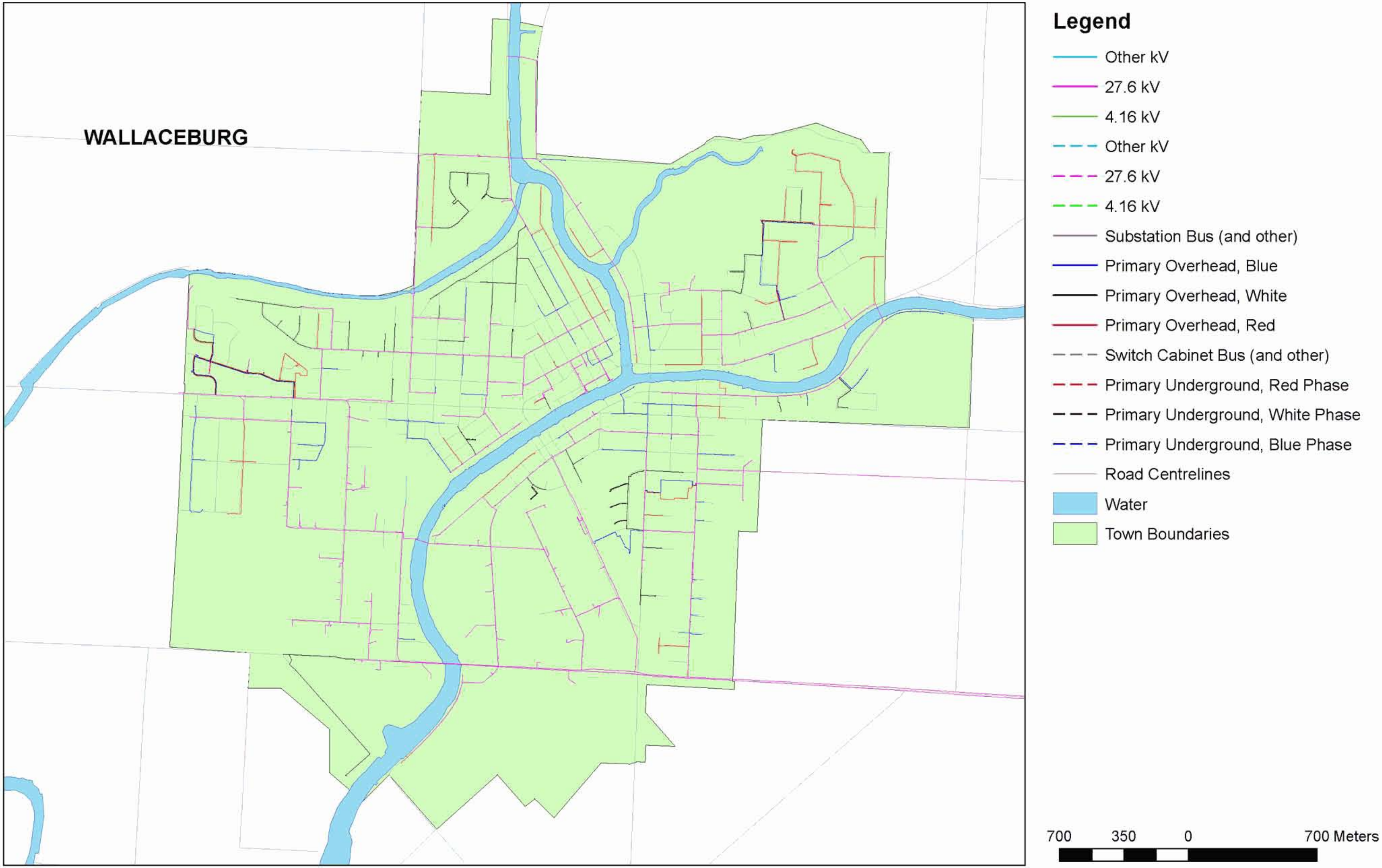

ERIEAU
Legend
Other kV
27.6 kV
4.16 kV
Other kV
27.6 kV
4.16 kV
Substation Bus (and other)
Primary Overhead, Blue
Primary Overhead, White
Primary Overhead, Red
Switch Cabinet Bus (and other)
Primary Underground, Red Phase
Primary Underground, White Phase
Primary Underground, Blue Phase
Road Centrelines
Water
270 135 0 270 Meters

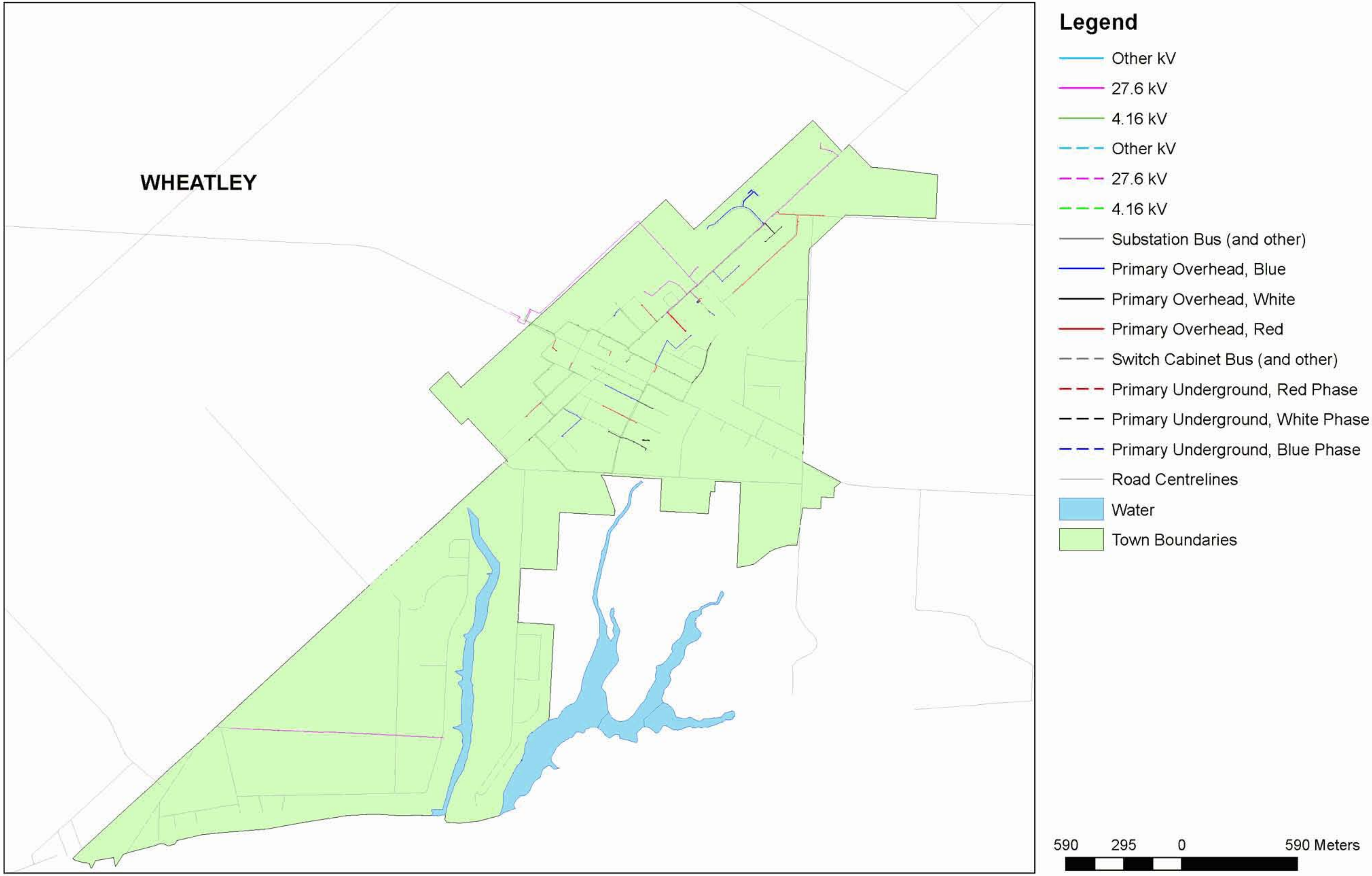

MERLIN
Legend
Other kV
27.6 kV
4.16 kV
Other kV
27.6 kV
4.16 kV
Substation Bus (and other)
Primary Overhead, Blue
Primary Overhead, White
Primary Overhead, Red
Switch Cabinet Bus (and other)
Primary Underground, Red Phase
Primary Underground, White Phase
Primary Underground, Blue Phase
Road Centrelines
Water
270 135 0 270 Meters


RIDGETOWN
Legend
Other kV
27.6 kV
4.16 kV
Other kV
27.6 kV
4.16 kV
Substation Bus (and other)
Primary Overhead, Blue
Primary Overhead, White
Primary Overhead, Red
Switch Cabinet Bus (and other)
Primary Underground, Red Phase
Primary Underground, White Phase
Primary Underground, Blue Phase
Road Centrelines
Water
Town Boundaries
425 212.5 0 425 Meters


THAMESVILLE
Legend
Other kV
27.6 kV
4.16 kV
Other kV
27.6 kV
4.16 kV
Substation Bus (and other)
Primary Overhead, Blue
Primary Overhead, White
Primary Overhead, Red
Switch Cabinet Bus (and other)
Primary Underground, Red Phase
Primary Underground, White Phase
Primary Underground, Blue Phase
Road Centrelines
Water
240 120 0 240 Meters


TILBURY
Legend
Other kV
27.6 kV
4.16 kV
Other kV
27.6 kV
4.16 kV
Substation Bus (and other)
Primary Overhead, Blue
Primary Overhead, White
Primary Overhead, Red
Switch Cabinet Bus (and other)
Primary Underground, Red Phase
Primary Underground, White Phase
Primary Underground, Blue Phase
Road Centrelines
Water
Town Boundaries
590 295 0 590 Meters


WALLACEBURG
Legend
Other kV
27.6 kV
4.16 kV
Other kV
27.6 kV
4.16 kV
Substation Bus (and other)
Primary Overhead, Blue
Primary Overhead, White
Primary Overhead, Red
Switch Cabinet Bus (and other)
Primary Underground, Red Phase
Primary Underground, White Phase
Primary Underground, Blue Phase
Road Centrelines
Water
Town Boundaries
700 350 0 700 Meters


WHEATLEY
Legend
Other kV
27.6 kV
4.16 kV
Other kV
27.6 kV
4.16 kV
Substation Bus (and other)
Primary Overhead, Blue
Primary Overhead, White
Primary Overhead, Red
Switch Cabinet Bus (and other)
Primary Underground, Red Phase
Primary Underground, White Phase
Primary Underground, Blue Phase
Road Centrelines
Water
Town Boundaries
590 295 0 590 Meters

LIST OF NEIGHBOURING UTILITIES:

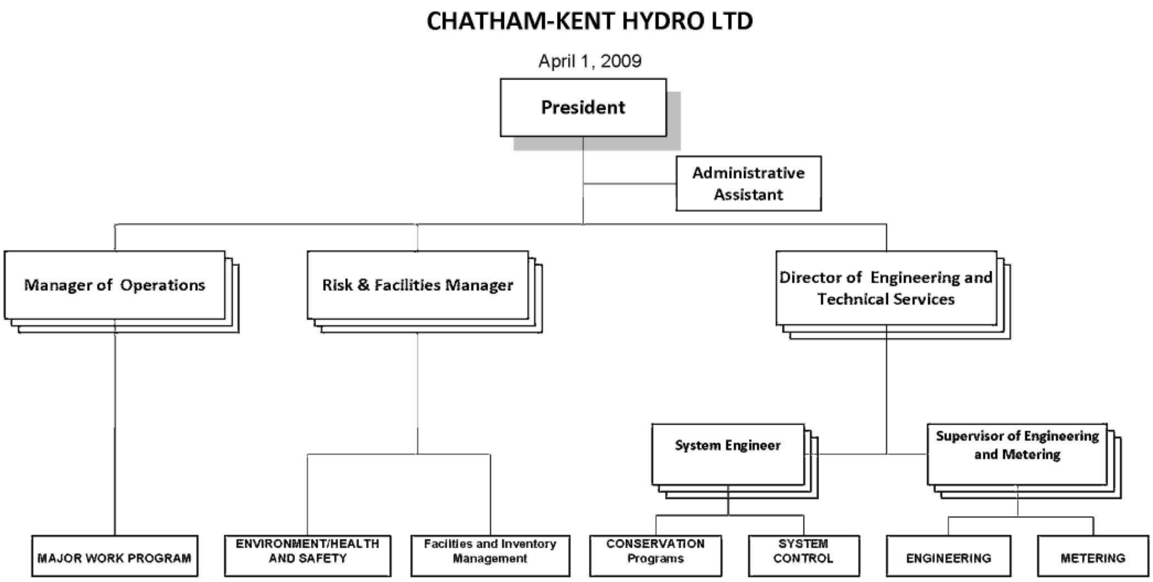
Chatham-Kent Hydro is comprised of twelve geographically separate service territories and each territory is bounded by Hydro One Networks Inc.

EXPLANATION OF HOST AND EMBEDDED UTILITIES:

Chatham-Kent Hydro has two services areas, the Chatham and Bloomfield Business Park service areas that are directly connected to the Hydro One transmission system. This represents approximately 50% of Chatham-Kent Hydro's load. The remaining areas are embedded in Hydro One's distribution system; Blenheim, Bothwell, Dresden, Erieau, Merlin, Thamesville, Tilbury, Ridgetown, Wallaceburg and Wheatley.

UTILITY ORGANIZATION STRUCTURE:

Chatham-Kent Hydro's organizational chart follows;



CORPORATE ENTITIES RELATIONSHIP CHART

Chatham-Kent Hydro is wholly owned by Chatham-Kent Energy. Chatham-Kent Hydro has two affiliates, Chatham-Kent Utility Services and Middlesex Power Distribution Corporation.

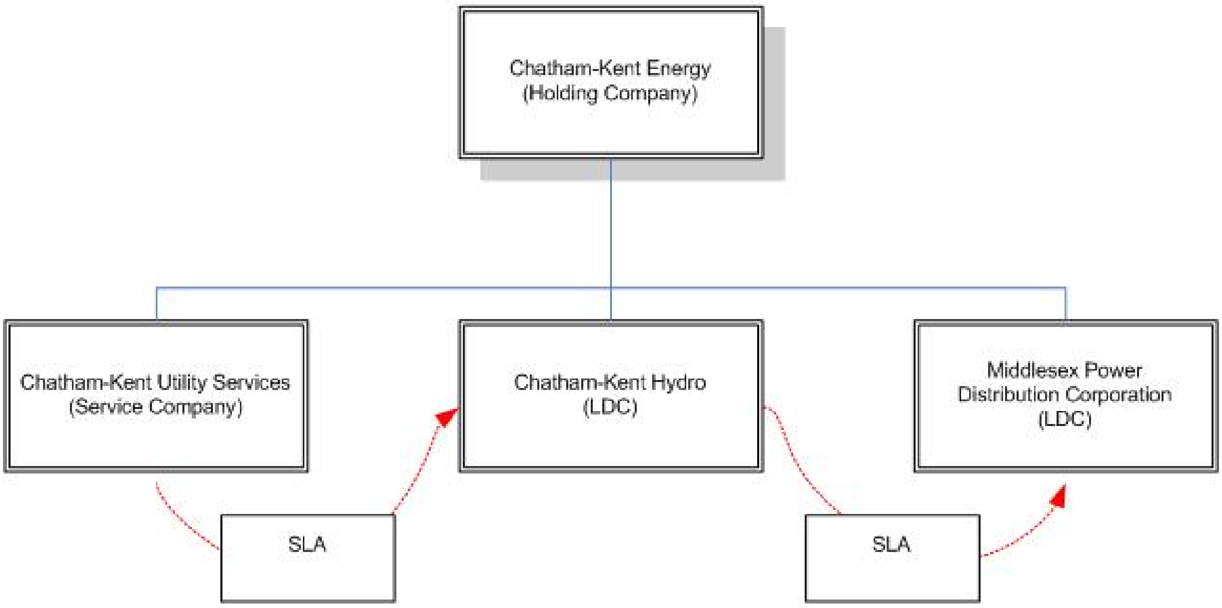
Description of the Businesses of the affiliates follows;

Chatham-Kent Energy Inc. is owned by the Municipality of Chatham-Kent (90%) and Corix Utilities (10%) and holds all of the shares of Chatham-Kent Hydro Inc. and Middlesex Power Distribution Corporation, licenced electricity distribution companies, and Chatham-Kent Utility Services Inc., an unregulated service provider to Chatham-Kent Hydro Inc. and Middlesex Power Distribution Corporation.

Middlesex Power Distribution Corporation owns, operates and manages the assets associated with the distribution of electrical power within the territory set out in Electricity Distribution Licence ED-2003-0059.

Chatham-Kent Utility Services Inc. provides billing, collection, administration, financial and regulatory services to Chatham-Kent Hydro Inc., Middlesex Power Distribution Corporation and the Chatham-Kent Public Utilities Commission, which operates the water and waste-water systems in the Municipality of Chatham-Kent.

CHATHAM-KENT ENERGY INC.



PLANNED CHANGES IN CORPORATE AND ORGANIZATIONAL STRUCTURE:

No changes to Chatham-Kent Hydro's corporate and operational structures are planned.

STATUS OF BOARD DIRECTIVES FROM PREVIOUS BOARD DECISIONS:

There are no outstanding OEB directives applicable specifically to Chatham-Kent Hydro as at the date of filing this Application.

Overview:

SUMMARY OF THE APPLICATION:

Preamble

Chatham-Kent Hydro has submitted this Application in order to meet its Corporate Mission and Corporate Goals as outlined below. Chatham-Kent Hydro's vision is to be a leading and progressive Ontario distribution company that maximizes value to its customers and shareholders. The increased rates are required to:

1) Maintain current capital investment levels in infrastructure to ensure a reliable distribution system;
2) Continue with training programs for linepersons needed to meet future staffing requirements;
3) Manage staffing levels and skills to ensure regulatory compliance, promote conservation programs along with the introduction of smart meters, and implement reporting changes resulting from the adoption of International Financial Reporting Standards; and
4) To provide a reasonable rate of return to the Shareholders.

Chatham-Kent Hydro's Mission Statement is as follows:

Chatham-Kent Hydro's mission is to deliver electricity from the transmission grid to our customers in a safe, reliable and efficient manner. Chatham-Kent Hydro is committed to competitive rates, environmental responsibility and to continue on the leading edge of technical innovation.

Chatham-Kent Hydro's priorities are defined in its Corporate Goals:

1. **Maintain a robust and safe workplace:**
The safety of Chatham-Kent Hydro's workers and the public is a primary objective. Chatham-Kent Hydro is a leader in safety after having received the President's award in 2006 for 250,000 hours with no lost time injuries and by achieving Gold status in the Electrical Utilities Safety Association Path to Zero Injuries "Zero Quest" awards program.

2. **Maintain competitive rates:**

   Chatham-Kent Hydro has operated efficiently and has been recognized in the "Benchmarking the Costs of Ontario Power Distributors" report by the Pacific Economics Group as one the lowest operating cost LDCs in the Province (see Exhibit 4, Tab 1, Schedule 1, Appendix A)

3. **Develop and Utilize Smart Grid Technology to improve Customer Service and ensure an efficient distribution system:**

   Chatham-Kent Hydro has selected AMI, SCADA and GIS systems that are the backbones of a smart grid that will improve reliable communication and control devices that will enable peak reduction and encourage renewable generation connections.

4. **Research and develop Green Technology and Sustainable environmental management:**

   Chatham-Kent Hydro has been aggressive in the elimination of PCB contaminated devices from its distribution system and is on a program to be PCB free by 2010. Chatham-Kent Hydro has also chosen more environmentally responsible processes including retrofitting meters to smart meters where possible to reduce scrap levels and planting trees to offset for the trimming of trees required to ensure powerlines are safe and reliable.

In keeping with this vision to pursue health and safety as its top priority, Chatham-Kent Hydro is actively involved in public safety initiatives highlighted by its annual grade 4/5 student training programs at the Chatham-Kent Children's Safety Village. This non-profit organization provides safety training including electricity safety training for over 800 local school children annually that visit the facilities.

Within its service territory, Chatham-Kent Hydro has partnered with local agencies and businesses to deliver innovative conservation and demand management programs.

Chatham-Kent Hydro has consistently exceeded the OEB's Service Quality Indicators and, as set out in Table 1-1 below, has targeted to maintain its performance at levels equal to or above the OEB's standards in 2009 and 2010.

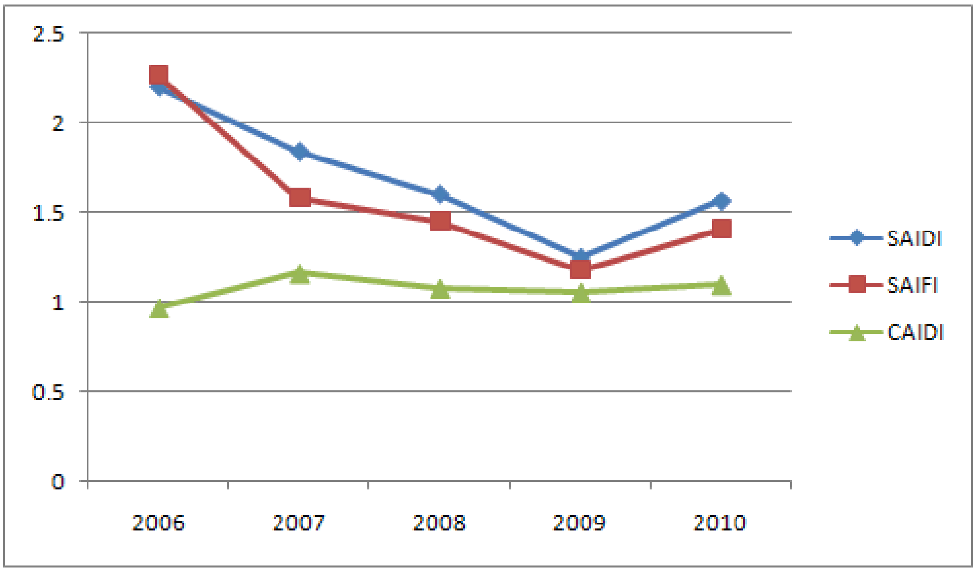
Table 1-1
CHATHAM-KENT HYDRO INC.'S SERVICE QUALITY INDICATORS
AVERAGE PERFORMANCE FOR 2008

Appointments Met – at the appointed time		
SQI Standard: 90% of the time		
2008 Actual	**2009 Target**	**2010 Target**
99.60%	100%	100%
Telephone Accessibility – answered in person within 30 seconds		
SQI Standard: 65% of the time		
2008 Actual	**2009 Target**	**2010 Target**
78.60%	80%	85%
Underground Cable Locates – within 5 working days		
SQI Standard: 90% of the time		
2008 Actual	**2009 Target**	**2010 Target**
90.40%	92%	94%
Connection of New Services –within 5 working days		
SQI Standard: 90% of the time		
2008 Actual	**2009 Target**	**2010 Target**
97.00%	98%	98%
Emergency Response – Urban within 60 minutes and Rural within 120 minutes		
SQI Standard: 90% of the time		
2008 Actual	**2009 Target**	**2010 Target**
92.50%	94%	95%
Written Responses to Inquiries – within 10 working days		
SQI Standard: 80% of the time		
2008 Actual	**2009 Target**	**2010 Target**
100.0%	100%	100%

Chatham-Kent Hydro tracks service reliability statistics SAIDI (System Average Interruption Duration Index), SAIFI (System Average Interruption Frequency Index) and CAIDI (Customer

Average Interruption Duration Index). The following table shows actual results for the past year and targets for 2009 and 2010.

	2006	2007	2008	2009	2010
SAIDI	2.199	1.839	1.602	1.249	1.563
SAIFI	2.265	1.582	1.453	1.179	1.405
CAIDI	0.971	1.163	1.08	1.059	1.101



The 2009 forecast is based upon 7 months of actual experience and is low due to minimal severe weather during the summer months. The 2010 forecasted rates are based upon the average of the three previous years.

Chatham-Kent Hydro is committed to the reliability of the distribution system and has set target indices for SAIDI, SAIFI and CAIDI in its 2009 Business Plan. In order to meet these targets Chatham-Kent Hydro will need to continue making capital investments in infrastructure.

Purpose and Need

Chatham-Kent Hydro's requested revenue requirement for 2010 in the amount of $15,825,336 includes the recovery of its costs to provide distribution services, its permitted Return on Equity

"ROE" and the funds necessary to service its debt as it transitions to a 60%/40% debt equity ratio by 2010.

When forecasted energy and demand levels for 2010 are considered, Chatham-Kent Hydro estimates that its present rates will produce a deficiency in gross distribution revenue of $1,799,705 for the 2010 Test Year. Should this revenue deficiency continue, Chatham-Kent Hydro will not be able to sustain the current standard of capital investment, operation and operations and maintenance program and powerline maintenance training programs required to ensure a safe and reliable distribution system.

Therefore, Chatham-Kent Hydro seeks the OEB's approval to revise its electricity distribution rates. The rates proposed to recover its projected revenue requirement and other relief sought are set out in Exhibit 1, Tab 1, Schedule 2, Appendix A and Exhibit 8, Tab 1, Schedule 9 to this Application.

The information presented in this Application is Chatham-Kent Hydro's forecasted results for its 2010 Test Year. Chatham-Kent Hydro is also presenting the historical actual information for fiscal 2006, OEB-Approved data for 2006, actual information for fiscal 2007, actual information for fiscal 2008 and forecast results for the 2009 Bridge Year.

Timing

The financial information supporting the Test Year for this Application will be Chatham-Kent Hydro's fiscal year ending December 31, 2010 (the "2010 Test Year"). However, this information will be used to set rates for the period May 1, 2010 to April 30, 2011.

Customer Impact

The Applicant has set out the total bill impacts (in percentage and dollar terms) arising out of the rates proposed in this Application in Table 1-2, on the following page.

Table 1-2
TOTAL CUSTOMER BILL IMPACT – PERCENT & DOLLAR

Class – Typical Usage	Monthly Dollar Impact	Total Bill Impact %
Residential - 800 kWh		
2010 total bill	93.60	0.9%
2009 total bill	92.76	
General Service <50 kW – 2,000 kWh		
2010 total bill	229.37	2.3%
2009 total bill	224.00	
General Service >50 kW - 250 kW		
2010 total bill	9,426.40	6.9%
2009 total bill	8,815.60	
General Service Intermediate - 4,000 kW		
2010 total bill	146,411.85	0.0%
2009 total bill	146,388.04	
Street Lighting		
2010 total bill	61,714.65	30.9%
2009 total bill	47,143.13	
Sentinel Lighting		
2010 total bill	5,709.15	40.8%
2009 total bill	4,055.11	
Unmetered Scattered Load		
2010 total bill	97,360.35	-0.4%
2009 total bill	97,741.89	
Standby Charge - 8,000 kW		
2010 total bill	231,276.47	2.4%
2009 total bill	225,864.52	

Capital Structure

Chatham-Kent Hydro has assumed a 40/60 capital structure in 2010 as outlined in the Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario Electricity Distributors dated December 20, 2006 (the "Cost of Capital Report").

Return on Equity

Chatham-Kent Hydro has assumed a return on equity of 8.01% consistent with the Cost of Capital Parameter Updates for 2009 Cost of Service Applications issued by the OEB on March 8, 2009. Chatham-Kent Hydro understands the OEB will be finalizing the return on equity for 2010 rates based on January 2010 market interest rate information.

Capital Expenditures

Chatham-Kent Hydro continues to expand and reinforce its distribution system in order to meet the demand of new and existing customers in its service territory. Expenditures are also being made to meet requirements of both the OEB and Independent Electricity System Operator (the "IESO") including load transfers and primary metering points. Some of the highlights in the 2010 capital program are: the system supporting the downtown core of the Chatham service area requires a rebuild from both overhead and the under river system; continuation of the conversion program from 4 kV to 27.6 kV system; new vehicles are required to maintain the system; and land and building upgrades These capital expenditures are required to meet the SQI targets and to provide a safe and reliable system for employees and customers.

Operating and Maintenance Costs

Chatham-Kent Hydro will be incurring some new costs in 2010 in order to meet the regulatory requirements, meet customer expectations as well as hiring new staff for apprenticeship programs since the workforce is aging and will be retiring over the next few years.

As such Chatham-Kent Hydro will be implementing monthly billing as a response to meeting the Low Energy Users requirements and the OEB's LEAP requirements. Chatham-Kent Hydro will be hiring five new staff, linepersons and meter technicians, to manage the expected retirements.

Chatham-Kent Hydro will also be increasing services to strengthen its computer network security in order to manage the data transfer requirements of smart meters and interface with the Meter Data Management Repository with the IESO.

Chatham-Kent Hydro a Low Cost Service Provider

Based on the OEB's *Comparison of Ontario Electricity Distributors Costs* (OEB File No. EB-2006-0268), as updated with 2007 Data issued on June 25, 2009, Chatham-Kent Hydro's OM&A costs per customer compare favorably with its "Mid Size Southern Medium-High Undergrounding" cohort. In 2007, the average OM&A cost per customer for the cohort was $214.00 while Chatham-Kent Hydro's cost was $164.00. Over the 3-year average from 2005 to 2007, Chatham-Kent Hydro's cost was $162.00 while the average for the cohort was $208.00. Details of the calculations supporting this analysis are included in Appendix D to this Schedule.

APPENDIX D

COMPARISON OF CHATHAM-KENT HYDRO INC.'S 2007 OM&A COSTS TO "Mid Size Southern Medium-High Undergrounding" COHORT GROUPING

SUMMARY OF THE APPLICATION

COMPARISON OF CHATHAM-KENT HYDRO INC.
OM&A Costs To "Mid Size Southern Medium-High Undergrounding" Cohort Grouping

Cohort Groupings	Total OM&A	
By Distribution Company	2005-2007 3 Year Avg.	2007
E.L.K. Energy Inc.	$ 155.00	$ 182.00
Wasaga Distribution Inc.	$ 157.00	$ 159.00
Chatham-Kent Hydro Inc.	**$ 162.00**	**$ 164.00**
Peterborough Distribution Incorporated	$ 181.00	$ 192.00
Festival Hydro Inc.	$ 182.00	$ 185.00
Welland Hydro-Electric System Corp.	$ 183.00	$ 209.00
Kingston Electricity Distribution Limited	$ 189.00	$ 182.00
Westario Power Inc.	$ 203.00	$ 196.00
COLLUS Power Corp.	$ 211.00	$ 225.00
St. Thomas Energy Inc.	$ 216.00	$ 214.00
Essex Powerlines Corporation	$ 221.00	$ 206.00
Woodstock Hydro Services Inc.	$ 223.00	$ 228.00
Niagara Falls Hydro Inc.	$ 247.00	$ 255.00
Bluewater Power Distribution Company	$ 261.00	$ 256.00
Erie Thames Powerline Corporation	$ 329.00	$ 356.00
Average for Cohort Group	**$ 208.00**	**$ 214.00**

SOURCE:

Comparison of Ontario Electricity Distributors Costs EB-2006-0268, updated with 2007 Data Issued June 25, 2009.

BUDGET DIRECTIVES:

Chatham-Kent Hydro compiles budget information for the three major components of the budgeting process: revenue forecasts; operating and maintenance expense forecast; and capital budget forecast. This budget information is compiled for both the 2009 Bridge Year and the 2010 Test Year.

Revenue Forecast

Chatham-Kent Hydro's energy sales and revenue forecast model was updated to reflect more recent information. This model was then used to prepare the throughput volume and revenue forecast at existing rates for fiscal 2009 and 2010. The load forecast is outlined in Exhibit 3, Tab 2, Schedule 1 and is a result of detailed regression analysis. Since the load forecast is a key component of any rate application and in particular to Chatham-Kent Hydro’s application due to the reduction in load, Chatham-Kent Hydro has a very detailed regression analysis. In order to have as accurate of a regression analysis as possible Chatham-Kent Hydro used ten variables. The variables used related to weather, economic conditions, population and customers to name a few. The resulting regression analysis had a predictive formula of a statistical R^2 of 93% which generally indicates the formula has a very good fit.

Operating, Maintenance and Administration (“OM&A”) Expense Forecast

The OM&A expenses for the 2009 Bridge Year and the 2010 Test Year have been based on an in-depth review of operating priorities and requirements and is strongly influenced by prior year experience. Each item is reviewed account by account for each of the forecast years with indirect costs allocated to direct costs for budget purposes.

Capital Budget

The capital budget forecast 2009 and 2010 is influenced, among other factors, by Chatham-Kent Hydro’s capacity to finance capital projects. Indirect costs are allocated to direct costs in the capital budget. All proposed capital projects are assessed in order to meet the objectives in selecting capital programs that are outlined in Exhibit 2, Tab 3, Schedule 2.

Chatham-Kent Hydro Board Approval

Chatham-Kent Hydro's Board of Directors has been informed of the main drivers in this application and have given their support to the direction and outcomes of this application.

CHANGES IN METHODOLOGY:

Chatham-Kent Hydro is not requesting any changes in methodology in the current proceeding.

CALCULATION OF REVENUE DEFICIENCY:

Description	2009 Bridge	2010 Test Existing Rates	2010 Test - Required Revenue
Revenue			
Revenue Deficiency			**1,799,705**
Distribution Revenue	12,800,555	12,838,181	12,838,181
Other Operating Revenue (Net)	1,181,584	1,187,450	1,187,450
Smart Meter Deferral Account Adjustment			
Total Revenue	**13,982,139**	**14,025,631**	**15,825,336**
Costs and Expenses			
Administrative & General, Billing & Collecting	4,064,299	4,574,078	4,574,078
Operation & Maintenance	1,761,886	2,229,034	2,229,034
Depreciation & Amortization	3,701,765	3,815,361	3,815,361
Property Taxes	0	0	0
Capital Taxes	91,104	30,805	30,805
Deemed Interest	2,088,763	2,422,602	2,422,602
Total Costs and Expenses	**11,707,817**	**13,071,881**	**13,071,881**
Less OCT Included Above			
Total Costs and Expenses Net of OCT	**11,707,817**	**13,071,881**	**13,071,881**
Utility Income Before Income Taxes	**2,274,322**	**953,750**	**2,753,455**
Income Taxes:			
Corporate Income Taxes	876,644	398,949	956,858
Total Income Taxes	**876,644**	**398,949**	**956,858**
Utility Net Income	**1,397,678**	**554,801**	**1,796,597**
Capital Tax Expense Calculation:			
Total Rate Base	55,490,686	56,073,568	56,073,568
Exemption	15,000,000	15,000,000	15,000,000
Deemed Taxable Capital	**40,490,686**	**41,073,568**	**41,073,568**
Ontario Capital Tax	91,104	30,805	30,805
Income Tax Expense Calculation:			
Accounting Income	2,274,322	953,750	2,753,455
Tax Adjustments to Accounting Income	382,175	333,183	333,183
Taxable Income	**2,656,497**	**1,286,933**	**3,086,638**
Income Tax Expense	876,644	398,949	956,858
	33.00%	31.00%	31.00%
Actual Return on Rate Base:			
Rate Base	55,490,686	56,073,568	56,073,568
Interest Expense	2,088,763	2,422,602	2,422,602
Net Income	1,397,678	554,801	1,796,597
Total Actual Return on Rate Base	**3,486,441**	**2,977,403**	**4,219,200**
Actual Return on Rate Base	6.28%	5.31%	7.52%
Required Return on Rate Base:			
Rate Base	55,490,686	56,073,568	56,073,568
Return Rates:			
Return on Debt (Weighted)	7.04%	7.20%	7.20%
Return on Equity	9.00%	8.01%	8.01%
Deemed Interest Expense	2,083,360	2,422,602	2,422,602
Return On Equity	2,330,775	1,796,597	1,796,597
Total Return	**4,414,135**	**4,219,200**	**4,219,200**
Expected Return on Rate Base	7.95%	7.52%	7.52%
Revenue Deficiency After Tax	**927,694**	**1,241,796**	**-0**
Revenue Deficiency Before Tax	**1,384,618**	**1,799,705**	**-0**

APPENDIX E

REVENUE REQUIREMENT WORK FORM

Revenue Requirement Work Form

Name of LDC:	Chatham-Kent Hydro	(1)
File Number:	EB-2009-0261	
Rate Year:	2010	*Version:* *1.0*

Table of Content

Notes:
(1) Pale green cells represent inputs
(2) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***

Revenue Requirement Work Form

Name of LDC: Chatham-Kent Hydro
File Number: EB-2009-0261
Rate Year: 2010

		Data Input				(1)
		Application		**Adjustments**	**Per Board Decision**	
1	**Rate Base**					
	Gross Fixed Assets (average)	$78,652,295	(4)		$78,652,295	
	Accumulated Depreciation (average)	($31,246,866)	(5)		($31,246,866)	
	Allowance for Working Capital:					
	Controllable Expenses	$6,803,112	(6)		$6,803,112	
	Cost of Power	$50,984,482			$50,984,482	
	Working Capital Rate (%)	15.00%			15.00%	
2	**Utility Income**					
	Operating Revenues:					
	Distribution Revenue at Current Rates	$12,838,181				
	Distribution Revenue at Proposed Rates	$14,637,886				
	Other Revenue:					
	Specific Service Charges	$494,368				
	Late Payment Charges	$188,861				
	Other Distribution Revenue	$360,988				
	Other Income and Deductions	$143,233				
	Operating Expenses:					
	OM+A Expenses	$6,803,112			$6,803,112	
	Depreciation/Amortization	$3,815,361			$3,815,361	
	Property taxes	$ -			$0	
	Capital taxes	$30,805				
	Other expenses	$ -			$0	
3	**Taxes/PILs**					
	Taxable Income:					
	Adjustments required to arrive at taxable income	$333,183	(3)			
	Utility Income Taxes and Rates:					
	Income taxes (not grossed up)	$660,232				
	Income taxes (grossed up)	$956,858				
	Capital Taxes	$30,805				
	Federal tax (%)	18.00%				
	Provincial tax (%)	13.00%				
	Income Tax Credits	$ -				
4	**Capitalization/Cost of Capital**					
	Capital Structure:					
	Long-term debt Capitalization Ratio (%)	56.0%				
	Short-term debt Capitalization Ratio (%)	4.0%	(2)			(2)
	Common Equity Capitalization Ratio (%)	40.0%				
	Prefered Shares Capitalization Ratio (%)				Capital Structure must total 100%	
	Cost of Capital					
	Long-term debt Cost Rate (%)	7.62%				
	Short-term debt Cost Rate (%)	1.33%				
	Common Equity Cost Rate (%)	8.01%				
	Prefered Shares Cost Rate (%)					

Notes:

This input sheet provides all inputs needed to complete sheets 1 through 6 (Rate Base through Revenue Requirement), except for Notes that the utility may wish to use to support the components. Notes should be put on the applicable pages to understand the context of each such note.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)
(2) 4.0% unless an Applicant has proposed or been approved for another amount.
(3) Net of addbacks and deductions to arrive at taxable income.
(4) Average of Gross Fixed Assets at beginning and end of the Test Year
(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

Revenue Requirement Work Form

Ontario

Name of LDC: Chatham-Kent Hydro
File Number: EB-2009-0261
Rate Year: 2010

Rate Base

Line No.	Particulars		Application	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(3)	$78,652,295	$ -	$78,652,295
2	Accumulated Depreciation (average)	(3)	($31,246,866)	$ -	($31,246,866)
3	Net Fixed Assets (average)	(3)	$47,405,429	$ -	$47,405,429
4	Allowance for Working Capital	(1)	$8,668,139	$ -	$8,668,139
5	**Total Rate Base**		$56,073,568	$ -	$56,073,568

	(1) Allowance for Working Capital - Derivation				
6	Controllable Expenses		$6,803,112	$ -	$6,803,112
7	Cost of Power		$50,984,482	$ -	$50,984,482
8	Working Capital Base		$57,787,594	$ -	$57,787,594
9	Working Capital Rate %	(2)	15.00%		15.00%
10	Working Capital Allowance		$8,668,139	$ -	$8,668,139

Notes

(2) Generally 15%. Some distributors may have a unique rate due as a result of a lead-lag study.
(3) Average of opening and closing balances for the year.

Revenue Requirement Work Form

Name of LDC: Chatham-Kent Hydro
File Number: EB-2009-0261
Rate Year: 2010

Utility income

Line No.	Particulars		Application	Adjustments	Per Board Decision
	Operating Revenues:				
1	Distribution Revenue (at Proposed Rates)		$14,637,886	$ -	$14,637,886
2	Other Revenue	(1)	$1,187,450	$ -	$1,187,450
3	Total Operating Revenues		$15,825,336	$ -	$15,825,336
	Operating Expenses:				
4	OM+A Expenses		$6,803,112	$ -	$6,803,112
5	Depreciation/Amortization		$3,815,361	$ -	$3,815,361
6	Property taxes		$ -	$ -	$ -
7	Capital taxes		$30,805	$ -	$30,805
8	Other expense		$ -	$ -	$ -
9	Subtotal		$10,649,278	$ -	$10,649,278
10	Deemed Interest Expense		$2,422,602	$ -	$2,422,602
11	Total Expenses (lines 4 to 10)		$13,071,881	$ -	$13,071,881
12	**Utility income before income taxes**		$2,753,455	$ -	$2,753,455
13	Income taxes (grossed-up)		$956,858	$ -	$956,858
14	**Utility net income**		$1,796,597	$ -	$1,796,597

Notes

(1)

Other Revenues / Revenue Offsets	Application	Per Board Decision
Specific Service Charges	$494,368	$494,368
Late Payment Charges	$188,861	$188,861
Other Distribution Revenue	$360,988	$360,988
Other Income and Deductions	$143,233	$143,233
Total Revenue Offsets	$1,187,450	$1,187,450

Revenue Requirement Work Form

Name of LDC: Chatham-Kent Hydro
File Number: EB-2009-0261
Rate Year: 2010

Taxes/PILs

Line No.	Particulars	Application	Per Board Decision
	Determination of Taxable Income		
1	Utility net income	$1,796,597	$1,796,597
2	Adjustments required to arrive at taxable utility income	$333,183	$333,183
3	Taxable income	$2,129,780	$2,129,780
	Calculation of Utility income Taxes		
4	Income taxes	$660,232	$660,232
5	Capital taxes	$30,805	$30,805
6	Total taxes	$691,037	$691,037
7	Gross-up of Income Taxes	$296,626	$296,626
8	Grossed-up Income Taxes	$956,858	$956,858
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$987,663	$987,663
10	Other tax Credits	$ -	$ -
	Tax Rates		
11	Federal tax (%)	18.00%	18.00%
12	Provincial tax (%)	13.00%	13.00%
13	Total tax rate (%)	31.00%	31.00%

Notes

Revenue Requirement Work Form

Name of LDC: Chatham-Kent Hydro
File Number: EB-2009-0261
Rate Year: 2010

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Application				
	Debt				
1	Long-term Debt	56.00%	$31,401,198	7.62%	$2,392,771
2	Short-term Debt	4.00%	$2,242,943	1.33%	$29,831
3	**Total Debt**	60.00%	$33,644,141	7.20%	$2,422,602
	Equity				
4	Common Equity	40.00%	$22,429,427	8.01%	$1,796,597
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$22,429,427	8.01%	$1,796,597
7	**Total**	100%	$56,073,568	7.52%	$4,219,200
	Per Board Decision				
	Debt				
8	Long-term Debt	56.00%	$31,401,198	7.62%	$2,392,771
9	Short-term Debt	4.00%	$2,242,943	1.33%	$29,831
10	**Total Debt**	60.00%	$33,644,141	7.20%	$2,422,602
	Equity				
11	Common Equity	40.0%	$22,429,427	8.01%	$1,796,597
12	Preferred Shares	0.0%	$ -	0.00%	$ -
13	**Total Equity**	40.0%	$22,429,427	8.01%	$1,796,597
14	**Total**	100%	$56,073,568	7.52%	$4,219,200

Notes

(1) 4.0% unless an Applicant has proposed or been approved for another amount.

Revenue Requirement Work Form

Name of LDC: Chatham-Kent Hydro
File Number: EB-2009-0261
Rate Year: 2010

Revenue Sufficiency/Deficiency

Line No.	Particulars	Per Application: At Current Approved Rates	Per Application: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$1,799,705		$1,799,705
2	Distribution Revenue	$12,838,181	$12,838,181	$12,838,181	$12,838,181
3	Other Operating Revenue Offsets - net	$1,187,450	$1,187,450	$1,187,450	$1,187,450
4	**Total Revenue**	$14,025,631	$15,825,336	$14,025,631	$15,825,336
5	Operating Expenses	$10,649,278	$10,649,278	$10,649,278	$10,649,278
6	Deemed Interest Expense	$2,422,602	$2,422,602	$2,422,602	$2,422,602
	Total Cost and Expenses	$13,071,881	$13,071,881	$13,071,881	$13,071,881
7	**Utility Income Before Income Taxes**	$953,750	$2,753,455	$953,750	$2,753,455
8	Tax Adjustments to Accounting Income per 2009 PILs	$333,183	$333,183	$333,183	$333,183
9	**Taxable Income**	$1,286,933	$3,086,638	$1,286,933	$3,086,638
10	Income Tax Rate	31.00%	31.00%	31.00%	31.00%
11	**Income Tax on Taxable Income**	$398,949	$956,858	$398,949	$956,858
12	**Income Tax Credits**	$ -	$ -	$ -	$ -
13	**Utility Net Income**	$554,801	$1,796,597	$554,801	$1,796,597
14	**Utility Rate Base**	$56,073,568	$56,073,568	$56,073,568	$56,073,568
	Deemed Equity Portion of Rate Base	$22,429,427	$22,429,427	$22,429,427	$22,429,427
15	Income/Equity Rate Base (%)	2.47%	8.01%	2.47%	8.01%
16	Target Return - Equity on Rate Base	8.01%	8.01%	8.01%	8.01%
	Sufficiency/Deficiency in Return on Equity	-5.54%	0.00%	-5.54%	0.00%
17	Indicated Rate of Return	5.31%	7.52%	5.31%	7.52%
18	Requested Rate of Return on Rate Base	7.52%	7.52%	7.52%	7.52%
19	Sufficiency/Deficiency in Rate of Return	-2.21%	0.00%	-2.21%	0.00%
20	Target Return on Equity	$1,796,597	$1,796,597	$1,796,597	$1,796,597
21	Revenue Sufficiency/Deficiency	$1,241,796	$ -	$1,241,796	$ -
22	**Gross Revenue Sufficiency/Deficiency**	$1,799,705 **(1)**		$1,799,705 **(1)**	

Notes:

(1) Revenue Sufficiency/Deficiency divided by (1 - Tax Rate)

Revenue Requirement Work Form

Name of LDC: Chatham-Kent Hydro
File Number: EB-2009-0261
Rate Year: 2010

Line No.	Particulars	Revenue Requirement: Application	Revenue Requirement: Per Board Decision
1	OM&A Expenses	$6,803,112	$6,803,112
2	Amortization/Depreciation	$3,815,361	$3,815,361
3	Property Taxes	$ -	$ -
4	Capital Taxes	$30,805	$30,805
5	Income Taxes (Grossed up)	$956,858	$956,858
6	Other Expenses	$ -	$ -
7	Return		
	Deemed Interest Expense	$2,422,602	$2,422,602
	Return on Deemed Equity	$1,796,597	$1,796,597
8	Distribution Revenue Requirement before Revenues	$15,825,336	$15,825,336
9	Distribution revenue	$14,637,886	$14,637,886
10	Other revenue	$1,187,450	$1,187,450
11	**Total revenue**	$15,825,336	$15,825,336
12	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$ - **(1)**	$ - **(1)**

Notes

(1) Line 11 - Line 8

Revenue Requirement Work Form

Name of LDC: Chatham-Kent Hydro
File Number: EB-2009-0261
Rate Year: 2010

		Selected Delivery Charge and Bill Impacts Per Draft Rate Order							
		Monthly Delivery Charge				Total Bill			
		Current	Per Draft Rate Order	Change $	Change %	Current	Per Draft Rate Order	Change $	Change %
Residential	**1000** kWh/month	$ 28.34	$ 28.25	-$ 0.09	-0.3%	$ 113.57	$ 113.37	-$ 0.21	-0.2%
GS < 50kW	**2000** kWh/month	$ 51.52	$ 55.50	$ 3.98	7.7%	$ 224.00	$ 229.37	$ 5.37	2.4%

Notes:

FINANCIAL STATEMENTS - 2008:

The audited financial statements for Chatham-Kent Hydro, its parent Chatham-Kent Energy, and an affiliate Middlesex Power Distribution Corporation, are provided in Appendix F.

The audited financial statements of Chatham-Kent Hydro's other affiliate, Chatham-Kent Utility Services Inc., are being filed with the OEB in confidence for the reasons set out in the cover letter to this Application. Chatham-Kent Utility Services engages in competitive business activities and the information is consistently treated in a confidential manner.

APPENDIX F

COPY OF AUDITED FINANCIAL STATEMENTS FOR 2008

Financial Statements of

CHATHAM-KENT ENERGY INC.

December 31, 2008

TABLE OF CONTENTS

Deloitte.

Deloitte & Touche LLP
One London Place
255 Queens Avenue
Suite 700
London ON N6A 5R8
Canada

Tel: 519-679-1880
Fax: 519-640-4625
www.deloitte.ca

Notice to Reader

To the Chairman and Board Members of Chatham-Kent Energy Inc.

On the basis of information provided by management, we have compiled the balance sheet of Chatham-Kent Energy Inc. (the "Company") as at December 31, 2008 and the statement of earnings, comprehensive income and retained earnings for the year then ended.

We have not performed an audit or a review engagement in respect of these financial statements and, accordingly, we express no assurance thereon.

Readers are cautioned that these statements may not be appropriate for their purposes.

Deloitte & Touche LLP

Chartered Accountants
Licensed Public Accountants

February 27, 2009

Member of
Deloitte Touche Tohmatsu

CHATHAM-KENT ENERGY INC.

Balance Sheet
December 31, 2008
(Unaudited – see Notice to Reader)

	2008	2007
	$	$
ASSETS		
CURRENT		
Bank	**1,717,643**	41,617
Accounts receivable	**15,501**	24,302
Taxes receivable	-	24,444
Due from subsidiaries	**25,980**	25,980
	1,759,124	116,343
OTHER		
Other investment projects	**268,680**	742,292
Note receivable from subsidiary	**4,300,000**	4,300,000
Investment in subsidiaries	**29,224,760**	29,224,760
	33,793,440	34,267,052
	35,552,564	34,383,395
LIABILITIES		
CURRENT		
Accounts payable and accrued liabilities	**132,389**	151,268
Taxes payable	**(12,957)**	-
Due to shareholder	**(23,639)**	1,882,844
Due to subsidiaries	-	250,000
	95,793	2,284,112
LONG-TERM		
Employee future benefits	**3,098,300**	3,138,709
	3,194,093	5,422,821
SHAREHOLDER'S EQUITY		
Share capital	**26,882,150**	23,855,797
Retained earnings	**5,476,321**	5,104,777
	32,358,471	28,960,574
	35,552,564	34,383,395

CHATHAM-KENT ENERGY INC.

Statement of Earnings, Comprehensive Income and Retained Earnings
Year Ended December 31, 2008
(Unaudited – see Notice to Reader)

	2008	2007
	$	$
SERVICE REVENUE	**687,158**	552,732
INTEREST INCOME	**349,779**	312,621
DIVIDEND INCOME	**1,886,000**	1,708,000
	2,922,937	2,573,353
ADMINISTRATIVE EXPENSE		
General administration	**884,001**	844,008
Interest	**1,682**	26,034
	885,683	870,042
EARNINGS BEFORE PAYMENTS IN LIEU OF TAXES	**2,037,254**	1,703,311
Payments in lieu of taxes	**(24,290)**	(38,035)
NET EARNINGS AND COMPREHENSIVE INCOME	**2,061,544**	1,741,346
RETAINED EARNINGS, BEGINNING OF YEAR	**5,104,777**	4,613,431
LESS DIVIDENDS PAID	**(1,690,000)**	(1,250,000)
RETAINED EARNINGS, END OF YEAR	**5,476,321**	5,104,777

Financial Statements of

CHATHAM-KENT HYDRO INC.

December 31, 2008

Management's Responsibility for Financial Reporting

Chatham-Kent Hydro's management is responsible for the preparation and presentation of the financial statements and all other information included in this annual report. Management is also responsible for the selection and use of accounting principles that are appropriate in the circumstances, and for the internal controls over the financial reporting process to reasonably ensure that relevant and reliable information is produced. Financial statements are not precise in nature as they include certain amounts based on estimates and judgment. Management has determined such amounts on a reasonable basis in order to ensure that the financial statements are presented fairly, in all material respects.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control over the financial reporting process. The Board exercises this responsibility through the Audit Committee of the Board. This committee, which is comprised of three directors of the Chatham-Kent Energy Board, with one member also on the Chatham-Kent Hydro board, meets with management and the external auditors to ensure that management responsibilities are properly discharged and to review the financial statements and other information included in the annual report before they are presented to the Board of Directors for approval. The financial statements have been approved by the Board of Directors on the recommendation of the Audit Committee.

Deloitte & Touche LLP, an independent firm of Chartered Accountants, has been appointed by the audit committee and engaged to examine the accompanying financial statements in accordance with generally accepted auditing standards in Canada and provide an independent professional opinion. Their report is presented with the financial statements.

Dave Kenney
President

Jim Hogan
Chief Financial & Regulatory Officer

TABLE OF CONTENTS

Deloitte.

Deloitte & Touche LLP
One London Place
255 Queens Avenue
Suite 700
London ON N6A 5R8
Canada

Tel: 519-679-1880
Fax: 519-640-4625
www.deloitte.ca

Auditors' Report

To the Chairman and Board Members of Chatham-Kent Hydro Inc.

We have audited the balance sheet of Chatham-Kent Hydro Inc. as at December 31, 2008 and the statements of earnings, comprehensive income and retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

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

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2008 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Deloitte & Touche LLP

Chartered Accountants
Licensed Public Accountants

February 27, 2009

CHATHAM-KENT HYDRO INC.

Balance Sheet
December 31, 2008

	2008	2007
	$	$
ASSETS		
CURRENT		
Cash and cash equivalents	**6,340,035**	4,091,078
Accounts receivable (Note 4)	**3,383,525**	3,407,706
Accounts receivable -unbilled revenue	**8,987,257**	9,336,743
Taxes receivable	**109,388**	838,981
Due from Chatham-Kent Energy Inc.	-	250,000
Due from Middlesex Power Distribution Corporation	**383,262**	324,993
Inventories	**676,263**	780,574
Prepaid expenses	**91,079**	68,359
	19,970,809	19,098,434
CAPITAL ASSETS (Note 5)	**46,125,163**	44,736,362
OTHER		
Deferred assets (Note 6)	**2,565,256**	3,681,778
Computer software	**305,533**	198,061
	2,870,789	3,879,839
	68,966,761	67,714,635
LIABILITIES		
CURRENT		
Accounts payable and accrued liabilities	**9,036,529**	9,382,408
Due to the Municipality of Chatham-Kent	**2,248,214**	2,727,229
Current portion of customer deposits	**1,116,267**	842,699
	12,401,010	12,952,336
LONG-TERM		
Note payable (Note 7)	**23,523,326**	23,523,326
Asset retirement obligation	**15,000**	15,000
Employee future benefits (Note 8)	**858,565**	800,909
Long-term portion of customer deposits	**3,463,476**	2,982,893
	27,860,367	27,322,128
	40,261,377	40,274,464
CONTINGENCY AND COMMITMENTS (Notes 11 and 17)		
SHAREHOLDER'S EQUITY		
Share capital (Note 12)	**23,523,425**	23,523,425
Retained earnings	**5,181,959**	3,916,746
	28,705,384	27,440,171
	68,966,761	67,714,635

CHATHAM-KENT HYDRO INC.

Statement of Earnings, Comprehensive Income and Retained Earnings
Year Ended December 31, 2008

	2008	2007
	$	$
SERVICE REVENUE		
Residential	**22,355,009**	22,872,748
General service	**42,194,791**	42,408,480
Street lighting	**624,942**	661,073
	65,174,742	65,942,301
Change in unbilled revenue	**(77,358)**	(121,720)
	65,097,384	65,820,581
Retailer energy sales	**9,659,952**	11,600,231
	74,757,336	77,420,812
COST OF POWER	**61,185,688**	64,186,838
GROSS MARGIN ON SERVICE REVENUE	**13,571,648**	13,233,974
OTHER OPERATING REVENUE	**1,444,621**	1,579,746
OPERATING INCOME	**15,016,269**	14,813,720
OPERATING AND MAINTENANCE EXPENSE		
Distribution	**2,475,778**	2,287,642
ADMINISTRATIVE EXPENSE		
Billing and collection	**1,416,110**	1,281,282
General administration	**2,117,686**	2,063,134
Interest	**1,985,886**	2,009,246
DEPRECIATION AND AMORTIZATION	**3,595,770**	3,315,639
	11,591,230	10,956,943
EARNINGS BEFORE PAYMENTS IN LIEU OF TAXES	**3,425,039**	3,856,777
Payments in lieu of taxes (Note 16)	**1,009,826**	1,572,951
NET EARNINGS AND COMPREHENSIVE INCOME	**2,415,213**	2,283,826
RETAINED EARNINGS, BEGINNING OF YEAR	**3,916,746**	2,782,920
LESS DIVIDENDS PAID	**(1,150,000)**	(1,150,000)
RETAINED EARNINGS, END OF YEAR	**5,181,959**	3,916,746

CHATHAM-KENT HYDRO INC.

Statement of Cash Flows
Year Ended December 31, 2008

	2008	2007
	$	$
OPERATING ACTIVITIES		
Net earnings	**2,415,213**	2,283,826
Adjustments for:		
Depreciation of capital assets	**3,876,504**	3,590,366
Depreciation of computer software	**128,457**	84,734
Amortization of contributed capital	**(156,138)**	(142,742)
Allowance for deferred assets	**(84,582)**	(254,196)
Gain on disposal of capital assets	**(35,721)**	(63,083)
Accretion of asset retirement obligation	**-**	14,410
Employee future benefits	**57,656**	46,226
Changes in non-cash working capital items (Note 13)	**825,256**	(3,199,113)
Change in asset retirement obligation	**-**	(15,000)
Change in long-term customer deposits	**480,583**	749,293
	7,507,228	3,094,721
INVESTING ACTIVITIES		
Change in deferred assets	**1,553,057**	2,741,367
Recovery of deferred assets	**(351,952)**	(1,774,261)
Proceeds on disposal of capital assets	**37,743**	227,037
Additions to capital assets and computer software	**(5,347,119)**	(6,382,677)
Repayment from Chatham-Kent Energy Inc.	**-**	1,350,000
	(4,108,271)	(3,838,534)
FINANCING ACTIVITIES		
Dividends paid	**(1,150,000)**	(1,150,000)
NET CHANGE IN CASH AND CASH EQUIVALENTS	**2,248,957**	(1,893,813)
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR	**4,091,078**	5,984,891
CASH AND CASH EQUIVALENTS, END OF YEAR	**6,340,035**	4,091,078

See Note 13 for supplemental cash flow information.

1. NATURE OF OPERATIONS

(a) Incorporation of Chatham-Kent Hydro Inc.

Chatham-Kent Hydro Inc. ("the Company") was incorporated September 22, 2000 under the *Business Corporations Act (Ontario).*

The Company is wholly-owned by Chatham-Kent Energy Inc. which in turn is owned 90% by the Municipality of Chatham-Kent ("the Municipality") and 10% by Corix Utilities ("Corix").

The principal activity of the Company is to distribute electricity to customers within the Municipality of Chatham-Kent, under the licence issued by the OEB.

Under a Municipal by-law, dated September 5, 2000, the former Public Utilities Commission of the Municipality of Chatham-Kent – Electrical Division ("the Commission") and the Municipality transferred the assets, liabilities and employees associated with the distribution of electricity at book value effective October 1, 2000. The book value of the net assets transferred to the Company at October 1, 2000 was $47,046,751. In consideration for the transfer the Company issued long-term notes payable to the Municipality in the aggregate principal amount of $23,523,326. Shares valued at $23,523,425 have been issued to Chatham-Kent Energy Inc.

The incorporation and subsequent reorganization was required by provisions of Bill 35, *The Energy Competitions Act, 1998* enacted by the Province of Ontario to introduce competition in the electricity market.

(b) Rate Regulated Entity

The Company is a regulated Local Distribution Company ("LDC") and has a distribution licence that is regulated by the OEB. The OEB has regulatory oversight of electricity matters in Ontario. *The Ontario Energy Board Act, 1998* sets out the OEB's authority to issue a distribution licence which must be obtained by owners or operators of a distribution system in Ontario. The OEB prescribes licence requirements and conditions including, among other things, specified accounting records, regulatory accounting principles and filing process requirements for rate-setting purposes.

The OEB's authority and responsibilities include the power to approve and fix rates for the transmission and distribution of electricity, the power to provide continued rate protection for rural and remote electricity customers and the responsibility of ensuring the electricity distribution companies fulfill obligations to connect and service customers.

1. NATURE OF OPERATIONS (continued)

The Company is required to charge its customers for the following amounts (all of which, other than the distribution rates, represent a pass through of amounts payable to third parties):

- Electricity Price – The electricity price represents the commodity cost of electricity.
- Distribution Rate – The distribution rate is designed to recover the costs incurred by the Company in delivering electricity to customers and the OEB allowed rate of return.
- Retail Transmission Rate – The retail transmission rate represents the wholesale costs incurred by Company in respect of the transmission of electricity from generating stations to the local areas.
- Wholesale Market Service Charge – The wholesale market service charge represents the various wholesale market support costs.

In order to operate in the Ontario electrical industry all market participants, including the Company, are required to satisfy and maintain prudential requirements with the Independent Electricity System Operator ("IESO"), which include credit support with respect to outstanding market obligations in the form of obtaining a credit rating, letters of credit, cash deposits or guarantees from third parties with prescribed credit ratings.

Market Based Rate of Return

The Company had reset their rates and received approval from the OEB for a change in rates effective May 1, 2006 which approved rates that included a rate of return of 9.0% on equity and rebased the rate base and operating costs at the 2004 historical levels. The rate of return of 9.0% was the maximum allowed by the OEB at that time.

Incentive Rate Mechanism

The OEB regulates the rates of the Company in an Incentive Rate Mechanism ("IRM") regime for 2007-2010. The process includes a formulae approach to establishing 2007 rates with a rate rebasing approach (cost-of-service) to be staggered across all Ontario distributors between 2008 and 2010. The Company self-nominated for a rate rebasing in 2010.

The IRM rate setting process provides an increase in rates for inflationary cost increases with a 1% offset for productivity gains. The IRM process also includes changes in the tax rates and a movement from the 2006 approved capital structure of 50% long-term debt and 50% equity to 4% short-term debt, 56% long-term debt and 40% equity.

The distribution rates decreased by 0.6% in 2008 using the OEB's approved IRM.

Smart Meter Program

The Company has been named in Ontario Regulation 427/06 which gives the Company the ability to install smart meters to their low volume customer. By the end of 2007, the Company had installed a smart meter to substantially all of their residential customers.

1. NATURE OF OPERATIONS (continued)

The Company participated in a regulatory proceeding in 2007 along with the other utilities that were named in the Ontario Regulation. The regulatory process was to determine that the Company acted prudently in implementing its smart meter program. The Company was also seeking rate recovery for all capital costs invested up to April 30, 2007.

The OEB found the Company acted prudently and approved full recovery of all capital costs invested up to April 30, 2007.

In 2008 the Company applied for and received approval from the OEB for recovery of all smart meter costs installed between May 1, 2007 and December 31, 2007.

Consolidation in the Ontario Local Distribution Sector

The Provincial Government has provided a transfer-tax exemption window in order to entice LDC's to purchase, merge or amalgamate with one another. The exemption window was expected to close on October 18, 2008 but has been extended for an additional year. The Company is reviewing its strategic options.

LDC's that purchase, merge or amalgamate will have the option to defer rate rebasing for up to five years. This will give the LDC's the benefit of keeping any possible synergies for a longer period of time which will offset the transaction costs. The benefits to the customers will be improved service and lower costs over the long term.

Regulatory Assets and Liabilities

Electricity distributors are required to reflect certain prescribed costs on their balance sheets until the manner and timing of distribution is determined by the OEB. These costs are:

- Transition costs resulting from preparation of Open Access;
- Settlement variance between amounts charged by the Company to customers (based on regulated rates) and corresponding cost of non-competitive electricity service incurred by it in the wholesale market administered by the IESO after May 1, 2002;
- The deferral of OEB annual cost assessments for the OEB's fiscal year 2004 and 2005;
- The deferral of incremental OMERS pension expenditures for fiscal years starting after January 1, 2005;
- Costs incurred to invest in and install a smart meter at all our customer premises; and
- Payment-in-lieu of taxes ("PILS") variances since the Company became taxable October 2002

The regulatory assets and liabilities balances are detailed in Note 6. The regulatory asset balances have been recovered in rates on an interim basis since April 2004. The Company had applied to the OEB for full and final recovery of the regulatory asset balances that were in place at December 31, 2004. The OEB approved the recovery of these assets over a two year period ending April 30, 2008.

1. NATURE OF OPERATIONS (continued)

The Company on an annual basis will continue to apply to the OEB for rate recovery of the investments made in smart meters. The recovery of variances for the PILS will occur sometime after the OEB completes their generic regulatory proceeding which will provide the filing guidelines for this regulatory asset or liability.

Electricity Sector Reorganization

In December 2004, the Province initiated a further restructuring of Ontario's electricity industry with the passage of the *Electricity Restructuring Act, 2004* ("Bill 100"). The restructuring was intended, among other things, to ensure efficient and effective management of electricity, promote the expansion of new electricity supply and capacity, encourage electricity conservation and renewable energy and regulate prices in parts of the electricity sector.

Bill 100:

i) Established the Ontario Power Authority ("OPA"), as an independent, non-profit, self-financed corporation, with a broad mandate to ensure adequate long-term electricity supply in the Province;
ii) Reorganized the Independent Electricity Market Operator as the IESO, a non-share corporation, which will continue to operate the wholesale market and be responsible for the operation and reliability of the integrated power system; and
iii) Established a Conservation Bureau within the OPA responsible for assuming a leadership role in planning and coordinating electricity conservation measures and load management in the Province.

Under Bill 100, the commodity cost of electricity for certain customer classes will be regulated by the OEB. Customers who did not wish to or were not eligible to participate in the regulated plan purchased electricity in the competitive market or through licensed retailers.

Effective January 1, 2005, the IESO implemented, pursuant to Bill 100, a new price adjustment applicable to customers not subject to price protection and rate caps. The new price adjustment, referred to as Global Adjustment, is a variable rate calculated by the IESO based on the difference between electricity market prices and the mix of regulated and contract prices paid to electricity generators. This calculation results in positive or negative bill adjustments depending on prevailing electricity market conditions.

The difference between the amount credited to customers and the amount received from the IESO by LDC is being tracked in a variance account and is currently reflected as a settlement variance regulatory liability. The disposition of the variance account balance shall be in accordance with the OEB's guidelines for reviewing variance and deferral accounts.

1. NATURE OF OPERATIONS (continued)

On February 23, 2005, the Minister of Energy announced a new fixed pricing structure for electricity supplied by Ontario Power Generation ("OPG"). The new pricing structure, effective April 1, 2005 through March 31, 2008, which has been extended, is based on a blended price for electricity supplied by OPG's regulated and unregulated assets.

The new pricing structure had an immediate impact on large industrial and commercial electricity customers who use more than 250,000 kWh per year. While residential, small business and other consumers were not immediately affected by the new pricing structure, the OEB blended the various prices paid to generators into a new fixed price that these consumers now pay under the Regulated Price Plan ("RPP"), which took effect on April 1, 2005.

The OEB has formulated two pricing plans for RPP-eligible customers, depending on how customers' electricity consumption is metered – that is, a pricing plan for customers without smart meters, and a pricing plan for customers with smart meters. For both plans, prices were effective April 1, 2005.

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, including PILS recoveries, that LDC may charge and the costs that LDC may recover, including the balance of its regulatory assets.

2. CHANGES IN ACCOUNTING POLICIES

Current Accounting Changes

The Company adopted the following recommendations of the Canadian Institute of Chartered Accountants ("CICA") Handbook:

a) *Section 3862, Financial Instruments – Disclosures and Section 3863, Financial Instruments – Presentation*

In December 2006, the CICA issued Section 3862, Financial Instruments – Disclosures and Section 3863, Financial Instruments – Presentation. Originally these sections were applicable to financial statements relating to fiscal years beginning on or after October 1, 2007. Accordingly, the Company had planned to adopt the new standards for its fiscal year beginning January 1, 2008. However, in October 2008, the Accounting Standards Board ("AcSB") of the CICA decided that rate-regulated enterprises that are not public enterprises as defined in Section 1300, Differential Reporting, will not be required to apply Sections 3862 and 3863 and would continue to apply Section 3861, Financial Instruments — Disclosure and Presentation. Therefore, in accordance with this decision, the Company continues to apply Section 3861.

2. CHANGES IN ACCOUNTING POLICIES (continued)

b) *Section 1535, Capital Disclosures*

This Section requires disclosure of the Company's objectives, policies and processes for managing capital as well as its compliance with any external capital requirements. The required disclosures are included in Note 15.

c) *Section 3031, Inventories*

This Section is based on the International Accounting Standards Board's guidance for inventories and replaced existing CICA Handbook Section 3030, Inventories. Under this new standard, inventories are required to be measured at the lower of cost and net realizable value and any items considered to be major future components of property, plant and equipment are to be transferred to property, plant and equipment. The new standard also provides updated guidance on the appropriate methods of determining cost and the impact of any write-downs to net realizable value. The implementation of this standard did not have a material impact on the Company's results of operations.

The Company recognized operating expenses of $65,539, related to the inventory used in the servicing of electrical distribution assets (2007-$65,991)

Future accounting changes

a) *International Financial Reporting Standards ("IFRS")*

On February 13, 2008, the AcSB confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian Generally Accepted Accounting Principles ("GAAP") for fiscal years beginning on or after January 1, 2011. At this time, the impact on our future financial position and results of operations is not reasonably determinable or estimable. The OEB has also begun its own IFRS project to determine the nature of any changes that should be made in regulatory accounting requirements in response to IFRS. On May 8, 2008, the OEB announced the creation of an IFRS Consultation which will provide an opportunity for OEB staff to work with industry participants to identify transition issues and suggest how those issues might be addressed. We are participating in this process. On January 27, 2009 the OEB held a technical conference with stakeholders addressing issues to IFRS changeover from GAAP. We intend to closely monitor any International Financial Reporting Interpretations Committee ("IFRIC") initiatives with the potential to impact rate regulated accounting under IFRS and will participate in any related processes, as appropriate. In anticipation of the changes to our reporting standards due to the implementation of IFRS we will complete a diagnostic assessment of the impact of IFRS and outline a project plan in 2009. It is expected that IFRS will be implemented by the end of 2009 to ensure that 2010 has appropriate comparative financial information prior to full implementation on January 1, 2011. Although specific guidance to rate-regulated industries has yet to be confirmed, it is expected that the areas of greatest impact to LDC's will be property, plant and equipment, inventories, intangible assets, impairment of assets, employee benefits and the treatment of regulatory assets and liabilities.

2. CHANGES IN ACCOUNTING POLICIES (continued)

b) *Rate Regulated Accounting*

During 2007, the AcSB issued an exposure draft proposing to remove all specific references to rate regulated accounting from the CICA Handbook . In August 2007, the AcSB decided to remove a temporary exemption in CICA Handbook Section 1100, retain existing references to rate regulated accounting in the CICA Handbook, require the recognition of future income tax liabilities and assets as well as a corresponding regulatory asset or liability for the amount of future income taxes expected to be recovered from or refunded to customers, and retain existing requirements to disclose the effects of rate regulation. The new rules will apply to the Company prospectively effective January 1, 2009.

c) *Section 3064, Goodwill and Intangible Assets*

In February 2008, the CICA issued Section 3064, Goodwill and Intangible Assets, replacing Section 3062, Goodwill and Other Intangible Assets and Section 3450, Research and Development Costs. Various changes have been made to other sections of the CICA Handbook for consistency purposes. The new Section will be applicable to financial statements relating to fiscal years beginning on or after October 1, 2008. Accordingly, the Company will adopt the new standards for its fiscal year beginning January 1, 2009. It establishes standards for the recognition, measurement, presentation and disclosure of goodwill subsequent to its initial recognition and of intangible assets by profit-oriented enterprises. Standards concerning goodwill are unchanged from the standards included in the previous Section 3062. The Company does not expect that the adoption of this new Section will have a material impact on its financial statements.

3. SIGNIFICANT ACCOUNTING POLICIES

The financial statements have been prepared in accordance with GAAP and reflect the following policies as set forth in the Accounting Procedures Handbook issued by the OEB under the authority of the *Ontario Energy Board Act, 1998:*

Regulation

The Company is regulated by the OEB and any power rate adjustments require OEB approval.

Cash and cash equivalents

Cash and cash equivalents consist of cash on hand and balances with the bank.

Unbilled revenue

Unbilled revenue is an estimate of customers' consumption of power from the last meter read to December 31st.

3. SIGNIFICANT ACCOUNTING POLICIES (continued)

Inventories

Inventories are valued at the lower of cost and net realizable value with cost being determined using the weighted average method.

Capital assets

Capital assets are recorded at cost. Depreciation is calculated on a straight-line basis over the useful life of the asset as follows:

Buildings and fixtures	25 – 50 years
Distribution station equipment	30 years
Distribution lines	25 years
Distribution transformers	25 years
Distribution meters	25 years
General office equipment	10 years
Computer equipment	5 years
Rolling stock	4 - 8 years
Tools	10 years
System supervisory equipment	15 years
Automated mapping facility management	15 years
Services	25 years
Contributions in aid of construction	25 years
SCADA	15 years
Smart Meters	3 - 15 years

Impairment of long-lived assets

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

Contributions in aid of construction

Contributions in aid of construction consist of third party contributions toward the cost of constructing the Company's assets. For the year ended December 31, 2008 $36,029 (2007- $213,142) of contributed capital has been charged to capital assets and recorded as an offset to capital assets. Amortization is on a straight-line basis over 25 years.

Computer software

Computer software is stated at cost less accumulated depreciation. Distribution software is depreciated over 5 years on a straight-line basis. Smart meter software is depreciated over 3 years on a straight-line basis.

3. SIGNIFICANT ACCOUNTING POLICIES (continued)

Deferred assets

Deferred assets consist of qualifying capital costs and related expenditures incurred in the preparation for market opening, costs for conservation programs which meet the Minister of Energy's Directive and investments in smart meters, other expenditures that are not currently recovered in rates and variances for PILS.

Also included in deferred assets are retail settlement variance accounts. These variances are for non-competitive energy services which are a pass through for the Company.

Recovery of the deferred assets requires regulatory approval from the OEB.

In the absence of regulatory treatment, net earnings in the current year would have decreased by $454,074 (2007-increase of $527,124). Refer to Note 6 for additional details.

Customer deposits

Customer deposits are recorded when received or paid. Deposits earn interest at a rate of prime less 2%.

Asset retirement obligations

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

Post employment benefits other than pension

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

Use of estimates

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

3. SIGNIFICANT ACCOUNTING POLICIES (continued)

Revenue recognition and cost of power

Service revenue is recorded on the basis of regular meter readings and estimated customer usage since the last meter reading date to the end of the year. The related cost of power is recorded on the basis of power used. Any discrepancies in the revenue collected and associated cost of power related to distribution are charged to deferred assets.

Payments in lieu of income taxes

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

The Company, regulated by the OEB, provides for payments-in-lieu of corporate income taxes using the taxes payable method instead of the liability method.

Under the taxes payable method, no provisions are 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. Future income taxes are expected to be reflected in future rates and, accordingly, are not recognized in the financial information. Payment in lieu of taxes is henceforth referred to as income taxes.

Financial instruments

Financial assets and financial liabilities are initially recognized at fair value and their subsequent measurement is dependent on their classification as described below. Their classification depends on the purpose, for which the financial instruments were acquired or issued, their characteristics and the Company's designation of such instruments. Settlement date accounting is used.

Classification

Cash and cash equivalents	Held for trading
Accounts receivable	Loans and receivables
Due from Chatham-Kent Energy Inc.	Loans and receivables
Due from Middlesex Power Distribution Company	Loans and receivables
Accounts payable and accrued liabilities	Other liabilities
Due to the Municipality of Chatham-Kent	Other liabilities
Current portion of customer deposits	Other liabilities
Note payable	Other liabilities
Long-term portion of customer deposits	Other liabilities

3. SIGNIFICANT ACCOUNTING POLICIES (continued)

Held for trading

Held for trading financial assets are financial assets typically acquired for resale prior to maturity or that are designated as held for trading. They are measured at fair value at the balance sheet date. Fair value fluctuations including interest earned, interest accrued, gains and losses realized on disposal and unrealized gains and losses are included in other income.

Financial liabilities designated as held for trading are those non-derivative financial liabilities that the Company elects to designate on initial recognition as instruments that it will measure at fair value through other interest expense. These are accounted for in the same manner as held for trading assets. The Company has not designated any non-derivative financial liabilities as held for trading.

Loans and receivables

Loans and receivables are accounted for at amortized cost using the effective interest method.

Other liabilities

Other liabilities are recorded at amortized cost using the effective interest method and include all financial liabilities, other than derivative instruments.

Effective interest method

The Company uses the effective interest method to recognize interest income or expense which includes transaction costs or fees, premiums or discounts earned or incurred for financial instruments.

4. ACCOUNTS RECEIVABLE

	2008	2007
	$	$
Electrical energy	**3,126,055**	3,044,600
Other	**362,914**	470,106
	3,488,969	3,514,706
Allowance for doubtful accounts	**(105,444)**	(107,000)
Net accounts receivable	**3,383,525**	3,407,706

5. CAPITAL ASSETS

	2008			2007
	Cost	**Accumulated Depreciation**	**Net Book Value**	Net Book Value
	$	$	$	$
Plant and distribution system:				
Land	**686,357**	**-**	**686,357**	688,380
Buildings and fixtures	**3,674,553**	**797,166**	**2,877,387**	2,913,729
Distribution station equipment	**241,445**	**103,777**	**137,668**	108,616
Station retirement obligation	**20,599**	**5,599**	**15,000**	15,000
Distribution system:				
Overhead	**23,165,539**	**7,556,073**	**15,609,466**	15,304,890
Underground	**15,820,443**	**6,183,900**	**9,636,543**	9,708,573
Transformers	**14,359,933**	**4,941,260**	**9,418,673**	9,369,007
Meters	**3,197,022**	**1,147,956**	**2,049,066**	2,192,422
General office equipment	**124,426**	**75,823**	**48,603**	39,423
Computer equipment	**380,151**	**336,357**	**43,794**	41,164
Rolling stock	**2,519,105**	**1,560,960**	**958,145**	959,512
Tools	**638,613**	**498,094**	**140,519**	113,833
System supervisory equipment	**787,728**	**547,406**	**240,322**	272,666
Automated mapping facility	**1,750,427**	**906,542**	**843,885**	915,083
Services	**3,354,546**	**661,747**	**2,692,799**	2,478,846
Smart meters	**4,353,881**	**589,616**	**3,764,265**	2,473,779
	75,074,768	**25,912,276**	**49,162,492**	47,594,923
Contributions in aid of construction	**(3,886,753)**	**(849,424)**	**(3,037,329)**	(2,858,561)
	71,188,015	**25,062,852**	**46,125,163**	44,736,362

Depreciation and amortization in the amount of $214,588 (2007-$256,721) for rolling stock and $141,269 (2007-$203,305) for computer software is included with relevant cost centres.

6. DEFERRED ASSETS

Deferred assets and liabilities arise as a result of the rate-making process. As described in this note, the Company has recorded the following regulatory assets and related provisions. 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 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 process.

6. DEFERRED ASSETS (continued)

	2008	2007
	$	$
Costs		
Regulatory assets prior to 2004	-	590,117
Retail settlement variance accounts	**(1,600,214)**	(1,648,799)
Conservation and demand management	**12,364**	154,764
PIL's recoverable	**1,113,200**	1,113,200
Other deferred/transition costs	**1,429,479**	1,097,780
Smart meter	**1,409,246**	2,610,070
Gross deferred assets	**2,364,075**	3,917,132
Recoveries		
Regulatory asset prior to 2004 recovery	**134,554**	(73,545)
Conservation and demand management recovery	**(4,589)**	(109,538)
Smart meter recovery	**71,216**	32,311
Provision	-	(84,582)
Net deferred assets	**2,565,256**	3,681,778

a) Regulatory Costs/Recoveries

(i) Regulatory assets prior to 2004

The introduction of Bill 210 in November 2002 deferred future rate increases until 2007. However Bill 4 was introduced in December 2003 which allowed for the recovery of deferred assets over a four year period beginning in April 2004. The Company obtained full and final recovery of the deferred assets balances at December 31, 2004. The recovery was over a four-year period ended April 30, 2008. Deferred asset revenue for 2008 was $239,584 (2007-$709,938). Since the recovery of the regulatory assets has begun the provision has been reduced by $84,582 (2007-$254,196).

In 2008, $447,683 (2007-$2,238,415) of deferred asset revenue was allocated towards $447,683 (2007-$2,238,415) of deferred asset expense as per OEB guidelines. An interest receivable of $0 (2007-$53,863) was recorded as per OEB guidelines. Deferred asset revenue remained in place until April 30, 2008.

At December 31, 2008 the revenue collected was not sufficient to cover all the regulatory asset cost. The balance owing from customers is $134,544, of which $53,863 is interest. In the absence of regulatory treatment, net earnings in the current year would have increased by $159,323 (2007-increase of $453,508).

6. DEFERRED ASSETS (continued)

(ii) Retail settlement variance accounts

These accounts represent the variance between the revenue collected, using OEB approved rates for the non–competitive components of energy, and the corresponding cost of these non-competitive charges, beginning January 1, 2004 to the present. These variances will be held as a regulatory asset or liability, based on the expectation that the amounts held from one year to the next for rate setting purposes will be approved for collection from, or refund to, future customers. In the absence of regulatory treatment, net earnings in the current year would have decreased by $32,309 (2007-increase of $490,608).

(iii) Conservation and demand management

During 2008, the Company incurred costs for conservation and demand management of $12,364 (2007-$154,764). These costs are required in order to obtain the rate approval that was effective May 2005. The revenue received in 2008 was $4,589 (2007-$13,073). These approved programs were completed by December 2008. In 2008 the costs and revenue to December 31, 2007 were moved into the balance sheet and income statement and the revenue was recognized. A similar entry was made December 31, 2006. In the absence of regulatory treatment, net earnings in the current year would have decreased by $59,355 (2007-decrease of $13,617).

(iv) Payments in Lieu of Taxes

As prescribed by a regulatory rate order, income tax expense is recovered through customer rates based on taxes payable method. Therefore, rates do not include the recovery of future income taxes related to temporary differences between tax basis of assets and liabilities and their carrying amounts for accounting purposes. The Company has not recognized future income taxes, as it is expected that when these amounts become payable, they will be recovered through future rate revenues. Balance in the PILS account is $1,113,200 (2007-$1,113,200). In the absence of regulatory treatment, the net earnings effect in the current year would have been nil (2007-decrease of $354,000).

(v) Other deferred/transition costs

These balances represent OEB specific costs incurred up to 2005 not currently in rates. These costs will be applied for in the next rate rebasing application to the OEB. The OEB specific costs for 2008 are a credit of $87,202 (2007-$151,797). As well the OEB has authorized distributors to apply for other deferred costs including Loss Revenue Adjustment Mechanism ("LRAM") due to Demand Management Programs to their customers that have resulted in decreased kWh consumption. This amount may be claimed in a subsequent rate year as compensation for loss of revenue. LRAM balance is $418,901 (2007-nil). In the absence of regulatory

6. DEFERRED ASSETS (continued)

treatment, net earnings in the current year would have decreased by $220,580 (2007-decrease of $96,968).

(vi) Smart meters

The Company incurred costs for the implementation of smart meters of $619,086 (2007-$3,252,832). Smart meter revenue collected in 2008 was $482,815 (2007-$648,497). Effective November 2008 the OEB approved the recovery of smart meter costs incurred up to December 31, 2007. This resulted in the capitalization of smart meter costs of $1,747,126 (2007-$2,869,928), and the recognition of smart meter revenue of $521,720 (2007-$778,606) to the income statement. In the absence of regulatory treatment, net earnings in the current year would have decreased by $301,154 (2007-increase of $47,593).

7. NOTE PAYABLE

The note payable is due to the Municipality with no set repayment terms and interest payable monthly at 7.04%. Interest expense for the year amounted to $1,654,320 (2007-$1,654,320).

8. EMPLOYEE FUTURE BENEFITS

The Company measures its accrued benefit obligation as at December 31 of each year. The Company pays certain medical and life insurance benefits on behalf of its retired and current employees. The accrued benefit liability at December 31, 2008 was $858,565 (2007-$800,909). The most recent actuarial valuation of the benefit plans for funding purposes was as of December 31, 2007 and the next required valuation will be as of December 31, 2010.

Information about the Company's defined benefit plan is as follows:

	2008	2007
	$	$
Accrued benefit liability, beginning of year	**800,909**	754,683
Expense for the year	**57,656**	46,226
Estimated accrued benefit liability, end of year	**858,565**	800,909

8. EMPLOYEE FUTURE BENEFITS (continued)

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

General inflation

Future inflation levels, as measured by changes in the Consumers Price Index ("CPI"), were assumed to be 2.5% in 2009 and thereafter.

Interest (discount) rate

The present value of the future benefits, and the expense for the year ended December 31, 2008 was determined using a discount rate of 6.1%. This corresponds to the OEB approved non-arm's length cost of debt rate for 2008.

Health costs

Health costs were assumed to increase at 10% per year for 10 years, and then at the CPI rate plus 1% thereafter.

Dental costs

Dental costs were assumed to increase at the CPI rate plus 1% for 2009 and thereafter.

Salary Growth Rate

Salary growth rate was assumed to increase at a rate of 3.5% for 2009 and thereafter.

9. PENSION AGREEMENT

The Company provides a pension plan for its employees through the Ontario Municipal Employees' Retirement System ("OMERS"). OMERS is a multi-employer pension plan which operates as the Ontario Municipal Employees Retirement Fund ("the Fund") and provides pensions for employees of Ontario municipalities, local boards, public utilities, and school boards. The Fund is a contributory defined benefit pension plan, which is financed by equal contributions from participating employers and employees, and by the investment earnings of the Fund. As there is insufficient information to apply defined benefit plan accounting, defined contribution plan accounting has been used by the Company. The Company's contribution for employees' current service in 2008 was $191,617 (2007-$184,132).

10. RELATED PARTY TRANSACTIONS

The Company provided the following services in the normal course of operations to the Municipality of Chatham-Kent:

	2008	2007
	$	$
Energy (at commercial rates)	**4,467,487**	4,727,568
Streetlight maintenance	**196,152**	121,721
	4,663,639	4,849,289

The Municipality provided the following services in the normal course of operations to the Company:

	2008	2007
	$	$
Asset management	**119,002**	80,801

Chatham-Kent Utility Services Inc. is wholly owned by Chatham-Kent Energy Inc. Chatham-Kent Utility Services Inc. has provided the following services in the normal course of operations to the Company:

	2008	2007
	$	$
Billing, collection & administrative services	**2,984,887**	2,933,878

Included in the costs above are deferred costs of $62,139 (2007-$113,122) that are reflected on the balance sheet.

Middlesex Power Distribution Corporation is wholly owned by CKE. Middlesex Power Distribution Corporation received the following services in the normal course of operations from the Company.

	2008	2007
	$	$
Billing, collection & administrative services	**77,415**	87,722
Other services provided	**104,297**	14,648
	181,712	102,370

11. CONTINGENCY

Class Action Suit

This action has been brought under the Class Proceedings Act, 1992. The plaintiff class seeks $500 million in restitution for amounts paid to Toronto Hydro and to other Ontario municipal electric utilities who received late payment penalties which constitute interest at an effective rate in excess of 60% per year, contrary to section 347 of the Criminal Code. Pleadings have closed in this action. The action has not yet been certified as a class action and no discoveries have been held, as the parties were awaiting the outcome of a similar proceedings brought against Enbridge Gas Distribution Inc. (formerly Consumers Gas).

On April 22, 2004, the Supreme Court of Canada released a decision in the Enbridge Gas Distribution case rejecting all of the defenses which had been raised by Enbridge, although the Court did not permit the Plaintiff class to recover damages for any period prior to the issuance of the Statement of Claim in 1994 challenging the validity of late payment penalties. The Supreme Court remitted the matter back to the Ontario Superior Court of Justice for determination of the damages. At the end of 2006, a mediation process resulted in the settlement of the damages payable by Enbridge.

In 2007, Enbridge filed an application to the OEB to recover the Court-approved amount and related amounts from ratepayers. In February 2008, the OEB approved recovery of these amounts from ratepayers over a five year period.

After the release by the Supreme Court of Canada of its 2004 decision in the Enbridge Gas case, the plaintiffs in the LDC late payment penalties class action indicated their intention to proceed with their litigation against the LDC's. To date, no formal steps have been taken to move the action forward. The electric utilities intend to respond to the action if and when it proceeds on the basis that the LDC's situation may be distinguishable from that of Enbridge Gas.

The Company collected total late payment penalties of $2,736,198 from customers between 1994 until April 2002 when the Company implemented an interest rate penalty. Although recent settlement models for Union Gas and Enbridge have been decided, it remains unclear as to the settlement models for LDC's.

12. SHARE CAPITAL

The share capital of the Company consists of the following:

	2008	2007
Authorized	$	$
Unlimited common shares		
Issued		
2,000 common shares	**23,523,425**	23,523,425

13. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital items

	2008	2007
	$	$
Accounts receivable	**24,181**	2,003,032
Accounts receivable - unbilled revenue	**349,486**	(822,630)
Inventories	**104,311**	(80,068)
Prepaid expenses	**(22,720)**	141,268
Due from Chatham-Kent Energy	**250,000**	-
Due from Middlesex Power Distribution Corporation	**(58,269)**	68,997
Due to Municipality of Chatham-Kent	**(479,015)**	(1,720,871)
Accounts payable and accrued liabilities	**(345,879)**	(805,371)
Taxes receivable	**729,593**	(2,147,596)
Increase in current portion of customer deposits	**273,568**	164,126
	825,256	(3,199,113)

Payments in lieu of taxes of $1,338,060 (2007-$2,376,720) and interest of $1,986,124 (2007-$2,009,246) were paid during the year.

14. FINANCIAL INSTRUMENTS

Fair value

The fair values of cash and cash equivalents, accounts receivable, unbilled revenue, due from related parties, accounts payable and accrued liabilities and due to related parties approximate their carrying amounts due to their short-term nature. As there is no secondary market for customer deposits, the calculation of their fair value with appropriate reliability is impractical. The Company has a long term promissory note payable with the Municipality in the amount of $23,523,326. The promissory note was issued upon incorporation on September 22, 2000 with interest at 7.04%. There is no "term length" associated with the promissory note.

14. FINANCIAL INSTRUMENTS (continued)

In order to determine fair value, comparison was made to the approved interest rate from the OEB. The OEB approved the rate of return on the debt portion of "Cost of Capital" for non-arms length transactions. This maximum rate was set at 7.25% to calculate electricity distributor pricing effective May 1, 2001. The 7.04% interest rate has been approved by the OEB through the rate setting process on a number of occasions since May 2001.

Using the OEB approved non-arm's length cost of debt of 6.1% the annual interest expense would be reduced by approximately $221,000 which is well within current OEB materiality threshold of $2,324,000. If the Company was able to obtain a reduced interest rate on the Note Payable the OEB would most likely reduce the revenue in a rate proceeding therefore the impact to the net income would be much less. As a result, no changes have been made to the current financial statements.

Credit risk

The Company is exposed to credit risk from its customers. The Company has a large number of diverse customers for the most part minimizing concentration of risk. There are a select group of manufacturing based corporations that pose a significant increase in risk due to the current economy as well as the future outlook of the economy. Close monitoring of this sector is currently being examined through internal and external credit rating resources. The Company continues to utilize special payment arrangements and security deposits to reduce this risk.

15. CAPITAL DISCLOSURES

The Company's main objectives when managing capital are to:

- ensure ongoing access to funding to maintain and improve the electricity distribution system of LDC;
- maintain an A-credit rating on stand alone basis;
- maintain a capital structure comparable for regulated activities as approved by the OEB's deemed debt to equity structure in our rates.

As at December 31, 2008 the Company's definition of capital includes shareholder's equity and long-term debt. This definition has remained unchanged from December 31, 2007. As at December 31, 2008 shareholder's equity amounts to $28,705,384 (2007-$27,440,171) and long-term debt amounts to $23,523,326 (2007-$23,523,326).

The 2008 capital structure approved by the OEB in rates was 47% Equity (2007-50%) and 53% Long-Term Debt (2007-50%). The Company's 2008 actual capital structure was 55% Equity (2007-54%) with 45% Long-Term Debt (2007-46%).

16. FUTURE INCOME TAXES

If the liability method of accounting for income taxes were used, a future tax asset of $2,152,782 (2007-$2,846,833) would be recorded.

17. COMMITMENTS

The Company has entered into Service Level agreements with Chatham-Kent Utility Services Inc., to have them provide the services of billing, account collections, customer inquiries and meter reading as well as administrative services such as office space usage, rate submission support, accounting and budgeting support. The value of this contract is $2,984,887 (2007-$2,933,878).

The Company has entered into a Service Level agreement with Middlesex Power Distribution Corporation to provide them management, engineering and material purchasing services. The value of this contract is $77,415 (2007-$87,722).

Financial Statements of

MIDDLESEX POWER DISTRIBUTION CORPORATION

December 31, 2008

Management's Responsibility for Financial Reporting

Middlesex Power Distribution Corporation's management is responsible for the preparation and presentation of the financial statements and all other information included in this annual report. Management is also responsible for the selection and use of accounting principles that are appropriate in the circumstances, and for the internal controls over the financial reporting process to reasonably ensure that relevant and reliable information is produced. Financial statements are not precise in nature as they include certain amounts based on estimates and judgment. Management has determined such amounts on a reasonable basis in order to ensure that the financial statements are presented fairly, in all material respects.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control over the financial reporting process. The Board exercises this responsibility through the Audit Committee of the Board. This committee, which is comprised of three directors of the Chatham-Kent Energy Board, with one member who is also on the Middlesex Power Distribution Corporation board, meets with management and the external auditors to ensure that management responsibilities are properly discharged and to review the financial statements and other information included in the annual report before they are presented to the Board of Directors for approval. The financial statements have been approved by the Board of Directors on the recommendation of the Audit Committee.

Deloitte & Touche LLP, an independent firm of Chartered Accountants, has been appointed by the audit committee and engaged to examine the accompanying financial statements in accordance with generally accepted auditing standards in Canada and provide an independent professional opinion. Their report is presented with the financial statements.

Dave Kenney	**Jim Hogan**
President	**Chief Financial & Regulatory Officer**

TABLE OF CONTENTS

Deloitte.

Deloitte & Touche LLP
One London Place
255 Queens Avenue
Suite 700
London ON N6A 5R8
Canada

Tel: 519-679-1880
Fax: 519-640-4625
www.deloitte.ca

Auditors' Report

To the Chairman and Board Members of Middlesex Power Distribution Corporation.

We have audited the balance sheet of Middlesex Power Distribution Corporation as at December 31, 2008 and the statements of earnings, comprehensive income and retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

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

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2008 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Deloitte & Touche LLP

Chartered Accountants
Licensed Public Accountants

February 27, 2009

MIDDLESEX POWER DISTRIBUTION CORPORATION

Balance Sheet
December 31, 2008

	2008	2007
	$	$
ASSETS		
CURRENT		
Cash and cash equivalents	**1,998,722**	1,460,660
Accounts receivable (Note 4)	**916,400**	985,258
Accounts receivable - unbilled revenue	**1,518,794**	1,666,955
Inventories	**340,052**	246,351
Prepaid expenses	**46,259**	14,527
	4,820,227	4,373,751
CAPITAL ASSETS (Note 5)	**7,849,489**	7,401,936
OTHER		
Deferred assets (Note 6)	**756,340**	668,872
	13,426,056	12,444,559
LIABILITIES		
CURRENT		
Accounts payable and accrued liabilities	**2,498,408**	2,309,154
Taxes payable	**17,906**	20,399
Due to related parties (Note 7)	**512,412**	432,093
Current portion of customer deposits	**141,095**	120,735
	3,169,821	2,882,381
LONG-TERM		
Note payable (Note 8)	**4,300,000**	4,300,000
Employee future benefits (Note 9)	**47,636**	41,413
Long-term portion of customer deposits	**1,099,510**	757,038
	5,447,146	5,098,451
	8,616,967	7,980,832
CONTINGENCIES AND COMMITMENTS (Notes 12 and 18)		
SHAREHOLDER'S EQUITY		
Share capital (Note 13)	**4,631,198**	4,631,198
Retained earnings (deficit)	**177,891**	(167,471)
	4,809,089	4,463,727
	13,426,056	12,444,559

MIDDLESEX POWER DISTRIBUTION CORPORATION

Statement of Earnings, Comprehensive Income and Retained Earnings
Year Ended December 31, 2008

	2008	2007
	$	$
SERVICE REVENUE		
Residential	**5,712,408**	6,003,911
General service	**8,702,897**	9,540,984
Street lighting	**120,155**	131,452
	14,535,460	15,676,347
Change in unbilled revenue	**(122,268)**	(39,238)
	14,413,192	15,637,109
Retailer energy sales	**2,945,773**	2,578,974
	17,358,965	18,216,083
COST OF POWER	**14,496,661**	15,186,540
GROSS MARGIN ON SERVICE REVENUE	**2,862,304**	3,029,543
OTHER OPERATING REVENUE	**541,736**	475,451
OPERATING INCOME	**3,404,040**	3,504,994
OPERATING AND MAINTENANCE EXPENSE		
Distributuion	**684,209**	629,389
ADMINISTRATIVE EXPENSE		
Billing and collection	**673,213**	606,800
General administration	**54,394**	(99,991)
Interest	**379,170**	366,695
DEPRECIATION AND AMORTIZATION	**626,136**	544,056
	2,417,122	2,046,949
EARNINGS, BEFORE PAYMENTS IN LIEU OF TAXES	**986,918**	1,458,045
Payments in lieu of taxes (Note 17)	**155,556**	487,037
NET EARNINGS AND COMPREHENSIVE INCOME	**831,362**	971,008
(DEFICIT), BEGINNING OF YEAR	**(167,471)**	(780,479)
LESS DIVIDENDS PAID	**(486,000)**	(358,000)
RETAINED EARNINGS (DEFICIT), END OF YEAR	**177,891**	(167,471)

MIDDLESEX POWER DISTRIBUTION CORPORATION

Statement of Cash Flows
Year Ended December 31, 2008

	2008	2007
	$	$
OPERATING ACTIVITIES		
Net earnings	**831,362**	971,008
Adjustments for:		
Depreciation of capital assets	**701,934**	617,849
Amortization of contributed capital	**(33,105)**	(29,200)
Employee future benefits	**6,223**	1,625
Change in non-cash working capital items (Note 14)	**379,026**	(171,914)
Change in long-term customer deposits	**342,472**	375,186
	2,227,912	1,764,554
INVESTING ACTIVITIES		
Change in deferred assets	**40,778**	14,006
Recovery of deferred assets	**(128,246)**	(658,015)
Additions to capital assets	**(1,116,382)**	(1,206,433)
Regulatory revenue payable	**-**	(57,149)
	(1,203,850)	(1,907,591)
FINANCING ACTIVITIES		
Dividends paid	**(486,000)**	(358,000)
NET CHANGE IN CASH AND CASH EQUIVALENTS	**538,062**	(501,037)
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR	**1,460,660**	1,961,697
CASH AND CASH EQUIVALENTS, END OF YEAR	**1,998,722**	1,460,660

See Note 14 for supplemental cash flow information.

1. NATURE OF OPERATIONS

a) Incorporation of Middlesex Power Distribution Corporation

Middlesex Power Distribution Corporation ("the Company") was incorporated April 11, 2000 under the *Business Corporations Act (Ontario)*.

The Company is wholly-owned by Chatham-Kent Energy Inc. ("CKE") which purchased 100% of the outstanding shares on June 30, 2005. CKE is owned 90% by the Municipality of Chatham-Kent ("the Municipality") and 10% by Corix Utilities ("Corix").

The principal activity of the Company is to distribute electricity to customers within the Township of Strathroy-Caradoc and the Municipality of North Middlesex, under the licence issued by the Ontario Energy Board ("OEB").

The incorporation and subsequent reorganization was required by provisions of Bill 35, *The Energy Competition Act, 1998* enacted by the Province of Ontario to introduce competition in the electricity market.

b) Rate Regulated Entity

The Company is a regulated electricity Local Distribution Company ("LDC") and has a distribution licence that is regulated by the OEB. The OEB has regulatory oversight of electricity matters in Ontario. *The Ontario Energy Board Act, 1998* sets out the OEB's authority to issue a distribution licence which must be obtained by owners or operators of a distribution system in Ontario. The OEB prescribes licence requirements and conditions including, among other things, specified accounting records, regulatory accounting principles and filing process requirements for rate-setting purposes.

The OEB's authority and responsibilities include the power to approve and fix rates for the transmission and distribution of electricity, the power to provide continued rate protection for rural and remote electricity customers and the responsibility of ensuring the electricity distribution companies fulfill obligations to connect and service customers.

The Company is required to charge its customers for the following amounts (all of which, other than the distribution rates, represent a pass through of amounts payable to third parties):

- Electricity Price – The electricity price represents the commodity cost of electricity.
- Distribution Rate – The distribution rate is designed to recover the costs incurred by the Company in delivering electricity to customers and the OEB allowed rate of return.
- Retail Transmission Rate – The retail transmission rate represents the wholesale costs incurred by Company in respect of the transmission of electricity from generating stations to the local areas.
- Wholesale Market Service Charge – The wholesale market service charge represents the various wholesale market support costs.

1. NATURE OF OPERATIONS (continued)

In order to operate in the Ontario electrical industry all market participants, including the Company, are required to satisfy and maintain prudential requirements with the Independent Electricity System Operator ("IESO"), which include credit support with respect to outstanding market obligations in the form of obtaining a credit rating, letters of credit, cash deposits or guarantees from third parties with prescribed credit ratings.

Market Based Rate of Return

The Company had reset their rates and received approval from the OEB for a change in rates effective May 1, 2006 which approved rates that included a rate of return of 9.0% on equity and rebased the rate base and operating costs at the 2004 historical levels. The rate of return of 9.0% was the maximum allowed by the OEB at that time.

Incentive Rate Mechanism

The OEB regulates the rates of the Company in an Incentive Rate Mechanism ("IRM") regime for 2007-2010. The process includes a formulae approach to establishing 2007 rates with a rate rebasing approach (cost-of-service) to be staggered across all Ontario distributors between 2008 and 2010.

The OEB allows for the rate rebasing to be deferred for up to five years where there is a purchase or merger of LDC's. The Company on February 9, 2009 was approved by the OEB to purchase 100% of the shares of Dutton Hydro Ltd. and Newbury Power Inc. which also approved the deferral of the rate rebasing to 2014.

The IRM rate setting process provides an increase in rates for inflationary cost increases with a 1% offset for productivity gains. The IRM process also includes changes in the tax rates and a movement from the 2006 approved capital structure of 50% long-term debt and 50% equity to 4% short-term debt, 56% long-term debt and 40% equity.

The distribution rates did not change in 2008 using the OEB's approved IRM.

Smart Meter Program

The Company has been named in Ontario Regulation 427/06 which gives the Company the ability to install smart meters to their low volume customers. By the end of 2007, the Company had installed a smart meter to substantially all of their residential customers.

The Company participated in a regulatory proceeding in 2007 along with the other utilities that were named in the Ontario Regulation. The regulatory process was to determine that the Company acted prudently in implementing its smart meter program. The Company was also seeking rate recovery for all capital costs invested up to April 30, 2007.

1. NATURE OF OPERATIONS (continued)

The OEB found the Company acted prudently and approved full recovery of all capital costs invested up to April 30, 2007.

In 2008 the Company applied for and received approval from the OEB for recovery of all smart meter costs installed between May 1, 2007 and December 31, 2007.

Consolidation in the Ontario Local Distribution Sector

The Provincial Government has provided a transfer-tax exemption window in order to entice LDC's to purchase, merge or amalgamate with one another. The exemption window was expected to close on October 18, 2008 but has been extended for an additional year. The Company received approval from the OEB on February 9, 2009 to purchase 100% of the shares of Dutton Hydro Ltd. and Newbury Power Inc. which is expected to close on March 31, 2009 (Note 19). At the closing the Dutton Hydro Ltd. and Newbury Power Inc. companies will be merged into the Company. The Company will continue to review its strategic options.

LDC's that purchase, merge or amalgamate will have the option to defer rate rebasing for up to five years. This will give the LDC's the benefit of keeping any possible synergies for a longer period of time which will offset the transaction costs. The benefits to the customers will be improved service and lower costs over the long term.

Regulatory Assets and Liabilities

Electricity distributors are required to reflect certain prescribed costs on their balance sheet until the manner and timing of distribution is determined by the OEB. These costs are:

- Transition costs resulting from preparation of Open Access;
- Settlement variance between amounts charged by the Company to customers (based on regulated rates) and corresponding cost of non-competitive electricity service incurred by it in the wholesale market administered by the IESO after May 1, 2002;
- The deferral of OEB annual cost assessments for the OEB's fiscal year 2004 and 2005;
- The deferral of incremental Ontario Municipal Employees Retirement System pension expenditures for fiscal years starting after January 1, 2005;
- Costs incurred to invest in and install a smart meter at all our customer premises; and
- Payment-in-lieu of taxes ("PILS") variances since the Company became taxable October 2002

The regulatory assets and liabilities balances are detailed in Note 6. The regulatory asset balances have been recovered in rates on an interim basis since April 2004. The Company had applied to the OEB for full and final recovery of the regulatory asset balances that were in place at December 31, 2004. The OEB approved the recovery of these assets over a two year period ending April 30, 2008.

1. NATURE OF OPERATIONS (continued)

The Company on an annual basis will continue to apply to the OEB for rate recovery of the investments made in smart meters. The recovery of variances for the PILS will occur sometime after the OEB completes their generic regulatory proceeding which will provide the filing guidelines for this regulatory asset or liability.

Electricity Sector Reorganization

In December 2004, the Province initiated a further restructuring of Ontario's electricity industry with the passage of the *Electricity Restructuring Act, 2004* ("Bill 100"). The restructuring was intended, among other things, to ensure efficient and effective management of electricity, promote the expansion of new electricity supply and capacity, encourage electricity conservation and renewable energy and regulate prices in parts of the electricity sector.

Bill 100:

i) Established the Ontario Power Authority ("OPA"), as an independent, non-profit, self-financed corporation, with a broad mandate to ensure adequate long-term electricity supply in the Province;
ii) Reorganized the Independent Electricity Market Operator as the IESO, a non-share corporation, which will continue to operate the wholesale market and be responsible for the operation and reliability of the integrated power system; and
iii) Established a Conservation Bureau within the OPA responsible for assuming a leadership role in planning and coordinating electricity conservation measures and load management in the Province.

Under Bill 100, the commodity cost of electricity for certain customer classes will be regulated by the OEB. Customers who did not wish to or were not eligible to participate in the regulated plan purchased electricity in the competitive market or through licensed retailers.

Effective January 1, 2005, the IESO implemented, pursuant to Bill 100, a new price adjustment applicable to customers not subject to price protection and rate caps. The new price adjustment, referred to as Global Adjustment, is a variable rate calculated by the IESO based on the difference between electricity market prices and the mix of regulated and contract prices paid to electricity generators. This calculation results in positive or negative bill adjustments depending on prevailing electricity market conditions.

The difference between the amount credited to customers and the amount received from the IESO by LDC is being tracked in variance account and is currently reflected as a settlement variance regulatory liability. The disposition of the variance account balance shall be in accordance with the OEB's guidelines for reviewing variance and deferral accounts.

1. NATURE OF OPERATIONS (continued)

On February 23, 2005, the Minister of Energy announced a new fixed pricing structure for electricity supplied by OPG. The new pricing structure, effective April 1, 2005 through March 31, 2008, which has been extended, based on a blended price for electricity supplied by OPG's regulated and unregulated assets.

The new pricing structure had an immediate impact on large industrial and commercial electricity customers who use more than 250,000 kWh per year. While residential, small business and other consumers were not immediately affected by the new pricing structure, the OEB blended the various prices paid to generators into a new fixed price that these consumers now pay under the Regulated Price Plan ("RPP"), which took effect on April 1, 2005.

The OEB has formulated two pricing plans for RPP-eligible customers, depending on how customers' electricity consumption is metered – that is, a pricing plan for customers without smart meters, and a pricing plan for customers with smart meters. For both plans, prices were effective April 1, 2005.

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, including PILS recoveries, that LDC may charge and the costs that LDC may recover, including the balance of its regulatory assets.

2. CHANGES IN ACCOUNTING POLICIES

Current Accounting Changes

The Company adopted the following recommendations of the Canadian Institute of Chartered Accountants ("CICA") Handbook:

a) *Section 3862, Financial Instruments – Disclosures and Section 3863, Financial Instruments – Presentation*

In December 2006, the CICA issued Section 3862, Financial Instruments – Disclosures and Section 3863, Financial Instruments – Presentation. Originally these sections were applicable to financial statements relating to fiscal years beginning on or after October 1, 2007. Accordingly, the Company had planned to adopt the new standards for its fiscal year beginning January 1, 2008. However, in October 2008, the Accounting Standards Board ("AcSB") of the CICA decided that rate-regulated enterprises that are not public enterprises as defined in Section 1300, Differential Reporting, will not be required to apply Sections 3862 and 3863 and would continue to apply Section 3861, Financial Instruments — Disclosure and Presentation. Therefore, in accordance with this decision, the Company continues to apply Section 3861.

2. CHANGES IN ACCOUNTING POLICIES (continued)

b) *Section 1535, Capital Disclosures*

This Section requires disclosure of the Company's objectives, policies and processes for managing capital as well as its compliance with any external capital requirements. The required disclosures are included in Note 16.

c) *Section 3031, Inventories*

This Section is based on the International Accounting Standards Board's guidance for inventories and replaced existing CICA Handbook Section 3030, Inventories. Under this new standard, inventories are required to be measured at the lower of cost and net realizable value and any items considered to be major future components of property, plant and equipment are to be transferred to property, plant and equipment. The new standard also provides updated guidance on the appropriate methods of determining cost and the impact of any write-downs to net realizable value. The implementation of this standard did not have a material impact on the Company's results of operations.

The Company recognized operating expenses of $25,960, related to the inventory used in the servicing of electrical distribution assets (2007-$19,376).

Future accounting changes

a) *International Financial Reporting Standards ("IFRS")*

On February 13, 2008, the AcSB confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian Generally Accepted Accounting Principles ("GAAP") for fiscal years beginning on or after January 1, 2011. At this time, the impact on our future financial position and results of operations is not reasonably determinable or estimable. The OEB has also begun its own IFRS project to determine the nature of any changes that should be made in regulatory accounting requirements in response to IFRS. On May 8, 2008, the OEB announced the creation of an IFRS Consultation which will provide an opportunity for OEB staff to work with industry participants to identify transition issues and suggest how those issues might be addressed. We are participating in this process. On January 27, 2009 the OEB held a technical conference with stakeholders addressing issues to IFRS changeover from GAAP. We intend to closely monitor any International Financial Reporting Interpretations Committee ("IFRIC") initiatives with the potential to impact rate regulated accounting under IFRS and will participate in any related processes, as appropriate. In anticipation of the changes to our reporting standards due to the implementation of IFRS we will complete a diagnostic assessment of the impact of IFRS and outline a project plan in 2009. It is expected that IFRS will be implemented by the end of 2009 to ensure that 2010 has appropriate comparative financial information prior to full implementation on January 1, 2011. Although specific guidance to rate-regulated industries has yet to be confirmed, it is expected that the areas of greatest impact to LDC's will be property, plant and equipment, inventories, intangible assets, impairment of assets, employee benefits and the treatment of regulatory assets and liabilities.

2. CHANGES IN ACCOUNTING POLICIES (continued)

b) *Rate Regulated Accounting*

During 2007, the AcSB issued an exposure draft proposing to remove all specific references to rate regulated accounting from the CICA Handbook . In August 2007, the AcSB decided to remove a temporary exemption in CICA Handbook Section 1100, retain existing references to rate regulated accounting in the CICA Handbook, require the recognition of future income tax liabilities and assets as well as a corresponding regulatory asset or liability for the amount of future income taxes expected to be recovered from or refunded to customers, and retain existing requirements to disclose the effects of rate regulation. The new rules will apply to the Company prospectively effective January 1, 2009.

c) *Section 3064, Goodwill and Intangible Assets*

In February 2008, the CICA issued Section 3064, Goodwill and Intangible Assets, replacing Section 3062, Goodwill and Other Intangible Assets and Section 3450, Research and Development Costs. Various changes have been made to other sections of the CICA Handbook for consistency purposes. The new Section will be applicable to financial statements relating to fiscal years beginning on or after October 1, 2008. Accordingly, the Company will adopt the new standards for its fiscal year beginning January 1, 2009. It establishes standards for the recognition, measurement, presentation and disclosure of goodwill subsequent to its initial recognition and of intangible assets by profit-oriented enterprises. Standards concerning goodwill are unchanged from the standards included in the previous Section 3062. The Company does not expect that the adoption of this new Section will have a material impact on its financial statements.

3. SIGNIFICANT ACCOUNTING POLICIES

The financial statements have been prepared in accordance with GAAP and reflect the following policies as set forth in the Accounting Procedures Handbook issued by the OEB under the authority of the *Ontario Energy Board Act, 1998:*

Regulation

The Company is regulated by the OEB and any rate adjustments require OEB approval.

Cash and cash equivalents

Cash and cash equivalents consist of cash on hand and balances with the bank.

Unbilled revenue

Unbilled revenue is an estimate of customers' consumption of power from the last meter read to December 31st.

3. SIGNIFICANT ACCOUNTING POLICIES (continued)

Inventories

Inventories are valued at the lower of cost and net realizable value with cost being determined using the weighted average method.

Capital assets

Capital assets are recorded at cost. Depreciation is calculated on a straight-line basis over the useful life of the asset as follows:

Buildings and fixtures	25 – 50 years
Distribution station equipment	30 years
Distribution lines	25 years
Distribution transformers	25 years
Distribution meters	25 years
General office equipment	10 years
Computer equipment	5 years
Rolling stock	4 – 8 years
Tools	10 years
System supervisory equipment	15 years
Services	25 years
Contributions in aid of construction	25 years
SCADA	15 years
Smart meters	3-15 years

Impairment of long-lived assets

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

Contributions in aid of construction

Contributions in aid of construction consist of third party contributions toward the cost of constructing the Company's assets. For the year ended December 31, 2008 $82,351 was charged (2007-$46,047) to contributed capital that had been charged to capital assets and recorded as an offset to capital assets. Amortization is on a straight-line basis over 25 years.

3. SIGNIFICANT ACCOUNTING POLICIES (continued)

Computer software

Computer software is stated at cost less accumulated depreciation. Distribution software is depreciated over 5 years on a straight-line basis. Smart meter software is depreciated over 3 years on a straight-line basis.

Deferred assets

Deferred assets consist of qualifying capital costs and related expenditures incurred in the preparation for market opening, costs for conservation programs which meet the Minister of Energy's Directive and investments in smart meters, other expenditures that are not currently recovered in rates and variances for PILS.

Also included in deferred assets are retail settlement variance accounts. These variances are for non-competitive energy services which are a pass through for the Company.

Recovery of the deferred assets requires regulatory approval from the OEB.

In the absence of regulatory treatment, net earnings in the current year would have decreased by $473,223 (2007-increase of $135,255). Refer to Note 6 Deferred Assets for additional details.

Customer deposits

Customer deposits are recorded when received or paid. Deposits earn interest at a rate of prime less 2%.

Asset retirement obligations

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

Post employment benefits other than pension

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

3. SIGNIFICANT ACCOUNTING POLICIES (continued)

Use of estimates

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

Revenue recognition and cost of power

Service revenue is recorded on the basis of regular meter readings and estimated customer usage since the last meter reading date to the end of the year. The related cost of power is recorded on the basis of power used. Any discrepancies in the revenue collected and associated cost of power related to distribution are charged to deferred assets.

Payments in lieu of income taxes

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

The Company, regulated by the OEB, provides for payments-in-lieu of corporate income taxes using the taxes payable method instead of the liability method.

Under the taxes payable method, no provisions are 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. Future income taxes are expected to be reflected in future rates and, accordingly, are not recognized in the financial information. Payment in lieu of taxes is henceforth referred to as income taxes.

Financial instruments

Financial assets and financial liabilities are initially recognized at fair value and their subsequent measurement is dependent on their classification as described below. Their classification depends on the purpose, for which the financial instruments were acquired or issued, their characteristics and the Company's designation of such instruments. Settlement date accounting is used.

3. SIGNIFICANT ACCOUNTING POLICIES (continued)

Classification

Cash and cash equivalents	Held for trading
Accounts receivable	Loans and receivables
Accounts payable and accrued liabilities	Other liabilities
Due to related parties	Other liabilities
Current portion of customer deposits	Other liabilities
Note payable	Other liabilities
Long-term portion of customer deposits	Other liabilities

Held for trading

Held for trading financial assets are financial assets typically acquired for resale prior to maturity or that are designated as held for trading. They are measured at fair value at the balance sheet date. Fair value fluctuations including interest earned, interest accrued, gains and losses realized on disposal and unrealized gains and losses are included in other income.

Financial liabilities designated as held for trading are those non-derivative financial liabilities that the Company elects to designate on initial recognition as instruments that it will measure at fair value through other interest expense. These are accounted for in the same manner as held for trading assets. The Company has not designated any non-derivative financial liabilities as held for trading.

Loans and receivables

Loans and receivables are accounted for at amortized cost using the effective interest method.

Other liabilities

Other liabilities are recorded at amortized cost using the effective interest method and include all financial liabilities, other than derivative instruments.

Effective interest method

The Company uses the effective interest method to recognize interest income or expense which includes transaction costs or fees, premiums or discounts earned or incurred for financial instruments.

4. ACCOUNTS RECEIVABLE

	2008	2007
	$	$
Electrical energy	757,921	810,085
Other	175,079	191,773
	933,000	1,001,858
Allowance for doubtful accounts	(16,600)	(16,600)
Net accounts receivable	916,400	985,258

5. CAPITAL ASSETS

	2008			2007
	Cost	Accumulated Depreciation	Net Book Value	Net Book Value
	$	$	$	$
Plant and distribution system:				
Land	11,982	-	11,982	11,982
Buildings and fixtures	91,365	18,937	72,428	74,334
Distribution station equipment	595,868	512,067	83,801	67,616
Distribution system:				
Overhead	6,780,793	3,409,941	3,370,852	3,208,917
Underground	2,969,815	1,716,584	1,253,231	1,334,912
Transformers	3,216,923	1,708,371	1,508,552	1,465,781
Meters	1,214,057	601,550	612,507	655,797
General office equipment	88,248	79,610	8,638	9,804
Computer equipment	65,601	42,622	22,979	22,121
Rolling stock	813,825	590,342	223,483	225,802
Tools	358,534	335,644	22,890	27,377
Scada	96,826	8,409	88,417	27,352
Smart meters	979,085	140,844	838,241	514,993
Services	457,850	89,217	368,633	343,048
	17,740,772	9,254,138	8,486,634	7,989,836
Contributions in aid of construction	(838,745)	(201,600)	(637,145)	(587,900)
	16,902,027	9,052,538	7,849,489	7,401,936

Depreciation and amortization in the amount of $42,694 (2007-$44,531) for rolling stock and $16,899 (2007-$44,591) for computer software were included in operating, maintenance and administrative expenses.

6. DEFERRED ASSETS

Deferred assets and liabilities arise as a result of the rate-making process. As described in this note, the Company has recorded the following regulatory assets and related provisions. 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 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 process.

	2008	2007
	$	$
Costs		
Regulatory assets prior to 2004	-	103,275
Retail settlement variance accounts	**(353,226)**	(333,302)
Conservation and demand management costs	**554**	171,754
PILs recoverable	**207,851**	207,851
Other deferred costs	**746,723**	160,500
Smart meter	**257,718**	590,320
Gross deferred assets	**859,620**	900,398
Recoveries		
Regulatory assets prior to 2004 recovery	**3,897**	(92,260)
Conservation and demand management recovery	-	(128,473)
Other deferred recovery	**(89,732)**	-
Smart meter recovery	**(17,445)**	(10,793)
Net deferred assets	**756,340**	668,872

a) Regulatory Costs/Recoveries

(i) Regulatory Assets prior to 2004

The introduction of Bill 210 in November 2002 deferred future rate increases until 2007. However Bill 4 was introduced in December 2003 which allowed for the recovery of deferred assets over a four year period beginning in April 2004. The Company obtained full and final recovery of the deferred assets balances at December 31, 2004. The recovery was over a four-year period ending April 30, 2008. Deferred asset revenue for 2008 was $74,764 (2007-$233,503).

In 2008, $170,920 of deferred asset revenue was allocated towards $170,920 of deferred asset expense, as per OEB guidelines. An interest receivable of $nil in 2008 (2007-$7,420) was recorded as per OEB guidelines. Deferred asset revenue remained in place until April 2008. At April 30, 2008 that the revenue collected was not sufficient to cover the regulatory assets costs prior to 2004. A balance of $3,897 is required to cover the remaining costs. In the absence of regulatory

6. DEFERRED ASSETS (continued)

treatment, net earnings in the current year would have increased by $49,718 (2007 - increase of $149,162).

(ii) Retail settlement variance accounts

These accounts represent the variance between the revenue collected, using OEB approved rates for the non-competitive components of energy, and the corresponding cost of these non-competitive charges, beginning January 1, 2004 to the present. These variances will be held as a regulatory asset or liability, based on the expectation that the amounts held from one year to the next for rate setting purposes will be approved for collection from, or refund to, future customers. In the absence of regulatory treatment, net earnings for the year would have increased by $13,249 (2007-increase of $181,523).

(iii) Conservation and demand management

During 2008, the Company incurred costs for conservation and demand management of $544 (2007-$167,883). These costs are required in order to obtain the rate approval that was effective May 2005. No revenue was received in 2008 (2007-$18,220). The approved programs were completed by December 2008. In 2008, the 2007 balances were capitalized and expensed and the corresponding revenue was recognized. A similar entry was recorded during the year ended December 31, 2006. In the absence of regulatory treatment, net earnings in the current year would have decreased by $85,105 (2007-decrease of $5,033).

(iv) Payments in Lieu of Taxes

As prescribed by a regulatory rate order, income tax expense is recovered through customer rates based on taxes payable method. Therefore, rates do not include the recovery of future income taxes related to temporary differences between tax basis of assets and liabilities and their carrying amounts for accounting purposes. The Company has not recognized future income taxes, as it is expected that when these amounts become payable, they will be recovered through future rate revenues. Balance in PILS account $207,851 (2007-$207,851). In the absence of regulatory treatment, the effect on net earnings would have been nil (2007-decrease of $207,851).

(v) Other deferred

These balances represent OEB specific costs incurred up to 2005 not currently in rates. These costs will be applied for in the next rate rebasing application to the OEB. Balance for these costs are $412,210 (2007-$27,673). As well the OEB has authorized distributors to apply for Loss Revenue Adjustment Mechanism ("LRAM") due to Demand Management Programs to their customers that have

6. DEFERRED ASSETS (continued)

resulted in decreased kWh consumption. This amount may be claimed in a subsequent rate year as compensation for loss of revenue. The LRAM balance was $84,282 (2007-$0). Finally, in the May 2006 rate application, the OEB approved in rates additional funding or Tier 2 recovery to support capital, operation and maintenance expenditures that were required to improve the reliability of the distribution system. In 2009, the company will apply to the OEB to remove the additional funding from their rates. Final disposition of any variance between the revenue and expenditures will be applied for when the Company applies for rate rebasing. The Tier 2 balance was $89,732 (2007-$0). In the absence of regulatory treatment, net earnings in the current year would have decreased by $389,839 (2007-decrease of $17,678).

(vi) Smart meters

The Company incurred costs for the implementation of smart meters of $100,545 (2007-$961,149). Smart meter revenue collected in 2008 was $119,820 (2007-$134,987). Effective November 2008 the OEB approved the recovery of smart meter costs incurred up to December 31, 2007. This resulted in the capitalization of smart meter assets of $421,361 (2007-$557,724), and the movement of deferred asset smart meter revenue of $113,168 (2007-$145,118) to the income statement. In the absence of regulatory treatment, net earnings for the current year would have decreased by $61,247 (2007 increase of $35,132).

7. DUE TO RELATED PARTIES

	2008	2007
	$	$
Due to Chatham-Kent Utility Services Inc.	**19,649**	22,747
Due to Chatham-Kent Hydro Inc.	**383,262**	324,993
Due to Chatham-Kent Energy Inc.	**25,980**	25,980
Due to the Municipality of Chatham-Kent	**83,521**	58,373
Net due to related parties	**512,412**	432,093

8. LONG-TERM LOANS

Note Payable

The note payable of $4,300,000 is due to CKE and was issued as part of the acquisition of the Company by CKE on June 30, 2005. It has no set repayment terms and interest payable monthly at 7.25%. Interest expense on this note was $311,750 (2007-$311,750).

9. EMPLOYEE FUTURE BENEFITS

The Company measures its accrued benefit obligation as at December 31 of each year. The Company pays certain medical and life insurance benefits on behalf of its retired and current employees. The accrued benefit liability at December 31, 2008 was $47,636 (2007-$41,413). The most recent actuarial valuation of the benefit plans for funding purposes was as of December 31, 2007 and the next required valuation will be as of December 31, 2010.

Information about the Company's defined benefit plan is as follows:

	2008	2007
	$	$
Accrued benefit liability, beginning of year	**41,413**	39,788
Expense for the year	**6,223**	1,625
Estimated accrued benefit liability, end of year	**47,636**	41,413

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

General inflation

Future inflation levels, as measured by changes in the Consumers Price Index ("CPI"), were assumed to be 2.5% in 2009 and thereafter.

Interest (discount) rate

The present value of the future benefits, and the expense for the year ended December 31, 2008 was determined using a discount rate of 6.1%. This corresponds to the OEB approved non-arms length cost of debt rate for 2008.

Health costs

Health costs were assumed to increase at 10% per year for 10 years, and then at the CPI rate plus1% thereafter.

Dental costs

Dental costs were assumed to increase at the CPI rate plus 1% for 2009 and thereafter.

Salary growth

Salary growth rate was assumed to increase at a rate of 3.5% for 2009 and thereafter.

10. PENSION AGREEMENT

The Company provides a pension plan for its employees through the Ontario Municipal Employees' Retirement System ("OMERS"). OMERS is a multi-employer pension plan which operates as the Ontario Municipal Employees Retirement Fund ("the Fund") and provides pensions for employees of Ontario municipalities, local boards, public utilities, and school boards. The Fund is a contributory defined benefit pension plan, which is financed by equal contributions from participating employers and employees, and by the investment earnings of the Fund. As there is insufficient information to apply defined benefit plan accounting, defined contribution plan accounting has been used by the Company. The Company's contribution for employees' current service in 2008 was $46,167 (2007-$45,550).

11. RELATED PARTY TRANSACTIONS

Chatham-Kent Hydro Inc. (wholly owned by CKE) and Chatham-Kent Utility Services Inc. (wholly owned by CKE) provided the following services in the normal course of operations to the Company:

	2008	2007
	$	$
Chatham-Kent Utility Services Inc.		
Management, financial, regulatory and customer support	**273,336**	269,122
Chatham-Kent Hydro Inc.		
Management, engineering and purchasing	**77,415**	87,722
Other services provided	**104,297**	14,648
	181,712	102,370

12. CONTINGENCIES

a) Class Action Suit

This action has been brought under the *Class Proceedings Act, 1992*. The plaintiff class seeks $500 million in restitution for amounts paid to Toronto Hydro and to other Ontario municipal electric utilities ("LDCs") who received late payment penalties which constitute interest at an effective rate in excess of 60% per year, contrary to section 347 of the *Criminal Code*. Pleadings have closed in this action. The action has not yet been certified as a class action and no discoveries have been held, as the parties were awaiting the outcome of a similar proceedings brought against Enbridge Gas Distribution Inc. (formerly Consumers Gas).

On April 22, 2004, the Supreme Court of Canada released a decision in the Enbridge Gas case rejecting all of the defences which had been raised by Enbridge, although the Court did not permit the Plaintiff class to recover damages for any period prior to the issuance of the

12. CONTINGENCIES (continued)

Statement of Claim in 1994 challenging the validity of late payment penalties. The Supreme Court remitted the matter back to the Ontario Superior Court of Justice for determination of the damages. At the end of 2006, a mediation process resulted in the settlement of the damages payable by Enbridge.

In 2007, Enbridge filed an application to the OEB to recover the Court-approved amount and related amounts from ratepayers. On February 4, 2008 the OEB approved recovery of the said amounts from ratepayers over a five year period.

After the release by the Supreme Court of Canada of its 2004 decision in the Enbridge case, the plaintiffs in the LDC late payment penalties class action indicated their intention to proceed with their litigation against the LDCs. To date, no formal steps have been taken to move the action forward. The electric utilities intend to respond to the action if and when it proceeds on the basis that the LDCs' situation may be distinguishable from that of Enbridge.

The Company collected total late payment penalties of $276,714 from customers between 1994 until August 2001 when the Company implemented an interest rate penalty. Although recent settlement models for Union Gas and Enbridge have been decided, it remains unclear as to the settlement models for LDC's.

b) Letter of Credit

In order to obtain the electricity it requires to distribute to its customers, the Company was required to provide security to the Independent Electricity System Operator based on usage. The security obtained was a letter of credit from a financial institution for $834,984 (2007- $834,984) and was not drawn on at December 31, 2008. The financial institution does not have financial restrictions on the Company.

13. SHARE CAPITAL

The share capital of the Company consists of the following:

Authorized
Unlimited number of Class A preference shares without par value
Unlimited number of Class B preference shares without par value
Unlimited number of voting common shares without par value

	2008	2007
	$	$
Issued		
4,631,198 voting common shares	**4,631,198**	4,631,198

14. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital items

	2008	2007
	$	$
Accounts receivable	68,858	574,768
Accounts receivable -- unbilled revenue	148,161	(141,112)
Inventories	(93,701)	12,009
Prepaid expenses	(31,732)	44,936
Accounts payable and accrued liabilities	189,254	(251,992)
Taxes payable	(2,493)	(315,271)
Due to related parties	80,319	(87,808)
Current portion of customer deposits	20,360	(7,444)
	379,026	(171,914)

Payments in lieu of taxes of $344,753 (2007-$540,369) and interest of $379,170 (2007-$366,695) were paid during the year.

15. FINANCIAL INSTRUMENTS

Fair Value

The Company's recognized financial instruments consist of cash and cash equivalents, accounts receivable, unbilled revenue, accounts payable and accrued liabilities, due to related parties, customer deposits and note payable.

The fair values of cash and cash equivalents, accounts receivable, unbilled revenue, accounts payable, accrued liabilities and due to related parties approximate their carrying amounts due to their short-term nature. As there is no secondary market for customer deposits, the calculation of their fair value with appropriate reliability is impractical.

The Company has a long term promissory note payable with Chatham-Kent Energy in the amount of $4,300,000. The promissory note was issued upon Chatham-Kent Energy purchasing 100% of the shares on June 30, 2005. The interest rate on the promissory note is 7.25%. There is no "term length" associated with the promissory note.

15. FINANCIAL INSTRUMENTS (continued)

In order to determine fair value, comparison was made to the approved interest rate from the OEB. The OEB approved the rate of return on the debt portion of "Cost of Capital" for non-arms length transactions. This maximum rate was set at 7.25% to calculate electricity distributor pricing effective May 1, 2001. The interest rate has been approved by the OEB through the rate setting process on a number of occasions since May 2001.

Using the OEB approved non-arm's length cost of debt of 6.1% the annual interest expense would be reduced by approximately $50,000 which is well within current OEB materiality threshold of $413,000. If the Company was able to obtain a reduced interest rate on the Note Payable the OEB would most likely reduce the revenue in a rate proceeding therefore the impact to the net income would be much less. As a result, no changes have been made to the current financial statements.

Credit risk

The Company is exposed to credit risk from its customers. The Company has a large number of diverse customers for the most part minimizing concentration of risk. There are a select group of manufacturing based corporations that pose a significant increase in risk due to the current economy as well as the future outlook of the economy. Close monitoring of this sector is currently being examined through internal and external credit rating resources. The Company continues to utilize special payment arrangements and security deposits to reduce this risk.

16. CAPITAL DISCLOSURES

The Company's main objectives when managing capital are to:

- ensure ongoing access to funding to maintain and improve the electricity distribution system of LDC;
- maintain an A-credit rating on stand alone basis;
- maintain a capital structure comparable for regulated activities as approved by the OEB's deemed debt to equity structure in our rates.

As at December 31, 2008 the Company's definition of capital includes shareholder's equity and long-term debt. This definition has remained unchanged from December 31, 2007. As at December 31, 2008 shareholder's equity amounted to $4,809,089 (2007-$4,463,727) and long-term debt amounted to $4,300,000 (2007-$4,300,000).

The 2008 capital structure approved by the OEB in rates was 47% Equity (2007-50%) and 53% Long-Term Debt (2007-50%). The Company's 2008 actual capital structure was 53% Equity (2007-50%) with 47% Long-Term Debt (2007-50%).

17. FUTURE INCOME TAXES

If the liability method of accounting for income taxes were used, a future tax asset of $181,991 (2007-$221,315) would be recorded.

18. COMMITMENTS

The Company has entered into a letter of agreement with Chatham-Kent Utility Services Inc., a related company, to have them provide the services of certain management, human resources, financial, regulatory and customer support, rate submission support and accounting and budgeting support. The value of the agreement is $273,336 (2007-$269,122).

The Company has entered into a Customer Agreement for the services of a data collection system, data storage and access to specific software and systems. The terms of the agreement have been extended for five years commencing April 1, 2009. Annual payments were $33,348 (2007-$33,935).

The Company entered into an agreement with an unrelated party to perform meter reading and associated services on behalf of the Company on a year to year basis. The cost of this service to the Company was $84,844 (2007-$85,291).

The Company has entered into an agreement with the Township of Strathroy-Caradoc to lease a portion of the premises known as 351 Frances Street, Strathroy, Ontario for a period of 5 years effective July 1, 2005. The cost of the lease is $37,000 annually plus 60% of operating costs. The cost of this service was $75,400 (2007-$86,504).

The Company has entered into an agreement with the Township of Strathroy-Caradoc to provide the services of billing of water services for a period of 5 years. Contracts for maintenance of streetlight and traffic lights as well as installation of water meters, locate services and backhoe services are renewed annually. Revenues received for these services was $339,160 (2007-$298,712).

The Company has entered into a Service Level agreement with the Township of Strathroy-Caradoc to pay for administrative assistance. The cost of this agreement was $16,841 (2007-$17,407).

The Company has entered into a Service Level agreement with Chatham-Kent Hydro Inc., a related Company, to have them provide management, engineering and purchasing services. The value of the agreement is $77,415 (2007-$87,722).

19. SUBSEQUENT EVENT

The Company's purchase of Dutton Hydro Ltd. and Newbury Power Inc. was approved by the OEB on February 9, 2009. The purchase price is $490,000 for Dutton Hydro Ltd. and $163,350 for Newbury Power Inc. and is subject to normal closing adjustments. The transaction is expected to close March 31, 2009.

PRO FORMA FINANCIAL STATEMENTS - 2009 AND 2010:

The Chatham-Kent Hydro Pro Forma Financial Statements for the 2009 Bridge Year and the 2010 Test Year accompany this Schedule as Appendix G and Appendix H respectively.

APPENDIX G

COPY OF CHATHAM-KENT HYDRO INC.

2009 PRO FORMA FINANCIAL STATEMENTS

2009 INCOME STATEMENT

Account Description	Total
3000-Sales of Electricity	
4006-Residential Energy Sales	(11,884,931)
4010-Commercial Energy Sales	-
4015-Industrial Energy Sales	-
4020-Energy Sales to Large Users	-
4025-Street Lighting Energy Sales	(433,156)
4030-Sentinel Energy Sales	(24,482)
4035-General Energy Sales	(24,405,818)
4040-Other Energy Sales to Public Authorities	-
4045-Energy Sales to Railroads and Railways	-
4050-Revenue Adjustment	-
4055-Energy Sales for Resale	(5,141,322)
4060-Interdepartmental Energy Sales	-
4062-Billed WMS	(4,538,052)
4064-Billed WMS-One Time	-
4066-Billed NW	(3,791,316)
4068-Billed CN	(3,192,909)
4075-Billed LV	(243,015)
3000-Sales of Electricity Total	**(53,655,001)**
3050-Revenues From Services - Distirbution	
4080-Distribution Services Revenue	(12,800,555)
4082-RS Rev	(65,004)
4084-Serv Tx Requests	(1,996)
4090-Electric Services Incidental to Energy Sales	-
3050-Revenues From Services - Distirbution Total	**(12,867,555)**
3100-Other Operating Revenues	
4205-Interdepartmental Rents	(156,996)
4210-Rent from Electric Property	(126,996)
4215-Other Utility Operating Income	-
4220-Other Electric Revenues	(9,996)
4225-Late Payment Charges	(170,000)
4230-Sales of Water and Water Power	-
4235-Miscellaneous Service Revenues	(444,996)
4240-Provision for Rate Refunds	-
4245-Government Assistance Directly Credited to Income	-
3100-Other Operating Revenues Total	**(908,984)**
3150-Other Income & Deductions	
4305-Regulatory Debits	-
4310-Regulatory Credits	(34,000)
4315-Revenues from Electric Plant Leased to Others	-
4355-Gain on Disposition of Utility and Other Property	-
4360-Loss on Disposition of Utility and Other Property	(39,996)
4390-Miscellaneous Non-Operating Income	(30,996)
4395-Rate-Payer Benefit Including Interest	-
4398-Foreign Exchange Gains and Losses, Including Amortization	-
3150-Other Income & Deductions Total	**(258,116)**
3200-Investment Income	
4405-Interest and Dividend Income	(150,608)
4415-Equity in Earnings of Subsidiary Companies	-
3200-Investment Income Total	**(150,608)**

3350-Power Supply Expenses	
4705-Power Purchased	41,889,709
4708-Charges WMS	4,538,052
4710-Cost of Power Adjustments	-
4712-Charges-One-Time	-
4714-Charges NW	3,791,316
4715-System Control and Load Dispatching	23,977
4716-Charges CN	3,192,909
4720-Other Expenses	-
4725-Competition Transition Expense	-
4730-Rural Rate Assistance Expense	-
4750-LV Charges	243,015
3350-Power Supply Expenses Total	**53,678,977**
3500-Distribution Expenses - Operation	
5005-Operation Supervision and Engineering	98,227
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	55,365
5017-Distribution Station Equipment - Operation Supplies and Expenses	5,295
5020-Overhead Distribution Lines and Feeders - Operation Labour	98,369
5025-Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	31,852
5030-Overhead Subtransmission Feeders - Operation	-
5035-Overhead Distribution Transformers - Operation	50,206
5040-Underground Distribution Lines and Feeders - Operation Labour	159,122
5045-Underground Distribution Lines and Feeders - Operation Supplies and Expenses	22,863
5050-Underground Subtransmission Feeders - Operation	-
5055-Underground Distribution Transformers - Operation	47
5060-Street Lighting and Signal System Expense	-
5065-Meter Expense	235,006
5070-Customer Premises - Operation Labour	27,777
5075-Customer Premises - Materials and Expenses	2,098
5085-Miscellaneous Distribution Expense	-
5090-Underground Distribution Lines and Feeders - Rental Paid	-
5095-Overhead Distribution Lines and Feeders - Rental Paid	-
5096-Other Rent	-
3500-Distribution Expenses - Operation Total	**786,225**
3550-Distribution Expenses - Maintenance	
5105-Maintenance Supervision and Engineering	200,912
5110-Maintenance of Structures	-
5112-Maintenance of Transformer Station Equipment	-
5114-Mtaint Dist Stn Equip	139,466
5120-Maintenance of Poles, Towers and Fixtures	38,980
5125-Maintenance of Overhead Conductors and Devices	150,495
5130-Maintenance of Overhead Services	118,705
5135-Overhead Distribution Lines and Feeders - Right of Way	170,000
5145-Maintenance of Underground Conduit	3,084
5150-Maintenance of Underground Conductors and Devices	5,092
5155-Maintenance of Underground Services	49,657
5160-Maintenance of Line Transformers	76,075
5165-Maintenance of Street Lighting and Signal Systems	-
5170-Sentinel Lights - Labour	-
5172-Sentinel Lights - Materials and Expenses	34
5175-Maintenance of Meters	23,159
5178-Customer Installations Expenses - Leased Property	-
5195-Maintenance of Other Installations on Customer Premises	-
3550-Distribution Expenses - Maintenance Total	**975,660**

3650-Billing and Collecting	
5305-Supervision	134,027
5310-Meter Reading Expense	43,848
5315-Customer Billing	847,640
5320-Collecting	341,446
5325-Collecting - Cash Over and Short	-
5330-Collection Charges	-
5335-Bad Debt Expense	212,806
5340-Miscellaneous Customer Accounts Expenses	-
3650-Billing and Collecting Total	**1,579,767**
3700-Community Relations	
5405-Supervision	-
5410-Community Relations - Sundry	33,123
5415-Energy Conservation	-
5420-Community Safety Program	5,973
5425-Miscellaneous Customer Service and Informational Expenses	-
5155-Advertising Expense	2,049
3700-Community Relations Total	**41,145**
3800-Administrative and General Expenses	
5605-Executive Salaries and Expenses	70,521
5610-Management Salaries and Expenses	717,697
5615-General Administrative Salaries and Expenses	148,724
5620-Office Supplies and Expenses	55,962
5625-Administrative Expense Transferred-Credit	-
5630-Outside Services Employed	386,276
5635-Property Insurance	83,186
5640-Injuries and Damages	-
5645-Employee Pensions and Benefits	231,197
5650-Franchise Requirements	-
5655-Regulatory Expenses	238,662
5660-General Advertising Expenses	-
5665-Miscellaneous Expenses	-
5670-Rent	-
5675-Maintenance of General Plant	511,162
5680-Electrical Safety Authority Fees	-
5685-Independent Market Operator Fees and Penalties	-
5695-OM&A Contra Account	-
3800-Administrative and General Expenses Total	**2,443,387**
3850-Amortization Expense	
5705-Amortization Expense - Property, Plant and Equipment	3,701,765
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	-
3850-Amortization Expense Total	**3,701,765**

3900-Interest Expense	
6005-Interest on Long Term Debt	-
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	1,771,613
6040-Allowance for Borrowed Funds Used During Construction-Credit	-
6042-Allowance for Other Funds Used During Construction	-
6045-Interest Expense on Capital Lease Obligations	-
3900-Interest Expense Total	**1,771,613**
3950-Taxes Other Than Income Taxes	
6105-Taxes Other Than Income Taxes	-
3950-Taxes Other Than Income Taxes Total	**-**
4000-Income Taxes	
6110-Income Taxes	967,748
6115-Provision for Future Income Taxes	-
4000-Income Taxes Total	**967,748**
4100-Extraordinary & Other Items	
6205-Donations	200,000
6210-Life Insurance	-
6215-Penalties	-
6225-Green Energy Initiatives - OM&A	-
4100-Extraordinary & Other Items Total	**200,000**
Net Income - (Gain)/Loss	**(1,693,975)**

2009 BALANCE SHEET

Account Description	Total
1050-Current Assets	
1005-Cash	3,875,877
1010-Cash Advances and Working Funds	2,200
1020-Interest Special Deposits	-
1030-Dividend Special Deposits	-
1040-Other Special Deposits	-
1060-Term Deposits	-
1070-Current Investments	-
1100-Customer Accounts Receivable	3,017,500
1102-Accounts Receivable - Services	-
1104-Accounts Receivable - Recoverable Work	250,000
1105-Accounts Receivable - Merchandise, Jobbing, etc.	-
1110-Other Accounts Receivable	-
1120-Accrued Utility Revenues	7,918,800
1130-Accumulated Provision for Uncollectable Accounts -- Credit	(100,000)
1140-Interest and Dividends Receivable	-
1150-Rents Receivable	-
1170-Notes Receivable	-
1180-Prepayments	200,000
1190-Miscellaneous Current and Accrued Assets	-
1200-Accounts Receivable from Associated Companies	-
1210-Notes Receivable from Associated Companies	-
1050-Current Assets Total	**15,164,377**

1100-Inventory	
1305-Fuel Stock	-
1330-Plant Materials and Operating Supplies	800,000
1340-Merchandise	-
1350-Other Material and Supplies	-
1100-Inventory Total	**800,000**

1150-Non-Current Assets	
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 Subsidiary Companies - Significant Influence	-
1490-Investment in Subsidiary Companies	-
1150-Non-Current Assets Total	**-**

1200-Other Assets and Deferred Charges	
1505-Unrecovered Plant and Regulatory Study Costs	-
1508-Other Regulatory Assets	937,681
1510-Preliminary Survey and Investigation Charges	-
1515-Emission Allowance Inventory	-
1516-Emission Allowance Withheld	-
1518-RCVA retail	(163,779)
1525-Miscellaneous Deferred Debits	156,002
1530-Deferred Losses from Disposition of Utility Plant	-
1540-Deferred Losses from Disposition of Utility Plant	-
1545-Development Charge Deposits/ Receivables	-
1548-RCVA - Service Transaction Request (STR)	111,549
1550-LV Charges - Variance	(188,993)
1555-Smart Meters Recovery	2,103,571
1556-Smart Meters OM & A	504,545
1562-Deferred PILs	(4,225,539)
1563-Deferred PILs - Contra	4,496,953
1565-C & DM Costs	-
1566-C & DM Costs Contra	-
1570-Qualifying Transition Costs	14,410
1571-Pre Market CofP Variance	-
1572-Extraordinary Event Losses	102,807
1574-Deferred Rate Impact Amounts	80,000
1580-RSVA - Wholesale Market Services	(1,926,385)
1582-RSVA - One-Time	59,094
1584-RSVA - Network Charges	513,849
1586-RSVA - Connection Charges	(1,238,187)
1588-RSVA - Commodity (Power)	1,313,123
1590-Recovery of Regulatory Assets (25% of 2002 bal.)	135,595
1592-PILs and Tax Variance forr 2006 & Subsequent Years	(60,127)
1200-Other Assets and Deferred Charges Total	**2,726,169**

1450-Distribution Plant	
1805-Land	117,846
1806-Land Rights	-
1808-Buildings and Fixtures	339,972
1810-Leasehold Improvements	-
1815-Transformer Station Equipment - Normally Primary above 50 kV	-
1820-Distribution Station Equipment - Normally Primary below 50 kV	795,093
1825-Storage Battery Equipment	-
1830-Poles, Towers and Fixtures	4,746,932
1835-Overhead Conductors and Devices	19,628,594
1840-Underground Conduit	1,278,455
1845-Underground Conductors and Devices	15,181,831
1850-Line Transformers	15,347,757
1855-Services	3,755,475
1860-Meters	7,069,054
1865-Other Installations on Customer's Premises	-
1450-Distribution Plant Total	**68,261,008**

1500-General Plant	
1905-Land	768,511
1906-Land Rights	-
1908-Buildings and Fixtures	3,473,081
1910-Leasehold Improvements	-
1915-Office Furniture and Equipment	131,926
1920-Computer Equipment - Hardware	586,217
1925-Computer Software	613,095
1930-Transportation Equipment	2,881,106
1935-Stores Equipment	-
1940-Tools, Shop and Garage Equipment	685,613
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	827,728
1985-Sentinel Lighting Rentals	-
1990-Other Tangible Property	1,826,998
1995-Contributions and Grants	(4,161,753)
1500-General Plant Total	**7,632,521**

1550-Other Capital Assets	
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 Lease	-
1550-Other Capital Assets Total	**-**

1600-Accumulated Amortization	
2105-Accumulated Amortization of Electric Utility Plant - Property, Plant and Equipment	(29,187,227)
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	-
1600-Accumulated Amortization Total	**(29,187,227)**

Total Assets	**65,396,848**

1650-Current Liabilities	
2205-Accounts Payable	8,803,068
2208-Customer Credit Balances	-
2210-Current Portion of Customer Deposits	1,116,267
2215-Dividends Declared	-
2220-Miscellaneous Current and Accrued Liabilities	-
2225-Notes and Loans Payable	-
2240-Accounts Payable to Associated Companies	2,697,090
2242-Notes Payable to Associated Companies	-
2250-Competition Transition Charges Payable	-
2252-Transmission Charges Payable	-
2254-Electric 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.	115,017
2296-Future Income Taxes - Current	-
1650-Current Liabilities Total	**12,731,442**

1700-Non-Current Liabilities	
2305-Accumulated Provision for Injuries and Damages	-
2306-Employee Future Benefits	858,565
2308-Other Pensions - Past Service Liability	-
2310-Vested Sick Leave Liability	-
2315-Accumulated Provision for Rate Refunds	-
2320-Other Miscellaneous Non-Current Liabilities	15,000
2325-Obligations Under Capital Lease--Non-Current	-
2330-Devolpment Charge Fund	-
2335-Long Term Customer Deposits	3,463,476
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	-
1700-Non-Current Liabilities Total	**4,337,041**

1800-Long-Term Debt	
2505-Debentures Outstanding - Long Term Portion	-
2510-Debenture Advances	-
2515-Required Bonds	-
2520-Other Long Term Debt	1,000,000
2525-Term Bank Loans - Long Term Portion	-
2530-Ontario Hydro Debt Outstanding - Long Term Portion	-
2550-Advances from Associated Companies	23,523,326
1800-Long-Term Debt Total	**24,523,326**

1850-Shareholders' Equity	
3005-Common Shares Issued	23,523,425
3008-Preference Shares Issued	-
3010-Contributed Surplus	-
3020-Donations Received	-
3022-Devolpment 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	4,087,639
3046-Balance Transferred From Income	1,693,975
3047-Appropriations of Retained Earnings - Current Period	-
3048-Dividends Payable-Preference Shares	-
3049-Dividends Payable-Common Shares	(5,500,000)
3055-Adjustment to Retained Earnings	-
3065-Unappropriated Undistributed Subsidiary Earnings	-
1850-Shareholders' Equity Total	**23,805,040**

Total Liabilities & Shareholder's Equity	**65,396,848**

Balance Sheet Total	(1)

APPENDIX H

COPY OF CHATHAM-KENT HYDRO INC.
2010 PRO FORMA FINANCIAL STATEMENTS

2010 STATEMENT OF INCOME AND RETAINED EARNINGS	
Account Description	**Total**
3000-Sales of Electricity	
4006-Residential Energy Sales	(10,883,765)
4010-Commercial Energy Sales	-
4015-Industrial Energy Sales	-
4020-Energy Sales to Large Users	-
4025-Street Lighting Energy Sales	(455,313)
4030-Sentinel Energy Sales	(24,183)
4035-General Energy Sales	(25,136,740)
4040-Other Energy Sales to Public Authorities	-
4045-Energy Sales to Railroads and Railways	-
4050-Revenue Adjustment	-
4055-Energy Sales for Resale	(4,222,896)
4060-Interdepartmental Energy Sales	-
4062-Billed WMS	(4,359,335)
4064-Billed WMS-One Time	-
4066-Billed NW	(3,078,724)
4068-Billed CN	(2,595,180)
4075-Billed LV	(228,345)
3000-Sales of Electricity Total	**(50,984,481)**
3050-Revenues From Services - Distirbution	
4080-Distribution Services Revenue	(12,838,181)
4082-RS Rev	(65,004)
4084-Serv Tx Requests	(1,996)
4090-Electric Services Incidental to Energy Sales	-
3050-Revenues From Services - Distirbution Total	**(12,905,181)**
3100-Other Operating Revenues	
4205-Interdepartmental Rents	(156,996)
4210-Rent from Electric Property	(126,996)
4215-Other Utility Operating Income	-
4220-Other Electric Revenues	(9,996)
4225-Late Payment Charges	(188,861)
4230-Sales of Water and Water Power	-
4235-Miscellaneous Service Revenues	(494,368)
4240-Provision for Rate Refunds	-
4245-Government Assistance Directly Credited to Income	-
3100-Other Operating Revenues Total	**(977,217)**
3150-Other Income & Deductions	
4305-Regulatory Debits	-
4310-Regulatory Credits	-
4315-Revenues from Electric Plant Leased to Others	-
4355-Gain on Disposition of Utility and Other Property	-
4360-Loss on Disposition of Utility and Other Property	(40,000)
4365-Gains from Disposition of Allowances for Emission	-
4370-Losses from Disposition of Allowances for Emission	-
4375-Revenues from Non-Utility Operations	(396,329)
4380-Expenses of Non-Utility Operations	166,642
4385-Expenses of Non-Utility Operations	-
4390-Miscellaneous Non-Operating Income	(30,996)
4395-Rate-Payer Benefit Including Interest	-
4398-Foreign Exchange Gains and Losses, Including Amortization	-
3150-Other Income & Deductions Total	**(300,683)**
3200-Investment Income	
4405-Interest and Dividend Income	(122,237)
4415-Equity in Earnings of Subsidiary Companies	-
3200-Investment Income Total	**(122,237)**

3350-Power Supply Expenses	
4705-Power Purchased	40,722,897
4708-Charges WMS	4,359,335
4710-Cost of Power Adjustments	-
4712-Charges-One-Time	-
4714-Charges NW	3,078,724
4715-System Control and Load Dispatching	40,151
4716-Charges CN	2,595,180
4720-Other Expenses	-
4725-Competition Transition Expense	-
4730-Rural Rate Assistance Expense	-
4750-LV Charges	228,345
3350-Power Supply Expenses Total	**51,024,633**
3500-Distribution Expenses - Operation	
5005-Operation Supervision and Engineering	164,224
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	107,180
5017-Distribution Station Equipment - Operation Supplies and Expenses	6,471
5020-Overhead Distribution Lines and Feeders - Operation Labour	110,535
5025-Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	36,711
5030-Overhead Subtransmission Feeders - Operation	-
5035-Overhead Distribution Transformers - Operation	50,252
5040-Underground Distribution Lines and Feeders - Operation Labour	163,707
5045-Underground Distribution Lines and Feeders - Operation Supplies and Expenses	26,656
5050-Underground Subtransmission Feeders - Operation	-
5055-Underground Distribution Transformers - Operation	47
5060-Street Lighting and Signal System Expense	-
5065-Meter Expense	345,446
5070-Customer Premises - Operation Labour	27,909
5075-Customer Premises - Materials and Expenses	2,098
5085-Miscellaneous Distribution Expense	-
5090-Underground Distribution Lines and Feeders - Rental Paid	-
5095-Overhead Distribution Lines and Feeders - Rental Paid	-
5096-Other Rent	-
3500-Distribution Expenses - Operation Total	**1,041,236**
3550-Distribution Expenses - Maintenance	
5105-Maintenance Supervision and Engineering	315,211
5110-Maintenance of Structures	-
5112-Maintenance of Transformer Station Equipment	-
5114-Mtaint Dist Stn Equip	151,068
5120-Maintenance of Poles, Towers and Fixtures	53,155
5125-Maintenance of Overhead Conductors and Devices	190,050
5130-Maintenance of Overhead Services	120,532
5135-Overhead Distribution Lines and Feeders - Right of Way	180,000
5145-Maintenance of Underground Conduit	3,706
5150-Maintenance of Underground Conductors and Devices	5,863
5155-Maintenance of Underground Services	54,106
5160-Maintenance of Line Transformers	91,936
5165-Maintenance of Street Lighting and Signal Systems	-
5170-Sentinel Lights - Labour	-
5172-Sentinel Lights - Materials and Expenses	35
5175-Maintenance of Meters	22,170
5178-Customer Installations Expenses - Leased Property	-
5195-Maintenance of Other Installations on Customer Premises	-
3550-Distribution Expenses - Maintenance Total	**1,187,833**

3650-Billing and Collecting	
5305-Supervision	137,237
5310-Meter Reading Expense	34,853
5315-Customer Billing	1,025,552
5320-Collecting	416,389
5325-Collecting - Cash Over and Short	-
5330-Collection Charges	-
5335-Bad Debt Expense	212,766
5340-Miscellaneous Customer Accounts Expenses	-
3650-Billing and Collecting Total	**1,826,798**
3700-Community Relations	
5405-Supervision	-
5410-Community Relations - Sundry	44,929
5415-Energy Conservation	-
5420-Community Safety Program	9,557
5425-Miscellaneous Customer Service and Informational Expenses	-
5515- Advertising Expense	2,043
3700-Community Relations Total	**56,529**
3800-Administrative and General Expenses	
5605-Executive Salaries and Expenses	73,847
5610-Management Salaries and Expenses	875,544
5615-General Administrative Salaries and Expenses	245,314
5620-Office Supplies and Expenses	59,699
5625-Administrative Expense Transferred-Credit	-
5630-Outside Services Employed	233,633
5635-Property Insurance	84,175
5640-Injuries and Damages	-
5645-Employee Pensions and Benefits	250,137
5650-Franchise Requirements	-
5655-Regulatory Expenses	339,852
5660-General Advertising Expenses	-
5665-Miscellaneous Expenses	-
5670-Rent	-
5675-Maintenance of General Plant	528,550
5680-Electrical Safety Authority Fees	-
5685-Independent Market Operator Fees and Penalties	-
5695-OM&A Contra Account	-
3800-Administrative and General Expenses Total	**2,690,751**
3850-Amortization Expense	
5705-Amortization Expense - Property, Plant and Equipment	3,815,361
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	-
3850-Amortization Expense Total	**3,815,361**

3900-Interest Expense	
6005-Interest on Long Term Debt	-
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	1,800,831
6040-Allowance for Borrowed Funds Used During Construction-Credit	-
6042-Allowance for Other Funds Used During Construction	-
6045-Interest Expense on Capital Lease Obligations	-
3900-Interest Expense Total	**1,800,831**
3950-Taxes Other Than Income Taxes	
6105-Taxes Other Than Income Taxes	-
3950-Taxes Other Than Income Taxes Total	**-**
4000-Income Taxes	
6110-Income Taxes	429,754
6115-Provision for Future Income Taxes	-
4000-Income Taxes Total	**429,754**
4100-Extraordinary & Other Items	
6205-Donations	200,000
6210-Life Insurance	-
6215-Penalties	-
6225-Green Energy Initiatives - OM&A	-
4100-Extraordinary & Other Items Total	**200,000**
Net Income - (Gain)/Loss	**(1,216,073)**

2010 BALANCE SHEET

Account Description	Total
1050-Current Assets	
1005-Cash	2,714,222
1010-Cash Advances and Working Funds	2,200
1020-Interest Special Deposits	-
1030-Dividend Special Deposits	-
1040-Other Special Deposits	-
1060-Term Deposits	-
1070-Current Investments	-
1100-Customer Accounts Receivable	2,692,000
1102-Accounts Receivable - Services	-
1104-Accounts Receivable - Recoverable Work	100,000
1105-Accounts Receivable - Merchandise, Jobbing, etc.	-
1110-Other Accounts Receivable	-
1120-Accrued Utility Revenues	5,891,300
1130-Accumulated Provision for Uncollectable Accounts -- Credit	(100,000)
1140-Interest and Dividends Receivable	-
1150-Rents Receivable	-
1170-Notes Receivable	-
1180-Prepayments	210,000
1190-Miscellaneous Current and Accrued Assets	-
1200-Accounts Receivable from Associated Companies	-
1210-Notes Receivable from Associated Companies	-
1050-Current Assets Total	**11,509,722**

Account Description	Total
1100-Inventory	
1305-Fuel Stock	-
1330-Plant Materials and Operating Supplies	800,000
1340-Merchandise	-
1350-Other Material and Supplies	-
1100-Inventory Total	**800,000**

Account Description	Total
1150-Non-Current Assets	
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 Subsidiary Companies - Significant Influence	-
1490-Investment in Subsidiary Companies	-
1150-Non-Current Assets Total	**-**

1200-Other Assets and Deferred Charges	
1505-Unrecovered Plant and Regulatory Study Costs	-
1508-Other Regulatory Assets	941,474
1510-Preliminary Survey and Investigation Charges	-
1515-Emission Allowance Inventory	-
1516-Emission Allowance Withheld	-
1518-RCVA retail	(164,436)
1525-Miscellaneous Deferred Debits	156,120
1530-Deferred Losses from Disposition of Utility Plant	-
1540-Deferred Losses from Disposition of Utility Plant	-
1545-Development Charge Deposits/ Receivables	-
1548-RCVA - Service Transaction Request (STR)	111,990
1550-LV Charges - Variance	(189,896)
1555-Smart Meters Recovery	2,911,643
1556-Smart Meters OM & A	504,545
1562-Deferred PILs	(4,225,539)
1563-Deferred PILs - Contra	4,496,953
1565-C & DM Costs	-
1566-C & DM Costs Contra	-
1568-Green Energy Initiatives	-
1570-Qualifying Transition Costs	14,466
1571-Pre Market CofP Variance	-
1572-Extraordinary Event Losses	103,209
1574-Deferred Rate Impact Amounts	80,000
1580-RSVA - Wholesale Market Services	(1,934,285)
1582-RSVA - One-Time	59,310
1584-RSVA - Network Charges	515,926
1586-RSVA - Connection Charges	(1,243,022)
1588-RSVA - Commodity (Power)	1,319,968
1590-Recovery of Regulatory Assets (25% of 2002 bal.)	135,942
1592-PILs and Tax Variance forr 2006 & Subsequent Years	(60,127)
1200-Other Assets and Deferred Charges Total	**3,534,241**

1450-Distribution Plant	
1805-Land	117,846
1806-Land Rights	-
1808-Buildings and Fixtures	404,972
1810-Leasehold Improvements	-
1815-Transformer Station Equipment - Normally Primary above 50 kV	-
1820-Distribution Station Equipment - Normally Primary below 50 kV	895,093
1825-Storage Battery Equipment	-
1830-Poles, Towers and Fixtures	5,331,377
1835-Overhead Conductors and Devices	20,307,012
1840-Underground Conduit	1,519,893
1845-Underground Conductors and Devices	16,020,671
1850-Line Transformers	16,407,317
1855-Services	4,179,211
1860-Meters	7,098,553
1865-Other Installations on Customer's Premises	-
1450-Distribution Plant Total	**72,281,944**

1500-General Plant	
1905-Land	793,511
1906-Land Rights	-
1908-Buildings and Fixtures	3,951,081
1910-Leasehold Improvements	-
1915-Office Furniture and Equipment	143,926
1920-Computer Equipment - Hardware	642,217
1925-Computer Software	613,095
1930-Transportation Equipment	3,661,106
1935-Stores Equipment	-
1940-Tools, Shop and Garage Equipment	984,613
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	867,728
1985-Sentinel Lighting Rentals	-
1990-Other Tangible Property	1,908,593
1995-Contributions and Grants	(4,436,753)
1500-General Plant Total	**9,129,117**

1550-Other Capital Assets	
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 Lease	-
1550-Other Capital Assets Total	**-**

1600-Accumulated Amortization	
2105-Accumulated Amortization of Electric Utility Plant - Property, Plant and Equipment	(33,306,505)
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	-
1600-Accumulated Amortization Total	**(33,306,505)**

Total Assets	**63,948,518**

1650-Current Liabilities	
2205-Accounts Payable	6,723,224
2208-Customer Credit Balances	-
2210-Current Portion of Customer Deposits	1,116,267
2215-Dividends Declared	-
2220-Miscellaneous Current and Accrued Liabilities	-
2225-Notes and Loans Payable	-
2240-Accounts Payable to Associated Companies	2,083,620
2242-Notes Payable to Associated Companies	-
2250-Competition Transition Charges Payable	-
2252-Transmission Charges Payable	-
2254-Electric 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.	(39,071)
2296-Future Income Taxes - Current	-
1650-Current Liabilities Total	**9,884,040**

1700-Non-Current Liabilities	
2305-Accumulated Provision for Injuries and Damages	-
2306-Employee Future Benefits	858,565
2308-Other Pensions - Past Service Liability	-
2310-Vested Sick Leave Liability	-
2315-Accumulated Provision for Rate Refunds	-
2320-Other Miscellaneous Non-Current Liabilities	15,000
2325-Obligations Under Capital Lease--Non-Current	-
2330-Devolpment Charge Fund	-
2335-Long Term Customer Deposits	3,463,476
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	-
1700-Non-Current Liabilities Total	**4,337,041**

1800-Long-Term Debt	
2505-Debentures Outstanding - Long Term Portion	-
2510-Debenture Advances	-
2515-Required Bonds	-
2520-Other Long Term Debt	3,000,000
2525-Term Bank Loans - Long Term Portion	-
2530-Ontario Hydro Debt Outstanding - Long Term Portion	-
2550-Advances from Associated Companies	23,523,326
1800-Long-Term Debt Total	**26,523,326**

1850-Shareholders' Equity	
3005-Common Shares Issued	23,523,425
3008-Preference Shares Issued	-
3010-Contributed Surplus	-
3020-Donations Received	-
3022-Devolpment 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	(35,386)
3046-Balance Transferred From Income	1,216,073
3047-Appropriations of Retained Earnings - Current Period	-
3048-Dividends Payable-Preference Shares	-
3049-Dividends Payable-Common Shares	(1,500,000)
3055-Adjustment to Retained Earnings	-
3065-Unappropriated Undistributed Subsidiary Earnings	-
1850-Shareholders' Equity Total	**23,204,112**

Total Liabilities & Shareholder's Equity	**63,948,518**

Balance Sheet Total	0

RECONCILIATION BETWEEN PRO FORMA STATEMENTS AND REVENUE DEFICIENCY STATEMENTS

Chatham-Kent Hydro 2009 Pro Forma Statements have a couple items not included on the Revenue Deficiency Statement, the differences are:

- Investment Income on the Pro Forma Statement – the Interest and Dividend Income (Account 4405) includes interest estimated for the RSVA accounts whereas on the Deficiency Statement the amount has been excluded from the calculation ($50,000).
- Interest Expense on the Pro Forma Statement (Account 6035) is the actual interest expense ($1,771,663) that will incur for the year where as the Interest on the Deficiency Statements is the Deemed Interest ($2,088,763).
- Extraordinary and Other Items on the Pro Forma Statement - the Charitable Donation (Account 6205) has been excluded from the calculation on the Deficiency Statement ($200,000).

Chatham-Kent Hydro 2010 Pro Forma Statements have a couple items not included on the Revenue Deficiency Statement, the differences are:

- Investment Income on the Pro Forma Statement – the Interest and Dividend Income (Account 4405) includes interest estimated for the RSVA accounts whereas on the Deficiency Statement the amount has been excluded from the calculation ($50,000).
- In the Distribution Expense Maintenance on the Pro Forma Statement – Sentinel Light Material and expenses (Account 5172) of $35 is not included in the Deficiency Statement under the Operation and Maintenance.
- Interest Expense on the Pro Forma Statement (Account 6035) is the actual interest expense of ($1,800,831) that will incur for the year where as the Interest on the Deficiency Statements is the Deemed Interest ($2,422,602).
- Extraordinary and Other Items on the Pro Forma Statement - the Charitable Donation (Account 6205) has been excluded from the calculation on the Deficiency Statement ($200,000).

INFORMATION ON AFFILIATES

The corporate entities are found in Exhibit 1, Tab 1, Schedule 13. Further detail of the services provided and the relationship is as follows;

Chatham-Kent Energy provides executive oversight from the services of the Chief Executive Officer and Chief Financial/Regulatory Officer. These services are provided to Chatham-Kent Utility Services which in turn will bundle these services with other services to Chatham-Kent Hydro, Middlesex Power Distribution Corporation and the Chatham-Kent Public Utilities Commission.

Chatham-Kent Utility Services provides information technology, billing, collection, administration, financial and regulatory services to Chatham-Kent Hydro, Middlesex Power Distribution Corporation and the Chatham-Kent Public Utilities Commission, which operates the water and waste-water systems in the Municipality of Chatham-Kent. Some of the services that are provided by Chatham-Kent Utility Services are from other affiliates such as Chatham-Kent Energy (administration, financial, regulatory) and the Municipality of Chatham-Kent (information technology, collection, human resources).

Middlesex Power Distribution Corporation owns, operates and manages the assets associated with the distribution of electrical power within its service territory. Middlesex Power Distribution Corporation has their own line crews and a small office staff that provides the services to their customers.

Chatham-Kent Hydro owns, operates and manages the assets associated with the distribution of electrical power within its service territory. Chatham-Kent Hydro also oversees the operations of Middlesex Power Distribution Corporation by sharing the President, Director of Engineering, Safety Officer, Purchasing staff and other support staff.

RATE BASE:

Rate Base Overview:

The rate base used for the purpose of calculating the revenue requirement used in this Application follows the definition used in the 2006 EDR Handbook as an average of the balances at the beginning and the end of the 2010 Test Year, plus a working capital allowance, which is 15% of the sum of the cost of power and controllable expenses.

The net fixed assets include those distribution assets that are associated with activities that enable the conveyance of electricity for distribution purposes. The Chatham-Kent Hydro rate base calculation excludes any non-distribution assets. Controllable expenses include operations and maintenance, billing and collecting and administration expenses.

Chatham-Kent Hydro has provided its rate base calculations for the years 2006 Board Approved, 2006 Actual, 2007 Actual, 2008 Actual, 2009 Bridge Year and 2010 Test Year in Table 2-1 below. Chatham-Kent Hydro has calculated its 2010 rate base as $56,073,568.

Table 2-1
Summary of Rate Base

Description	2006 OEB Approved	2006 Actual	2007 Actual Year	2008 Actual Year	2009 Bridge Year	2010 Test Year
Gross Fixed Assets	51,052,305	60,480,801	66,400,507	71,671,139	75,893,529	81,411,060
Accumulated Depreciation	10,575,078	18,088,598	21,466,084	25,240,414	29,187,227	33,306,505
Net Book Value	40,477,227	42,392,203	44,934,422	46,430,725	46,706,302	48,104,555
Average Net Book Value	40,570,317	41,527,805	43,663,313	45,682,574	46,568,514	47,405,429
Working Capital	65,548,632	68,571,683	68,934,337	66,346,818	59,481,151	57,787,594
Working Capital Allowance	9,832,295	10,285,752	10,340,151	9,952,023	8,922,173	8,668,139
Rate Base	50,309,522	51,813,558	54,003,463	55,634,596	55,490,686	56,073,568

Chatham-Kent Hydro's change in average net fixed assets is driven 60% by regulatory changes and investment requirements since 2004 for the following items: smart meters - Chatham-Kent Hydro obtained OEB approval for smart meter assets installed up to April 30, 2007 in 2007 and also approved assets from May 1, 2007 to December 31, 2007 in 2008; wholesale meters that required replacement once their seals were expired in order to meet the IESO regulations; and elimination of load transfers.

The other significant investments were in land which has come available over the past few years which has allowed Chatham-Kent Hydro to provide parking for staff, additional building for the fleet storage, improved security of the property and to allow for future growth as the current property is land locked.

Chatham-Kent Hydro invested in its fleet as many of the vehicles were fully depreciated and past their useful expected life. The remaining increase in rate base is approximately only $200,000 per year (2004 to 2010). A high level summary of changes in net book value between 2006 Board Approved and the 2010 Test Year is as follows:

Net Book Value			
2006 Board Approved	$	40,570,317	
2010 Proposed	$	47,405,429	
Change	$	6,835,112	16.8%
Significant investments			
Smart meters and related hardware and software	$	3,363,390	49.2%
Wholesale meters	$	470,000	6.9%
Load transfers	$	175,000	2.6%
Subtotal regulatory Changes	$	4,008,390	58.6%
Land	$	590,000	8.6%
Transportation	$	900,000	13.2%
Other Capital	$	1,336,722	19.6%
Total	$	6,835,112	100.0%

Chatham-Kent Hydro has provided a summary of its calculations of the cost of power and controllable expenses used in the calculations for determining working capital for the years 2006 Board Approved, 2006 Actual, 2007 Actual, 2008 Actual, 2009 Bridge Year and 2010 Test Year in Table 2-2, below. Details of Chatham-Kent Hydro's calculation of its working capital allowance are provided in Table 2-18.

Table 2-2
Summary of Working Capital Calculation

Description	2006 OEB Approved	2006 Actual	2007 Actual Year	2008 Actual Year	2009 Bridge Year	2010 Test Year
Cost of Power	59,642,533	63,434,169	63,655,163	60,667,641	53,655,001	50,984,482
Operations	799,526	723,678	825,806	898,928	786,225	1,041,236
Maintenance	861,403	981,801	904,698	1,031,028	975,626	1,187,798
Billing & Collecting	1,478,645	1,390,478	1,288,334	1,423,199	1,579,767	1,826,798
Community Relations	23,011	23,211	93,127	53,431	41,145	56,529
Administration & General Expense	2,743,514	2,018,346	2,167,209	2,272,590	2,443,387	2,690,751
Property Taxes	0	0	0	0	0	0
Working Capital	65,548,632	68,571,683	68,934,337	66,346,818	59,481,151	57,787,594

The working capital reduction is driven by the decrease in the cost of power between the 2006 Board Approved year and the 2010 Test Year. The decrease in cost of power is driven by a large decrease in the volume of energy being consumed by Chatham-Kent Hydro's customers. The decrease is caused by the economic challenges in Chatham-Kent Hydro's service area along with significant conservation results by the residential customers.

The Chatham-Kent Hydro Distribution System:

Chatham-Kent Hydro owns and operates the electricity distribution system in its licensed service area in the Municipality of Chatham-Kent, serving approximately 32,300 Residential, General Service, Intermediate, Stand-by, Street Light, Sentinel Light and Unmetered Scattered Load customers/connections.

The distribution system extends over approximately 2,500 sq kilometres, and Chatham-Kent Hydro serves the 11 urban communities within that area. It includes three primary voltages (27.6 kV, 8kV, 4kV) and fourteen 4,000 volt substations. Approximately 50% of the system is directly connected to the Hydro One transmission system and the remaining 50% is embedded and supplied by the Hydro One distribution system. Over 90% of the General Service, Intermediate and Stand-by class customers are supplied by 27.6kV voltages while the Residential, Street Light, Sentinel Light and Unmetered Scattered Load customers are supplied by all the secondary system voltages.

Supervisory Control and Data Acquisition ("SCADA") is a combination of hardware, software and communication technology deployed to monitor and control SCADA enabled devices installed on the distribution system. SCADA defines several standards and protocols that permit vendors to provide special hardware that once installed can provide critical data about the distribution system, such as voltage, and current, and if so equipped will enable an Operator to control the device remotely. An Operator can effectively monitor the condition of the system and react to abnormal conditions by commanding the remote devices to open or close (or perform some other function) to correct the problem. SCADA also allows a Distributor to deploy equipment that will provide an alarm when a contingency situation develops allowing crews to respond almost immediately to either effect changes manually in the field, or remotely operate devices as previously described. SCADA also acts as a method of recording historical data about the distribution system garnered from a myriad of monitoring devices deployed in the field. Historical data can be used to review system conditions before, during and after an event and help diagnose a problem either during the event or afterwards. Historical data can also be used for forecasting load and demand management systems. SCADA in effect provides the "eyes and ears" into the distribution system for the control room operator and is a critical component of any type of smart grid.

In an effort to conserve energy, the Ontario government has mandated that all electrical meters in Ontario be upgraded to "smart" meters by the end of 2010. After a technical review of available Smart Meter Systems, in late 2004 Chatham-Kent Hydro initiated a pilot project with Tantalus Systems Corporation's TUNet Smart Meter System. Full deployment of the Tantalus Smart Meter System began in mid-2006. This system uses a two way 900 MHz communication network to transfer data from the meters to the transceiver and 220 MHz radio frequency back haul to the Advanced Metering Control Computer (AMCC) set up at Chatham-Kent Hydro service centre. Using this system capitalizes on low communication costs, eliminating cell and land line rental costs. Data is transferred from the AMCC daily into the Harris Customer Information System (CIS) for billing and customer presentment. All the meter data is considered live. The smart meter system also provides energy usage, power outages and restoration information that will be used in Outage Management, SCADA Systems and Distribution System Automation as well as Distribution System Modelling. Chatham-Kent Hydro has 28,644 (end of 2009) Smart Meters installed in the residential rate category and is billing 215 customers on Time of Use Rates and remaining customers on Regulated Price Plan (RPP).

Management of Assets

In managing its distribution system assets, Chatham-Kent Hydro's main objective is to optimize performance of the assets at a reasonable cost with due regard for system reliability, public and worker safety and customer service requirements. This Application incorporates Chatham-Kent Hydro's 2010 Capital and Operation, Maintenance &Administration Budgets in determining the revenue requirement to bring these plans to fruition. Further information will be provided later in this Application. Chatham-Kent Hydro considers performance-related asset information including, but not limited to, data on reliability, asset age and condition, loading, customer connection requirements, and system configuration, to determine investment needs with respect to the system.

On an annual basis, Chatham-Kent Hydro reviews capital projects identified for potential implementation and attempts to prioritize each project based on defined criteria on a relative basis. All members of the management team follow the criteria as they individually complete their work on preparing outlines of their recommendations, which are then discussed by the full group. After examining all recommended projects they are listed in order from higher to lower priority and then moved forward based on appropriate financial parameters.

Chatham-Kent Hydro follows the same process in developing a budget for the maintenance of the assets. Further information on Chatham-Kent Hydro's Capital and Operation, Maintenance and Administration expenditures will follow later in this Application.

Chatham-Kent Hydro assets fall into two broad categories – distribution plant, which includes assets such as wires, overhead and underground electricity distribution infrastructure, transformers, meters and substations; and general plant which includes assets such as transportation, SCADA, equipment and tools. More detailed lists of distribution and general plant categories can be found in the Gross Assets Table in Table 2-12.

Capital Projects:

Chatham-Kent Hydro's capital budget items include:

- **Customer Demand:**

These are projects that Chatham-Kent Hydro undertakes to meet its customer service obligations in accordance with the OEB's Distribution System Code (the "DSC") and Chatham-Kent Hydro's Conditions of Service. Activities include connecting new customers, building new subdivisions and relocating system plant for roadway reconstruction work. Capital contributions toward the cost of these projects are collected by Chatham-Kent Hydro in accordance with the DSC and the provisions of its Conditions of Service. Chatham-Kent Hydro uses the economic evaluation methodology from the DSC to determine the level of capital contribution for each project and those levels are injected into the annual capital budget.

- **Renewal:**

Renewal projects are completed when assets reach their end of useful life and must be replaced. Chatham-Kent Hydro completes visual inspections of its plant and performs predictive testing on certain assets where such testing is available, and replaces assets based on these inspection and testing activities if warranted. In some cases the projects involve spot replacement of assets; in others, the projects involve complete asset replacement within a geographic area. New assets require less maintenance, deliver better reliability and reduce safety risks to the general public.

- **Security:**

The probability and impact of asset failure are considered at peak load to determine the risk the failure creates. In these cases, projects are developed to add switching devices or create a backup feeder supply to reduce the risk to typical restoration times for Chatham-Kent Hydro.

- **Capacity:**

Load growth caused by new customer connections and increased demand of existing customers over time can result in a need for capacity improvements on the system. Projects can take the form of new or upgraded feeders, transformers or voltage conversion projects, substations or transformer stations. These projects are not customer-specific, but rather, they benefit many customers.

- **Reliability:**

The main driver for these investments is an analysis of what measures could be undertaken to improve Chatham-Kent Hydro reliability performance as measured by SAIDI, SAIFI and CAIDI indices. These indices are indicators of the reliability of Chatham-Kent Hydro's distribution system. These activities will support maintenance of or improvement to the Service Quality Indices measured and submitted to the OEB each year by Chatham-Kent Hydro. The Asset Management Plan provided in Exhibit 2, Tab 4, Schedule 1 supports the capital and maintenance programs needed to maintain and enhance the reliability of Chatham-Kent Hydro's distribution system.

- **Regulatory Requirements:**

These projects are system capital investments, which are being driven by regulatory requirements. These requirements may include, among others, directions from the OEB, the IESO, the Ministry of Energy or the Ministry of Environment. In 2009 and 2010 Chatham-Kent Hydro has placed into this category those projects relating to the elimination of long-term load transfers pursuant to the DSC.

- **Substations:**

Substation investments are undertaken to improve or maintain reliability to large numbers of customers and to maintain security and safety at the substations. Substations are actively being phased out over time. The order in which substations are removed is based on several criteria such as asset condition, loading, projected development in the serviced area, condition of the 4.16kV distribution system, power quality issues to name a few. Since 1985, Chatham-Kent Hydro has been converting to a 27.6kV system with the objective of eliminating the 4.16kV network. Elimination of 4.16kV distribution will contribute to a reduction in operating and maintenance costs, system losses, and overall improvements in the efficiency of the electrical distribution system.

- **Customer Connections and Metering:**

Capital expenditures in this pool include meter installations, meter upgrades, and the capital components of wholesale and retail meter verification activities. Chatham-Kent Hydro is initiating a smart meter program, as approved by Ontario Regulation 427/06 and 428/06.
Chatham-Kent Hydro capital projects for the 2010 Test Year are discussed in further detail below. Chatham-Kent Hydro has provided project-specific justifications in Exhibit 2, Tab 3, Schedule 2. Similarly, written explanations have been provided for rate base-related variances that exceed materiality of $79,127 (0.5% of Chatham-Kent Hydro revenue requirement threshold from the updated Filing Requirements).

Gross Assets – Property, Plant and Equipment and Accumulated Depreciation:

The 2009 Bridge and 2010 Test Years' gross asset balances reflect the capital expenditure programs forecast for both years. These programs are described in detail in Chatham-Kent Hydro's written evidence at Exhibit 2, Tab 3, Schedule 2.

The following comments provide an overview of Chatham-Kent Hydro's budgeting process.

Budgeting Process

Chatham-Kent Hydro goes through a budget process annually with some of the following objectives;

- Provide safe and reliable service to the customers
- Ensure the staff complement, qualifications, safety education and procedures are in place to meet the service quality standards
- Ensure that the budget can meet the many industry and regulatory changes
- Meet the financial targets to ensure a strong balance sheet is in place

Responsibilities

The President, CFO and CEO work together and are responsible for setting the financial, regulatory and service targets. Targets relate to (for example) cost per customer, meeting the regulated return on equity, service quality indicators and safety of employees and customers. These targets are set in order to minimize cost and improve the quality of service towards the customers.

Once these targets are set the management team prepares the detailed budgets for their respective areas.

The Engineering group prepares a load and customer forecast based upon historical activity. The load forecast will also try to reflect the impacts of weather, particularly the impact during the summer as Chatham-Kent Hydro is a summer peaking Utility.

The President will work with Chatham-Kent Utility Services on the level of service and the related costs that are to be provided to Chatham-Kent Hydro. Chatham-Kent Utility Services provide Chatham-Kent Hydro with a service level agreement that entails the following services Billing/Collecting, IT Service, Regulatory, Administration and Executive.

The accounting staff from Chatham-Kent Utility Services will prepare the budgeted financial statements for approval.

Approval Process

The President of Chatham-Kent Hydro, with the assistance of management team will approve the budget for presentation to the CFO and CEO. Once approved by all Executives the budget is presented to the Board.

The budget is then reviewed and approved by the Board of Chatham-Kent Hydro, 45 days prior to the beginning of the budget year.

The budget will not change during the year and will form the basis for reviewing monthly financial statements and variance analysis.

Any unexpected significant expenditure that is not included in the budget will be brought to the attention of the Board prior to undertaking the expenditure unless it is an emergency situation.

RATE BASE VARIANCE ANALYSIS:

The following Table 2-3 sets out Chatham-Kent Hydro's rate base and working capital calculations for 2006 Board Approved and Actual, 2007 Actual, 2008 Actual, 2009 Bridge Year and 2010 Test Year, and the following variances:

- 2006 Actual against 2006 Board Approved;
- 2007 Actual against 2006 Actual;
- 2008 Actual against 2007 Actual
- 2009 Bridge Year against 2008 Actual; and
- 2010 Test Year against 2009 Bridge Year.

Table 2-3
Rate Base Variances

Description	2006 OEB Approved*	2006 Actual	Variance from 2006 OEB Approved	2007 Actual Year	Variance from 2006 Actual	2008 Actual Year	Variance from 2007 Actual Year	2009 Brdge Year	Variance from 2008 Actual Year	2010 Test Year	Variance from 2009 Bridge Year
Gross Fixed Assets	51,052,305	60,480,801	9,428,496	66,400,507	5,919,705	71,671,139	5,270,633	75,893,529	4,222,390	81,411,060	5,517,531
Accumulated Depreciation	10,575,078	18,088,598	7,513,520	21,466,084	3,377,486	25,240,414	3,774,330	29,187,227	3,946,813	33,306,505	4,119,278
Net Book Value	40,477,227	42,392,203	1,914,976	44,934,422	2,542,219	46,430,725	1,496,303	46,706,302	275,577	48,104,555	1,398,253
Average Net Book Value	40,570,317	41,527,805	957,488	43,663,313	2,135,507	45,682,574	2,019,261	46,568,514	885,940	47,405,429	836,915
Working Capital	65,548,632	68,571,683	3,023,051	68,934,337	362,654	66,346,818	(2,587,519)	59,481,151	(6,865,667)	57,787,594	(1,693,558)
Working Capital Allowance	9,832,295	10,285,752	453,457	10,340,151	54,398	9,952,023	(388,128)	8,922,173	(1,029,850)	8,668,139	(254,034)
Rate Base	50,309,522	51,813,558	1,504,036	54,003,463	2,189,905	55,634,596	1,631,133	55,490,686	(143,910)	56,073,568	582,881

Chatham-Kent Hydro notes that the 2006 OEB Approved rate base was determined through the 2006 EDR process and is based on the 2004 average rate base adjusted for Tier 1 Adjustments. Accordingly, the variance between 2006 Actual and 2006 OEB Approved spans a two-year period.

Chatham-Kent Hydro has calculated the materiality threshold on its rate base to be $79,127 for 2010 in accordance with the updated Filing Requirements. This calculation and those for 2006, 2007, 2008, 2009 and 2010 are summarized in Table 2-4 below:

Table 2-4
Rate Base Materiality

Description	2006 OEB Approved	2006 Actual	2007 Actual Year	2008 Actual Year	2009 Bridge Year	2010 Test Year
Rate Base	$50,309,522	$51,813,558	$54,003,463	$55,634,596	$55,490,686	$56,073,568
Cost Capital	8.02%	8.02%	8.02%	7.95%	7.89%	7.52%
Return on Rate Base	$4,034,824	$4,155,447	$4,331,078	$4,425,583	$4,377,809	$4,219,200
Distribution Expense	$8,723,462	$8,107,926	$8,594,813	$9,274,947	$9,527,916	$10,618,473
PILS	$1,572,932	$1,349,735	$1,405,223	$1,207,671	$1,096,204	$987,663
Revenue Requirement	$14,331,218	$13,613,108	$14,331,114	$14,908,201	$15,001,929	$15,825,336
Materiality Cal .5%	$71,656	$68,066	$71,656	$74,541	$75,010	$79,127

Chatham-Kent Hydro offers the following comments in respect of the relevant variances identified above:

- **2010 Test Year:**

As shown in Table 2-4 above, the total rate base in the 2010 test year is forecast to be $56,073,568. Average net fixed assets accounts for $47,405,429 of this total. The allowance for working capital totals $8,668,139.

- **2010 Test Year vs. 2009 Bridge Year:**

The total rate base is expected to be $582,881 higher in the 2010 Test Year than in the 2009 Bridge Year. This increase is shown in Table 2-3 above and is attributable primarily to an increase capital projects. In 2010 there is an increase in Substation conversions and upgrades in the distribution system. The increase in Capital along with the required detailed information for projects is discussed in detail by capital project in Exhibit 2, Tab 3, Schedule 2.

The working capital allowance decreased by $254,034 compared to 2009 Bridge Year. A detailed calculation of the working capital allowance for the 2010 Test Year can be found in Table 2-18 below.

- **2009 Bridge Year vs. 2008 Actual:**

The total rate base for the 2009 Bridge Year is expected to be $55,490,686, which represents a decrease of $143,910 over the 2008 Actual year. This change results in part from a decrease in Working Capital resulting from a decrease in cost of power. The working capital allowance decreased by $1,029,850 compared to 2008. A detailed calculation of the working capital allowance for the 2009 Bridge Year can be found in Table 2-18, below.

- **2008 Actual vs. 2007 Actual:**

The rate base of $55,634,596 for 2008 Actual increased over 2007 Actual by $1,631,133. This increase is attributable to a change in average net assets of $2,019,261 as a result of capital expenditures for Smart Meters approved assets in rate base (EB-2008-0155). The change in average net assets is offset by a decrease in working capital of $2,587,519. The decrease in working capital is caused by a decrease in the cost of power; in last quarter of 2008 a number of general service customers slowed down production or closed due to economic conditions.

- **2007 Actual vs. 2006 Actual:**

The rate base of $54,003,463 for 2007 Actual increased over 2006 Actual by $2,189,905. This increase is attributable to a change in average net assets of $2,135,507 as a result of capital expenditures for Smart Meters approved assets in rate base (EB-2007-0063). The working capital allowance increased by $54,398 compared to 2006.

- **2006 Actual vs. 2006 Board Approved:**

The rate base of $51,813,558 for 2006 Actual was higher than the 2006 Board Approved by $1,504,036. The difference reflects the fact that the 2006 Board Approved amounts were calculated as the average of the 2003 and 2004 actual amounts.

The variance between the 2006 Actual and the 2006 Board Approved included the difference between the 2004 actual and the 2006 Board Approved amounts as well as the 2005 normal investments.

Gross Assets – Property, Plant and Equipment Accumulated Depreciation

Continuity Statements

Chatham-Kent Hydro has provided 2004 to 2010 fixed asset continuity schedules in the following tables 2-5 to 2-11 which illustrates the additions by USoA format with their related depreciation for the years. Table 2-12 includes the gross asset schedules from 2006 Board Approved to 2010 together with variances between the consecutive years.

Table 2-5
Chatham-Kent Hydro Inc.
Fixed Asset Continuity Schedule
As at December 31, 2004

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
N/A	1805	Land	195,144		11,863	183,281				0	183,281
CEC	1806	Land Rights				0				0	0
1	1808	Buildings and Fixtures	507,125			507,125	74,525	21,563		96,089	411,037
	1810	Leasehold Improvements				0				0	0
	1815	Transformer Station Equipment - Normally Primary above 50 kV				0				0	0
1	1820	Distribution Station Equipment - Normally	274,999	244,103	1,074	518,028	65,951	18,966	263	84,654	433,374
	1825	Storage Battery Equipment				0				0	0
1	1830	Poles, Towers and Fixtures	1,648,490	462,953		2,111,443	134,710	81,786		216,496	1,894,947
1	1835	Overhead Conductors and Devices	14,573,256	992,495		15,565,751	2,434,463	837,881		3,272,344	12,293,406
1	1840	Underground Conduit	546,511	140,422		686,933	46,258	27,477		73,736	613,198
1	1845	Underground Conductors and Devices	11,949,143	492,104		12,441,247	2,183,885	709,103		2,892,988	9,548,259
1	1850	Line Transformers	10,477,985	713,046		11,191,031	1,808,951	565,367		2,374,318	8,816,713
1	1855	Services	1,498,414	430,718		1,929,132	131,549	77,165		208,715	1,720,417
1	1860	Meters	2,315,122	134,682		2,449,804	433,557	157,570		591,127	1,858,677
	1861	Smart Meters				0				0	0
	1865	Other Installations on Customer's Premises				0				0	0
N/A	1905	Land	205,766			205,766				0	205,766
CEC	1906	Land Rights				0				0	0
1	1908	Buildings and Fixtures	2,517,443	71,237		2,588,680	229,521	75,659		305,180	2,283,500
	1910	Leasehold Improvements				0				0	0
8	1915	Office Furniture and Equipment	63,502	25,051		88,553	30,971	9,354		40,325	48,228
45	1920	Computer Equipment - Hardware	298,303	7,933		306,236	179,264	52,688		231,952	74,284
	1920	Computer - Hardware post Mar 22/04	0	12,114		12,114				0	12,114
	1920	Computer - Hardware post Mar19/07				0				0	0
12	1925	Computer Software	8,361	5,000		13,361	0	3,433		3,433	9,928
10	1930	Transportation Equipment	1,279,325	338,050	44,020	1,573,355	807,709	154,074	35,377	926,405	646,949
10	1935	Stores Equipment				0				0	0
8	1940	Tools, Shop and Garage Equipment	483,433	8,662		492,096	256,337	69,830		326,167	165,928
	1945	Measurement and Testing Equipment				0				0	0
	1950	Power Operated Equipment				0				0	0
10	1955	Communication Equipment				0				0	0
	1960	Miscellaneous Equipment				0				0	0
	1970	Load Management Controls - Customer Premises				0				0	0
	1975	Load Management Controls - Utility Premises				0				0	0
	1980	System Supervisory Equipment	584,592	26,727		611,319	217,295	80,719		298,014	313,305
	1985	Sentinel Lighting Rentals				0				0	0
	1990	Other Tangible Property	1,285,825	51,948		1,337,773	286,306	93,187		379,494	958,279
1	1995	Contributions and Grants	(2,209,718)	(557,404)		(2,767,122)	(188,873)	(111,355)		(300,227)	(2,466,894)
		Total before Work in Process	**48,503,021**	**3,599,841**	**56,957**	**52,045,905**	**9,132,379**	**2,924,470**	**35,640**	**12,021,209**	**40,024,696**
WIP		Work in Process				0	0	0	0	0	0
		Total after Work in Process	**48,503,021**	**3,599,841**	**56,957**	**52,045,905**	**9,132,379**	**2,924,470**	**35,640**	**12,021,209**	**40,024,696**

-

10	1935	Transportation
10	1955	Communication Equipment

Less: Fully Allocated Depreciation		
Transportation	154,074	
Computer Software		
Net Depreciation	2,770,396	12,021,209

Table 2-6
Chatham-Kent Hydro Inc.
Fixed Asset Continuity Schedule
As at December 31, 2005

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
N/A	1805	Land	183,281		2,222	181,059	0			0	181,059
CEC	1806	Land Rights	0			0	0			0	0
1	1808	Buildings and Fixtures	507,125		20,545	486,580	96,089	19,908	9,099	106,897	379,683
	1810	Leasehold Improvements	0			0	0			0	0
	1815	Transformer Station Equipment - Normally	0			0	0			0	0
1	1820	Distribution Station Equipment - Normally	518,028	79,558	14,436	583,149	84,654	16,899	9,849	91,704	491,445
	1825	Storage Battery Equipment	0			0	0			0	0
1	1830	Poles, Towers and Fixtures	2,111,443	453,493		2,564,936	216,496	105,269		321,765	2,243,171
1	1835	Overhead Conductors and Devices	15,565,751	695,448		16,261,198	3,272,344	851,535		4,123,879	12,137,319
1	1840	Underground Conduit	686,933	280,914		967,848	73,736	38,714		112,449	855,398
1	1845	Underground Conductors and Devices	12,441,247	402,311		12,843,559	2,892,988	725,203		3,618,191	9,225,368
1	1850	Line Transformers	11,191,031	667,537		11,858,568	2,374,318	592,068		2,966,386	8,892,183
1	1855	Services	1,929,132	344,423		2,273,554	208,715	90,942		299,657	1,973,898
1	1860	Meters	2,449,804	78,144		2,527,948	591,127	141,396		732,523	1,795,426
	1861	Smart Meters	0			0	0			0	0
	1865	Other Installations on Customer's Premise	0			0	0			0	0
N/A	1905	Land	205,766			205,766	0			0	205,766
CEC	1906	Land Rights	0			0	0			0	0
1	1908	Buildings and Fixtures	2,588,680	379,149		2,967,829	305,180	84,288		389,468	2,578,361
	1910	Leasehold Improvements	0			0	0			0	0
8	1915	Office Furniture and Equipment	88,553	3,411		91,964	40,325	8,787		49,112	42,852
45	1920	Computer Equipment - Hardware	306,236	0		306,236	231,952	39,705		271,657	34,580
	1920	Computer - Hardware post Mar 22/04	12,114	15,217		27,331	0	5,156		5,156	22,175
	1920	Computer - Hardware post Mar19/07	0			0	0			0	0
12	1925	Computer Software	13,361		3,933	9,428	3,433	0		3,433	5,995
10	1930	Transportation Equipment	1,573,355	193,703	12,911	1,754,146	926,405	157,886	12,911	1,071,380	682,765
10	1935	Stores Equipment	0			0	0			0	0
8	1940	Tools, Shop and Garage Equipment	492,096	34,185		526,281	326,167	61,233		387,401	138,880
	1945	Measurement and Testing Equipment	0			0	0			0	0
	1950	Power Operated Equipment	0			0	0			0	0
10	1955	Communication Equipment	0			0	0			0	0
	1960	Miscellaneous Equipment	0			0	0			0	0
	1970	Load Management Controls - Customer P	0			0	0			0	0
	1975	Load Management Controls - Utility Premi	0			0	0			0	0
	1980	System Supervisory Equipment	611,319	65,148	22,848	653,619	298,014	74,847	11,703	361,159	292,460
	1985	Sentinel Lighting Rentals	0			0	0			0	0
	1990	Other Tangible Property	1,337,773	102,548		1,440,321	379,494	106,691		486,184	954,136
1	1995	Contributions and Grants	(2,767,122)	(118,720)		(2,885,841)	(300,227)	(116,101)		(416,329)	(2,469,512)
		Total before Work in Process	**52,045,905**	**3,676,468**	**76,896**	**55,645,478**	**12,021,209**	**3,004,424**	**43,563**	**14,982,070**	**40,663,408**
WIP		Work in Process				0	0	0	0	0	0
		Total after Work in Process	**52,045,905**	**3,676,468**	**76,896**	**55,645,478**	**12,021,209**	**3,004,424**	**43,563**	**14,982,070**	**40,663,408**

10	1935	Transportation
10	1955	Communication Equipment

Less: Fully Allocated Depreciation		
Transportation	157,886	
Computer Software		
Net Depreciation	2,846,538	14,982,070

Table 2-7
Chatham-Kent Hydro Inc.
Fixed Asset Continuity Schedule
As at December 31, 2006

		Cost				Accumulated Depreciation				
OEB	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
1805	Land	181,059	0	11,191	169,868	0			0	169,868
1806	Land Rights	0			0	0			0	0
1808	Buildings and Fixtures	486,580		14,608	471,972	106,897	18,678	11,755	113,820	358,151
1810	Leasehold Improvements	0			0	0			0	0
1815	Transformer Station Equipment - Normally	0			0	0			0	0
1820	Distribution Station Equipment - Normally	583,149	165,751		748,900	91,704	32,531		124,235	624,665
1825	Storage Battery Equipment	0			0	0			0	0
1830	Poles, Towers and Fixtures	2,564,936	690,814		3,255,749	321,765	130,230		451,995	2,803,755
1835	Overhead Conductors and Devices	16,261,198	876,812		17,138,011	4,123,879	863,130		4,987,009	12,151,002
1840	Underground Conduit	967,848	62,455		1,030,303	112,449	41,212		153,662	876,641
1845	Underground Conductors and Devices	12,843,559	731,457		13,575,016	3,618,191	754,434		4,372,625	9,202,391
1850	Line Transformers	11,858,568	717,354		12,575,923	2,966,386	620,768		3,587,154	8,988,769
1855	Services	2,273,554	417,753		2,691,307	299,657	107,652		407,309	2,283,998
1860	Meters	2,527,948	428,948		2,956,897	732,523	147,298		879,821	2,077,076
1861	Smart Meters	0			0	0			0	0
1865	Other Installations on Customer's Premise	0			0	0			0	0
1905	Land	205,766	358,875		564,641	0			0	564,641
1906	Land Rights	0			0	0			0	0
1908	Buildings and Fixtures	2,967,829	240,303		3,208,132	389,468	90,764		480,232	2,727,900
1910	Leasehold Improvements	0			0	0			0	0
1915	Office Furniture and Equipment	91,964	14,638		106,601	49,112	8,573		57,684	48,917
1920	Computer Equipment - Hardware	306,236		7,927	298,310	271,657	16,435	7,927	280,165	18,144
1920	Computer - Hardware post Mar 22/04	27,331	28,000		55,331	5,156	8,266		13,422	41,909
1920	Computer - Hardware post Mar19/07	0			0	0			0	0
1925	Computer Software	9,428	6,739		16,167	3,433			3,433	12,734
1930	Transportation Equipment	1,754,146	312,975	10,991	2,056,130	1,071,380	166,788	10,991	1,227,177	828,953
1935	Stores Equipment	0			0	0			0	0
1940	Tools, Shop and Garage Equipment	526,281	16,861		543,142	387,401	50,323		437,724	105,418
1945	Measurement and Testing Equipment	0			0	0			0	0
1950	Power Operated Equipment	0			0	0			0	0
1955	Communication Equipment	0			0	0			0	0
1960	Miscellaneous Equipment	0			0	0			0	0
1970	Load Management Controls - Customer P	0			0	0			0	0
1975	Load Management Controls - Utility Premi	0			0	0			0	0
1980	System Supervisory Equipment	653,619	88,832		742,450	361,159	79,562		440,720	301,730
1985	Sentinel Lighting Rentals	0			0	0			0	0
1990	Other Tangible Property	1,440,321	174,338		1,614,659	486,184	134,771		620,955	993,704
1995	Contributions and Grants	(2,885,841)	(452,865)		(3,338,707)	(416,329)	(134,216)		(550,545)	(2,788,162)
	Total before Work in Process	**55,645,478**	**4,880,041**	**44,717**	**60,480,801**	**14,982,070**	**3,137,201**	**30,673**	**18,088,598**	**42,392,203**
	Work in Process				0	0	0	0	0	0
	Total after Work in Process	**55,645,478**	**4,880,041**	**44,717**	**60,480,801**	**14,982,070**	**3,137,201**	**30,673**	**18,088,598**	**42,392,203**

1935	Transportation
1955	Communication Equipment

Less: Fully Allocated Depreciation		
Transportation	166,788	
Computer Software		
Net Depreciation	2,970,412	18,088,598

Note: 2006 Board Approved amount for gross asset total is $51,054,305, including CDM assets (Account 1565) of $524,558. CDM assets are not included in the 2010 Test Year rate base calculation; accordingly, Account 1565 is omitted from this table.

Table 2-8
Chatham-Kent Hydro Inc.
Fixed Asset Continuity Schedule
As at December 31, 2007

CCA Class	OEB	Description	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value
N/A	1805	Land	169,868		50,000	119,868	0			0	119,868
CEC	1806	Land Rights	0			0	0			0	0
1	1808	Buildings and Fixtures	471,972		132,000	339,972	113,820	15,172	18,480	110,512	229,459
0	1810	Leasehold Improvements	0			0	0			0	0
0	1815	Transformer Station Equipment - Normally	0			0	0			0	0
1	1820	Distribution Station Equipment - Normally P	748,900	18,973	14,410	753,463	124,235	33,511		157,746	595,717
0	1825	Storage Battery Equipment	0			0	0			0	0
1	1830	Poles, Towers and Fixtures	3,255,749	456,056		3,711,805	451,995	148,472		600,467	3,111,338
1	1835	Overhead Conductors and Devices	17,138,011	769,779		17,907,789	4,987,009	876,315		5,863,324	12,044,465
1	1840	Underground Conduit	1,030,303	80,208		1,110,511	153,662	44,420		198,082	912,429
1	1845	Underground Conductors and Devices	13,575,016	362,694		13,937,710	4,372,625	768,942		5,141,566	8,796,143
1	1850	Line Transformers	12,575,923	1,042,557		13,618,480	3,587,154	662,319		4,249,473	9,369,007
1	1855	Services	2,691,307	315,104		3,006,411	407,309	120,256		527,565	2,478,845
1	1860	Meters	2,956,897	62,833	203,404	2,816,325	879,821	140,764	73,669	946,916	1,869,409
	1861	Smart Meters	0	2,577,598		2,577,598	0	204,551		204,551	2,373,047
0	1865	Other Installations on Customer's Premises	0			0	0			0	0
N/A	1905	Land	564,641	3,870		568,511	0			0	568,511
CEC	1906	Land Rights	0			0	0			0	0
1	1908	Buildings and Fixtures	3,208,132	48,365		3,256,497	480,232	91,995		572,227	2,684,270
0	1910	Leasehold Improvements	0			0	0			0	0
8	1915	Office Furniture and Equipment	106,601		1,418	105,183	57,684	9,059	984	65,760	39,423
45	1920	Computer Equipment - Hardware	298,310		243	298,067	280,165	11,666	243	291,588	6,478
	1920	Computer - Hardware post Mar 22/04	55,331			55,331	13,422	11,066		24,489	30,843
	1920	Computer - Hardware post Mar19/07	0	123,954		123,954	0	19,379		19,379	104,575
12	1925	Computer Software	16,167	256,644		272,812	3,433	71,318		74,751	198,061
10	1930	Transportation Equipment	2,056,130	333,864	48,081	2,341,913	1,227,177	203,305	48,081	1,382,401	959,512
10	1935	Stores Equipment	0			0	0			0	0
8	1940	Tools, Shop and Garage Equipment	543,142	43,140		586,282	437,724	34,725		472,449	113,833
0	1945	Measurement and Testing Equipment	0			0	0			0	0
0	1950	Power Operated Equipment	0			0	0			0	0
10	1955	Communication Equipment	0			0	0			0	0
0	1960	Miscellaneous Equipment	0			0	0			0	0
0	1970	Load Management Controls - Customer Pr	0			0	0			0	0
0	1975	Load Management Controls - Utility Premis	0			0	0			0	0
0	1980	System Supervisory Equipment	742,450	25,060		767,510	440,720	54,124		494,844	272,666
0	1985	Sentinel Lighting Rentals	0			0	0			0	0
0	1990	Other Tangible Property	1,614,659	61,705		1,676,364	620,955	140,325		761,280	915,084
1	1995	Contributions and Grants	(3,338,707)	(213,142)		(3,551,848)	(550,545)	(142,742)		(693,287)	(2,858,562)
		Total before Work in Process	**60,480,801**	**6,369,261**	**449,556**	**66,400,507**	**18,088,598**	**3,518,943**	**141,457**	**21,466,084**	**44,934,422**
WIP	0	Work in Process	0			0	0	0	0	0	0
		Total after Work in Process	**60,480,801**	**6,369,261**	**449,556**	**66,400,507**	**18,088,598**	**3,518,943**	**141,457**	**21,466,084**	**44,934,422**

	1935	Transportation
	1940	Stores Equipment

Less: Fully Allocated Deprecia			
Transportation	203,305		
Computer Softw			
Net Depreciatior	3,315,639		21,466,084

Table 2-9
Chatham-Kent Hydro Inc.
Fixed Asset Continuity Schedule
As at December 31, 2008

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
N/A	1805	Land	119,868		2,022	117,846	0			0	117,846
CEC	1806	Land Rights	0			0	0			0	0
1	1808	Buildings and Fixtures	339,972			339,972	110,512	14,813		125,325	214,647
0	1810	Leasehold Improvements	0			0	0			0	0
0	1815	Transformer Station Equipment - Normally	0			0	0			0	0
1	1820	Distribution Station Equipment - Normally	753,463	41,630		795,093	157,746	35,535		193,281	601,812
0	1825	Storage Battery Equipment	0			0	0			0	0
1	1830	Poles, Towers and Fixtures	3,711,805	515,834		4,227,639	600,467	169,106		769,572	3,458,066
1	1835	Overhead Conductors and Devices	17,907,789	865,152		18,772,941	5,863,324	900,706		6,764,030	12,008,911
1	1840	Underground Conduit	1,110,511	93,729		1,204,240	198,082	48,170		246,252	957,988
1	1845	Underground Conductors and Devices	13,937,710	678,494		14,616,203	5,141,566	796,081		5,937,648	8,678,555
1	1850	Line Transformers	13,618,480	741,454		14,359,934	4,249,473	691,787		4,941,260	9,418,674
1	1855	Services	3,006,411	348,135		3,354,546	527,565	134,182		661,747	2,692,799
1	1860	Meters	2,816,325	12,637		2,828,962	946,916	139,606		1,086,522	1,742,441
	1861	Smart Meters	2,577,598	1,633,216		4,210,814	204,551	335,161		539,712	3,671,102
0	1865	Other Installations on Customer's Premise	0			0	0			0	0
N/A	1905	Land	568,511			568,511	0			0	568,511
CEC	1906	Land Rights	0			0	0			0	0
1	1908	Buildings and Fixtures	3,256,497	78,084		3,334,581	572,227	99,613		671,841	2,662,741
0	1910	Leasehold Improvements	0			0	0			0	0
8	1915	Office Furniture and Equipment	105,183	19,243		124,426	65,760	10,063		75,823	48,603
45	1920	Computer Equipment - Hardware	298,067			298,067	291,588	5,685		297,273	794
	1920	Computer - Hardware post Mar 22/04	55,331			55,331	24,489	11,066		35,555	19,776
	1920	Computer - Hardware post Mar19/07	123,954	45,865		169,819	19,379	34,054		53,433	116,386
12	1925	Computer Software	272,812	210,284		483,095	74,751	102,812		177,563	305,532
10	1930	Transportation Equipment	2,341,913	213,221	36,029	2,519,106	1,382,401	214,588	36,029	1,560,960	958,145
10	1935	Stores Equipment	0			0	0			0	0
8	1940	Tools, Shop and Garage Equipment	586,282	52,331		638,613	472,449	25,645		498,094	140,519
0	1945	Measurement and Testing Equipment	0			0	0			0	0
0	1950	Power Operated Equipment	0			0	0			0	0
10	1955	Communication Equipment	0			0	0			0	0
0	1960	Miscellaneous Equipment	0			0	0			0	0
0	1970	Load Management Controls - Customer Pr	0			0	0			0	0
0	1975	Load Management Controls - Utility Premis	0			0	0			0	0
0	1980	System Supervisory Equipment	767,510	20,218		787,728	494,844	52,562		547,406	240,322
0	1985	Sentinel Lighting Rentals	0			0	0			0	0
0	1990	Other Tangible Property	1,676,364	74,063		1,750,427	761,280	145,262		906,542	843,885
1	1995	Contributions and Grants	(3,551,848)	(334,905)		(3,886,753)	(693,287)	(156,138)		(849,424)	(3,037,329)
		Total before Work in Process	**66,400,507**	**5,308,684**	**38,051**	**71,671,139**	**21,466,084**	**3,810,358**	**36,029**	**25,240,414**	**46,430,725**
WIP		Work in Process	0			0	0			0	0
		Total after Work in Process	**66,400,507**	**5,308,684**	**38,051**	**71,671,139**	**21,466,084**	**3,810,358**	**36,029**	**25,240,414**	**46,430,725**

	1935	Transportation
	1940	Stores Equipment

Less: Fully Allocated Depreciatior		
Transportation	214,588	
Computer Software		
Net Depreciation	3,595,770	25,240,414

Table 2-10
Chatham-Kent Hydro Inc.
Fixed Asset Continuity Schedule
As at December 31, 2009

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
N/A	1805	Land	117,846			117,846	0			0	117,846
CEC	1806	Land Rights	0			0	0			0	0
47	1808	Buildings and Fixtures	339,972			339,972	125,325	13,591		138,916	201,056
13	1810	Leasehold Improvements	0			0	0			0	0
47	1815	Transformer Station Equipment - Normally P	0			0	0			0	0
47	1820	Distribution Station Equipment - Normally P	795,093			795,093	193,281	35,536		228,816	566,277
47	1825	Storage Battery Equipment	0			0	0			0	0
47	1830	Poles, Towers and Fixtures	4,227,639	519,294		4,746,932	769,572	189,877		959,450	3,787,483
47	1835	Overhead Conductors and Devices	18,772,941	855,653		19,628,594	6,764,030	915,617		7,679,647	11,948,947
47	1840	Underground Conduit	1,204,240	74,215		1,278,455	246,252	51,139		297,391	981,064
47	1845	Underground Conductors and Devices	14,616,203	565,628		15,181,831	5,937,648	818,708		6,756,356	8,425,475
47	1850	Line Transformers	14,359,934	987,823		15,347,757	4,941,260	732,602		5,673,862	9,673,895
47	1855	Services	3,354,546	400,929		3,755,475	661,747	150,219		811,966	2,943,509
47	1860	Meters	2,828,962	29,278		2,858,240	1,086,522	140,776		1,227,297	1,630,943
	1861	Smart Meters	4,210,814			4,210,814	539,712	375,787		915,499	3,295,315
N/A	1865	Other Installations on Customer's Premises	0			0	0			0	0
N/A	1905	Land	568,511	200,000		768,511	0			0	768,511
CEC	1906	Land Rights	0			0	0			0	0
47	1908	Buildings and Fixtures	3,334,581	138,500		3,473,081	671,841	110,929		782,770	2,690,312
13	1910	Leasehold Improvements	0			0	0			0	0
8	1915	Office Furniture and Equipment	124,426	7,500		131,926	75,823	11,499		87,321	44,604
10	1920	Computer Equipment - Hardware	298,067			298,067	297,273	794		298,067	0
	1920	Computer - Hardware post Mar 22/04	55,331			55,331	35,555	9,854		45,409	9,922
	1920	Computer - Hardware post Mar19/07	169,819	63,000		232,819	53,433	11,651		65,083	167,736
12	1925	Computer Software	483,095	130,000		613,095	177,563	66,787		244,350	368,745
10	1930	Transportation Equipment	2,519,106	362,000		2,881,106	1,560,960	245,048		1,806,008	1,075,097
8	1935	Stores Equipment	0			0	0			0	0
8	1940	Tools, Shop and Garage Equipment	638,613	47,000		685,613	498,094	28,190		526,284	159,329
8	1945	Measurement and Testing Equipment	0			0	0			0	0
8	1950	Power Operated Equipment	0			0	0			0	0
8	1955	Communication Equipment	0			0	0			0	0
8	1960	Miscellaneous Equipment	0			0	0			0	0
47	1970	Load Management Controls - Customer Pre	0			0	0			0	0
47	1975	Load Management Controls - Utility Premis	0			0	0			0	0
47	1980	System Supervisory Equipment	787,728	40,000		827,728	547,406	55,023		602,429	225,299
47	1985	Sentinel Lighting Rentals	0			0	0			0	0
47	1990	Other Tangible Property	1,750,427	76,572		1,826,998	906,542	150,325		1,056,867	770,131
47	1995	Contributions and Grants	(3,886,753)	(275,000)		(4,161,753)	(849,424)	(167,138)		(1,016,562)	(3,145,191)
		Total before Work in Process	**71,671,139**	**4,222,390**	**0**	**75,893,529**	**25,240,414**	**3,946,813**	**0**	**29,187,227**	**46,706,302**
WIP		Work in Process	0			0	0			0	0
		Total after Work in Process	**71,671,139**	**4,222,390**	**0**	**75,893,529**	**25,240,414**	**3,946,813**	**0**	**29,187,227**	**46,706,302**

	1925	Transportation
	1930	Stores Equipment

Less: Fully Allocated Depreciation		
Transportation	245,048	
Communication		
Net Depreciation	3,701,765	29,187,227

Table 2-11
Chatham-Kent Hydro Inc.
Fixed Asset Continuity Schedule
As at December 31, 2010

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
N/A	1805	Land	117,846			117,846	0			0	117,846
CEC	1806	Land Rights	0			0	0			0	0
47	1808	Buildings and Fixtures	339,972	65,000		404,972	138,916	16,191		155,107	249,865
13	1810	Leasehold Improvements	0			0	0			0	0
47	1815	Transformer Station Equipment - Normally	0			0	0			0	0
47	1820	Distribution Station Equipment - Normally I	795,093	100,000		895,093	228,816	38,555		267,371	627,722
47	1825	Storage Battery Equipment	0			0	0			0	0
47	1830	Poles, Towers and Fixtures	4,746,932	584,444		5,331,377	959,450	213,255		1,172,705	4,158,672
47	1835	Overhead Conductors and Devices	19,628,594	678,418		20,307,012	7,679,647	927,277		8,606,924	11,700,088
47	1840	Underground Conduit	1,278,455	241,438		1,519,893	297,391	60,796		358,187	1,161,706
47	1845	Underground Conductors and Devices	15,181,831	838,840		16,020,671	6,756,356	852,282		7,608,638	8,412,033
47	1850	Line Transformers	15,347,757	1,059,560		16,407,317	5,673,862	768,983		6,442,845	9,964,472
47	1855	Services	3,755,475	423,737		4,179,211	811,966	167,168		979,135	3,200,077
47	1860	Meters	2,858,240	29,499		2,887,739	1,227,297	141,970		1,369,267	1,518,472
	1861	Smart Meters	4,210,814			4,210,814	915,499	331,925		1,247,424	2,963,390
N/A	1865	Other Installations on Customer's Premises	0			0	0			0	0
N/A	1905	Land	768,511	25,000		793,511	0			0	793,511
CEC	1906	Land Rights	0			0	0			0	0
47	1908	Buildings and Fixtures	3,473,081	478,000		3,951,081	782,770	121,529		904,299	3,046,783
13	1910	Leasehold Improvements	0			0	0			0	0
8	1915	Office Furniture and Equipment	131,926	12,000		143,926	87,321	9,472		96,793	47,132
10	1920	Computer Equipment - Hardware	298,067			298,067	298,067			298,067	0
	1920	Computer - Hardware post Mar 22/04	55,331			55,331	45,409	7,122		52,531	2,800
	1920	Computer - Hardware post Mar19/07	232,819	56,000		288,819	65,083	23,551		88,634	200,185
12	1925	Computer Software	613,095			613,095	244,350	79,287		323,638	289,458
10	1930	Transportation Equipment	2,881,106	780,000		3,661,106	1,806,008	303,916		2,109,924	1,551,181
8	1935	Stores Equipment	0			0	0			0	0
8	1940	Tools, Shop and Garage Equipment	685,613	299,000		984,613	526,284	41,085		567,369	417,244
8	1945	Measurement and Testing Equipment	0			0	0			0	0
8	1950	Power Operated Equipment	0			0	0			0	0
8	1955	Communication Equipment	0			0	0			0	0
8	1960	Miscellaneous Equipment	0			0	0			0	0
47	1970	Load Management Controls - Customer Pr	0			0	0			0	0
47	1975	Load Management Controls - Utility Premis	0			0	0			0	0
47	1980	System Supervisory Equipment	827,728	40,000		867,728	602,429	47,330		649,759	217,969
47	1985	Sentinel Lighting Rentals	0			0	0			0	0
47	1990	Other Tangible Property	1,826,998	81,595		1,908,593	1,056,867	145,722		1,202,589	706,004
47	1995	Contributions and Grants	(4,161,753)	(275,000)		(4,436,753)	(1,016,562)	-178,138		(1,194,700)	(3,242,053)
		Total before Work in Process	**75,893,529**	**5,517,531**	**0**	**81,411,060**	**29,187,227**	**4,119,278**	**0**	**33,306,505**	**48,104,555**
WIP		Work in Process	0			0	0			0	0
		Total after Work in Process	**75,893,529**	**5,517,531**	**0**	**81,411,060**	**29,187,227**	**4,119,278**	**0**	**33,306,505**	**48,104,555**

	1935	Transportation
	1940	Stores Equipment

Less: Fully Allocated Depreciation		
Transportation	303,916	
Communication		
Net Depreciation	3,815,361	33,306,505

Table 2-12
Chatham-Kent Hydro Inc.
Gross Assets

Description	2006 Board Approved ($)	2006 Actual ($)	Variance from 2006 Board Approved	2007 Actual ($)	Variance from 2006 Actual	2008 Actual ($)	Variance from 2007 Actual	2009 Bridge ($)	Variance from 2008 Actual	2010 Test ($)	Variance from 2009 Bridge
Land and Buildings											
1805-Land	189,212	169,868	(19,344)	119,868	(50,000)	117,846	(2,022)	117,846		117,846	
1806-Land Rights											
1808-Buildings and Fixtures	435,610	471,972	36,362	339,972	(132,000)	339,972		339,972		404,972	65,000
1905-Land	205,766	564,641	358,875	568,511	3,870	568,511		768,511	200,000	793,511	25,000
1906-Land Rights											
1810-Leasehold Improvements											
Sub-Total-Land and Buildings	830,588	1,206,480	375,892	1,028,350	(178,130)	1,026,328	(2,022)	1,226,328	200,000	1,316,328	90,000
DS											
1820-Distribution Station Equipment - Normally Primary below 50 kV	210,827	748,900	538,073	753,463	4,563	795,093	41,630	795,093		895,093	100,000
Sub-Total-DS	210,827	748,900	538,073	753,463	4,563	795,093	41,630	795,093		895,093	100,000
Poles and Wires											
1830-Poles, Towers and Fixtures	1,879,967	3,255,749	1,375,782	3,711,805	456,056	4,227,639	515,834	4,746,932	519,294	5,331,377	584,444
1835-Overhead Conductors and Devices	15,069,503	17,138,011	2,068,508	17,907,789	769,779	18,772,941	865,152	19,628,594	855,653	20,307,012	678,418
1840-Underground Conduit	616,722	1,030,303	413,581	1,110,511	80,208	1,204,240	93,729	1,278,455	74,215	1,519,893	241,438
1845-Underground Conductors and Devices	12,195,195	13,575,016	1,379,821	13,937,710	362,694	14,616,203	678,494	15,181,831	565,628	16,020,671	838,840
Sub-Total-Poles and Wires	29,761,387	34,999,079	5,237,692	36,667,815	1,668,736	38,821,023	2,153,208	40,835,812	2,014,789	43,178,952	2,343,141
Line Transformers											
1850-Line Transformers	10,834,508	12,575,923	1,741,415	13,618,480	1,042,557	14,359,934	741,454	15,347,757	987,823	16,407,317	1,059,560
Sub-Total-Line Transformers	10,834,508	12,575,923	1,741,415	13,618,480	1,042,557	14,359,934	741,454	15,347,757	987,823	16,407,317	1,059,560
Services and Meters											
1855-Services	1,713,773	2,691,307	977,534	3,006,411	315,104	3,354,546	348,135	3,755,475	400,929	4,179,211	423,737
1860-Meters	2,803,649	2,956,897	153,248	2,816,325	(140,571)	2,828,962	12,637	2,858,240	29,278	2,887,739	29,499
1861-Smart Meters				2,577,598	2,577,598	4,210,814	1,633,216	4,210,814		4,210,814	
Sub-Total-Services and Meters	4,517,422	5,648,204	1,130,782	8,400,334	2,752,131	10,394,323	1,993,988	10,824,529	430,207	11,277,764	453,235
General Plant											
1908-Buildings and Fixtures	2,644,076	3,208,132	564,056	3,256,497	48,365	3,334,581	78,084	3,473,081	138,500	3,951,081	478,000
1910-Leasehold Improvements											
Sub-Total-General Plant	2,644,076	3,208,132	564,056	3,256,497	48,365	3,334,581	78,084	3,473,081	138,500	3,951,081	478,000
IT Assets											
1920-Computer Equipment - Hardware	308,327	298,310	(10,017)	298,067	(243)	298,067		298,067		298,067	
1921-Computer Equipment		55,331	55,331	55,331		55,331		55,331		55,331	
1921-Computer Equipment - Hardware post March 22, 2005				123,954	123,954	169,819	45,865	232,819	63,000	288,819	56,000
1925-Computer Software	9,144	16,167	7,023	272,812	256,644	483,095	210,284	613,095	130,000	613,095	
Sub-Total-IT Assets	317,471	369,808	52,337	750,163	380,355	1,006,312	256,149	1,199,312	193,000	1,255,312	56,000
Equipment											
1915-Office Furniture and Equipment	76,027	106,601	30,574	105,183	(1,418)	124,426	19,243	131,926	7,500	143,926	12,000
1930-Transportation Equipment	1,426,340	2,056,130	629,790	2,341,913	285,783	2,519,106	177,193	2,881,106	362,000	3,661,106	780,000
1935-Stores Equipment											
1940-Tools, Shop and Garage Equipment	487,765	543,142	55,377	586,282	43,140	638,613	52,331	685,613	47,000	984,613	299,000
1945-Measurement and Testing Equipment											
Sub-Total-Equipment	1,990,132	2,705,873	715,741	3,033,378	327,506	3,282,144	248,766	3,698,644	416,500	4,789,644	1,091,000
Other Distribution Assets											
1980-System Supervisory Equipment	597,956	742,450	144,494	767,510	25,060	787,728	20,218	827,728	40,000	867,728	40,000
1985-Sentinel Lighting Rental Units											
1990-Other Tangible Property	1,311,799	1,614,659	302,860	1,676,364	61,705	1,750,427	74,063	1,826,998	76,572	1,908,593	81,595
1995-Contributions and Grants - Credit	(2,488,420)	(3,338,707)	(850,287)	(3,551,848)	(213,142)	(3,886,753)	(334,905)	(4,161,753)	(275,000)	(4,436,753)	(275,000)
1996-Hydro One S/S Contribution											
Sub-Total-Other Distribution Assets	(578,665)	(981,597)	(402,932)	(1,107,974)	(126,377)	(1,348,599)	(240,624)	(1,507,027)	(158,428)	(1,660,432)	(153,405)
GROSS ASSET TOTAL	50,527,746	60,480,801	9,953,055	66,400,507	5,919,705	71,671,139	5,270,633	75,893,529	4,222,390	81,411,060	5,517,531

VARIANCE ANALYSIS ON GROSS ASSETS:

Materiality thresholds for rate base related costs and expenditures, being 0.5 per cent of revenue requirement in accordance with the OEB's updated Filing Requirements are set out in Table 2-13.

Table 2-13
Rate Base Materiality

Description	2006 OEB Approved	2006 Actual	2007 Actual Year	2008 Actual Year	2009 Bridge Year	2010 Test Year
Rate Base	$50,309,522	$51,813,558	$54,003,463	$55,634,596	$55,490,686	$56,073,568
Cost Capital	8.02%	8.02%	8.02%	7.95%	7.89%	7.52%
Return on Rate Base	$4,034,824	$4,155,447	$4,331,078	$4,425,583	$4,377,809	$4,219,200
Distribution Expense	$8,723,462	$8,107,926	$8,594,813	$9,274,947	$9,527,916	$10,618,473
PILS	$1,572,932	$1,349,735	$1,405,223	$1,207,671	$1,096,204	$987,663
Revenue Requirement	$14,331,218	$13,613,108	$14,331,114	$14,908,201	$15,001,929	$15,825,336
Materiality Cal .5%	$71,656	$68,066	$71,656	$74,541	$75,010	$79,127

The particulars of those variances over the materiality threshold in the above table 2-13, are highlighted in yellow in the following schedules.

The opening of the wholesale electricity market created the potential for transfer of wholesale meters from Hydro One to local distribution companies when their seals expired. As seal dates expired Hydro One transferred the ownership of the meters to Chatham-Kent Hydro and Chatham-Kent Hydro proceeded to upgrade and replace these meters. The wholesale meters had originally been classified these assets as meter assets in account 1860 which should have been classified as Distribution Station Equipment asset in account 1820. Through the preparation of this Application the value of these assets has been reclassified to the appropriate accounts. Therefore, the balances shown in Chatham-Kent Hydro's Reporting and Record keeping Requirements (RRR) filings in respect of these accounts will not be the same as the balances shown in this Application due to the current reclassifications. The assets have been retroactively changed from 2005 to 2008 and the corresponding depreciation for those years has been adjusted in the appropriate accounts.

2004 Actual Capital Jobs

Job Description		Grand Total	1805 Land	1808 Building	1820 Distribution Station	1830 Poles	1835 O/H conductor & devices	1840 U/G conduit	1845 U/G conductor & Devices	1850 Transformers	1855 Services O/H & U/G	1860 Meters	1860 Smart Meters	1908 Building	1915 Office Furniture	1920 Computer	1925 Software	1930 Fleet	1940 Tools	1980 Scada	1990 AM/FM	3030 Contributed Capital
30041	Control Room Work Station	5,068				-	-	-	-	-	-	-			5,068							
30070	Cut off saw	1,075				-	-	-	-	-	-	-			-				1,075			
30071	Digital Video Recorder Stores	1,799				-	-	-	-	-	-	-				1,799						
30072	TCC Software	5,000				-	-	-	-	-	-	-			-		5,000					
30073	Tablet PC	8,236				-	-	-	-	-	-	-			-	8,236						
30074	MG Megger	7,588				-	-	-	-	-	-	-							7,588			
30078	Display Pop up	3,974				-	-	-	-	-	-	-			3,974							
30091	Automated HVAC	8,016				-	-	-	-	-	-	-		8,016								
30092	400 KW Diesel Generator/Backup	56,616				-	-	-	-	-	-	-		56,616								
30094	Secured File Area	2,134				-	-	-	-	-	-	-		2,134								
30096	AM/FM Capital Support	53,491				-	1,543	-	-	-	-	-									51,948	
30097	Scada Capital	24,299				-	-	-	-	-	-	-								24,299		
30101	Engineering Plotter	7,933				-	-	-	-	-	-	-				7,933						
30102	Computer Admin assistant	2,079				-	-	-	-	-	-	-				2,079						
30103	Boardroom Upgrade	20,480				-	-	-	-	-	-	-		4,472	16,008							
30110	46' Single Aerial 04BK20	225,142				-	-	-	-	-	-	-						225,142				
30111	Purchase 05PU127	29,926				-	-	-	-	-	-	-						29,926				
30112	Purchase 04pu128	31,835				-	-	-	-	-	-	-						31,835				
30113	Utility body 04PU128	13,887				-	-	-	-	-	-	-						13,887				
30114	New chipper 04wc13	37,260				-	-	-	-	-	-	-						37,260				
31000	Residential New Services	124,531				9,740	16,111	914	13,597	4,081	74,056	6,032										
31030	Parkland Estate sub Ph 5 Tilbu	38,802				346	6,597	3,065	18,815	6,385	3,593	-										
31037	Smith Subdivison Chatham	57,312				346	6,597	2,285	11,483	28,885	7,715	-										
31038	DR Courtyard walk development	20,157				346	6,597	665	6,052	2,278	4,218	-										
31051	St. Ambrose Develpment Chatham	36,689				1,647	6,597	665	16,436	7,750	3,593	-										
31052	Green Acres Phase 3 Chatham	73,082				346	6,597	2,665	15,789	26,666	21,019	-										
31053	Courtyard walk develop Chatham	63,350				346	9,151	6,132	26,227	15,002	6,491	-										
31054	Trerice Trails Subdiv. Ph 1	33,693				346	6,597	2,360	14,542	6,245	3,602	-										
31055	Mclean/Schnabel Deve. Rdgetwn	21,479				346	6,935	332	6,052	4,220	3,593	-										
31056	Queensgate Ph 7 Tilbury	74,014				346	6,597	3,580	34,649	24,565	3,850	425										
31057	Enclave place subdivision	74,178				346	6,597	3,832	27,631	16,885	18,593	293										
31058	Life lease townhouse Wheatley	48,082				11,120	15,947	-	6,650	9,520	4,843	-										
31059	Hamlet Court Subdivision	76,908				346	6,597	3,832	31,717	18,724	15,691	-										
31060	Faas devel Cathcart st Ridgtwn	22,166				346	6,597	3,800	5,943	1,885	3,593	-										
31500	Residential Rebuild	39,881				969	12,088	42	1,946	96	24,685	56										
31510	C & Ind New - 1 & 3 Phases	45,807				5,798	9,242	936	7,749	3,709	10,405	7,968										
31545	Westerly Pump Station 401 Ind.	16,339				-	8,415	-	-	7,924	-	-										
31546	Prefer partner carpet Wallbg	43,896				889	12,248	-	3,851	26,907	-	-										
31547	Tilbury Autoliv pump station	11,097				-	5,595	-	-	5,502	-	-										
32000	C & Ind Rbd - 1 & 3 Phase	68,794				2,878	8,264	-	18,517	14,978	18,496	5,661										
32046	Dickson Motors Thamesville	6,355				-	4,580	-	-	1,775	-	-										
32047	Rebuild Lyon St. Pump Station	12,967				1,959	7,993	-	-	3,015	-	-										

Job Description		Grand Total	1805 Land	1808 Building	1820 Distribution Station	1830 Poles	1835 O/H conductor & devices	1840 U/G conduit	1845 U/G conductor & Devices	1850 Transformers	1855 Services O/H & U/G	1860 Meters	1860 Smart Meters	1908 Building	1915 Office Furniture	1920 Computer	1925 Software	1930 Fleet	1940 Tools	1980 Scada	1990 AM/FM	3030 Contributed Capital
32048	Reb 350 Riverview Blue Water	6,866				923	1,901	0	0	2,173	1,870	0										
32049	Jackson seeds Dresden	48,814				615	7,957	6,040	5,797	28,405	0	0										
32050	Oxford Farmers Coop Thamesvill	9,698				999	1,370	0	430	6,447	0	451										
32051	Indian creek insall transforme	3,324				424	1,370	0	0	1,530	0	0										
32052	Remove ABS Arnold st Walbg	3,464				0	3,464	0	0	0	0	0										
32053	Water Treatment Plt Grand Ave	24,350				572	10,726	0	0	0	0	13,052										
32054	Rebuild 80 Erie St Rdgtwn	11,501				1,692	8,205	0	0	1,111	492	0										
32055	Intergrated Children Grand Ave	23,838				4,295	13,241	0	3,096	3,206	0	0										
32056	Rebuild Kent stress and Temper	44,068				1,315	7,850	0	5,430	29,473	0	0										
32057	Merlin United Church	3,940				0	234	0	0	3,706	0	0										
32400	Transformer Replacement	59,065				0	2,121	0	401	56,189	122	232										
32401	HY- Transformer capital offset	(9,967)				0	0	0	0	(9,967)	0	0										
32402	Trsfmr 186 Chatham St Blenheim	7,401				2,142	2,968	0	0	2,290	0	0										
32410	Meter Replacement - Retail	96,799				0	0	0	0	0	0	96,799										
32435	Control Room Support Capital	57,871				56,501	1,370	0	0	0	0	0										
32440	Account Concellation	10,848				0	2,306	0	0	321	6,315	1,906										
32460	Scada Capital Support	3,798				0	1,370	0	0	0	0	0								2,428		
32481	Single Feeder 401 Industrial	113,649				1,835	108,407	0	0	1,658	1,750	0										
32485	Relo. pole Long term care	20,800				9,062	7,941	0	0	0	3,797	0										
32500	Contributed Capital Received	(557,404)				0	0	0	0	0	0	0										(557,404)
33050	Sub 5 Conversion	10,071				1,732	2,809	0	735	3,357	1,437	0										
33060	Insulator Replace	25,547				273	23,837	0	0	0	1,437	0										
33103	Sub 8 Conv. Indian Crest	12,424				1,910	2,857	0	2,862	3,357	1,437	0										
33104	Warwick Rebuild - Ridgetown	11,115				2,089	1,370	0	2,862	3,357	1,437	0										
33105	Wholesale Meter Repl - Dresden	4,453				693	3,760	0	0	0	0	0										
33109	Emergencies	3,364				0	1,370	0	1,994	0	0	0										
33114	Tilbury Conv. F2 Extension	11,780				1,732	2,779	0	2,862	2,970	1,437	0										
33121	Primary Meter Wallaceburg	4,899			336	1,732	2,740	0	0	0	0	91										
33125	Queen St N Tilbury Phase 1	15,432				1,732	2,853	0	6,052	3,357	1,437	0										
33130	Emergency Parry Drive	14,805				0	2,740	7,469	2,957	1,639	0	0										
33131	Emer. McFarlane Ave cable repl	3,590				0	2,946	468	175	0	0	0										
33140	Tilbury Conversion Queen St	409,737				111,877	190,719	892	36,502	35,687	34,060	0										
33141	Sub 8 Conversion	455,708				20,546	33,622	86,897	101,487	174,329	38,828	0										
33142	Dresden Back lot Re-construct	150,784				39,035	71,889	3,355	10,476	15,097	9,855	1,077										
33143	Dresden Conversion	175,137				17,923	82,654	196	23,200	37,678	13,485	0										
33144	Engineer study new hydro	13,163				13,163	0	0	0	0	0	0										
33145	M4 Cable Replacement	267,529				47,187	81,182	0	17,064	45,592	76,504	0										
33149	LIS Switch #1	19,805				17,065	2,740	0	0	0	0	0										
33152	Wallaceburg M2 WM Upgrade	51,373			35,610	1,965	13,719	0	80	0	0	0										
33153	Wallaceburg M6 WM upgrade	51,163			35,257	4,300	11,515	0	0	0	0	91										
33154	Erieau WM Upgrade	39,291			30,743	3,208	5,249	0	0	0	0	91										
33155	Tilbury DS F1 WM Upgrade	56,740			33,950	2,368	20,331	0	0	0	0	91										
33156	Tilbury DS F2 WM Upgrade	44,480			33,950	4,776	5,663	0	0	0	0	91										
33157	Ridgetown WM Upgrade	111,578			31,994	25,687	38,356	0	0	10,483	4,967	91										
33159	Ridgetown M16 Primary meter	8,183			3,263	2,856	1,974	0	0	0	0	91										
33160	Pole Replacement	8,442				6,981	1,370	0	0	0	0	91										
33161	Low Voltage Juliana St	13,678				7,905	3,765	0	0	0	2,008	0										
33162	Pole Replacmt 78 Talbot Whly	5,959				4,463	1,496	0	0	0	0	0										
33170	Storm July 14, 2004	22,470				566	9,304	0	0	12,600	0	0										
Asset Retirement Obligation - CICA 3110		39,000			39,000	0	0	0	0	0	0	0										
	Grand Total	3,599,841	0	0	244,103	462,953	992,495	140,422	492,104	713,046	430,718	134,682	0	71,237	25,051	20,047	5,000	338,050	8,662	26,727	51,948	(557,404)

Year 2004 Actual Capital Jobs Over Materiality

- Job 30110 - Purchase 46'Single Aerial Bucket Truck – $225,142 -04BK20 – one of the Bucket Trucks was replaced based on the replacement criteria of full depreciation; repair history and manufacturers' guide lines, Chatham-Kent Hydro replacement schedule for service trucks is 7-10 years.

- Job 31000 - New Residential Service - $124,531 – overhead service was installed for a new service. The Distributions System Code requires the Local Distribution Company to supply and to install up to 30m of overhead service conductor at its expense to connect a new residential customer. In 2004 the area had 138 new Residential customer connections.

- Job 32410 - Meter Replacement Retail - $96,799 – Annual maintenance program to replace retail electric meters that have reached end of life, have failed, or the seals of which have expired in compliance with Measurement Canada requirements.

- Job 32481 - Single Feeder 401 Industrial - $113,649 – this job entails extending the M3 Feeder down Lacroix St. to Cecile Ave. west to Faubert Dr. and south to Indian Creek Rd. Convert three single phases and one three phase transformer on Lacrox and Faubert, install LIS on Howard Rd for open point, and install two new SCADA operated reclosures on the M3 and M8 at Hitchock and Bloomfield. Also install a single phase transformer on the Seventh Line for lighting and temporary services.

- Job 32500 Contributed Capital – ($332,237) – Residential - the construction of a new structure for subdivision in the Chatham-Kent Hydro service area. The contribution methodology is set out in the Distribution System Code and the amount is based on the economic evaluation.

- Job 32500 Contributed Capital – ($225,167) – General Service - the construction of new service for consumption over 50, the amount of the contribution methodology set out in the Distribution System Code is based on the economic evaluation.

- Job 33140 - Tilbury Conversion - $409,737 – converted a 4.16kV distribution to 27.6 kV in Tilbury, the strategy was adopted in 1998 after amalgamation that the conversion would be based on the size of the town and the expected life of the system, therefore, the conversions were done in stages in order to provide a more reliable system in all the service areas. The Tilbury conversion was planned over a 5 year time period, since the entire town required the distribution system conversion. The conversion involves installing 3 step down transformers to feeders in 3 different locations from a 16kV primary.

- Job 33141 - Sub 8 Conversion - $455,708 – conversion involved replacing an aging 5 kV systems and converted to 27.6 kV. Part of long term plan to convert all 5 kV in order to eliminate older assets and reduce outages caused by failing equipment. This investment was required to reduce the number of failures and better manage O&M costs in the long run.

- Job 33142 - Dresden Back Lot Reconnection – $150,784 – was to remove distribution system from non-accessible area and upgrade from 4.16kV to 27.6kV.

- Job 33143 - Dresden Conversion – $175,137 – was a conversion of 4.16kV to 27.6kV distribution line in Dresden, the strategy was adopted in 1998 after amalgamation that the conversion would be based on the size of the town and the expected life of the system, therefore, the conversions were done in stages in order to provide a more reliable system in all the service areas. Dresden conversion was planned over a 3 year time period, since the entire town required the distribution system conversion.

- Job 33145 - M4 Cable Replacement -$267,529 – was to eliminate the section of 5M4 underground primary cable, from Spencer Ave at Lacroix St to Lorne Ave at McDougal Ave. Extend 5M4 feeder from Spencer Ave, north to Lorne Ave and west to connect to existing 556 MCM overhead line west of Lacroix St. Install ten new single phase transformers and one new three phase transformer, replace primary conductor and poles, on West St Lorne Ave (between West and Inshes) and Raleigh St.

- Job 33157 - Ridgetown WM upgrade – $111,578 – this project involved tying a feeder between 5M15 and 5M16. This allowed more system flexibility and reliability. Install nine 50' wooden poles to extend M16, 27.6 kV feeder from Tecumseh Substation, south to tie into M16 feeder at Richard and George St. Convert one three phase transformer and one single phase transformer from 2.4/4.16kV to 16/27.6 kV primary.

Year 2005 Actual Capital Jobs

Job Description		Grand Total	1805 Land	1808 Building	1820 Distribution Station	1830 Poles	1835 O/H conductor & devices	1840 U/G conduit	1845 U/G conductor & Devices	1850 Transformers	1855 Services O/H & U/G	1860 Meters	1860 Smart Meters	1908 Building	1915 Office Furniture	1920 Computer	1925 Software	1930 Fleet	1940 Tools	1980 Scada	1990 AM/FM	3030 Contributed Capital
30081	Magna trak locator	1,026				0	0	0	0	0	0	0							1,026			
30082	Defibrilator	3,411				0	0	0	0	0	0	0			3,411							
30083	P line pilot rope	6,167				0	0	0	0	0	0	0							6,167			
30085	Powerpro Logger	13,203				0	0	0	0	0	0	0							13,203			
30086	Radiodetection sec equip	9,202				0	0	0	0	0	0	0							9,202			
30087	MEGGAR	4,588				0	0	0	0	0	0	0							4,588			
30092	400 KW Diesel Generator/Backup	6,291				0	0	0	0	0	0	0		6,291								
30095	Enclosure for Radio Equipment	8,441				0	0	0	0	0	0	0		8,441								
30096	AM/FM Capital Support	52,548				0	0	0	0	0	0	0									52,548	
30097	Scada Capital	65,148				0	0	0	0	0	0	0								65,148		
30098	Scada Upgrade AM FM GIS	50,000				0	0	0	0	0	0	0									50,000	
30121	Van 05VN148 - For Locates	23,298				0	0	0	0	0	0	0						23,298				
30122	Vehicle 05VN122	26,765				0	0	0	0	0	0	0						26,765				
30123	Vehicle 05BK16	143,640				0	0	0	0	0	0	0						143,640				
30131	Laptop Manager Service/Mainten	2,412				0	0	0	0	0	0	0				2,412						
30132	Laptop Engineering Tech	4,739				0	0	0	0	0	0	0				4,739						
30133	Laptop metering dept	2,775				0	0	0	0	0	0	0				2,775						
30134	Laptop Metering Dept	5,291				0	0	0	0	0	0	0				5,291						
30141	Generator installation	70,929				0	0	0	0	0	0	0		70,929								
30142	Construction BDO Office	6,822				0	0	0	0	0	0	0		6,822								
30143	New Garage	286,667				0	0	0	0	0	0	0		286,667								
31000	Residential New Services	203,762				13,589	24,595	5,350	36,207	2,717	121,030	274										
31030	Parkland Estate sub Ph 5 Tilbu	9,805				0	0	0	7,968	1,837	0	0										
31051	St. Ambrose Develpment Chatham	9,886				0	0	0	8,048	1,837	0	0										
31057	Enclave place subdivision	19,074				0	0	0	8,081	10,600	393	0										
31058	Life lease townhouse Wheatley	27,250				0	29	5,554	14,079	7,460	129	0										
31060	Faas devel Cathcart st Ridgtwn	44,463				0	0	7,249	22,188	15,026	0	0										
31065	St Lawrence way	27,070				0	0	729	10,282	12,057	3,960	42										
31066	Brochu Townhousing Tilbury	20,848				0	0	0	6,027	4,546	10,275	0										
31067	Country crossing Ph 2 Tilbury	39,184				0	0	6,156	13,033	6,014	13,783	198										
31068	Landings Phase 2 -Chatham	14,815				0	0	0	6,793	5,585	2,436	0										
31069	Gateway twins Keil Trail	12,072				0	0	0	10,234	1,837	0	0										
31500	Residential Rebuild	33,075				1,303	4,378	217	341	60	26,776	0										
31510	C & Ind New - 1 & 3 Phases	48,640				9,758	10,336	30	8,801	4,645	14,220	850										
31550	Rogers commun tower Thamsville	5,464				561	0	0	4,165	738	0	0										
31551	Dorsers Inc Blenheim	6,135				2,253	3,882	0	0	0	0	0										
31552	LP Wood at 351 Hart Place	9,307				0	2,628	0	0	6,680	0	0										
31553	Comm Ursuline Mother House McNaughtor	47,876				3,508	0	0	17,784	26,584	0	0										
31554	Interior feed Bloomfield Business Park	61,817				11,508	49,818	0	0	491	0	0										
31555	New Armory 280 Bloomfield Rd Chatham	12,911				596	3,817	0	0	8,498	0	0										
31556	Ridgetown College additional service	7,045				1,542	4,244	0	0	1,259	0	0										
31557	Comm 943 Wellington st Dresden	10,152				0	0	0	0	10,152	0	0										
32000	C & Ind Rbd - 1 & 3 Phase	36,098				3,055	13,567	0	579	856	13,189	4,853										
32046	Dickson Motors Thamesville	754				0	0	0	0	754	0	0										
32053	Water Treatment Plt Grand Ave	5,783				0	4,243	0	0	0	0	1,540										
32055	Intergrated Children Grand Ave	19,764				0	0	0	1,016	18,597	0	151										
32056	Rebuild Kent stress and Temper	25				0	0	0	25	0	0	0										
32061	Maple city gas Park ave Chtm	1,361				0	0	0	0	1,361	0	0										
32062	Anderson Machine Ridgetown	10,346				653	0	0	0	9,693	0	0										
32063	St Paul School Thamesville	18,065				6,438	9,995	0	0	1,602	0	30										
32064	MouldTech 7 Hattie St Merlin	46,005				16,707	19,754	0	0	9,544	0	0										
32066	Minacs Contact Centre	21,730				3,466	0	0	7,652	10,612	0	0										

Job	Description	Grand Total	1805 Land	1808 Building	1820 Distribution Station	1830 Poles	1835 O/H conductor & devices	1840 U/G conduit	1845 U/G conductor & Devices	1850 Transformers	1855 Services O/H & U/G	1860 Meters	1860 Smart Meters	1908 Building	1915 Office Furniture	1920 Computer	1925 Software	1930 Fleet	1940 Tools	1980 Scada	1990 AM/FM	3030 Contributed Capital
32067	Com reb 65 McNaughton Ave Wallacburg	3,709				0	2,290	0	0	1,419	0	0										
32068	Global Design 985 Richmond st Chatham	29,725				1,497	4,233	0	0	23,995	0	0										
32069	Rewire CT 745 Richmond st Chatham	729				0	0	0	0	0	0	729										
32400	Transformer Replacement	156,652				0	3,287	0	99	152,094	1,172	0										
32401	Transformer Inventory	(24,286)				0	0	0	0	(24,286)	0	0										
32402	Trsfmr 186 Chatham St Blenheim	1,847				0	1,112	0	0	736	0	0										
32403	Transformer Rep National Rd	14,387				0	12,335	0	0	2,052	0	0										
32404	Transformer sandy/McNaughton	15,663				0	0	0	0	15,663	0	0										
32405	Tx replace Bothwell/Thamesville	58,382				7,382	0	0	0	51,000	0	0										
32410	Meter Replacement - Retail	49,414				0	0	0	0	0	0	49,414										
32435	Control Room Support Capital	49,047				48,778	0	0	0	0	269	0										
32440	Account Concellation	6,720				537	721	0	0	400	4,834	227										
32486	King St W Widening	11,866				5,094	5,323	0	0	0	1,449	0										
32500	Contributed Capital Received	(118,720)				0	0	0	0	0	0	0										(118,720)
33050	Sub 5 Conversion	43,644				3,289	30,615	0	0	2,573	7,168	0										
33060	Insulator Replace	28,035				0	27,393	0	0	641	0	0										
33100	John St. Blenheim Conversion	60,485				6,577	38,958	0	5,166	2,573	7,211	0										
33109	Emergencies	7,607				7,607	0	0	0	0	0	0										
33114	Tilbury Conv. F2 Extension	61,458				6,577	38,958	280	5,166	3,309	7,168	0										
33131	Emer. McFarlane Ave cable repl	17,591				0	492	7,310	9,789	0	0	0										
33140	Tilbury Conversion Queen St	392,753				72,974	152,431	19,088	43,334	51,606	53,321	0										
33141	Sub 8 Conversion	105				0	0	0	0	0	105	0										
33142	Dresden Back lot Re-construct	54,220				6,577	38,958	0	0	1,516	7,168	0										
33143	Dresden Conversion	312,067				54,702	69,991	37,519	53,329	55,095	41,431	0										
33144	Engineer study new hydro	1,500				1,500	0	0	0	0	0	0										
33145	M4 Cable Replacement	5,366				125	0	0	5,241	0	0	0										
33147	Sub 7 Birdland Conversion	391,701				9,418	0	191,431	54,966	133,292	2,593	0										
33152	Wallaceburg M2 WM Upgrade	3,410			1,214	938	1,259	0	0	0	0	0										
33153	Wallaceburg M6 WM upgrade	2,115			888	469	758	0	0	0	0	0										
33154	Erieau WM Upgrade	4,925			1,067	1,753	2,105	0	0	0	0	0										
33155	Tilbury DS F1 WM Upgrade	9,324			564	276	8,484	0	0	0	0	0										
33156	Tilbury DS F2 WM Upgrade	7,226			989	414	5,822	0	0	0	0	0										
33157	Ridgetown WM Upgrade	11,692			805	1,297	8,313	0	0	1,277	0	0										
33159	Ridgetown M16 Primary meter	4,072				1,859	2,213	0	0	0	0	0										
33160	Pole Replacement	15,854				15,854	0	0	0	0	0	0										
33161	Low Voltage Juliana St	(2)				0	(2)	0	0	0	0	0										
33163	Thamesville Taven Pole Repl	11,698				3,866	7,632	0	0	0	201	0										
33164	Pole Replacement McKee Nelson	10,347				3,494	6,853	0	0	0	0	0										
33172	Storm June 5 and 6	35,869				20,311	9,740	0	0	1,709	4,109	0										
33173	Storm Jun 30 and July 1,2	39,575				24,669	9,740	0	5,166	0	0	0										
33174	Storm July 26 2005	26,651				10,099	2,320	0	5,166	9,031	34	0										
33175	Primary cable failure Maryknoll Rd Chath	29,212				0	2,792	0	26,420	0	0	0										
33182	Sub 10 Conversion	8,188				230	2,792	0	5,166	0	0	0										
33183	LIS Switch	20,953				20,953	0	0	0	0	0	0										
33184	LIS Switch	21,132				7,643	13,489	0	0	0	0	0										
33185	Wheatley PME	72,778			34,907	21,055	16,816	0	0	0	0	0										
33187	Kent T4 WM	11,943			11,943	0	0	0	0	0	0	0										
33188	Blenheim DSF3	44,141			27,181	10,742	6,018	0	0	200	0	0										
33190	LIS 810 Richmond St Chatham	9,923				0	9,923	0	0	0	0	0										
33504	Demand Meter Replacement	19,836				0	0	0	0	0	0	19,836										
	Grand Total	3,676,468	0	0	79,558	453,493	695,448	280,914	402,311	667,537	344,423	78,144	0	379,149	3,411	15,217	0	193,703	34,185	65,148	102,548	(118,720)

2005 Actual Capital Jobs over Materiality

- Job 30123 - Purchase Bucket Truck - $143,640 - 05BK16 – one of the Bucket Trucks was replaced based on the replacement criteria of full depreciation; repair history and manufacturers' guide lines, Chatham-Kent Hydro replacement schedule for service trucks is 7-10 years.

- Job 30143 - Construction of new garage – $286,667 – the building was constructed for the vehicles and equipment, to protect the equipment from weather conditions and vandalism.

- Job 31000 - New Residential Service - $203,762 – overhead service was installed for a new service. The Distribution System Code requires the Local Distribution Company to supply and to install up to 30m of overhead service conductor at its expense to connect a new residential customer. In 2005 the area had 219 new Residential customer connections.

- Job 32400 - Transformer Replacement – $156,652 - this capital job is the annual program to replace transformers that have been identified as defective or damaged.

- Job 32500 - Contributed Capital – ($118,720) - Residential - the construction of a new structure for subdivision in the Chatham-Kent Hydro service area. The contribution methodology is set out in the Distribution System Code and the amount is based on the economic evaluation.

- Job 33140 - Project Tilbury Conversion - $392,753 - this is a continuing project from 2004, see job 33140 for further details.

- Job 33143 - Dresden Conversion – $312,067 – continued work from 2004, see job 33143 for further details.

- Job 33147 - Sub 7 Bird land Conversion- $391,701 – this conversion involved converting a portion of the distribution system from 4.16kV to 27.6 kV in order to replace plant at end of life while reducing system losses by increasing voltages and moving substations at McNaughton Ave W. in Chatham.

Year 2006 Actual Capital Jobs

Job Description		Grand Total	1805 Land	1808 Building	1820 Distribution Station	1830 Poles	1835 O/H conductor & devices	1840 U/G conduit	1845 U/G conductor & Devices	1850 Transformers	1855 Services O/H & U/G	1860 Meters	1905 Land	1908 Building	1915 Office Furniture	1920 Computer	1925 Software	1930 Fleet	1940 Tools	1980 Scada	1990 AM/FM	3030 Contributed Capital
30800	System Loss Project CDM	244,076				0	244,076	0	0	0	0	0										
30963	Smart Meter Pilot CDM	357,781				0	0	0	0	0	0	357,781										
30125	Bucket Truck 06BK11	243,809				0	0	0	0	0	0	0						243,809				
30126	46" Single bucket	10,517				0	0	0	0	0	0	0						10,517				
30127	Repair Transmission VEBK08	52,716				0	0	0	0	0	0	0						52,716				
30128	New Dump Truck 06DP77	5,933				0	0	0	0	0	0	0						5,933				
30143	New Garage	6,759				0	0	0	0	0	0	0		6,759								
30145	Building Capital	7,508				0	0	0	0	0	0	0		7,508								
30146	Engineering Drawings meter shop	4,360				0	0	0	0	0	0	0		4,360								
30147	Building Capital - US rep relocate	19,206				0	0	0	0	0	0	0		19,206								
30148	Modify Mail Room	11,901				0	0	0	0	0	0	0		11,901								
30149	Mezzanine & Meter Shop	178,144				0	0	0	0	0	0	0		178,144								
30150	Office Equipment	5,554				0	0	0	0	0	0	0			5,554							
30151	Laptop - J. Berkvens	4,794				0	0	0	0	0	0	0				4,794						
30152	New Computer - IT	2,795				0	0	0	0	0	0	0				2,795						
30153	2 Laptops for Engineering	4,912				0	0	0	0	0	0	0				4,912						
30154	Furniture Mike Goodwin	1,795				0	0	0	0	0	0	0			1,795							
30155	New Computer Control Room	4,613				0	0	0	0	0	0	0				4,613						
30156	Meter Test Board	1,126				0	0	0	0	0	0	0				1,126						
30157	New Laptop-Stations&Distribution Technol	2,344				0	0	0	0	0	0	0				2,344						
30160	Distribution Analysis Program	6,740				0	0	0	0	0	0	0					6,740					
30161	Temporary Residential Supply Equipment	4,455				0	0	0	0	0	0	0							4,455			
30162	upgrade meter test console	13,140				0	0	0	0	0	0	0				7,416			5,724			
30163	New Hydraulic Press	3,168				0	0	0	0	0	0	0							3,168			
30164	Front Mounted John Deere Snow Plow Blade	3,515				0	0	0	0	0	0	0							3,515			
30170	SCADA Capital Support	16,489				0	0	0	0	0	0	0								16,489		
30175	AM/FM Capital Support	147,567				0	0	0	0	0	0	0									147,567	
30180	Upgrade AM/FM to GIS	26,771				0	0	0	0	0	0	0									26,771	
30181	New Carpeting - Engineering Dept	7,289				0	0	0	0	0	0	0			7,289							
30183	Master Radio for Scada	72,343				0	0	0	0	0	0	0								72,343		
30185	8 Cubicles for Field Reps	12,425				0	0	0	0	0	0	0		12,425								
30186	Property 342 Queen St.	358,875				0	0	0	0	0	0	0	358,875									
31000	Residential New Services	186,801				23,496	24,657	2,329	19,651	1,898	114,543	227										
31068	Landings Phase 2 -Chatham	115,908				0	0	7,899	41,383	27,531	39,095	0										
31069	Gateway twins Keil Trail	66,400				0	0	3,537	18,924	17,710	26,229	0										
31070	Bloomfield Heights Retest	23,769				0	0	0	10,806	2,308	10,655	0										
31071	Chelesa Meadows Keil Dr Chatham	87,841				0	0	4,759	30,885	28,202	23,996	0										
31072	Paulus Sub Ph 1 Tilbury	59,423				0	0	3,000	17,446	17,551	21,426	0										
31073	McNaughton Oaks - Phase 2	50,132				0	0	1,093	17,349	13,229	18,461	0										
31074	Detached Residential - Lanz Subdivision	84,416				11,321	3,235	1,951	26,808	19,461	21,641	0										
31075	Davies St. Subdivision Dresden	15,291				0	0	0	7,655	2,308	5,327	0										
31076	Eastman Ave, Wheatley Townhousing	23,077				430	0	0	7,154	2,797	12,696	0										
31500	Residential Rebuild	31,329				1,258	1,485	0	7,099	0	21,486	0										
31501	Residential Rebuild-125 DD St. Dresden	5,700				860	297	281	0	0	4,262	0										
31510	Com & Ind New -1 & 3 Phase	82,352				17,990	13,592	424	16,431	12,246	16,755	4,913										
31550	Rogers commun tower Thamsville	455				0	0	0	0	455	0	0										
31554	Interior feed Bloomfield Business Park	-1,403				0	-1,403	0	0	0	0	0										
31556	Ridgetown College additional service	172				0	172	0	0	0	0	0										
31558	1540 Roberts Rd. Erieau	9,522				4,322	2,231	0	0	2,137	832	0										
31559	346 Lacroix St. - Com/Ind Rebuild	11,886				0	3,709	0	0	8,113	0	63										
31560	Walmart - 58 mcNaughton Ave Wburg	38,359				2,823	3,109	0	5,478	26,949	0	0										
31561	Ridgetown College-Additional Service fro	6,039				0	0	0	0	6,039	0	0										
31562	Engineered Waste Solutions Inc.	38,312				0	0	0	10,197	28,116	0	0										
32000	Com & Ind Rebuild 1&3Phase	61,682				5,264	25,514	187	3,109	9,089	8,757	9,763										
32065	Ridgetown college primary metering upgr	5,173				0	0	0	0	0	968	4,205										
32066	Minacs Contact Centre	10,785				0	0	0	0	10,785	0	0										

Job Description		Grand Total	1805 Land	1808 Building	1820 Distribution Station	1830 Poles	1835 O/H conductor & devices	1840 U/G conduit	1845 U/G conductor & Devices	1850 Transformers	1855 Services O/H & U/G	1860 Meters	1905 Land	1908 Building	1915 Office Furniture	1920 Computer	1925 Software	1930 Fleet	1940 Tools	1980 Scada	1990 AM/FM	3030 Contributed Capital
32067	Com reb 65 McNaughton Ave Wallacburg	6,604				0	0	0	0	6,604	0	0										
32068	Global Design 985 Richmond st Chatham	-15,526				96	614	0	0	-16,235	0	0										
32069	Rewire CT 745 Richmond st Chatham	-581				0	0	0	0	0	0	-581										
32070	330 National Road Chatham Rebuild Ind	36,035				1,997	0	0	14,235	19,803	0	0										
32071	Extend service on Kingsway Dr. - Thames	13,777				5,014	6,616	131	0	232	1,784	0										
32072	Erieau Dock Facility - Extend Secondary	3,316				2,221	0	0	0	0	1,095	0										
32073	132 Richmond St. - Com/Ind Rebuild	30,630				0	0	3,329	8,440	18,801	0	60										
32074	Holy Trinity School - Wallaceburg	18,495				3,666	12,478	0	0	2,352	0	0										
32075	St. Elizabeth School - Wallaceburg	9,099				3,881	3,535	0	0	1,639	0	45										
32076	WJ Baird Public School, Blenheim-Comm Re	2,714				0	0	0	0	2,714	0	0										
32400	Transformer Replacement	92,013				821	157	0	2,077	87,842	980	136										
32401	Transformer Inventory	112,826				0	0	0	0	112,826	0	0										
32405	Tx replace Bothwell/Thamesville	809				0	0	0	0	809	0	0										
32407	Transformer reloc 21 Hagen court Wallace	19,131				0	0	5,115	1,447	12,569	0	0										
32410	Meter Replacements-Retail	30,371				0	0	0	0	0	0	30,371										
32435	Control Room Support Capital	81,088				81,059	0	0	29	0	0	0										
32440	Account Cancellation	9,052				0	121	0	0	0	8,162	770										
32500	Contributed Capital Recieved	-452,865				0	0	0	0	0	0	0										-452,865
33060	Insulator Replace	13,691				0	13,691	0	0	0	0	0										
33064	Operations Captial Support	-203				0	-101	0	-101	0	0	0										
33140	Tilbury Conversion Queen St	55,163				4,116	33,975	0	14,308	2,763	0	0										
33143	Dresden Conversion	61,872				4,116	42,745	0	13,445	1,566	0	0										
33147	Sub 7 Birdland Conversion	60,196				2,058	17,706	0	35,037	4,476	919	0										
33185	Wheatley PME	4,571			4,242	0	0	0	0	329	0	0										
33187	Kent T4 WM	4,242			4,242	4,242	0	0	0	0	0	-4,242										
33188	Blenheim DSF3	4,242			4,242	0	0	0	0	0	0	0										
33504	Demand Meter Replacement	18,757				0	0	0	0	0	0	18,757										
34000	Tilbury Conversion	310,672				82,465	116,210	5,657	4,615	68,840	32,886	0										
34001	Sub 8 Conversion	306				0	50	0	31	0	225	0										
34002	Dresden Feeder Tie	114,322				37,313	64,161	0	6,561	3,576	2,712	0										
34003	New TS	47				47	0	0	0	0	0	0										
34004	Sub 9 Conversion	78,931				10,282	13,588	0	15,126	38,274	1,660	0										
34005	Sub 7 Conversion	445,159				2,792	3,198	22,764	308,472	95,677	12,255	0										
34006	Insulator Replacement	23,016				-3	23,020	0	0	0	0	0										
34007	Victoria & Gladstone ext. pole top	407				0	407	0	0	0	0	0										
34008	M21 Overhead River Crossing	104,981				32,331	72,650	0	0	0	0	0										
34011	Storm Feb 3/4	11,220				11,005	215	0	0	0	0	0										
34012	Emergency M21 River Crossing	71,729				0	8,804	0	62,926	0	0	0										
34013	Wind Damage December 1, 2006	5,463				4,812	0	0	0	0	651	0										
34021	VanAllen Widening - Municipal Request	17,372				8,719	6,969	0	0	0	1,684	0										
34025	Distribution Automation	3,681				3,681	0	0	0	0	0	0										
34026	LIS Switches	17,426				31	17,395	0	0	0	0	0										
34029	Ridgetown WM North	41,366			34,380	6,986	0	0	0	0	0	0										
34030	Blenheim PME HWY 40	43,860			35,843	5,533	2,483	0	0	0	0	0										
34031	Merlin DS Primary Meter	39,801			33,122	6,680	0	0	0	0	0	0										
34032	Kent T1/T2	301,413			49,679	209,929	36,382	0	3,478	1,824	0	120										
34033	Smart Meter Residential	0				19,440	0	0	0	0	0	-19,440										
34036	Pole repl Jane St Thamesville	14,318				6,428	6,001	0	0	1,889	0	0										
34037	Pole repl Flemingo St Blenheim	11,755				7,125	4,014	0	0	406	210	0										
34038	Pole rep McNaugton ave/Craven Dr Chatham	4,848				3,796	1,052	0	0	0	0	0										
34039	Pole repl 42 Stanley Ave Chatham	7,601				455	2,162	0	0	877	4,107	0										
34041	Wholesale Meter Exit Fees	26,000				0	0	0	0	0	0	26,000										
34042	Pole Replacement various locations	3,981				3,981	0	0	0	0	0	0										
34043	Transformer Replacement 583 King St. W	8,799				671	2,995	0	0	5,134	0	0										
34051	Elim. Load Tfrs. Chatham St. N Blenheim	95,207				45,265	42,847	0	956	4,845	1,294	0										
		4,880,042	0	0	165,751	690,814	876,812	62,455	731,457	717,354	417,753	428,948	358,875	240,303	14,638	28,000	6,740	312,975	16,861	88,832	174,338	-452,865

2006 Actual Capital Jobs over Materiality

- Job 30800 - System Loss Reduction - $244,076 – this is part of Chatham-Kent Hydro's Approved third Tranche Conservation and Demand Management Project to convert its distribution lines to the standard 27.6 kV.

- Job 30963 - Smart Meter Pilot - $357,781 – this was part of Chatham-Kent Hydro's Conservation and Demand Project of installing 1,000 Smart Meters in Residential units.

- Job 30125 - Purchase Bucket Truck - $243,809 - 07BK11 - one of the Bucket Trucks was replaced based on the replacement criteria of full depreciation; repair history and manufacturers' guide lines, Chatham-Kent Hydro replacement schedule for service trucks is 7-10 years.

- Job 30149 - Construction of new garage for Fleet - $178,144 - continued project from 2005, see above for further details

- Job 30175 - AM/FM Capital Support – $147,567 – these costs are related to IT support, computer hardware/software upgrades, software support and computer consultant support.

- Job 30186 - Property 342 Queen St. - $358,875 - Purchased the property located at 342 Queen St. Chatham directly abutting Chatham-Kent Hydro office. Transaction approved by Board of Directors and President CK Hydro Nov 17, 2006

- Job 31000 - New Residential Services – $186,801 – overhead service was installed for a new service. The Distribution System Code requires the Local Distribution Company to supply and to install up to 30m of overhead service conductor at its expense to connect a new residential customer. In 2006 the area had 155 New Residential customer connections.
- Job 31068 - Landing Phase 2 - $115,908 - this expenditure involves the servicing of a new 50 lot subdivision extension in the Landings Subdivision. The project includes,

extending one phase 16kV, 1/0 aluminum 27.6 KV underground primary cable from an existing switching cubicle on Landings Pass to Hudson Dr, to supply four new 50kVA pad mount transformers; and installing 3/0 underground triplex to lots lines of each new lot.

- Job 31071 – Chelesa Meadows - $87,841 – this expenditure involves the servicing of a new 46 lot subdivision off of Keil Drive. The project involved installing four 75kVA, 1.6kV to 120/240V pad mount transformers and makes all primary and secondary terminations. Installed two single phase primary risers at existing 16/27.6kV overhead pole line.

- Job 31074 – Detached Residential - $84,416 – this is a new subdivision, Lanz subdivision in Blenheim for 14 new lots. The project included installing on wood pole and extend existing 2.4/4.16KV overhead primary feeder one span on Chatham St S to new subdivision entrance and installed two 50KVA, 2400V to 120/240V padmount transformers and make all primary and secondary terminations.

- Job 31510 – Commercial & Industrial new - $82,352 – this work order is to cover all labor, equipment and material expenses to connect new commercial/industrial customers to Chatham-Kent Hydro's Distribution System. If costs to make these connections or required system expansions are greater than $5,000, a specific work order is created by location.

- Job 32400 - Transformer Replacement – $92,103 – this capital job is the annual program to replace transformers that have been identified as defective or damaged.

- Job 32401 - Transformer Inventory – $112,826 – Chatham-Kent Hydro increased the number of transformers in inventory as a shortage of core steel increased the delivery time of ordered transformers from 20 weeks to 52 weeks. Chatham-Kent Hydro increased its volumes based on past usage as compared to anticipated usage.

- Job 32435 - Control Room Support - $81,088 – this job captures the administrative cost related to this position in supporting the lineman and administrative duties. The operator duties entail monitors the distribution system status, dispatches line crews, writes switching orders for power restoration and feeder balancing.

- Job 32500 - Contributed Capital – ($320,590) - Residential - the construction of a new structure for subdivision in the Chatham-Kent Hydro service area. The contribution methodology is set out in the Distribution System Code and the amount is based on the economic evaluation.

- Job 32500 - Contributed Capital – ($132,275) - General Service– the construction of new service for General Service > 50, the contribution methodology is set out in the Distribution System Code and the amount is based on the economic evaluation.

- Job 34000 - Tilbury Conversion - $310,672 – Continued job from 2004, see Job 33140 for further details.

- Job 34002 - Dresden Feeder Tie - $114,322 – the project was to transfer six residential service from rear lot to front of the lot and eliminate the rotten poles. This entailed installing six poles with secondary hardware, string in 5 spans of 3/0 triplex and re-attach secondary existing secondary conductor. Also, install two 50kVA pole transformer locations to supply new secondary conductors.

- Job 34004 - Sub 9 Conversion - $78,931 – this conversion moved the load from Chatham Substation #9 and transfer load directly to 27.6 kV feeder. Remove Sub 9 transformer to old Sub 5 yard for disposal. Install four pole mount transformers and install 500 mcm secondary cable to existing vaults remove submersible transformers, make secondary connections in existing vaults. Convert four submersible transformers to pad mounts, reusing existing vaults.

- Job 34005 - Sub 7 Conversion – $445,159 – this project involved the conversion of a portion of the distribution system from 4.16kV to 27.6 kV in order to replace plant at end of life while reducing system losses by increasing voltages and eliminating substation. The project entails installing transformers at McNaughton and Crane Drive and extends line at Finch Place.

- Job 34008 – M21 Overhead River Crossing - $104,981 – this project was to extend the 1M21 feeder to the north side of the Thames River providing an additional supply and feeder flexibility to the north side of the city of Chatham. This involved installing three wood poles with 27.6kV primary hardware and string 556 MCM ASC from Stanley Ave across Thames River to Dover St Chatham.

- Job 34032 - Kent T1/T2 – $301,413 - The load for Chatham is directly connected to the grid off the 27.6kV breakers at Kent TS. This project involves the replacement of Wholesale meter that has an expired seal, the meter point has to be upgraded to the IESO standards.

- Job 34051 - Elimination Load transfer Chatham St N Blenheim - $95,207 – this project involved eliminating load transfers between Hydro One and Chatham-Kent Hydro on Chatham St. N. Blenheim, by building double circuit pole line from Allison Line to Story St. along with new PME. Install 13-55', 1-50' and 1-60' pole and string new 3/0 ACSR from Allison Line to Story St Blenheim. Hydro One to transfer their line to new CK Hydro poles

2007 Actual Capital Jobs

Job Description		Grand Total	1805 Land	1808 Building	1820 Distribution Station	1830 Poles	1835 O/H conductor & devices	1840 U/G conduit	1845 U/G conductor & Devices	1850 Transformers	1855 Services O/H & U/G	1860 Meters	1860 Smart Meters	1905 Land	1908 Building	1915 Office Furniture	1920 Computer	1925 Software	1930 Fleet	1940 Tools	1980 Scada	1990 AM/FM	3030 Contributed Capital
30170	SCADA Capital Support	19,699				0	0	0	0	0	0	0									19,699		
30171	Repairs to Scadamate Switch	5,361				0	0	0	0	0	0	0									5,361		
30175	AM/FM Capital Support	50,905				0	0	0	0	0	0	0										50,905	
30180	Upgrade AM/FM to GIS	10,800				0	0	0	0	0	0	0										10,800	
30186	Property 342 Queen St.	3,870				0	0	0	0	0	0	0		3,870									
30200	new body & chassis for 06PU116	44,965				0	0	0	0	0	0	0							44,965				
30201	07BK06 - 55" double bucket truck (replac	278,017				0	0	0	0	0	0	0							278,017				
30202	07BK04 replacement truck for VEBK04	2,261				0	0	0	0	0	0	0							2,261				
30217	Upgrade Parking Lot, 342 Queen St.	41,628				0	0	0	0	0	0	0			41,628								
30219	Window Tinting 320 Queen St.	2,147				0	0	0	0	0	0	0			2,147								
30220	Construction of New Director's Office	4,590				0	0	0	0	0	0	0			4,590								
30233	Tablet PC for locator	4,270				0	0	0	0	0	0	0					4,270						
30247	Springboard Management	86,316				0	0	0	0	0	0	0						83,999		2,317			
30248	VEBK19 Differential Repair	8,621				0	0	0	0	0	0	0							8,621				
30249	Servisavor	4,455				0	0	0	0	0	0	0								4,455			
30250	Repair MUS	28,787				0	0	0	0	0	0	0								28,787			
30251	Service Load Limiter	7,582				0	0	0	0	0	0	0								7,582			
31000	Residential New Services	181,462				9,686	18,738	3,017	41,014	5,349	103,658	0											
31075	Davies St. Subdivision Dresden	40,717				0	14,476	0	14,447	3,770	8,024	0											
31077	Davies St. Dresden Subdivision (carry ov	78,103				0	17,922	923	35,903	15,294	8,061	0											
31078	Morning Glory Ph2 Subdivision	134,215				12,782	46,818	5,881	33,500	14,735	20,499	0											
31079	Braemar Blvd. Extension	71,015				0	17,922	2,483	28,361	9,822	12,427	0											
31080	Port Sunilght Ph1 Development Pole Ext	66,147				10,883	28,262	0	13,267	5,711	8,024	0											
31081	Dale Dr Phase 2 Detached Residential	52,660				0	17,922	1,791	22,034	2,889	8,024	0											
31500	Residential Rebuild	28,749				261	15,699	0	1,365	0	11,425	0											
31510	C & Ind New - 1 & 3 Phases	48,563				2,070	16,271	0	639	4,569	6,026	18,988											
31560	Walmart - 58 mcNaughton Ave Wburg (use 3	9,225				0	6,575	0	2,650	0	0	0											
31563	Walmart - McNaughton Ave. Wburg	43,710				0	658	0	8,651	34,402	0	0											
31564	20 Mill St. Tilbury, Health Clinic	14,493				611	7,930	0	5,951	0	0	0											
31565	37 Marlborough St. Blenheim	10,085				0	5,515	0	0	4,569	0	0											
31566	Kent Essex Mutual Insurance Chatham New	15,725				2,970	0	0	0	12,755	0	0											
31567	New Com/Industrial 20 Mill St Tilbury Sh	26,385				4,481	9,609	0	1,365	10,931	0	0											
31568	New Com/Ind Ecole St Marie 90 Dale Dr	17,725				0	0	0	8,668	9,057	0	0											
32000	C & Ind Rbd - 1 & 3 Phase	16,332				3,064	4,099	204	4,971	474	1,774	1,747											
32078	580 Lowe St., Millenium Building System	41,052				0	0	1,115	7,316	32,621	0	0											
32079	Artic Glasier 745 Park Ave W	37,111				0	0	0	1,396	27,691	8,024	0											
32080	430 Catherine St. Blenheim-Curling Club	17,453				3,707	5,661	0	0	61	8,024	0											
32081	St. Michael's School Upgrade	22,381				115	4,421	0	0	9,821	8,024	0											
32082	Baseline Pump-In Line Switch	13,336				0	1,730	0	0	3,582	8,024	0											
32400	Transformer Replacement	142,468				1,840	9,492	0	0	124,090	7,045	0											
32401	Transformer Iventory	331,662				0	0	0	0	331,662	0	0											
32408	Transformer Replacement-891 Mariner's Rd	7,413				202	452	0	0	6,635	124	0											
32409	Transformer Replacement-Baldoon Rd.	6,379				0	0	0	0	6,379	0	0											
32410	Meter Replacement - Retail	8,520				0	0	0	0	0	0	8,520											
32412	Transformer Repl. Kyle Dr. S	12,928				0	0	0	0	12,928	0	0											

Job	Description	Grand Total	1805 Land	1808 Building	1820 Distribution Station	1830 Poles	1835 O/H conductor & devices	1840 U/G conduit	1845 U/G conductor & Devices	1850 Transformers	1855 Services O/H & U/G	1860 Meters	1860 Smart Meters	1905 Land	1908 Building	1915 Office Furniture	1920 Computer	1925 Software	1930 Fleet	1940 Tools	1980 Scada	1990 AM/FM	3030 Contributed Capital
32413	Transformer Repl. Keil Dr. (Pizza Hut/Ho	28,947				0	0	0	0	28,947	0	0											
32414	Transformer Repl 175 Lindsley St W Dresd	3,112				0	0	0	0	3,112	0	0											
32435	Control Room Support Capital	55,893				48,268	1,004	0	0	832	832	4,957											
32440	Account Cancellation	10,811				0	994	0	0	1,820	7,499	499											
32500	Contributed Capital	(213,142)				0	0	0	0	0	0	0											(213,142)
33504	Demand Meter Replacement	12,522				0	0	0	0	0	0	12,522											
34000	Tilbury Conversion	40,158				9,202	11,030	0	11,902	0	8,024	0											
34002	Dresden Feeder Tie	28,457				9,403	11,030	0	0	0	8,024	0											
34005	Sub 7 Conversion	49,798				7,361	28,953	0	5,460	0	8,024	0											
34011	Storm Feb 3/4	39				39	0	0	0	0	0	0											
34029	Ridgetown WM North	0				0	0	0	0	0	0	0											
34038	Pole rep McNaugton ave/Craven Dr Chatham	13				13	0	0	0	0	0	0											
34040	Operation Support (use 34170 in 2007)	141				0	71	0	69	0	0	0											
34041	Wholesale Meter Exit Fees	15,600				0	0	0	0	0	0	15,600											
34051	Elim. Load Tfrs. Chatham St. N Blenheim	(820)				0	(820)	0	0	0	0	0											
34100	Tilbury Conversion	598,011			11,931	118,018	245,740	43,130	30,771	138,941	9,481	0											
34101	Sub 8 Conversion	28,998				23,375	0	0	0	5,623	0	0											
34102	North Chatham Supply Enhancement	101,648				24,113	50,166	0	140	19,517	7,712	0											
34103	Downtown Chatham	12,176				0	28	0	10,417	0	1,731	0											
34104	Sub 7 Conversion	167,065				5,817	8,669	16,056	53,750	82,773	0	0											
34105	Insulator Replacement	22,665				269	21,892	0	0	504	0	0											
34106	Blenheim PME 40 Hwy (carryover from 2006	14,025			3,219	5,454	5,352	0	0	0	0	0											
34107	Chatham St. N-Eliminate Load Transfers (	53,839				5,422	36,262	0	6,101	1,655	4,399	0											
34108	Replace 3 ways & Elbows in the Maples	36,046				0	0	0	252	35,794	0	0											
34110	Emergencies	11,683				121	0	0	2,598	0	8,965	0											
34111	Storm Repairs April 16	22,355				13,436	8,800	0	0	0	119	0											
34112	Dresden FI (primary) Cable Replacement	12,290				0	0	5,609	6,681	0	0	0											
34113	Repair Manhole St Clair St @ Grand Ave	3,019				0	0	0	3,019	0	0	0											
34114	M7 Wholesale Meter Repair	6,849			3,822	0	3,027	0	0	0	0	0											
34131	Distribution Automation	40,000				40,000	0	0	0	0	0	0											
34132	LIS Switch #43 Bloomfield Rd.	24,790				649	24,141	0	0	0	0	0											
34133	LIS Switch #44 Richmond St.	18,223				2,838	15,385	0	0	0	0	0											
34134	LIS #45 Arnold St Wallaceburg	15,971				3,699	12,272	0	0	0	0	0											
34150	Pole Replacement	20,850				11,889	8,961	0	0	0	0	0											
34151	Closed Recoverable Jobs 2006 (write-offs	7,952				7,952	0	0	0	0	0	0											
34152	Replace 5 Wooden Poles-Wburg	17,316				15,771	1,545	0	0	0	0	0											
34153	Pole Replacement-55 Gladstone Low Voltag	5,227				659	634	0	0	3,934	0	0											
34154	Blenheim High School Pole Replacement	37,226				7,581	338	0	0	29,307	0	0											
34155	Dresden Pole Replacement	20,131				10,529	2,557	0	0	0	7,045	0											
34156	Pole Repl Powell Lane Erieau	11,553				7,900	3,653	0	0	0	0	0											
34157	Pole Replacement Stanley St Merlin/Ridge	23,606				23,606	0	0	0	0	0	0											
34200	Tilbury Conversion	34,004				0	17,922	0	35	0	16,047	0											
35000	Smart Meter Deployment	2,869,927				0	0	0	0	0	0	0	2,577,598				119,684	172,645					
	Grand Total	6,369,261	0	0	18,973	456,056	769,779	80,208	362,694	1,042,557	315,104	62,833	2,577,598	3,870	48,365	0	123,954	256,644	333,864	43,140	25,060	61,705	(213,142)

2007 Actual Capital Jobs over materiality

- Job 30201 - Purchase 55' Double Bucket Truck - $278,017 - 07BK06 - one of the Bucket Trucks was replaced based on the replacement criteria of full depreciation; repair history and manufacturers' guide lines, Chatham-Kent Hydro replacement schedule for service trucks is 7-10 years.

- Job 30247 - Springboard Management - $86,316 – purchased and installed a Springboard Management System software. The Springboard Software is a Risk Management Solution that features four management initiatives, regulation management, risk assessment management, document control and training management.

- Job 31000 - Residential New Service - $181,462 – overhead service was installed for a new service. The Distributions System Code requires the Local Distribution Company to supply and to install up to 30m of overhead service conductor at its expense to connect a new residential customer. In 2007 the area had 143 New Residential customer connections.

- Job 31078 - Morning Glory Phase 2 Subdivision - $134,215 –Installed 6 new poles, string 556 MCM conductor, extend 27.6kV feeder to feed subdivision expansion, install underground primary and secondary conductor, 2 new padmount transformers and make terminations to service 10 lots.

- Job 32400 - Transformer Replacement - $142,468 - this project is the annual program to replace transformers that have been identified as defective or damaged.

- Job 32401 - Transformer Inventory – $331,662 – Chatham-Kent Hydro increased the number of transformers in Inventory as a shortage of core steel increased the delivery time of ordered transformers from 20 weeks to 52 weeks. Chatham-Kent Hydro increased its volumes based on past usage as compared to anticipated usage.

- Job 32500 – Contributed Capital – ($185,136) - Residential - the construction of a new structure for subdivision in the Chatham-Kent Hydro service area. The contribution methodology is set out in the Distribution System Code and the amount is based on the economic evaluation.

- Job 32500 – Contributed Capital – ($28,006) – General Service - the construction of new service for General Service > 50, the contribution methodology set out in the Distribution System Code and the amount is based on the economic evaluation.

- Job 34100 - Tilbury Conversion – $598,011 - continuation of work order from 2004, see Job 33140 for more details.

- Job 34102 – North Chatham Supply Enhancement - $101,648 – this is a continuation of 2006 see Job 34008 for further details.

- Job 34104 - Sub 7 Conversion – $167,065 -Continuation of work order from 2006, see job 34005 for more details.

- Job 35000 - Smart Meter - $2,869,927 – Residential meters – in its Decision in the combined Smart Meter proceeding (EB-2007-0063), the OEB authorized the capitalization of smart meter assets from 2006 to April 2007. The project represented the cost of installing 17,052 meters for residential units.

2008 Actual Capital Jobs

Job	Description	Grand Total	1805 Land	1808 Building	1820 Distribution Station	1830 Poles	1835 O/H conductor & devices	1840 U/G conduit	1845 U/G conductor & Devices	1850 Transformers	1855 Services O/H & U/G	1860 Meters	1860 Smart Meters	1908 Building	1915 Office Furniture	1920 Computer	1925 Software	1930 Fleet	1940 Tools	1980 Scada	1990 AM/FM	3030 Contributed Capital
30301	New Furniture for Systems Engineer	4,103				0	0	0	0	0	0	0			4,103						0	
30311	Spectrum Analyzer	24,735				0	0	0	0	0	0	0							24,735		0	
30312	2 Presses	4,860				0	0	0	0	0	0	0							4,860		0	
30313	ServSavor	4,455				0	0	0	0	0	0	0							4,455		0	
30314	New Cable Locator	4,367				0	0	0	0	0	0	0							4,367		0	
30315	Manhole lift	6,746				0	0	0	0	0	0	0							6,746		0	
30316	Loadbreak tool	4,137				0	0	0	0	0	0	0							4,137		0	
30317	GPS Tracking	3,031				0	0	0	0	0	0	0							3,031		0	
30331	Purchase 2 Laptops John and Chris	6,426				0	0	0	0	0	0	0				6,426					0	
30332	Upgrade CAD software to AutoCad Map 3D	8,176				0	0	0	0	0	0	0					8,176				0	
30333	New Laptop for Admin Assistant and 2 Sub	5,116				0	0	0	0	0	0	0				5,116					0	
30334	Virtual Server Cluster	15,857				0	0	0	0	0	0	0					15,857				0	
30335	Chatham Kent Hydro Website	22,875				0	0	0	0	0	0	0					22,875				0	
30336	UPS Upgrade	10,941				0	0	0	0	0	0	0				10,941					0	
30341	Surveillance System	16,353				0	0	0	0	0	0	0		14,376	1,977						0	
30343	Wireless Gate Opener	6,518				0	0	0	0	0	0	0		3,936			2,583				0	
30344	Office Renovations- new flooring, wiring	36,845				0	0	0	0	0	0	0		23,682	13,163						0	
30345	Fuel Service Chemical Treatment System	5,550				0	0	0	0	0	0	0		5,550							0	
30346	Seal Coat Parking Lot 320 Queen St	7,408				0	0	0	0	0	0	0		7,408							0	
30347	Security Alarm System	9,523				0	0	0	0	0	0	0		9,523							0	
30348	Replace three failed heat pumps	7,285				0	0	0	0	0	0	0		7,285							0	
30350	Building Capital - New Sidewalk 320 Quee	6,327				0	0	0	0	0	0	0		6,327							0	
30360	Rolling Stock 07BK04 New Hydraulics	1,675				0	0	0	0	0	0	0						1,675			0	
30361	Rolling Stock 08PU03	35,715				0	0	0	0	0	0	0						35,715			0	
30362	Rolling Stock 08BK15	130,458				0	0	0	0	0	0	0						130,458			0	
30363	Rolling Stock 07PU150	45,373				0	0	0	0	0	0	0						45,373			0	
30370	SCADA Capital	20,218				0	0	0	0	0	0	0								20,218	0	
30375	AM/FM Capital	72,489				0	0	0	0	0	0	0									72,489	
30380	QMS and ISO Certification	20,176				0	0	0	0	0	0	0					20,176				0	
30385	Outage Management System	93,223				4,668	0	0	0	0	0	0					88,555				0	
30800	System Loss Project - CDM	139,009				0	139,009	0	0	0	0	0									0	
31000	Residential New Services	145,785				2,334	16,689	3,691	20,710	232	102,016	113									0	
31079	Braemar Blvd. Extension	31,371				0	0	0	15,160	2,018	14,194	0									0	
31081	Dale Dr Phase 2 Detached Residential	85,643				0	0	0	63,981	7,528	14,134	0									0	
31082	Morning Glory Ph2 Ext	103,826				0	0	2,383	37,956	28,583	34,904	0									0	
31083	Install U/G St Clair College Residence	38,142				391	7	3,564	19,481	7,427	7,272	0									0	
31084	Caleb Village Senior Residence	59,527				0	0	0	12,631	39,829	7,067	0									0	
31085	Vander Ave. Townhousing Blenheim	17,197				0	0	0	11,026	6,171	0	0									0	

Job Description		Grand Total	1805 Land	1808 Building	1820 Distribution Station	1830 Poles	1835 O/H conductor & devices	1840 U/G conduit	1845 U/G conductor & Devices	1850 Transformers	1855 Services O/H & U/G	1860 Meters	1860 Smart Meters	1908 Building	1915 Office Furniture	1920 Computer	1925 Software	1930 Fleet	1940 Tools	1980 Scada	1990 AM/FM	3030 Contributed Capital
31500	Residential Rebuild	14,103				1,690	6,070	284	0	0	6,059	0										
31510	C & Ind New - 1 & 3 Phases	61,011				782	27,403	0	2,355	2,160	28,078	233										
31567	New Com/Industrial 20 Mill St Tilbury Sh	13,980				0	10,386	0	1,577	2,018	0	0										
31568	New Com/Ind Ecole St Marie 90 Dale Dr	38,584				0	10,327	0	2,753	25,504	0	0									0	
31569	Ambulance Dispatch Centre Wallaceburg	27,838				0	922	0	4,456	19,991	895	0									1,574	
31570	New/Comm Shoppers Drug Mart Talbot St Bl	12,559				0	0	0	0	12,559	0	0									0	
31571	Goodwill Grand Ave W	20,206				2,864	6,162	0	0	11,179	0	0									0	
32000	C & Ind Rbd - 1 & 3 Phase	76,235				4,567	34,774	0	3,927	2,239	15,720	15,009									0	
32078	580 Lowe St., Millenium Building System	16,741				0	5,995	0	0	10,745	0	0									0	
32084	Com/Ind Rebuild 10 Centre St Post Office	59,654				7,096	21,570	0	4,710	26,277	0	0									0	
32085	Comm Rebuild 59 Adelaide St S Chatham	31,063				2,391	17,998	0	0	10,391	284	0									0	
32087	Baseline Pump Wallaceburg	61,897				2,334	10,327	0	11,453	37,783	0	0									0	
32088	King George School	14,542				0	1,308	140	7,967	5,127	0	0									0	
32089	Gil & Sons Ltd 304 Arnold St Wburg	4,025				0	173	0	0	3,852	0	0									0	
32400	Transformer Replacement	134,402				2,334	(24)	0	0	131,518	574	0									0	
32401	Transformer Inventory	(30,582)				0	0	0	0	(30,582)	0	0									0	
32415	PCB Transformer Replacements	46,364				5,219	3,009	0	0	37,961	175	0									0	
32435	Control Room Support Capital	53,195				53,195	0	0	0	0	0	0									0	
32440	Account Cancellation	16,873				396	4,270	0	863	490	10,545	308									0	
32445	OPA/CDM Program	25,584				0	25,584	0	0	0	0	0									0	
32487	St Clair Street Widening	664,471				184,371	271,140	16,470	109,395	56,905	24,904	1,285									0	
32500	Contributed Capital Received	(334,905)				0	0	0	0	0	0	0									0	(334,905)
33504	Demand Meter Replacement	(12,522)				0	0	0	0	0	0	(12,522)									0	
34131	Distribution Automation	3,200				3,200	0	0	0	0	0	0									0	
34170	Operations Support	(1,150)				0	(7,884)	0	6,734	0	0	0									0	
34200	Tilbury Conversion	311,445				26,020	60,922	880	60,081	117,210	38,151	8,181									0	
34202	Load Transfers 476 McNaughton Ave - Pub	19,686				4,650	0	2,644	11,958	433	0	0									0	
34203	Dresden North DS	7,073				0	0	0	0	7,073	0	0									0	
34204	Replace Poles on Park Ave	64,978				46,381	16,513	0	0	862	1,221	0									0	
34205	Reduction of Rabbits	32				32	0	0	0	0	0	0									0	
34206	Dresden Park St- Single Phase Line	166,666				2,309	18,447	40,276	71,536	20,233	13,865	0									0	
34207	Murray St Extension	18,155				9,224	8,381	0	0	330	219	0									0	
34210	Sub 7 Conversion	317,822				4,344	22,989	12,690	143,474	121,824	12,500	0									0	
34211	Insulator Replacement	22,879				7,797	15,082	0	0	0	0	0									0	
34213	M7 Wholesale Meter Repair Carry Over	30,062			30,032	0	0	0	0	0	0	29									0	
34214	St Anthony Primary Cable Replacement	27,100				0	0	6,366	11,364	8,860	509	0									0	
34215	Primary Cable failure Collegiate Dr	19,177				3,019	819	4,341	4,534	0	6,464	0									0	
34216	M5 Cable Repair- Chatham	28,282				0	0	0	28,282	0	0	0									0	
34217	Storm June 8, 2008	52,383				35,390	13,170	0	0	3,823	0	0									0	
34218	M6 Cable Repair River Crossing Wallacebu	10,232				0	104	0	10,129	0	0	0									0	
34219	Blenheim DS Repairs (fire)	6,328				0	6,328	0	0	0	0	0									0	
34220	Dec 28 CK Storm Repairs	13,802				1,002	12,758	0	0	42	0	0									0	
34222	New LIS Switch #47 McFarlene & St Clair	13,894				330	13,564	0	0	0	0	0									0	
34223	LIS Switch 2	15,065				4,091	10,974	0	0	0	0	0									0	
34226	Blenheim/Bothwell WM	58,888			11,597	38,495	8,795	0	0	0	0	0									0	
34227	Pole Replacement	29,847				7,087	22,759	0	0	0	0	0									0	
34228	Capital Pole Replacement - Various Locat	31,073				27,357	3,717	0	0	0	0	0									0	
34229	Capital Pole Replacement Merrit Ave Chat	56,330				20,473	24,615	0	0	2,858	8,384	0									0	
35000	Smart Meter Deployment	1,747,126				0	0	0	0	0	0	0	1,633,216			23,382	90,528				0	
	Grand Total	5,347,149	0	0	41,630	515,834	865,152	93,729	678,494	741,454	348,135	12,637	1,633,216	78,085	19,243	45,865	248,749	213,221	52,331	20,218	74,063	(334,905)

Year 2008 Actual Capital Jobs over materiality

- Job 30362 - Purchase Bucket Truck - $130,458 - 08BK15 - one of the Bucket Trucks was replaced based on the replacement criteria of full depreciation; repair history and manufacturers' guide lines, Chatham-Kent Hydro replacement schedule for service trucks is 7-10 years.

- Job 30385 - Outage Management System – $93,223 – installed a new outage management system and integrating Smart Meter and GIS data as the existing OMS is obsolete and requires replacement.

- Job 30800 - System Loss Reduction - $139,009 – this is part of Chatham-Kent Hydro's approved third tranche conservation and demand management program to upgrade our distribution line to the standard 27.6kV.

- Job 31000 – Residential New Service - $145,785 - overhead service was installed for a new service. The Distribution System Code requires the Local Distribution Company to supply and to install up to 30m of overhead service conductor at its expense to connect a new residential customer. In 2008 the area had 140 New Residential customer connections.

- Job 31081 - Dale Drive - $85,643 - this expenditure involves the servicing of a new 10 lot subdivision extension in the Subdivision. The project includes, extending one phase 16kV, 1/0 aluminium 27.6 KV underground primary cable from an existing switching.

- Job 31082 Morning Glory - $103,826 – continuation of project from 2007, see job 31078 for further details

- Job 32400 - Transformer Replacement - $134,402 - this capital project is the annual program to replace transformers that have been identified as defective or damaged.

- Job 32487 - St. Clair Street widening – $664,471 – this project was to relocate 2 major pole lines for a planned street widening of a major arterial road. The project involved significant pole, line and underground work to accommodate the new road.

- Job 32500 – Contributed Capital – ($181,740) – Residential - the construction of a new structure for subdivisions in the Chatham-Kent Hydro service area. The contribution methodology is set out in the Distribution System Code and the amount is based on the economic evaluation.

- Job 32500 – Contributed Capital ($153,165) – General Service - the construction of new service for General Service > 50, the contribution methodology set out in the distribution system code and the amount is based on the economic evaluation.

- Job 34200 - Tilbury Conversion - $311,445 - continuation of work order from 2004, see job 33140 for more details.

- Job 34206 - Dresden Park ST – Single Phase Line – $166,666 - this project involved converting homes on Fuller St., Livingston Ave., James Cres., John Cres. and Wilson St. from 4kV to 16kV primary, as well as removing back lot overhead primary.

- Job 34210 - Sub 7 Conversion –$317,822 - continued work order from 2006, see job 34005 for more details.

- Job 35000 - Smart Meter installation – $1,747,126 - residential meters – in its Decision from the smart Meter application (EB-2008-0155) OEB has authorized the capitalization of smart meter assets from May 2007 to December 2007. The asset represented the cost of installing 9,852 meters for residential units.

ACCUMULATED DEPRECIATION TABLE

Chatham-Kent Hydro has provided 2004 to 2010 Accumulated Depreciation in Table 2-14. The table also provides the variance between the consecutive year.

Table 2-14
Accumulated Depreciation

Description	2006 Board Approved ($)	2006 Actual ($)	from 2006 Board	2007 Actual ($)	Variance from 2006 Actual	2008 Actual ($)	Variance from 2007 Actual	2009 Bridge ($)	Variance from 2008 Actual	2010 Test ($)	Variance from 2009 Bridge
Land and Buildings											
1805-Land											
1806-Land Rights											
1808-Buildings and Fixtures	86,515	113,820	27,305	110,512	(3,308)	125,325	14,813	138,916	13,591	155,107	16,191
1905-Land											
1906-Land Rights											
1810-Leasehold Improvements											
Sub-Total-Land and Buildings	86,515	113,820	27,305	110,512	(3,308)	125,325	14,813	138,916	13,591	155,107	16,191
DS											
1820-Distribution Station Equipment - Normally Primary below 50 kV	57,577	124,235	66,658	157,746	33,511	193,281	35,535	228,816	35,536	267,371	38,555
Sub-Total-DS	57,577	124,235	66,658	157,746	33,511	193,281	35,535	228,816	35,536	267,371	38,555
Poles and Wires											
1830-Poles, Towers and Fixtures	192,310	451,995	259,685	600,467	148,472	769,572	169,106	959,450	189,877	1,172,705	213,255
1835-Overhead Conductors and Devices	2,871,343	4,987,009	2,115,666	5,863,324	876,315	6,764,030	900,706	7,679,647	915,617	8,606,924	927,277
1840-Underground Conduit	64,700	153,662	88,962	198,082	44,420	246,252	48,170	297,391	51,139	358,187	60,796
1845-Underground Conductors and Devices	2,538,472	4,372,625	1,834,153	5,141,566	768,942	5,937,648	796,081	6,756,356	818,708	7,608,638	852,282
Sub-Total-Poles and Wires	5,666,825	9,965,290	4,298,465	11,803,440	1,838,150	13,717,502	1,914,063	15,692,844	1,975,341	17,746,454	2,053,610
Line Transformers											
1850-Line Transformers	2,083,361	3,587,154	1,503,793	4,249,473	662,319	4,941,260	691,787	5,673,862	732,602	6,442,845	768,983
Sub-Total-Line Transformers	2,083,361	3,587,154	1,503,793	4,249,473	662,319	4,941,260	691,787	5,673,862	732,602	6,442,845	768,983
Services and Meters											
1855-Services	183,138	407,309	224,171	527,565	120,256	661,747	134,182	811,966	150,219	979,135	167,168
1860-Meters	533,045	879,821	346,776	946,916	67,095	1,086,522	139,606	1,227,297	140,776	1,369,267	141,970
1861-Smart Meters				204,551	204,551	539,712	335,161	915,499	375,787	1,247,424	331,925
Sub-Total-Services and Meters	716,183	1,287,130	570,947	1,679,032	391,903	2,287,981	608,949	2,954,763	666,782	3,595,826	641,063
General Plant											
1908-Buildings and Fixtures	265,581	480,232	214,651	572,227	91,995	671,841	99,613	782,770	110,929	904,299	121,529
1910-Leasehold Improvements											
Sub-Total-General Plant	265,581	480,232	214,651	572,227	91,995	671,841	99,613	782,770	110,929	904,299	121,529
IT Assets											
1920-Computer Equipment - Hardware	203,528	280,165	76,637	291,588	11,423	297,273	5,685	298,067	794	298,067	
1921-Computer Equipment		13,422	13,422	24,489	11,066	35,555	11,066	45,409	9,854	52,531	7,122
1921-Computer Equipment - Hardware post March 22, 2005				19,379	19,379	53,433	34,054	65,083	11,651	88,634	23,551
1925-Computer Software		3,433	3,433	74,751	71,318	177,563	102,812	244,350	66,787	323,638	79,287
Sub-Total-IT Assets	203,528	297,020	93,492	410,206	113,186	563,824	153,617	652,909	89,086	762,869	109,960
Equipment											
1915-Office Furniture and Equipment	35,383	57,684	22,301	65,760	8,076	75,823	10,063	87,321	11,499	96,793	9,472
1930-Transportation Equipment	812,881	1,227,177	414,296	1,382,401	155,224	1,560,960	178,559	1,806,008	245,048	2,109,924	303,916
1935-Stores Equipment											
1940-Tools, Shop and Garage Equipment	286,198	437,724	151,526	472,449	34,725	498,094	25,645	526,284	28,190	567,369	41,085
1945-Measurement and Testing Equipment											
Sub-Total-Equipment	1,134,462	1,722,585	588,123	1,920,610	198,024	2,134,877	214,267	2,419,614	284,737	2,774,087	354,473
Other Distribution Assets											
1825-Storage Battery Equipment											
1980-System Supervisory Equipment	261,494	440,720	179,226	494,844	54,124	547,406	52,562	602,429	55,023	649,759	47,330
1990-Other Tangible Property	332,989	620,955	287,966	761,280	140,325	906,542	145,262	1,056,867	150,325	1,202,589	145,722
1995-Contributions and Grants - Credit	(263,437)	(550,545)	(287,108)	(693,287)	(142,742)	(849,424)	(156,138)	(1,016,562)	(167,138)	(1,194,700)	(178,138)
Sub-Total-Other Distribution Assets	331,046	511,131	180,085	562,838	51,707	604,524	41,686	642,734	38,210	657,648	14,914
ACCUMULATED DEPRECIATION TOTAL	10,545,078	18,088,598	7,543,520	21,466,084	3,377,486	25,240,414	3,774,330	29,187,227	3,946,813	33,306,505	4,119,278

VARIANCE ANALYSIS ON ACCUMULATED DEPRECIATION:

Changes in accumulated depreciation are directly affected by changes in fixed assets due to additions, the removal of fully depreciated assets from the grouped asset classes, and the disposition of identifiable assets.

Materiality Analysis on Accumulated Depreciation

Materiality thresholds for rate base-related costs and expenditures being 0.5 percent of revenue requirement are set out in Table 2-15.

Table 2-15
Materiality Threshold

Description	2006 OEB Approved	2006 Actual	2007 Actual Year	2008 Actual Year	2009 Bridge Year	2010 Test Year
Rate Base	$50,309,522	$51,813,558	$54,003,463	$55,634,596	$55,490,686	$56,073,568
Cost Capital	8.02%	8.02%	8.02%	7.95%	7.89%	7.52%
Return on Rate Base	$4,034,824	$4,155,447	$4,331,078	$4,425,583	$4,377,809	$4,219,200
Distribution Expense	$8,723,462	$8,107,926	$8,594,813	$9,274,947	$9,527,916	$10,618,473
PILS	$1,572,932	$1,349,735	$1,405,223	$1,207,671	$1,096,204	$987,663
Revenue Requirement	$14,331,218	$13,613,108	$14,331,114	$14,908,201	$15,001,929	$15,825,336
Materiality Cal .5%	$71,656	$68,066	$71,656	$74,541	$75,010	$79,127

The Gross Asset Variance analysis for those variances highlighted in Table 2-14 is provided as follows.

The 2006 Board Approved closing balance for accumulated depreciation is based on Chatham-Kent Hydro's 2004 year end adjusted account balances. As such, the variance between 2006 Board Approved and 2006 Actual represents two years of depreciation charges, adjustments, and disposals. Chatham-Kent Hydro has a variance analysis threshold for changes in accumulated depreciation of $79,127. The following Table 2-16 outlines the OEB accounts which exceed the variance in each year.

Table 2-16
Changes in Accumulated Depreciation Exceeding Materiality Threshold by Year

	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual
1830-Poles, Towers and Fixtures	259,685	148,472	169,106	189,877	213,255
1835-Overhead Conductors and Devices	2,115,666	876,315	900,706	915,617	927,277
1840-Underground Conduit	88,962				
1845-Underground Conductors and Devices	1,834,153	768,942	796,081	818,708	852,282
1850-Line Transformers	1,503,793	662,319	691,787	732,602	768,983
1855-Services	224,171	120,256	134,182	150,219	167,168
1860-Meters	346,776		139,606	140,776	141,970
1861-Smart Meters		204,551	335,161	375,787	331,925
1908-Buildings and Fixtures	214,651	91,995	99,613	110,929	121,529
1925-Computer Software			102,812		79,287
1930-Transportation Equipment	414,296	155,224	178,559	245,048	303,916
1940-Tools, Shop and Garage Equipment	151,526				
1980-System Supervisory Equipment	179,226				
1990-Other Tangible Property	287,966	140,325	145,262	150,325	145,722

From 2006 Actual to the 2010 Test Year the above table shows the change in accumulated depreciation, which is a representation of the depreciation expense in the year for each of the above accounts. The change in accumulated depreciation is a result of capital expenditures over a four year period. Since a detailed analysis of capital expenditures has been provided in this Exhibit no further explanation of the changes in accumulated depreciation amounts is required.

CAPITAL BUDGET:

Introduction

Chatham-Kent Hydro, on an annual basis, as part of the complete budgeting process, will budget for various capital programs. The capital budget process will take a longer term view as it looks out 5 years. The capital program is approved by the President, CFO and CEO for submission to the Board of Directors for final approval.

Some of the objectives in selecting the programs during the capital process are;

- Total capital expenditures will be approximately the same level of depreciation
- Meet the connection requirements from all customer classes
- Capital projects will meet the short term and long term service quality targets
- Ensure that the distribution system is safe for the public, customers and the employees

The capital program is set for the upcoming year and is not changed. If a significant unbudgeted item becomes a priority Board approval must be sought prior to the expenditure the only exception is if the situation is an emergency. The capital program is reviewed on a monthly basis and any large variances are reported.

Capital Plan and Budget by Project:

Chatham-Kent Hydro annually presents a 4 year capital plan to the Board of Directors. During the course of the year emergencies may cause a variation to the approved budget. In the event of unforeseeable circumstances such as a storm or failure of critical portion of the distribution system, specific projects for the year will be adjusted to incorporate the emergency which may delay a pre plan project. The most recent four year capital plan for the years 2009 to 2012 is provided in Table 2-17.

The planning of projects has been divided into eight main categories:

- Customer Demand
- Renewal
- Security and Sustainment
- Capacity
- Regulatory Requirements
- Substations
- General Equipment

Table 2-17
Capital Budget Plan

Demand	**2009**	**2010**	**2011**	**2012**
Residential New	200,755	254,128	158,175	163,988
Detached Residential	245,486	191,488	189,675	205,540
Commerical Industrial New	149,521	205,285	171,427	177,439
Account Cancellation	6,090	6,181	6,274	6,368
Sub-total Demand	601,852	657,082	525,551	553,335
Contributed Capital	(275,000)	(275,000)	(275,000)	(275,000)
Total Demand	326,852	382,082	250,551	278,335

Renewals	**2009**	**2010**	**2011**	**2012**
Residential Rebuilds	30,780	47,757	25,255	25,633
Commerical & Industrial Rebuild	175,580	202,394	172,429	178,456
Pole Replacement	126,347	131,367	138,500	142,518
Transformer Replacement	168,985	172,531	148,501	152,519
Ridgetown PCB Transformer Replace	75,000			
Insulator Replacement	35,279	41,049	30,000	30,000
Retail Meter Replacement	30,010	30,471	29,650	30,095
Primary Cable Replacement Program	100,000	119,816	138,500	142,518
Low Voltage vault repairs		104,318		
Parry St.- backyard removal	43,232			
Emergencies	81,769	75,000	75,000	75,000
Outage Management System	130,000			
Thamesville DS Rebuild			68,500	
Sub-Total Renewals	996,982	924,703	826,335	776,739

Security and Sustainment	**2009**	**2010**	**2011**	**2012**
LIS switches(3 switches)	62,166	71,049	81,000	60,000
Asset Management and System Optimization P	-	311,049	159,500	143,000
Sub-Total Security and Sustainment	62,166	382,098	240,500	203,000

Capacity	**2009**	**2010**	**2011**	**2012**
Reduction of Step Down Transformer		104,619	138,500	242,518
Submarine Cable Replacement		206,938		
Downtown Chatham		247,557	259,500	385,035
M5 Submarine cable refurbishment	319,010	100,000		192,518
Sub 7/9 Conversion	574,739	307,930		
Capital Expansion Requests	50,000	50,750	69,011	52,284
Sub-total Capacity	943,749	1,017,794	467,011	872,355

Regulatory Requirement	**2009**	**2010**	**2011**	**2012**
Load Transfers	412,936			142,518
Asset Management	50,000			
	462,936	-	-	142,518

Substations	**2009**	**2010**	**2011**	**2012**
Substation 6 Conversion		347,930	338,500	364,018
Substation 8 Conversion	50,000			
Dresden Conversion	384,653	486,635	438,500	
Voltage sustainment			113,500	
Wheatley Conversion/Step Down Removal			338,500	
Blenheim Conversion				485,035
Sub-Total Substations	434,653	834,565	1,229,000	849,053

General Equipment	**2009**	**2010**	**2011**	**2012**
Rolling Stock	362,593	780,000	276,000	423,500
Computers	63,000	56,000	50,000	50,000
Office Furniture	7,500	12,000	12,000	5,000
Control Room Support	60,000	118,449	109,011	132,146
SCADA Capital	40,000	51,049	40,000	40,000
AM/FM	76,460	91,790	123,500	153,535
Small tools	47,000	99,000	49,500	53,500
Customer disconnect Switches		200,000	50,000	50,000
Building Upgrades	73,500	28,000	57,000	21,000
Fuel Tanks	40,000			
Land	200,000	25,000	75,000	
Repave Lot	25,000	350,000		
Storage Facility		50,000		
Secured Storage Building		100,000		
Substations Repairs		15,000		
Roofing				100,000
Replace AMI computer/controller				80,000
Sub-total General Equipment	995,053	1,976,288	842,011	1,108,681

Total Capital	4,222,391	5,517,530	3,855,408	4,230,681

Chatham-Kent Hydro's Capital Budget Plan in Table 2-17 is provided in USoA Format in Table 2-18 and 2-19 for 2009 and 2010 respectively.

The detailed project plan for each project for 2009 and 2010 follows.

Table 2-18
2009 Capitol Budget
USoA Format

Job Description	Grand Total	1805 Land	1808 Building	1820 Distribution Station	1830 Poles	1835 O/H conductor & devices	1840 U/G conduit	1845 U/G conductor & Devices	1850 Transformers	1855 Services O/H & U/G	1860 Meters	1860 Smart Meters	1905 Land	1908 Building Fixtures	1915 Office Furniture	1920 Computer	1925 Software	1930 Fleet	1940 Tools	1980 Scada	1990 AM/FM	3030 Contributed Capital
Residential New Service	200,755				0	11,542	3,531	11,794	339	173,496	52										**0**	
Detached Residential	245,486				229	10,562	3,481	107,340	54,272	69,603	0										**0**	
Comm/Industrial New	149,521				6,422	30,961	0	13,417	74,952	23,499	271										**0**	
Account Cancellation	6,090				143	0	1,541	0	312	177	3,806										**111**	
Contributed Capital	(275,000)				0	0	0	0	0	0	0										**0**	(275,000)
Residential Rebuild	30,780				4,018	11,684	674	0	0	14,404	0										**0**	
Comm/Industrial Rebuild	175,580				7,416	56,346	97	26,657	68,380	6,218	10,464										**0**	
Pole Replacement	126,347				75,720	37,532	0	0	3,550	9,545	0										**0**	
Transformer Replacement	168,985				2,166	(44)	0	0	165,826	1,038	0										**0**	
Ridgetown PCB Transformer replacement	75,000				2,156	0	4,395	10,600	33,877	23,972	0										**0**	
Insulator Replacement	35,279				10,224	25,055	0	0	0	0	0										**0**	
Retail Meter Replacement	30,010				4,088	2,357	0	0	23,417	137	10										**0**	
Primary Cable Replacement Program	100,000				0	0	5,510	43,348	51,142	0	0										**0**	
Parry St - Backyard removal	43,232				0	0	0	24,288	18,944	0	0										**0**	
Emergencies	81,769				18,461	4,074	5,191	29,954	6,149	3,381	14,560										**0**	
Outage Management Software	130,000				0	0	0	0	0	0	0						130,000				**0**	
LIS Switches	62,166				19,307	42,859	0	0	0	0	0										**0**	
Capital Expansion Requests	50,000				15,502	17,332	1,459	8,975	5,040	1,580	114										**0**	
M5 Extension to supply CKHA Chatham	319,010				105,996	164,690	0	20,159	28,165	0	0										**0**	
Sub7/9 Conversion	574,739				13,081	81,052	30,906	211,600	224,659	13,440	0										**0**	
Load Transfers	412,936				45,430	193,621	12,429	31,032	87,728	42,696	0										**0**	
Asset Mangement Development	50,000				10,000	10,000	5,000	10,000	10,000	5,000	0										**0**	
Sub 8 Conversion	50,000				14,685	5,000	0	0	30,315	0	0										**0**	
Dresden Conversion	384,653				104,252	151,030	0	16,464	100,163	12,744	0										**0**	
Purchase New Vehicle	362,593				0	0	0	0	593	0	0							362,000			**0**	
Computer upgrades	63,000				0	0	0	0	0	0	0					63,000					**0**	
Office Furniture	7,500				0	0	0	0	0	0	0				7,500						**0**	
Control Room Support Capital	60,000				60,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Upgrades to Scada System	40,000				0	0	0	0	0	0	0									40,000	**0**	
Upgrades to AM/FM	76,460				0	0	0	0	0	0	0										**76,460**	
Small Tools	47,000				0	0	0	0	0	0	0								47,000		**0**	
Building Upgrades	73,500				0	0	0	0	0	0	0			73,500							**0**	
Fuel Tanks	40,000				0	0	0	0	0	0	0			40,000							**0**	
CN Land	200,000				0	0	0	0	0	0	0		200,000								**0**	
Driveway Upgrades	25,000				0	0	0	0	0	0	0			25,000							**0**	
Grand Totals	4,222,390	0	0	0	519,294	855,653	74,215	565,628	987,823	400,929	29,278	0	200,000	138,500	7,500	63,000	130,000	362,000	47,000	40,000	76,572	(275,000)

Table 2-19
2010 Capitol Budget Plan
USoA Format

Job Description	Grand Total	1805 Land	1808 Building	1820 Distribution Station	1830 Poles	1835 O/H conductor & devices	1840 U/G conduit	1845 U/G conductor & Devices	1850 Transformers	1855 Services O/H & U/G	1860 Meters	1860 Smart Meters	1905 Land	1908 Building Fixtures	1915 Office Furniture	1920 Computer	1925 Software	1930 Fleet	1940 Tools	1980 Scada	1990 AM/FM	3030 Contributed Capital
Residential New Service	254,128	0	0	0	2,198	50,554	626	21,946	2,503	176,098	53	0	0	0	0	0	0	0	0	0	148	0
Detached Residential	191,488	0	0	0	4,628	4	5,834	95,479	54,526	30,719	0	0	0	0	0	0	0	0	0	0	296	0
Comm/Industrial New	205,285	0	0	0	8,366	47,940	329	22,109	75,796	50,469	275	0	0	0	0	0	0	0	0	0	0	0
Account Cancellation	6,181	0	0	0	145	0	1,564	0	316	180	3,863	0	0	0	0	0	0	0	0	0	113	0
Contributed Capital	(275,000)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(275,000)
Residential Rebuild	47,757	0	0	0	4,078	28,374	684	0	0	14,620	0	0	0	0	0	0	0	0	0	0	0	0
Comm/Industrial Rebuild	202,394	0	0	0	11,574	68,122	428	34,063	71,285	6,312	10,610	0	0	0	0	0	0	0	0	0	0	0
Pole Replacement	131,367	0	0	0	73,006	32,253	0	0	3,254	22,854	0	0	0	0	0	0	0	0	0	0	0	0
Transformer Replacement	172,531	0	0	0	0	(45)	0	0	171,523	1,053	0	0	0	0	0	0	0	0	0	0	0	0
Insulator Replacement	41,049	0	0	0	10,224	30,826	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retail Meter Replacement	30,471	0	0	0	4,150	2,393	0	0	23,768	140	21	0	0	0	0	0	0	0	0	0	0	0
Primary Cable Replacement Program	119,816	0	0	0	0	0	5,510	63,164	51,142	0	0	0	0	0	0	0	0	0	0	0	0	0
Low Voltage vault repairs	104,318	0	0	0	0	0	0	50,000	4,318	50,000	0	0	0	0	0	0	0	0	0	0	0	0
Emergencies	75,000	0	0	0	18,461	4,074	5,191	23,185	6,149	3,381	14,560	0	0	0	0	0	0	0	0	0	0	0
LIS Switches	71,049	0	0	0	17,141	53,908	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Capital Expansion Requests	50,750	0	0	0	15,734	17,592	1,481	9,109	5,115	1,603	116	0	0	0	0	0	0	0	0	0	0	0
Asset Management and System Optimization	311,049	0	0	100,000	100,000	11,049	0	0	100,000	0	0	0	0	0	0	0	0	0	0	0	0	0
Reduction of Step Down Transformers	104,619	0	0	0	33,077	30,692	0	0	36,602	4,248	0	0	0	0	0	0	0	0	0	0	0	0
Submarine Cable Replacement	206,938	0	0	0	0	0	100,000	106,938	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Downtown Chatham	247,557	0	0	0	4,396	27,123	81,330	72,654	35,762	26,218	0	0	0	0	0	0	0	0	0	0	74	0
M5 Submarine Cable Replacement	100,000	0	0	0	0	0	0	100,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sub 7/9 Conversion	307,930	0	0	0	9,053	36,840	17,857	109,288	127,053	7,765	0	0	0	0	0	0	0	0	0	0	74	0
Sub 6 Conversion	347,930	0	0	0	9,769	38,335	20,604	123,966	146,221	8,960	0	0	0	0	0	0	0	0	0	0	74	0
Dresden Conversion (South)	486,635	0	0	0	151,045	165,235	0	6,938	144,227	19,115	0	0	0	0	0	0	0	0	0	0	74	0
New Truck Purchases (2)	780,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	780,000	0	0	0	0
Computer upgrades	56,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	56,000	0	0	0	0	0	0
Office Furniture	12,000	0	0	0	0	0	0	0	0	0	0	0	0	0	12,000	0	0	0	0	0	0	0
Control Room Support Capital	118,449	0	0	0	107,400	11,049	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Upgrades to Scada System	51,049	0	0	0	0	11,049	0	0	0	0	0	0	0	0	0	0	0	0	0	40,000	0	0
Upgrades to AM/FM	91,790	0	0	0	0	11,049	0	0	0	0	0	0	0	0	0	0	0	0	0	0	80,741	0
Small Tools	99,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	99,000	0	0	0
Customer Switches	200,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	200,000	0	0	0
Building Upgrades	28,000	0	0	0	0	0	0	0	0	0	0	0	0	28,000	0	0	0	0	0	0	0	0
Land - upkeep	25,000	0	0	0	0	0	0	0	0	0	0	0	25,000	0	0	0	0	0	0	0	0	0
Repave Parking Lot	350,000	0	0	0	0	0	0	0	0	0	0	0	0	350,000	0	0	0	0	0	0	0	0
Environmental Storage Building	50,000	0	50,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Secured Storage Building	100,000	0	0	0	0	0	0	0	0	0	0	0	0	100,000	0	0	0	0	0	0	0	0
Substation Repairs	15,000	0	15,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Grand Total	5,517,531	0	65,000	100,000	584,444	678,418	241,438	838,840	1,059,560	423,737	29,499	0	25,000	478,000	12,000	56,000	0	780,000	299,000	40,000	81,595	(275,000)

Customer Demand

The projects are concentrated on providing the distribution system with the capabilities to handle the load increases as Chatham-Kent Hydro customer base grows within the service area. One of the important steps that Chatham-Kent Hydro conducts during the system planning is to review the status of the distribution system through line patrols, SCADA system and various annual maintenance programs. Through this information and knowledge, training and experience, system planning can specifically identify issues and areas of concern. The planning of projects are conduct on priority, that would provide a more secure and reliable distribution system.

Information on the residential load growth in the Chatham-Kent service area is gathered through the subdivision developers, and the Municipal Economic Development department. Through these meetings the area of growth would be a contributing factor in developing the areas distribution lines. From this information a subdivision plan is developed by the engineering department.

The Customer Demand projects include:

- Residential New
- Detached Residential
- Commercial/Industrial New
- Account Cancellations

Chatham-Kent Hydro has provided the project plans for 2009 and 2010 based on the above criteria.

Chatham-Kent Hydro Budgeted Project

Type of Project:	Residential New
Project Name:	Various

Purpose:

The purpose of this project is to connect new residential customers to Chatham-Kent Hydro's Distribution System.

Summary:

Chatham-Kent Hydro has 28,684 customers in the Residential rate category.
The Distributions System Code requires the Local Distribution Company to supply and to install up to 30m of overhead service conductor at its expense to connect a new residential customer. For customers requiring service beyond this, the material cost only is passed onto the customer and is deposited into a Chatham-Kent Hydro contributed capital account.
This budget item is used to supply and install all material required to make new residential customer connections.
Types of new customer connections are; new homes in a new subdivision, infill in a mature residential subdivision or an additional meter at an existing location.
The following chart illustrates the trend for new Residential connections to the Chatham-Kent Hydro distribution system.

Year	Connections
2004	138
2005	219
2006	155
2007	143
2008	140

It is expected that this trend will continue for the next four years.

Impact:

- Meet customer requests for connections
- Satisfy Distribution System Code
- Increase system load

Estimated Annual Expenditures

Cost	2009	2010	2011	2012
Budgeted Capital Cost	200,755	254,128	158,175	163,988

Chatham-Kent Hydro Budgeted Project

Type of Project:	Detached Residential
Project Name:	Various

Purpose:

The purpose of this project is to disconnect any new Residential Development within Chatham-Kent Hydro Service territory. This would include Residential Subdivisions or Townhouse Development.

Summary:

Each year Chatham-Kent Hydro connects new subdivisions and townhouse units to the distribution system that have been developed by third parties. On an average Chatham-Kent Hydro connects four of these developments each year.
Prior to commencing any work on the subdivision, an Offer to Connect is created for the developer, outlining costs and responsibilities. Chatham-Kent Hydro will submit a bid for installation of the subdivision distribution system; the developer may also obtain an alternate bid for any non-disputed work.
The cost to install the distribution system within the subdivision is drawn from this budget.
For customers that require expansion to the distribution system in order to connect the development, this cost is also drawn from this budget. The developers capital contributions will be rebated yearly for five years or until the development is full. Rebates are determined using an Economic Evaluation Model contingent on the number of connections.
The number of new developments is expected to be similar to 2008 and for the next four years; this will justify the required budget amount for this project.

The following table shows the yearly connection trend for the previous five years:

Year	Possible Connections
2004	233
2005	199
2006	46
2007	44
2008	71

Impact:

- Connect new Residential Developments
- Rebate developers of Residential System Expansions as customers are added
- Meeting requirements of Distribution System Code

Estimated Annual Expenditures

Cost	2009	2010	2011	2012
Budgeted Capital Cost	245,486	191,488	189,075	205,540

Chatham-Kent Hydro Budgeted Project

Type of Project:	New Commercial/ Industrial customers
Project Name:	Various locations

Purpose:

The purpose of this project is to connect new commercial/industrial customers to Chatham-Kent Hydro's Distribution System and fund any system expansions required to make these connections.

Summary:

Chatham-Kent Hydro has 3,656 customers in the Commercial/Industrial Rate category.
A new Commercial/Industrial customer is any customer that is not considered residential and generates a new account number. These customer connections range from installing a new electric meter to installation a new pole line or pad mount transformer.
An Economic Evaluation Model is used to calculate the required Capital Contribution required by new customer. This is depended on the amount of new load to be connected to the distribution system; as directed by the Distribution System Code.

The following chart illustrates the trend for new Commercial/Industrial connections on the Chatham-Kent Hydro Distribution System. It is expected that this trend will continue for the next four years.

Year	Connections
2004	30
2005	39
2006	60
2007	26
2008	30

Impact:

- Meet customer requests for connections
- Satisfy Distribution System Code
- Increase system load

Estimated Annual Expenditures

Cost	2009	2010	2011	2012
Budgeted Capital Cost	149,521	205,285	171,427	177,439

Chatham-Kent Hydro Budgeted Project

Type of Project:	Customer Maintenance
Project Name:	Account Cancellation

Purpose:

The purpose of this project is to disconnect or cancel a customer.

Summary:

Chatham-Kent Hydro has 32,340 active customers. Throughout the year approximately 40 general service and 60 residential customers request account cancelation. This may require the entire electric service to their property to be removed or only the electric meter.

These removals may be due to;

- Building being demolished
- Meters being combined to one
- Business closures

Chatham-Kent Hydro is obligated to perform these customer requests.

Impact:

- Reduction of total customers
- Reduction of total load
- Comply with customer requests

Estimated Annual Expenditures

Cost	2009	2010	2011	2012
Budgeted Capital Cost	6,090	6,181	6,274	6,368

Renewal

The SCADA and Outage Management system information is available to assist with identifying the required improvements to the system. The system is able to track the power failures, the occurrences and the duration of the outages. Through this information the areas of concern can be identified and evaluated. Depending on the conditions of the equipment and the information from the SCADA system it will assist in asset management plan. Chatham-Kent Hydro has designed several annual capital programs, and further descriptions are provided in the Asset Management Plan.

The system renewal involves:

- Residential Rebuilds
- Commercial/Industrial Rebuilds
- Pole Replacements
- Transformer Replacements
- Faulted cable and vault repairs and replacement
- Emergencies

Chatham-Kent Hydro has provided the project plan for 2009 and 2010 based on the above criteria.

Chatham-Kent Hydro Budgeted Project

Type of Project:	Residential Rebuild
Project Name:	Various

Purpose:

The purpose of this project is to perform any minor rebuilds to service conductor or secondary buss that supply Chatham-Kent Hydro residential customers.

Summary:

Chatham-Kent Hydro has 28,684 customers in the Residential rate category.
Each year it is necessary to rebuild small sections of the distribution system that supply these customers, mainly due to customer service upgrades. This budget item is not intended for major rebuilds, these would be completed under other specific capital projects.

Examples of the Residential Rebuilds that would be completed under this budget are;

- Increase service conductor size
- Convert service conductor from overhead to underground
- Replace overhead secondary bus from open conductor to triplex
- Increase overhead secondary bus size

Impact:

- Respond to residential customer requests
- Replace sections of Distribution System at end of life

Estimated Annual Expenditures

Cost	2009	2010	2011	2012
Budgeted Capital Cost	30,780	47,757	25,255	25,633

Chatham-Kent Hydro Budgeted Project

Type of Project:	Rebuild Commercial/ Industrial customers
Project Name:	Various

Purpose:

The purpose of this project is to provide upgrades to Chatham-Kent Hydro's Distributions System when necessary to continue to supply Commercial and Industrial customers.

Summary:

Chatham-Kent Hydro has 3,656 customers in the Commercial and Industrial rate category. Throughout the year a number of these customers require upgrades to Chatham-Kent Hydro's Distribution System due to increased electrical load at their facilities. These rebuilds normally consist of primary pole line extensions, underground cable installation, and transformer upgrades. The cost to rebuild the Distribution System to supply this increased load is drawn from this budget.

A customer capital contribution is calculated using an Economic Evaluation Model; the customer contribution is contingent on the amount of new load the customer is adding.
The following table outlines the trend of Commercial / Industrial rebuilds to the Chatham-Kent Hydro distribution system.

Year	Rebuilds
2004	60
2005	52
2006	60
2007	43
2008	37

This trend is expected to continue for the next four years.

Impact:

- Meet customer requests for system rebuild
- Satisfy Distribution System Code Increase system load
- Increase system load

Estimated Annual Expenditures

Cost	2009	2010	2011	2012
Budgeted Capital Cost	175,500	202,394	172,429	178,456

Chatham-Kent Hydro Budgeted Project

Type of Project:	Capital Pole Replacements
Project Name:	Various

Purpose:

The purpose of this project is to ensure that substandard & defective wood poles throughout Chatham-Kent Hydro Distribution System are identified and replaced on an annual basis.

Summary:

The Chatham-Kent Hydro Distribution System includes over 13,420 wooden poles with approximately 570 km of overhead primary and 825 km of overhead secondary attached.

Chatham-Kent Hydro has an annual maintenance program where approximately 35 poles are replaced, throughout Chatham Kent Hydro Distribution System. These poles are not part of any larger specific capital project. These locations are determined through formal system surveys as well as through trouble calls and staff observations.

Not replacing these poles would put the distribution system at risk of failure, leaving a public and employee safety hazard and ultimately leading to poor system reliability.

Impact:

- Replace poles that are at end of life
- Reduce the risk of public safety
- Increase system reliability

Estimated Annual Expenditures

Cost	2009	2010	2011	2012
Budgeted Capital Cost	126,347	131,367	138,500	142,518

Chatham-Kent Hydro Budgeted Project

Type of Project:	Transformer Replacements
Project Name:	Various Locations

Purpose:

The purpose of this project is to replace degenerated or overloaded transformers that have been identified during formal and informal inspection programs throughout the year.

Summary:

This project is an annual maintenance program that allows for spot replacements of transformers that are not part of a specific capital project.

During Infrared Inspections, PCB sampling and trouble calls, a number of transformers are identified as having poor connections, leaking, are overloaded, have high PCB content, or they fail prematurely. It is necessary to replace these overhead and pad mount transformers.

This project normally allows for the replacement of approximately 33 overhead and 6 pad mount transformers at various locations throughout Chatham-Kent Hydro's Distribution System.

Impact:

- Replace high PCB content transformer, meeting Ministry of Environment regulations
- Replace leaking or damaged transformers
- Replace overloaded transformers
- Increase system reliability

Estimated Annual Expenditures

Cost	2009	2010	2011	2012
Budgeted Capital Cost	168,985	172,531	148,501	152,519

Chatham-Kent Hydro Budgeted Project

Type of Project:	Transformer Replacement – PCB
Project Name:	Ridgetown – 25 West St.

Purpose:

The purpose of this project is to replace a three phase pole mount transformer bank that has a PCB content of greater than 50 parts per million, as well as correct a public safety concern.

Summary:

There is a bank of pole mount transformers at 25 West St, Ridgetown that is supplied by a 2.4/4.16KV to 277/480V located on the ground, protected by an inadequate station fence with exposed primary conductor, causing a major public safety hazard.
This transformer bank will be replaced with a new 2.4/4.16KV to 347/600V pole mount transformer bank. This is a common secondary voltage, 277/480V is not a secondary voltage supported by Chatham-Kent Hydro, and not a stocked transformer.

The secondary conductors will be replaced to meet Electrical Safety Code requirements.

The customer's service entrance equipment will be reworked to accommodate this secondary voltage, adding dry type step down transformers where required.

Impact:

- Eliminate public safety hazard
- Increase system reliability
- Remove transformer with PCB above Ministry of Environment specifications
- Reduce transformer stock

Estimated Annual Expenditures

Cost	2009	2010	2011	2012
Budgeted Capital Cost	75,000			

Chatham-Kent Hydro Budgeted Project

Type of Project:	Overhead Distribution Upgrades
Project Name:	Insulator Replacement

Purpose:

The purpose of this project is to replace porcelain post top insulators that have been targeted as being susceptible to breaking prematurely with new polymer insulators. Not preceding with this program will leave known substandard equipment in the field jeopardizing reliability and safety to customers and employees.

Summary:

Porcelain insulators are exposed to thermal and mechanical stress, chemical contamination and extreme weather conditions that have detrimental effects on this type of equipment.
The purpose of the insulator is to support the high voltage conductor on the pole while insulating it from other phases and ground. When porcelain insulators fail, the attached conductor falls leaving it suspended from adjacent insulators. The possibility of contact with public or staff is a great concern as well as contact to other conductors causing other LDC or customer equipment damage.
The program of replacing porcelain post top insulators of specifically EPAC types, prone to early failure ,will continue on an annual basis until these have been totally removed from the system.

Each year it is planned to replace approximately 150 porcelain insulators with new polymer type.

Any equipment replacement is an annual program needed to replace equipment that reaches end of life or becomes inoperable.

Impact:

- Reduce the risk of public and employee safety
- Increase system reliability
- Reduce risk of further equipment damage

Estimated Annual Expenditures

Cost	2009	2010	2011	2012
Budgeted Capital Cost	35,279	41,049	30,000	30,000

Chatham-Kent Hydro Budgeted Project

Type of Project:	Meter Replacement
Project Name:	Retail Meter Replacement

Purpose:

The purpose of this project is to replace retail electric meters that have reached end of life, have failed, or seals have expired in compliance with Measurement Canada requirements.

Summary:

Chatham-Kent Hydro has 32,340 retail electric meters in the system used to measure customers' kilowatt hour consumption and monthly demand.

Since 2004 Chatham-Kent Hydro has actively deploying its' Smart Meter system. Presently there are 290 outstanding meters to change to Smart Meters in the Residential Category. The General Service Rate Categories are now being focused on, and the General Service <50kW category is being targeted for completion in 2009.

This budget item is used for replacement of retail electric meters that are out of the scope of the Smart Meter System. Reasons for replacing these meters are end of life expectancy, failed, or have expired Measurement Canada Seals.

Impact:

- Maintain Measurement Canada meter seals
- Reliable and accurate retail meter population
- Eliminate legacy type meters

Estimated Annual Expenditures

Cost	2009	2010	2011	2012
Budgeted Capital Cost	30,010	30,471	29,650	30,095

Chatham-Kent Hydro Budgeted Project

Type of Project:	Underground Distribution Upgrades
Project Name:	Primary Cable Replacement Program

Purpose:

The purpose of this project is to replace underground primary cable that is at end of life and has failed or portions of the related system have failed.

Summary:

Chatham-Kent Hydro has approximately 230km of underground primary conductor in its Distribution System, and the life expectancy of this cable is approximately 30 years. Cable and splice failures are one of the largest contributor to Chatham-Kent Hydro's customer outages, therefore, sections of cable are targeted for replacement that are normally at or near end of life and have shown multiple failures.

The initial project is for the Campus Parkway which had two significant outages in 2008. The project entails replacing 3,000 m of 28kV primary underground cable and the project will take place over a 3 year period.

This will be accomplished by directional drilling 3" duct, pulling new 28KV cable and replacing submersible transformers with new pad mount transformers.

In 2012 a similar subdivision will be targeted that contains sections of cable that are at or near end of life.

Impact:

- Increase system reliability
- Reduce power outages due to cable and splice failure
- Continue to improve distribution system
- Eliminate safety hazard of submersible transformers

Estimated Annual Expenditures

Cost	2009	2010	2011	2012
Budgeted Capital Cost	100,000	119,816	138,500	142,518

Chatham-Kent Hydro Budgeted Project

Type of Project:	Safety Hazard
Project Name:	Low voltage vault repairs

Purpose:

The purpose of this project is to replace underground secondary distribution vaults that have been damaged by vehicles or the environment.

Summary:

In 2009 other Local Distribution Companies experienced personal injury occurring from underground secondary distribution vault lids being energized from poor insulation on the enclosed conductors and making contact with the metallic vault lids.

A directive from the Ontario Energy Board was made for Local Distribution Companies to inspect these vaults for any traces of voltage on the lids that may be accessible to the public. Chatham-Kent Hydro inspected 95 vaults, and no lids were found to have any recordable voltage, however many other public safety issues were reported related to these vaults and vault lids. For this reason it is necessary to replace approximately 50 vaults.

Impact:

- Continuous public safety
- Distribution system reliability
- Access to secondary connections

Estimated Annual Expenditures

Cost	2009	2010	2011	2012
Budgeted Capital Cost		104,318		

Chatham-Kent Hydro Budgeted Project

Type of Project:	Underground Distribution Upgrades
Project Name:	Parry St Back Yard Rebuild

Purpose:

The primary purpose of this project is to replace a failed section of 35 year old underground primary cable, leaving no loop feed.

Summary:

Presently the north side of Parry Dr, Chatham is supplied from an underground 2.4KV primary line from Baldoon Rd, with the pad mount transformers in the rear of the residential lots. The section of cable that completes this loop failed a number of years ago and must be replaced.

This project was started in 2007, where two transformer vaults were installed in the front boulevard of Parry Dr., and 3" duct from Baldoon Rd. to these locations as well as duct to the existing transformer locations was installed.

In 2009 primary cable will be installed in the duct from Baldoon Rd east to supply two new pad mount transformer locations. The primary supply will be the 5M21, 16/27.6KV feeder, converting these from 2.4KV.
The existing transformer locations will be replaced with URDs, new 500MCM secondary cable will be installed from the new transformer locations to the new URDs and connections made to supply the existing individual services.

This second part of the primary loop will be completed in 2010 as part of the Chatham #6 Subdivision conversion.

Impact:

- Replace underground primary cable at end of life
- Convert two pad mount transformers from 2.4 to 16KV
- Reduce system losses
- Increase system reliability
- Eliminate back lot transformers

Estimated Annual Expenditures

Cost	2009	2010	2011	2012
Budgeted Capital Cost	43,232			

Chatham-Kent Hydro Budgeted Project

Type of Project:	Emergencies
Project Name:	Various

Purpose:

The purpose of this project is to provide for any unexpected situations that arise throughout the year on the distribution system and that require immediate attention to Chatham-Kent Hydro's Distribution System

Summary:

Chatham-Kent Hydro uses both formal and informal inspection of its Distribution System ongoing through the year. This is done by infrared scanning, vault maintenance, transformer maintenance, switch maintenance and customer and system trouble calls.
Notwithstanding of the ongoing maintenance and inspection unforeseen emergencies still occur and the distributions system must be repaired or replaced.

Examples of these emergencies are:

- Wholesale metering unit failures
- Load break switch failures
- Underground primary feeder cable failures

Impact:

- Make major repairs to the distribution system
- Continuous system reliability to customers

Estimated Annual Expenditures

Cost	2009	2010	2011	2012
Budgeted Capital Cost	81,769	75,000	75,000	75,000

Chatham-Kent Hydro Budgeted Project

Type of Project:	Renewals
Project Name:	Outage Management System

Purpose:

Replace antiquated Outage Management system (OMS)

Summary:

The existing OMS software is10 years old and does not interface with the GIS or AMI systems. New software and associated interfaces will be installed.

Impact:

- Improve outage management
- Improve system planning and design

Estimated Annual Expenditures

Cost	2009	2010	2011	2012
Budgeted Capital Cost	130,000			

<u>Security and Sustainment</u>

These projects are related to upgrading and replacing high voltage switch gear throughout the distribution system where its reliability and safety could be a concern. There is a plan to replace at least three of the approximately 100 of these switches every year to insure safe equipment and limit the power failures.

The repair to for security

- Load Interrupter switches (LIS) switches
- Asset Management and system Optimization Program

Chatham-Kent Hydro has provided the project plan for 2009 and 2010 based on the above criteria.

Chatham-Kent Hydro Budgeted Project

Type of Project:	Overhead Distribution Upgrades
Project Name:	LIS switches

Purpose:

The purpose of this project is to replace a minimum of three existing Air Break Switches each year that have been identified as not operable and/or not repairable. This will maintain a reliable distribution system by targeting deteriorated equipment and ensure customers have a reliable supply of power.

Summary:

In 2009 the switch locations that have been identified for replacement are;

- Replace solid blade switch 01M5-76 at 30 Queen St, Chatham with new Load Break Switch, this will allow isolation of Chatham #1 Substation
- Replace existing Load Break Switch #45, Arnold St, Wallaceburg with new Load Break Switch, this switch has been identified as being inoperable however is required to maintain a functional distribution system
- Replace solid blade switch SB-81 at the intersection of Lyon St. S, and Superior St, Tilbury with new Load Break Switch, this is an open point between the Tilbury DS F1 and F2 feeders, the existing switches cannot be used to parallel these two feeders

In 2010 the switch locations that have been identified for replacement are;

- Replace existing Air Break Switch 08M8-47 at 6 Faubert Dr, Chatham with new Load Break Switch, this switch has been identified as being inoperable however is required to maintain a functional distribution system
- Replace existing Air Break Switch 84M6-33 at the intersection of Grand Ave E and Taylor Ave, Chatham with new Load Break Switch, this switch has been identified as being inoperable however is required to shift load between the 5M21 and 5M22 feeders
- Relocate existing Air Break Switch 76M6-34 at the intersection of Park Ave E Park St, Chatham with new Load Break Switch, this switch has been identified as being in a location that is not easily accessible as well as being near the end of life expectancy.

New poles will be installed at all of the above locations.

Locations beyond 2010 will be identified through Trouble Call reports and regular switch maintenance.

Impact:

- Maintain system reliability
- Improve customer power restoration time
- Maintain / improve system flexibility

Estimated Annual Expenditures

Cost	2009	2010	2011	2012
Budgeted Capital Cost	62,166	71,049	81,000	60,000

Chatham-Kent Hydro Budgeted Project

Type of Project:	Security and Optimization
Project Name:	Asset Management and System Optimization Program

Purpose:

Develop asset management and optimization model for distribution system

Summary:

Due to the inevitable increase in generation connections to the distribution system and the need to further optimize the existing feeders and stations, a detailed analysis of the system is required. The existing conversion and cable replacement programs will also be analyzed to determine the degree that reliability will be improved and the impact that embedded generation will have on these projects. The goal will be to maximize the volume of new generation that can be connected to the system and identify the most strategic locations. An additional goal will be to improve system efficiency and to ensure effective spending of capital.

Impact:

- Identify capacity and system shortfalls
- Identify optimum locations for connections of generation
- Identify greatest need for investment

Estimated Annual Expenditures

Cost	2009	2010	2011	2012
Budgeted Capital Cost	0	311,049	159,500	143,000

Capacity

The projects involve system improvements to handle increase in customer connections and demand. The improvements to the infrastructure are not based on specific customers but benefit various customers in a specific area.

The projects related to capacity

- Voltage Conversion
- Capital Expansion Request

Chatham-Kent Hydro has provided the project plan for 2009 and 2010 based on the above criteria.

Chatham-Kent Hydro Budgeted Project

Type of Project:	Reduction of Step Down Transformers
Project Name:	Voltage Conversion

Purpose:

The purpose of this project is to eliminate 16KV to 2.4KV step down transformers in the Chatham-Kent Hydro Distribution System.

Summary:

Within the Chatham-Kent Hydro distribution system there are ten16KV to 2.4KV step down transformers. These transformers were installed as a temporary measure to reduce load on 16/27.6kV to 2.4/4.16kV substations.

This project will remove three step down transformers in the next three years.

In 2010, the step down transformer supplying Churchill Ave and Devon Dr. will be eliminated. This entails installing 20 wooden poles; 650m of 3/0 ACSR overhead conductor and six 16kV-120/240V single phase pole mount transformers.

In 2011, the step down transformer supplying Canterbury St. will be eliminated. This entails installing 20 wood poles; 450m of 3/0 ACSR overhead conductor and four 16kV-120/240V single phase poles mount transformers.

In 2012, the step down transformer that is supplying Semenyn Ave will be replaced. This entails installing 12 wood poles, 300m of 3/0 ACSR overhead conductor, three 16KV-120/240V single phase pole mount transformers and two single phase pad mount transformer.

Impact:

- Replace equipment that is at end of life
- Reduce system losses
- Increase system reliability

Estimated Annual Expenditures

Cost	2009	2010	2011	2012
Budgeted Capital Cost		104,619	138,500	242,518

Chatham-Kent Hydro Budgeted Project

Type of Project:	Underground Distribution Upgrades
Project Name:	Submarine Cable Replacement

Purpose:

The purpose of this project is to install a new primary submarine cable, crossing the Thames River, Chatham.

Summary:

Presently Chatham-Kent Hydro has two overhead 27.6KV feeders and two submarine 27.6KV feeders crossing the Thames River, Chatham;

- 5M5, 400MCM, copper submarine river crossing, installed in 1979
- 5M7, 400MCM, copper submarine river crossing, installed in 1959
- 5M22, 556MCM, ASC, overhead river crossing, installed in 1995
- 5M21, 556MCM, ASC, overhead river crossing, installed in 2006

The Thames River is a navigatable water body west of Lacroix St, and for this reason overhead river crossings are not permitted in the westerly section of Chatham.

The majority of the new load growth in Chatham has been in the north-west quadrant.
For these reasons, Chatham-Kent Hydro is proposing to extend the 5M7 feeder under the Thames River at the Bear Line, Chatham to reinforce the supply to the north-west quadrant of the city.

Impact:

- Distribution System reliability
- Prepare for new load

Estimated Annual Expenditures

Cost	2009	2010	2011	2012
Budgeted Capital Cost		206,938		

Chatham-Kent Hydro Budgeted Project

Type of Project:	Voltage Conversion / Rebuild
Project Name:	Downtown Chatham - Voltage Conversion / Rebuild

Purpose:

The purpose of this project is to convert a section of Chatham-Kent Hydro Overhead Distribution to a new Underground Distribution System, while converting from 2.4/4.16kV to 16/27.6kV primary.

Summary:

This is the first year of a four year project to rebuild and convert downtown Chatham from 2.4/4.16KV to 16/27.6KV primary voltage.
Presently the King St. block of downtown Chatham is supplied from a 2.4/4.16KV underground to overhead supply with sections that were installed in mid twentieth century and are fully depreciated. Other sections of this overhead plant cross private property with no registered easements.
Existing 5M5 16/27.6KV primary underground feeder that supplies other sections of downtown Chatham will be utilized to supply this block. A single phase line will be extended from a man hole on Wellington St W, northerly on Forsyth St. to supply two new pad mount transformers. One additional pad mount transformer on Wellington St. W. will be converted from 2.4/4.16KV to 16/27.6KV to share a portion of this block.
Llewellyn Alley has two three phase and three single phase pole mount transformers. The underground primary will be extended in existing duct structures were possible to supply these transformers. Land will need to be secured for these transformer locations.
The north side of King St downtown Chatham is presently supplied from an underground to overhead 2.4/4.16KV feeder. This feeder supplies two three phase and two single phase pole mount and five three phase pad mount transformers. The existing pad mount transformers will be converted to 16/27.6KV primary while the pole mount transformers will be converted to pad mount transformers. Some existing 28KV cable and duct structures will be utilized where possible; others will require new duct structures to be installed.
Secondary services will be trenched from the new transformer locations to re-feed each existing customer.
To accomplish this, easements will be secured over the underground conductor and pad mount transformers.

Impact:

- Replace deteriorated distribution system
- Convert two single phase and one three phase transformers from 2.4/4.16KV to 16/27.6KV primary voltage
- Eliminate overhead conductors on private property with no easements
- Prepare for future load growth expected due to Capital Theatre opening

Estimated Annual Expenditures

Cost	2009	2010	2011	2012
Budgeted Capital Cost		247,557	259,500	385,035

Chatham-Kent Hydro Budgeted Project

Type of Project:	Feeder Extension - Reliability
Project Name:	M5 Extension to supply Chatham-Kent Health Alliance

Purpose:

The purpose of this project is to supply Chatham-Kent Health Alliance (Public General Hospital) from the most reliable feeder of the seven 27.6KV feeders that supply Chatham.

Summary:

This is a two year project where the first year consists of the overhead primary line extension, and the second year will consist of submarine cable refurbishment.
Presently, Chatham-Kent Health Alliance, Chatham Campus is supplied by the 5M21 feeder with the 5M7 as a back-up feeder. Both feeders feed into an automated switching cubicle were one circuit supplies this complex while the other is a backup.
To accomplish this project, the existing 5M21 pole line will be double circuited with the 5M5 feeder approximately 550m from the intersection of Kent St. and Dover St. to the primary riser supplying the switching cubicle on Grand Ave W.
The existing 5M21 feeder will continue to supply north Chatham.
The 5M5 feeder transitions from overhead to underground at the intersection of Queen St and Wellington St, Chatham, from here it continues northerly to the Thames River. The submarine cable that crosses the Thames River was installed approximately 30 years ago to supply sections of north Chatham.

In 2010 this section of cable will be rehabilitated by injecting a dielectric fluid into the cable to disperse any water in the insulation and fill any voids in the insulation of the cable. This process has been established in the industry as a viable alternative to replacing primary cables.
This will complete the extension of the 5M5 feeder extension to the Chatham-Kent Health Alliance.

Impact:

- Most reliable feeder will supply the most critical customer in the city of Chatham
- Will create a more flexible distribution system
- Offload load from 5M22 feeder to 5M5

Estimated Annual Expenditures

Cost	2009	2010	2011	2012
Budgeted Capital Cost	319,010	100,000		

Chatham-Kent Hydro Budgeted Project

Type of Project:	Voltage Conversion
Project Name:	Substation 7/9 Conversion

Purpose:

The purpose of this project is to convert Chatham #7 Substation feeders 7F02 and 7F04 Chatham #4 Substation feeders 4F03 from 2.4/4.16KV to 16/27.6KV primary and to decommission Chatham #9 Substation.

Summary:

Conversion of Chatham #7 Substation started in 2006, presently there three feeders that remain active out of this substation. Of the three remaining feeders two will be totally eliminated in this project.
Presently the 7F02 feeder is under built on the same wood pole line as the 5M7 16/27.6kV feeder. There are two single phase, six three phase transformers pole mount and one three phase pad mount transformers to be converted from 2.4/4.16kV to 16/27.6kV primary on this feeder. The three phase pad mount transformer is supplying a customer whose load and service size does not warrant a pad mount transformer; this will be replaced with a pole mount transformer supplied from the existing 5M7 feeder.
The 4F03 feeder from Chatham #4 Substation, this section of the feeder is also under built on the same wood pole line as the 5M7 16/27.6kV feeder. There are three three phase and two single phase transformers that will be converted from 2.4/4.16kV to 16/27.6kV primary on this feeder.
The 7F04 feeder has one three phase pole mount transformer remaining on this feeder. This is also under built on the same wood pole line as the 5M7 16/27.6kV feeder; this transformer will be converted to 16/27.6kV primary, on the same wood pole.

Wood poles that contain the transformers will be replaced as necessary throughout the conversion.

Chatham #9 Substation was constructed as a temporary measure to relieve load from Chatham #7 Substation. The 2009 Capital Projects included converting the last section of load on this substation. The actual decommissioning of this substation will take place as part of this project as they are in similar geographical areas.

Impact:

- Elimination of two of the three remaining feeders from Chatham #7 Substation
- Voltage conversion on a section of 4F03 feeder
- Decommission of Chatham #9 Substation

Estimated Annual Expenditures

Cost	2009	2010	2011	2012
Budgeted Capital Cost	574,739	307,930		

Chatham-Kent Hydro Budgeted Project

Type of Project:	Distribution System Relocation
Project Name:	Capital Expansion Requests

Purpose:

The purpose of this project is to provide line relocations of the Chatham-Kent Hydro Distribution System carried out at the request of the Municipal and Provincial road authorities under applicable legislation and Ministry of Transportation guidelines.

Summary:

It is a requirement of the Municipality to relocate or reconstruct its distribution system in order to accommodate the specific requirements of the road authorities, mainly The Municipality of Chatham-Kent.

The typical requests are to relocate lines and poles to accommodate changes to roads, highways and bridges. Also Chatham-Kent Hydro distribution occupies road allowances at no cost and in return is required to install, relocate or reconstruct its facilities in order to accommodate the specific requirements of the road authorities.

These projects are typically driven by other authorities' schedules for road works and vary in location. There is normally sufficient notice for these projects to be budgeted; however some arise with little notice.

Impact:

- Chatham-Kent Hydro meets its contractual and legal obligations, and maintains property rights of the Distribution line located on road

Estimated Annual Expenditures

Cost	2009	2010	2011	2012
Budgeted Capital Cost	50,000	50,750	69,011	52,284

Regulatory Requirement

These projects are directed by regulatory requirements which include OEB, IESO and Ministry of Energy.

Directed by OEB, the initiative is the elimination of load transfers. Chatham-Kent Hydro is in the process in eliminating 90% of the transfer loads form Hydro One by end of 2010. Since there are some priority for maintenance to the system that the elimination of the load transfers will continue in 2012. According to the OEB guidelines that all load transfer is to be completed by 2012 which is within our budget plan.

The projects related to Regulatory requirement

- Elimination of Load Transfers with Hydro One
- Asset Management Plan

Chatham-Kent Hydro has provided the project plan for 2009 and 2010 based on the above criteria.

Chatham-Kent Hydro Budgeted Project

Type of Project:	Long Term Load Transfers
Project Name:	Eliminate Hydro One Load Transfers

Purpose:

The purpose of this project is to comply with the Ontario Energy Board's mandate to eliminate Long Term Load Transfers with Hydro One Networks Inc.

Summary:

Within Chatham-Kent Hydro's service area there are 103 Chatham-Kent Hydro customers that are connected to Hydro One's distribution system; these are considered Long Term Load Transfers. Of these 103 customers 84 will be retained through extending Chatham-Kent Hydro's distribution system.
This project is made up of nine smaller projects:
Nichols Dr, Chatham – install new underground services from existing pad mount transformer- this will retain two Chatham-Kent Hydro customers.
Bear Line Rd, Chatham – extend 5M21feeder from McNaughton Ave. northerly 1.3Km to supply four existing pole mount transformers - this will retain four Chatham-Kent Hydro customers.
Indian Creek Rd E, Chatham – extend one phase of 16KV 20 spans easterly on Indian Creek Rd from Queen St. to supply two pole mount and seven pad mount transformers - this will retain 70 Chatham-Kent Hydro customers.
148 Main St. W, Ridgetown – extend single phase 2.4KV line 170m to supply one single phase pole mount transformer - this will retain three Chatham-Kent Hydro customers.
200 County Rd 46, Tilbury – install new underground service from existing pad mount transformer - this will retain one Chatham-Kent Hydro customer.
16 Rogers Rd. Tilbury – extend single phase 16KV primary 250m to supply one single phase pole mount transformer - this will retain one Chatham-Kent Hydro customer.
151 Queen St. S, Tilbury – install one three phase pole mount transformer bank and extend three phase secondary service, this will retain one Chatham-Kent Hydro customer.
444 Erie St. S, Wheatley – install new underground service from existing pole mount transformer - this will retain one Chatham-Kent Hydro customer.
196 Erie St. N, Wheatley – extend 16/27.6KV feeder two spans, and install new three phase pole mount transformer - this will retain one Chatham-Kent Hydro customer.
Date to eliminate LTLT has been extended to 2012, budget will be required to purchase H1 distribution system assets, transfer Chatham-Kent Hydro assets to H1.

Impact:

- Retain 84 Chatham-Kent Hydro customers
- Follow Ontario Energy Board's mandates

Estimated Annual Expenditures

Cost	2009	2010	2011	2012
Budgeted Capital Cost	412,936		142,518	

Chatham-Kent Hydro Budgeted Project

Type of Project:	Asset Management
Project Name:	Asset Management Development

Purpose:

Investigate software and systems for full asset management tracking system to be implemented in 2010.

Summary:

After initial investigation into available software and systems to track distribution assets it was determined that much of the data for proper implementation was not being collected in existing systems. It was determined that the GIS and planned OMS were excellent tools and repositories to collect, store and report this information. Money for this project was folded into the existing OMS implementation.

The OMS implementation is structured to accommodate this type of functionality.

Impact:

- Configure planned OMS to collect and store asset performance data.
- Configure OMS to report on asset performance data for use in the development of future maintenance and capital plans.
- Improved system performance, less equipment failures.

Estimated Annual Expenditures

Cost	2009	2010	2011	2012
Budgeted Capital Cost	50,000			

<u>Substations</u>

Within the Chatham-Kent service area there are several substations that are approaching end of useful life causing higher losses and potential power failures. The annual maintenance program includes analysis of the substations conditions. In the system plan for 2009 and 2010 there are several substations that are being eliminated to reduce the system losses and removing assets that have reached end of life.

The projects related to capacity

- Substation Conversion

Chatham-Kent Hydro has provided the project plan for 2009 and 2010 based on the above criteria.

1

Chatham-Kent Hydro Budgeted Project

Type of Project:	Voltage Conversion
Project Name:	Substation 6 Conversion

Purpose:

The purpose of this project is to replace distribution equipment at end of life supplied by Chatham #6 Substation and decommission the substation.

Summary:

Chatham #6 Substation was constructed in 1958 to service the north west quadrant of Chatham.
This is one of six 16/27.6KV to 2.4/4.16KV substations that service the city of Chatham, each being backed up by another. Presently there are four feeders that are supplied from this substation; all feeders are underground egress from the station and transition to overhead.
The underground distribution system is at end of life; to maintain system reliability Chatham-Kent Hydro has decided to convert this to 16/27.6KV primary voltage while replacing this section of the distribution system.

This project is expected to start in 2010 and continue for five years.
The first feeder to be eliminated in 2010 is the 6F01; this supplies McNaughton Ave W, and Juliette St., Chatham. New 28KV primary underground cable will be installed and 15, 2.4KV submersible transformers will be converted to16KV pad mount transformers in approximately the same locations utilizing transformer vaults and secondary conductor. The 16/27.6KV primary supply will from the 5M21 feeder.

In 2011 the 6F02 will be targeted for elimination, this supplies customer on Oxley Dr. and Andrea Cres., Chatham. New 28KV primary underground cable will be installed and 17, 2.4KV submersible transformers will be converted to16KV pad mount transformers in approximately the same locations utilizing transformer vaults and secondary conductor. The 16/27.6KV primary supply will also be from the 5M21 feeder.
This feeder conversion will continue in 2012, converting an additional 17, 2.4KV submersible to16KV pad mount transformers.

Impact:

- Reduction of system losses through this substation
- Replace underground primary cable at end of life
- Replace underground submersible transformer to pad mount transformers, eliminating a safety hazard to personnel

Estimated Annual Expenditures

Cost	2009	2010	2011	2012
Budgeted Capital Cost		347,930	338,500	364,018

Chatham-Kent Hydro Budgeted Project

Type of Project:	Voltage Conversion
Project Name:	Subdivision 8 Conversion

Purpose:

The purpose of this project is to convert the last feeder from Chatham #8 Substation from 2.4/4.16KV to 16/27.6KV and decommission this substation.

Summary:

Chatham #8 Substation was constructed in 1971, and mainly services residential customers in the south-west quadrant of Chatham, the voltage conversion to eliminate this station began in 2000. The underground cable was at end of life and cable failures were increasing, therefore, a distribution voltage conversion was constructed and completed in 2004.

In order for the Substation 8 to be de-energized and decommissioned, there are two single phase and one three phase pole mount transformers remaining on the 8F02 feeder from this station that needs to be replaced and eliminate the line to the 8F02 feeder.

The wood poles and transformers on this circuit are at end of life and will be replaced at each of these locations.

Impact:

- Decommissioning of Chatham #8 Substation
- Replacing end of life distribution equipment
- Reduction of system losses through this substation

Estimated Annual Expenditures

Cost	2009	2010	2011	2012
Budgeted Capital Cost	50,000			

Chatham-Kent Hydro Budgeted Project

Type of Project:	Voltage Conversion
Project Name:	Dresden Conversion

Purpose:

The purpose of this project is to relocate overhead primary back lot distribution system to the front lot, convert primary voltage and decommission Dresden South Distribution System.

Summary:

The town of Dresden is presently supplied by two 16/27.6KV to 2.4/4.16KV substations; Dresden North DS and Dresden South DS.

Dresden South DS was installed in approximately 1965. The distribution system supplied by this substation is at end of life including the substation equipment, and limited back up feeders are now in place.

Presently there are only two feeder egresses from this substation that are functioning - one underground and one overhead, as the third feeder underground cable has failed. Both remaining feeders cross private property with no registered easements. The overhead egress is not located within acceptable clearances to buildings creating a public safety hazard.
Many sections of this overhead distribution system are in rear lots with no vehicle access, minimal clearance to structures and are at end of life.

Rather than rebuild the existing 2.4/4.16KV distribution, Chatham-Kent Hydro has decided to reconstruct a new 16/27.6KV distribution in municipal right-of-ways in front lots.

Decommissioning this substation is expected to be an eight year project that was started in 2004

Impact:

- Distribution System reliability
- Reduce outage times
- Replace end of life equipment
- Public safety hazards
- Reduce Employee safety hazard

Estimated Annual Expenditures

Cost	2009	2010	2011	2012
Budgeted Capital Cost	384,653	486,635	438,500	

Customer Connection and Metering

These projects are directed by regulatory requirement which includes OEB, IESO, and Ministry of Energy.

One of the government mandates is to have Smart Meters installed by year 2010. Chatham-Kent Hydro has installed Smart Meters for Residential and a portion of the General Service. By the year 2010 Chatham-Kent Hydro will have completed Smart Meter installations for all rate classes.

The projects related to Customer Metering include:

- Smart Meter installation for all rate classes

The cost for installing the remainder of the Smart meters is recorded in the deferral accounts.

General Equipment

The focus of these projects is to support the capital projects. This category includes:

- Transportation
- Office Furniture and Equipment
- Engineering System
- Tools and Equipment
- Building and Land

Transportation

Chatham-Kent Hydro has a fleet of vehicles and associated equipment to carry out distribution system related work and other activities. The fleet includes:

- Bucket Trucks that are mainly used for overhead distribution system
    - single and double bucket trucks
- Pickup Trucks that are mainly used for minor services and inspections
    - Pickup Trucks
    - Vans
- Digger Derricks that are mainly used for underground distribution system and to dig pole holes
    - Diggers
- Dump Trucks that are mainly used in conjunction with the Digger Derricks
- Trailers and miscellaneous equipment that are used to move materials and equipment, including forklifts, chippers.

Chatham-Kent Hydro replaces the fleet on ongoing basis. The replacement period varies based on the type of truck:

Pickup and Vans	6-8 Years
Bucket Trucks	7-10 Years
Digger Derricks	12-15 Years

Replacement of any other equipment is based on condition based assessment.

Chatham-Kent Hydro Budgeted Project

Type of Project:	Rolling Stock (fleet and equipment)
Project Name:	Various

Purpose:

This capital spending project is necessary to meet the requirements of replacing existing assets and assisting in the completion of work programs.

Summary:

All Rolling Stock must be maintained at an optimum level to comply with various regulations such as Highway Traffic Act, CVOR, EUSA, Ontario Health and Safety Act and Public Safety.
Equipment must have a high productivity level and downtime must be minimized to achieve job production and its completion. Delaying this program would result in cost deficiencies due to lost production time by personal and higher maintenance costs.
C-K Hydro owns 40 light and heavy vehicles along with 30 trailers, and various equipment. Replacement criteria are based on full depreciation; repair history and manufacturers guide lines. Light vehicles are replaced every 6-8 years, service trucks every 7-10 years and heavy trucks every 12-15 years. Any other equipment replacement is based on a condition based assessment.

Impact:

- Reduce downtime and increase fleet utilization
- Reduce maintenance costs
- Safer work environment for staff.
- Reduce fuel emissions by using newer emission controls on vehicles.
- With newer technology greener fuels can be used such as E85 ethanol.
- A cleaner working environment with less emission when working around vehicles.

Estimated Annual Expenditures

Cost	2009	2010	2011	2012
Budgeted Capital Cost	362,593	780,000	276,000	423,500

Office Furniture and Equipment

Chatham-Kent Hydro assets include office furniture and equipment for approximately 18 employees, the furniture includes the desk, chairs and office structures.

The projects related to Office Furniture and Equipment

- Computers
- Office Furniture

Chatham-Kent Hydro has provided the project plan for 2009 and 2010 based on the above criteria.

Chatham-Kent Hydro Budgeted Project

Type of Project:	Computer Equipment
Project Name:	Computers

Purpose:

The purpose of this budget is to supply computers to new staff or existing staff that require computers to perform their duties. This budget is also used for replacement of existing computers that are at end of life.

Summary:

Presently Chatham-Kent Hydro has 38 computers in service used for operating the Local Distribution Company. Included in this 38 are office computers and computers used for operation of dedicated systems throughout the utility such as; HVAC control, MV90, GIS and SCADA. Computers are scheduled for replacement every five years as they are fully depreciated and as technology becomes out of date.

This budget is also used when machines fail and must be replaced prematurely.

By replacing computers on a life cycle basis it reduces the chance of lost data and lost production.

Impact:

- Maintain computer equipment that will operate up to date applications
- More efficient staff
- Reduction of computer down time.

Estimated Annual Expenditures

Cost	2009	2010	2011	2012
Budgeted Capital Cost	63,000	56,000	50,000	50,000

Chatham-Kent Hydro Budgeted Project

Type of Project:	Office Furniture
Project Name:	Office Furniture

Purpose:

Chatham-Kent Hydro has been very progressive with recent renovations to its 320 Queen St. main office. With these upgrades to its building it has been able maintain a reliable workplace and an up to date ergonomically correct work station for 2009 and 2010.

Summary:

In 2009 there are numerous reorganizing of space to accommodate the corporation growth

- New office furniture for New Risk Management Officer
- New office furniture for the Engineering/Operations Assistant and the Technical Services Assistant were required for a more ergonomically work area.

In 2010 further renovations are required to accommodate future growth in the corporation

- New work stations are required for engineering and meter technologist
- Re- lamping of the Stores area

Impact:

- The renovations and re-organization will allow Chatham-Kent Hydro to utilize its office space it its maximum potential

Estimated Annual Expenditures

Cost	2009	2010	2011	2012
Budgeted Capital Cost	7,500	12,000	12,000	5,000

Engineering System and Support

The engineering department uses the SCADA and GIS system that provides them with information on the distribution system through the entire service area. The SCADA system is a main resource for the Control Room Operator to isolate feeders, monitor the voltage and amperage of the system and provide a safe working environment for the linemen. The GIS system maps the entire system using geographic coordinates and stores key asset information.

Operation and Control Room Support provides support and implements the plans of capital jobs that will enhance the operation of the infrastructure and the safety of the employees.

The control room operator provides valuable information that locates possible system improvements, responsible in providing powerline maintainers with safe isolations of feeders, emergency switching to temporary relieve power problems and system can isolate future potential situations due to deteriorating structures. The monitoring system that Control Room Operator uses is the SCADA system; this is tool that contains all the information on the transformer locations allowing isolation of feeders, switching loads, notification of power failures and saved data can be used to track problems. This system is a vital tool to develop the plan in locating the areas that require upgrading to provide the crews a safe working system and minimize power failures for the customers.

These systems and employee support will be beneficial in assisting the organization accomplishing its goals.

The projects related to Engineering System and Support

- Control Room Support
- SCADA Capital updates
- GIS Development

Provided is the project plan for 2009 and 2010 based on the above criteria’s.

1

Chatham-Kent Hydro Budgeted Project

Type of Project:	Maintaining Distribution System Infrastructure
Project Name:	Control Room Support

Purpose:

The purpose of this budget item is to provide Control Room Support to Line Staff while working on capital construction projects.

Summary:

Presently Chatham-Kent Hydro has one Control Room Operator that monitors the distribution system status, dispatches line crews, writes switching orders for power restoration and feeder balancing and is the liaison with Hydro One Grid Control Centre. This is a full time position, 7:30 to 4:00, Monday to Friday.

Much of the time and expenses that are required for these functions are for capital projects being completed by the Chatham-Kent Hydro line crews.

This position is also required to ensure the safe operation of distribution equipment when operated by line personnel in the field.

In 2010 Chatham-Kent Hydro intends to increase the number of individuals in the Control Room, since the service area has increase over time another operator is required to provide the customers and staff a more efficient and reliable distribution system.

Impact:

- Assist line crews with capital projects
- Distribution System reliability
- Distribution System efficiency

Estimated Annual Expenditures

Cost	2009	2010	2011	2012
Budgeted Capital Cost	60,000	118,449	109,011	132,146

Chatham-Kent Hydro Budgeted Project

Type of Project:	SCADA Capital Upgrades
Project Name:	SCADA Capital

Purpose:

Upgrades to the SCADA system throughout the distribution system, to increase reliability and performance.

Summary:

The SCADA system communicates the performance of the distribution system to the control room, and assists in reducing losses and reducing outage duration. As the distribution system expands, there is a need for extending the capabilities of SCADA system which entails installing new SCADA devices such as automated switches, fault indicators, RTU's, servers and communication equipment to replace existing equipment at the end of their useful life.

Impact:

- Aids in measuring Distribution System reliability, Outage Management
- SCADA system redundancy
- Reduces System Operation cost
- Assists in Control room functions include: crew dispatching, system maintenance, crew safety and coordination, switching, and distributed generation dispatching

Estimated Annual Expenditures

Cost	2009	2010	2011	2012
Budgeted Capital Cost	40,000	51,049	40,000	40,000

Chatham-Kent Hydro Budgeted Project

Type of Project:	AM/FM Upgrades (GIS)
Project Name:	GIS Development

Purpose:

Enhance and upgrade AM/FM (GIS) system to accommodate new technologies, software and processes.

Summary:

GIS is a product that provides a geographic version of the distribution system and forms a basis for many other technologies such as: OMS, DMS and Load flow.

Since the GIS technologies become a more integral part of the day-to-day operations a greater number of users are demanding more functionality and better performance. As these technologies mature, the GIS system requires to be upgraded or a conversion on GIS data to accommodate the new functionality.

Chatham-Kent Hydro developed its GIS System in 1999, and within that time there had been 2 major upgrades to the system. The upgrades will incorporate new technologies to provide the Chatham-Kent Hydro staff with reliable and updated information.

Impact:

- Maintains GIS current and relevant as the technology evolves
- Adds functionality to better serve user needs and evolving processes

Estimated Annual Expenditures

Cost	2009	2010	2011	2012
Budgeted Capital Cost	76,460	91,790	123,500	153,535

Tools and Equipment

This category pertains to the equipment that the employees use to maintain, operate and repair the distribution system.

Chatham-Kent Hydro has provided the project plans for 2009 and 2010 based on the above criteria.

1

Chatham-Kent Hydro Budgeted Project

Type of Project:	Capital Equipment
Project Name:	Various

Purpose:

To replace major tools that have come to end of life, and purchase new equipment to keep up with today's technological standards. In doing so safer work practices are maintained.

Summary:

To execute work programs in a cost efficient and safe manner all major equipment must be kept up to standard.

Purchases in category include:

-testing equipment, presses, cutters, rubber goods, TDR equipment, locating equipment, trouble shooting equipment, radio system, pulling equipment.

Major equipment requirements will vary from year to year depending on rotation of equipment replacement or upgrades.

Not proceeding with the appropriate project spending level in service equipment leads to increased job costs and possible safety violations.

Impact:

- Major equipment will be maintained and kept up to current standards.

Estimated Annual Expenditures

Cost	2009	2010	2011	2012
Budgeted Capital Cost	47,000	99,000	49,500	53,500

<u>Building and Land</u>

Chatham-Kent Hydro has a main office and a service center along with substations

- The main office is located at 320 Queen Street
- Garage that contains the fleet
- Various locations of the Substations – 27,600-4,160 KVA
  - Chatham DS-1 - 152 Queen St.
  - Chatham DS-3 - 81 Grand Ave E
  - Chatham DS-4 - 429 Richmond St.
  - Chatham MS-6 - 480 St Clair St.
  - Chatham MS-7 - 292 Baldoon St.
  - Chatham MS-8 - 210 Tweedsmuir Ave
  - Dresden South MS - 263 Main St. Dresden
  - Dresden North MS - 253 Talbot St.
  - Thamesville MS - 4 London Rd.Thamesville
  - Tecumseh DS- 4 - Tecumseh St. Ridgetown
  - Centennial MS - 10 Centenial St Ridgetown
  - Blenheim East DS - 169 Chatham St. Blenheim
  - Blenheim West DS - William St Blenheim
  - Wheatley DS - 925 Talbot Rd W. Wheatley

- The property that Chatham-Kent Hydro owns is 320 Queen Street in Chatham and 25 Young St in Tilbury for operations and material storage

In 2009 and 2010 Chatham-Kent Hydro has budgeted for capital additions that are required to maintain the Building and surrounding area to provide a safe and working environment. The budgeted projects are:

- Security Building – to store copper and other material that will deteriorate in value from the environment and theft
- Repaving the asphalt in the yard because of the deterioration
- Transformer storage facility - complete with oil retention curb barrier Chatham-Kent Hydro will be able to contain any types of oil leaks, protect the asphalt and eliminate the potential of oil getting into the sewers that are located around the yard.

Chatham-Kent Hydro has provided the project plan for 2009 and 2010 based on the above criteria.

In 2009 Chatham-Kent Hydro will be purchasing land that is adjacent to the property at 320 Queen St. The land has become available and is required as Chatham-Kent Hydro is land locked and this property will allow for improved security for the fleet and inventory. The property will also provide opportunities for future expansion of the building if necessary, which will be much cheaper than moving a later date.

1

Chatham-Kent Hydro Budgeted Project

Type of Project:	Consumer Load disconnect switches
Project Name:	Switches

Purpose:

Install an estimated 1,000 remotely controlled load disconnect switches at existing smart meter locations.

Summary:

An advanced smart meter solution includes the capability to remotely disconnect customer loads due to power quality, safety or due to non-payment. Remotely disconnecting these customers reduces operations cost while maintaining the integrity of the system. The prudent installation of these types of devices will offer increased operational control over the distribution system.

Impact:

- reduction in operating cost and flexibility
- improved system reliability
- improved financial exposure to delinquent accounts
- improved response times

Estimated Annual Expenditures

Cost	2009	2010	2011	2012
Budgeted Capital Cost		200,000	50,000	50,000

Chatham-Kent Hydro Budgeted Project

Type of Project:	Building Renovations
Project Name:	Building Upgrades

Purpose:

Chatham-Kent Hydro has been very progressive with recent renovations to its 320 Queen St. main office. With these upgrades to its building it has been able maintain a reliable workplace and an up to date ergonomically correct work station for 2009 and 2010.

Summary:

In 2009 there are numerous projects involving reorganizing workspace to accommodate the corporation growth

- New office was constructed for New Risk Management Officer
- Retrofit office for the Distribution and Conservation Engineer. It was the former Health and Safety Officer's office and was in need of an upgrade. Also with this move it allows the Engineer to be repositioned to the area that he is responsible for. (Stations and Distributions and the Operation Centre, SCADA)
- New office furniture for the Engineering/Operations Assistant and the Technical Services Assistant were required for a more ergonomically work area.

In 2010 further renovations are required to accommodate future growth in the corporation

- New work stations are required for engineering and meter technologist
- New computer water tower controller; this will allow the corporation to control the building's thermostats
- Re- lamping of the Stores area

Impact:

- The renovations and re-organization will allow Chatham-Kent Hydro to utilize our office space it its maximum potential
- Automated HVAC system will allow Chatham-Kent Hydro to save power and assist in controlling the damage with heat pumps from thermostatic

Estimated Annual Expenditures

Cost	2009	2010	2011	2012
Budgeted Capital Cost	73,500	28,000	57,000	21,000

Chatham-Kent Hydro Budgeted Project

Type of Project:	General Equipment
Project Name:	Replace Fuel Storage Tanks

Purpose:

Replace the in ground fuel storage tanks with more environmentally appropriate above ground tanks

Summary:

Upon inspection of the underground fuel tanks, leaks were detected. The tanks are 20 years old and require replacement or removal. A business case was completed comparing the continuance of on site fuel storage verses sending vehicles to fuelling stations. The economics significantly favour on site fuel storage and it would be a better method from an environmental position to store fuel in above ground tanks.

Impact:

- A more environmentally friendly fuel storage method
- Continuance of the efficiencies of on site fuel storage

Estimated Annual Expenditures

Cost	2009	2010	2011	2012
Budgeted Capital Cost	40,000			

1

Chatham-Kent Hydro Budgeted Project

Type of Project:	Land
Project Name:	Land adjacent to 320 Queen St.

Purpose:

This property will allow for improved security for the fleet and inventory.

Summary:

The land adjacent to the current office at 320 Queen St. has become available and is required as Chatham-Kent hydro is land locked. The additional land will allow for improved security for the fleet and inventory.

Impact:

- Provide opportunity for growth

Estimated Annual Expenditures

Cost	2009	2010	2011	2012
Budgeted Capital Cost	200,000	25,000	75,000	

Chatham-Kent Hydro Budgeted Project

Type of Project:	Re-Surfacing of Yard
Project Name:	New Asphalt and Three Cement Pads for Yard

Purpose:

The rear yard at 320 Queen Street needs re-asphalting; presently the asphalt is over twenty three years old and has become a potential Health and Safety issue, due to the unevenness and its deteriorating in several areas. During this process the existing asphalt in the transformer storage area will be replaced with three separate cement pads. Over the years Chatham-Kent Hydro has attempted to preserve the asphalt but with the present state of the asphalt routine maintenance is becoming more difficult to perform.

Summary:

The transformers are heavy in weight and in the summer heat they have a tendency to sink in the asphalt. The storage area would consist of cement and the driving area would still be asphalt.
To make this project a success we must hire a company or companies to spread and compact approximately 8,860m2 of HL-3 surface asphalt pavement. The cost must include milling required joints, sweeping and a tack coat applied to the existing lot prior to paving. The paving will be completed in two stages which will include all the necessary adjustments to the catch basins and manholes. To make the cement part of this project successful the company must supply, spread and compact 226 ton of granular "A" stone. They would then form and pour 3 pads of cement 110' x 18' x 6" with 6 gauge wire mesh underneath.

Impact:

- By pouring three separate cement pads for the storage of transformers the area will be able to hold up better in the summer heat.
- Once all the work has been completed it will greatly reduce Chatham-Kent Hydro 's yearly costs on preventative maintenance. With proper routine maintenance the asphalt should exceed another twenty years of life cycle.

Estimated Annual Expenditures

Cost	2009	2010	2011	2012
Budgeted Capital Cost	25,000	350,000		

Chatham-Kent Hydro Budgeted Project

Type of Project:	Environmental Storage Facility
Project Name:	Oil Retention Compound

Purpose:

Chatham-Kent Hydro will have all of its transformers tested for PCB's and the high ppm's replaced by the end of the year 2010, therefore, it will no longer need it PCB storage facility.

Summary:

We would like to replace this area with a transformer contained storage area complete with a cement oil retention barrier

To build the containment area we must form and pour a 24' x 26' x 8" pad with 10m rebar. They will form and pour 76' x 10" x 10" curb and a 4' x 24'x 8" ramp for the forklift. It will also consist of a 4" water stop and 20 tons of granular "A" stone.

Impact:

- By building this environmental storage facility complete with oil retention curb barrier we will be able to contain any types of oil leaks.
- This will protect our new asphalt from sustaining any oil being absorbed or the potential of it getting into the sewers that are located around the yard.

Estimated Annual Expenditures

Cost	2009	2010	2011	2012
Budgeted Capital Cost		50,000		

Chatham-Kent Hydro Budgeted Project

Type of Project:	Material Holding Facility
Project Name:	Secured Compound

Purpose:

Due to the increase in the number of break-in incidents at Chatham-Kent Hydro's rear stock yard it has found it necessary to construct a secured building. This building will be used strictly for the storage of all aluminum wire, both overhead and underground and also the scrap copper wire bin.

Summary:

With amalgamation of thirteen utilities in 1998 and the centralization of Chatham-Kent Hydro warehouses it has become increasingly necessary for us to find more storage space.

Over the past year we have experienced numerous incidents from storing our wire outside in which our fence has been cut to gain access into the yard after hours. This building will store our wire (which is greatly affected by commodity prices) in a secured facility to limit theft and deterioration.

Facility will be a 48' x 60' post frame building with a 16' eave height. This building will be built with a 6" concrete slab floor (25 MPa). The walls will be built with 28Ga. 8000 series "channel wall" steel and the roof will consist with 29Ga. "hi-rib" roof steel. It will have two man doors and one 12' x 15' steel sliding door.

Impact:

- This new secured storage building it will reduce the risk for future potential thefts.
- Provide the necessary extra storage capacity it needs.
- Facility will also limit the exposure of material to weathering before being used.

Estimated Annual Expenditures

Cost	2009	2010	2011	2012
Budgeted Capital Cost		100,000		

Chatham-Kent Hydro Budgeted Project

Type of Project:	General Equipment
Project Name:	Substation Repairs

Purpose:

Replace the roofs at substations 3 and 4.

Summary:

Six of Chatham-Kent Hydro's substations are enclosed in buildings as they are located in residential areas. Two of these buildings require roof replacements.

Impact:

- Protect internal electrical equipment from the weather.
- Extend the life of the substation buildings

Estimated Annual Expenditures

Cost	2009	2010	2011	2012
Budgeted Capital Cost		15,000		

CAPITALIZATION POLICY:

Chatham-Kent Hydro records capital assets in accordance with Canadian Generally Accepted Accounting Principles and with Article 410 of the Accounting Procedures Handbook.

Materiality

Chatham-Kent Hydro uses a materiality threshold of $1,000, such that any single item that costs $1,000 or more and has a useful life of more than 1 year will be capitalized.

Rebuild / Repair / Replacement Projects

Chatham-Kent Hydro in operating and maintaining the distribution system will be required to rebuild, repair or replace parts of the distribution system or the equipment used (such as bucket trucks) to do so. In cases where the useful life of the distribution system or the equipment has been extended these costs are capitalized and amortized over the remaining useful life.

Inventory and Allocation of Stores Costs

In order for Chatham-Kent Hydro to operate the distribution system and meet the service level requirements of the OEB and the customers it is necessary to have a level of inventory. The costs of material being issued to capital and operation projects are the average cost of the material plus an allocation of the stores costs.

The stores costs include the direct labour and supplies to operate the warehouse. The stores allocation is a percentage of the average cost of the material be issued to the project.

Vehicle Costs

All projects whether they are capital or operation and maintenance costs will be directly allocated trucking costs for each hour that the trucks are used on the specific project. The vehicles are classified into two categories and the hourly rate for each truck is an average of the costs to operate the trucks.

Management's Time

Management and administrative staff support all projects and activities of the direct labour, therefore it is necessary to allocate a portion of their time and costs to the projects that are being worked on. An estimate of the time that each management and administrative staff member performs on capital projects is added to the direct labour that is performed on capital projects.

OVERVIEW OF ASSET MANAGEMENT PLAN:

General

The Chatham-Kent Hydro service area is unique in that it consists of several small to medium sized urbanized areas with the majority of the area being embedded in a larger rural zone serviced by Hydro One. Each urbanized zone is a former utility amalgamated in 1998. This complicated border adds complexity to the asset mix. Specifically,

- Each former utility used its own construction standards and materials.
- Each urbanized area is separately metered requiring a higher number of wholesale meter points than would otherwise be required for similarly sized utilities.
- Each former utility had its own population of substations resulting in more substation assets per customer than average.
- Each former utility managed its own assets to a varying degree resulting in an asset mix of significant age differences and condition.
- Many of the urbanized areas are radial fed by Hydro One owned feeders. A significant portion of the assets directly responsible for servicing many areas is not under the control of Chatham-Kent Hydro. Chatham-Kent Hydro's ability to isolate and transfer loads is also strictly limited for the same reasons.

At its formation, in 1998, Chatham-Kent Hydro initiated a GIS project to map and record information about all distribution assets. The GIS has continued to evolve and data has been updated and refined over the years. GIS now forms the basis for many of Chatham-Kent Hydro's maintenance projects, such as: pole replacement, tree trimming, Switches, vault maintenance, PCB testing, and Distribution Transformers and for many of its asset replacement projects: voltage conversion, cable replacement, transformer replacement, Subdivision Rebuilds, system Reinforcement, Public Safety and Demand Capital.

GIS is expected to become more critical with the implementation of smart meters and the smart grid in the coming years.

System Snapshot

Area Assessment

Town	Pop	Area(kM)	Res	GS < 50	GS > 50	TOU	Large Users	Voltage (kV)	27.6kV Feeders	Connection	WH Meters	Substations	No of Transformers	Trans/Cust	Age of Trans	No of Poles	Age of Poles
Chatham	43,690	35.3	16,237	1,687	230	3	1	27.6/4.16	5	Direct	6	5	1,839	23.8	20.8	8,037	30.3
Wallaceburg	11,114	10.7	4,319	458	75	-	1	27.6	3	Embedded	3	0	528	21.0	13.2	2,889	27.8
Tilbury	4,599	6.7	1,922	206	35	-	-	27.6	3	Embedded/Retail	3	0	231	19.9	6.6	1,235	29.7
Blenheim	4,870	4.6	1,678	221	34	1	-	27.6/4.16	2	Embedded	2	2	236	20.6	11.3	1,180	17.8
Ridgetown	3,358	4.7	1,378	181	21	-	-	27.6/4.16	2	Embedded	2	2	165	20.4	12.3	1,094	28.9
Dresden	2,572	3.5	1,020	135	15	-	-	27.6/4.16	1	Embedded	1	2	142	18.1	11.9	947	21.8
Wheatley	1,686	4.7	648	103	8			27.6/4.16	1	Embedded/Retail	2	1	98	17.2	16.7	596	23.9
Bothwell	1,002	2.0	381	66	5	-	-	8	1	Retail	1	0	71	14.1	20.8	509	41.8
Thamesville	928	2.2	360	89	6	-	-	4.16	1	Embedded	1	1	68	13.6	19.9	483	25.7
Erieau	442	0.9	329	53	1	-	-	4.16	1	Embedded	1	0	44	10.0	11.9	310	24
Merlin	500	1.6	279	38	-	-	-	8	1	Embedded	1	0	42	11.9	7.2	246	19
Total	**74,761**	**76.9**	**28,551**	**3,237**	**430**		**2**						**3,464**	**21.6**		**17,526**	27.7
Chatham-Kent	**107,341**				**Customers**		**32,220**										

This chart summarizes some system key statistics. It is used to help prioritize some projects and schedule work. It also gives a general overall view of the system by town.

Note: Population data for Merlin is not official. No official source available.

Maintenance Projects

Chatham-Kent Hydro manages several annual maintenance and inspection projects targeted at key assets critical to the distribution infrastructure. These related projects costs are built into the 2010 OM&A budget. Each project will be described below in more detail. In all cases the minimum standard is that set out by the DSC and in some cases are exceeded depending on inspection and measurements taken in the field.

Lines and Equipment

The Infrared screening of the Lines and Equipment 3 year Budget is the following:

	2010	***2011***	***2012***
Infrared screening	*20,000*	*20,000*	*20,000*

1/3 of all overhead lines, switches, padmount transformers, padmount switchgear are scanned via infrared annually. Any devices identified as operating X degrees above ambient are inspected and repairs made immediately. A standing budget is set aside each year to affect any required repairs specifically identified by this program.

Tree Trimming Program

The Tree Trimming Program 3 year Budget is the following:

	2010	***2011***	***2012***
Tree Trimming	*180,000*	*180,000*	*180,000*

Each year, 1/3 of the service area is scheduled for tree trimming starting in January and ending in May. Approximately one hundred kilometers of feeder lines are cleared of vegetation each year. With the tree trimming program there is generally a public education campaign to raise public awareness of tree interference with overhead lines culminating in the planting of 30 to 40 new trees annually in areas free of overhead lines.

Switches

The switches 3 year Budget is the following:

	2010	***2011***	***2012***
Switches	*50,000*	*50,000*	*50,000*

All switch data is maintained in the GIS, including nameplate data, age, and location. A new Outage Management System will track number of operations and is scheduled to be implemented in 2009; currently this data is maintained manually. Switch inspections are done via the infrared scanning program detailed above. Switches identified as "hot" or suspect are inspected and repairs made immediately.

Vaults

The Vaults Maintenance 3 year Budget is the following:

	2010	***2011***	***2012***
Vaults Maintenance	*25,000*	*25,000*	*25,000*

There are 396 vaults located throughout the Municipality of Chatham-Kent used primarily in residential subdivisions serviced before 1996 to house submersible transformers. The lids of these vaults are steel and often rust and corrode requiring repairs. Annually 1/3 of all vaults (~130/year) are inspected, cleaned and repaired. Sacrificial anodes are re-installed and any major repairs are noted and scheduled as required.

Substations

The Substations Maintenance 3 year Budget is the following:

	2010	***2011***	***2012***
Substations Maintenance	*65,000*	*65,000*	*65,000*

There are a total of 12-27.6kV/4.16kV substations owned by Chatham-Kent Hydro. All substation information is kept centrally filed and contains data on oil testing, monthly substation

inspections, triennial substation testing (~4 substations per year) and maintenance and any historical documentation such as schematics or past construction activity at the substation.
All substations are inspected monthly; information about each visit is documented and filed. Any deficiencies are highlighted and repairs are made quickly depending on the criticality of the problem.

All substations currently operate at 27.6kV and convert load to 4.16kV. 4.16kV is an antiquated distribution voltage that is actively being replaced. As a result, there is generally no real time data (e.g. SCADA) at stations located outside the Chatham service area. Loading data is collected manually and monthly at those particular sites. This data is used to plan for future maintenance programs, as well as to prioritize substation conversion and elimination.
Oil testing is done annually for each substation transformer. This establishes a trend whereby one can determine the rate of decay (or stability) of a particular transformer and properly plan ahead of time for replacement or refurbishment. Where possible, testing is done by the same testing agency in order to eliminate variability introduced by techniques and materials used by different laboratories.

Substation data of this type is not emendable to representation in GIS, as such much of this data remains in paper form. This is not a significant issue as substations are eliminated at a rate of 1 every 1-3 years.

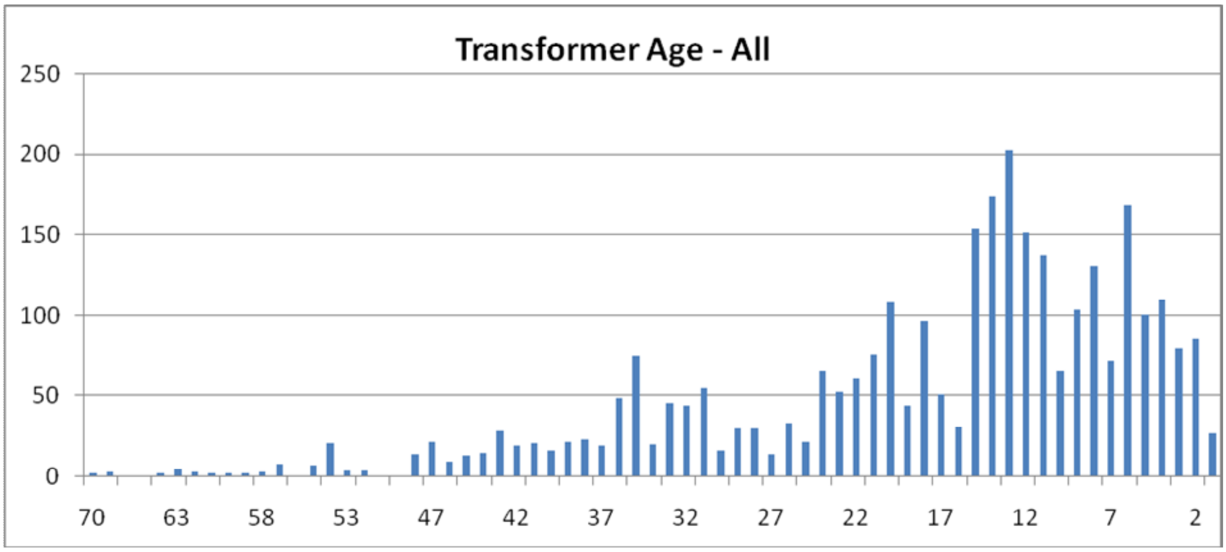
Distribution Transformers

The Distribution Transformer 3 year Budget is the following:

	2010	***2011***	***2012***
Distribution Transformers	*80,000*	*70,000*	*70,000*

There are 3,470 transformer installations in the Chatham-Kent Hydro system. Asset data for all distribution transformers is kept and maintained in the GIS. Transformer data is maintained for the life of the transformer and records are not deleted. Transformers that are sold or scrapped are marked “SOLD” or “SCRAPPED” in the database and the record is tagged as inactive. All PCB test data, purchasing data and current installation details are tracked for the life of the asset.

PCB testing is done for all transformers not tagged “NON_PCB” or has a manufacturing date before 1986. All distribution transformers are scheduled to be tested by the end of 2010. At which time any transformer above the 50PPM limit will be scheduled for removal from the system in 2010 but no later than 2011. Conversion projects may also influence when the transformer is replaced.



The age of transformers reflects a heavier focus on transformer replacements and conversions over the last 10 years.

Capital Programs

Capital programs consist of projects to extend the distribution to accommodate new load and to replace assets on the field that are at the end of their useful life. Capital programs are formulated in advance and related costs are built into the capital budget in 5 year plans. These plans are reviewed annually and adjusted to reflect the results of annual maintenance programs and inspections, as well as planned load growth or other planned projects, such as road widening or public works.

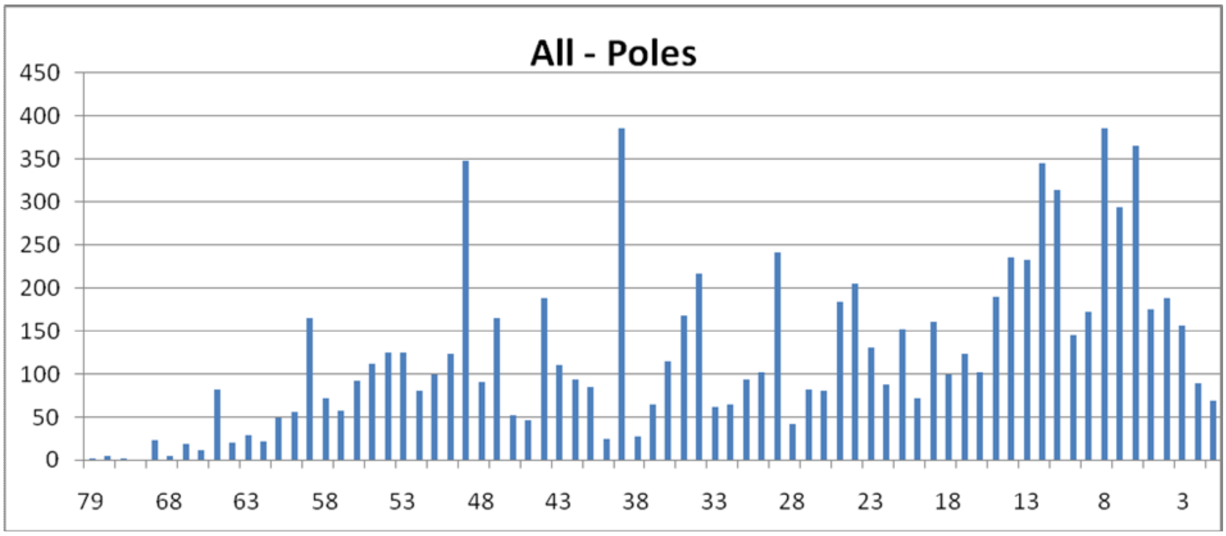
Poles

The Pole Replacement Program 3 year Budget is the following:

	2010	***2011***	***2012***
Pole Replacement	*100,000*	*100,000*	*100,000*

All pole data is maintained in the GIS. Poles are inspected as part of the annual tree trimming program as well during any other major construction project. Any damaged or deteriorated poles are identified and further inspected. Poles are replaced as required as determined by further inspection by an Engineering Technologist.

Poles that are deemed sound for the short term are identified for inclusion as part of a larger future project in the overall plan. Annual revisions to the plan may be altered to include the replacement of these poles as warranted.



Pole age distribution is reflective of past activity. Over the past 10 years there has been more of a focus on conversion and line rebuild resulting in a more significant population of poles less than 10 years old. This trend is expected to continue.

Load Interrupter Switches Replacement

The LIS 3 year Budget is the following:

	2010	***2011***	***2012***
Switches	*60,000*	*60,000*	*60,000*

Annually, switches are identified for replacement based on several criteria:

- age
- location - critical switching juncture
- Number of operations

Three switches are chosen accordingly and scheduled for replacement. In the rare instance where more than 3 are highlighted as critical the list is expanded accordingly. Conversion projects or other major line rebuilds incorporate these switch replacements (or other switches so identified) whenever possible to avoid duplication of effort.

27.6kV Conversion Projects

The Conversion Projects 3 year Budget is the following:

	2010	***2011***	***2012***
Conversions	*910,750*	*351,511*	*702,284*

Since 1998 Chatham-Kent Hydro has instituted an active conversion program to eliminate all older 4.16kV distribution from the system. Conversion to a higher voltage can significantly reduce losses and the elimination of a 4.16kV substation incurs significant other savings in ongoing maintenance cost into the long term.

To date, 2 towns (Wallaceburg and Tilbury) have been fully converted and six 4.16kV substations have been eliminated. As mentioned, these are long term ongoing projects. Areas for conversion are targeted based on several criteria. Age and condition of the 4.16kV plant, distribution and type of customer base (i.e. industrial vs. residential), condition of the 4.16kV substations, and operating issues related to switching and sharing load among other 4.16kV distribution. Chatham-Kent Hydro's current plans concentrate activity in the Chatham service area where plant age and condition is warranted and Chatham-Kent Hydro plans to target each town in turn for full conversion over 2-3 years each, depending on the extent of the 4.16kV distribution. Currently Dresden and Blenheim have been targeted for conversion. Each year the conversion projects are broken down into 3-4 medium size projects to allow for better scheduling and allow for time for completion of design and engineering plans.

Subdivision Rebuilds

The Subdivision Rebuilds 3 year Budget is the following:

	2010	***2011***	***2012***
Subdivisions	*131,950*	*133,929*	*135,938*

Underground cable in some older subdivisions is nearing end of life resulting in higher rates of failures over the past 5 years. As a result, these older residential subdivisions are being rebuilt to have all underground cable and transformers replaced. Projects such as these are multi-year commitments and typically each subdivision requires 2 or more years to be fully rebuilt. The opportunity to rebuild these areas also allows for the installation of more modern and current designs and construction practices. Specifically, all distribution is converted to 27.6kV, all submersible transformers are replaced with above grade mini-pad transformers and all new cable is installed through directionally bored continuous duct.

Transformer Replacements

The Transformers Replacement 3 year Budget is the following:

	2010	***2011***	***2012***
Transformers	*152,250 (forecasted increased activity due to accelerated PCB testing program)*	*110,001*	*110,001*

As mentioned in the maintenance portion of this report, transformers are chosen for replacement based on their PCB content, age and condition as identified visually and through infrared inspection. Each year a varying number of transformers are replaced depending on their criticality. This is listed as a separate budget item on an ongoing basis.

System Reinforcement

The System Reinforcement 3 year Budget is the following:

	2010	***2011***	***2012***
System Reinforcement	*800,000*	*475,000*	*750,000*

New load growth areas are identified while formulating the plans and each year an assessment is made on whether or not the distribution system needs to be expanded or reinforced to support this new load. Operating issues are also considered, such as a difficulty to transfer load for maintenance purposes or the absence of tie lines and switches to reduce outages. Currently there are several areas highlighted for improvement as identified in the plan.

Public Safety

The Public Safety 3 year Budget is the following:

	2010	***2011***	***2012***
Public Safety	*130,000 (includes repairs to low voltage vaults)*	*30,000*	*30,000*

As indicated above, some of the former utilities had widely different construction practices. What was acceptable 20 years ago is not standard practice today and as a result some existing plant is located in difficult to access areas, or too close to buildings. These situations have been identified and prioritized since 1998 and eliminated as time and budgets allowed. Although fewer, some situations still persist and are identified annually to remediation.

Demand Capital

The Demand Capital 3 year Budget is the following:

	2010	***2011***	***2012***
Demand Capital	*1,172,531*	*1,187,907*	*1,269,176*

This portion of the capital program summarizes all activity principally driven by customer demand. Often these projects are difficult to forecast specifically. An attempt is made to forecast expected activity on a per group basis reducing the statistical error but the variability for a utility the size of Chatham-Kent Hydro is still significant. This portion of the capital plan is divided into several groups separated by customer class driving the need for the investment.

Other budget items heavily influenced by this activity are also grouped into Demand Capital. Unless specific projects are planned well ahead of time, such as a road widening, or large industrial load, specific budget dollar forecasts are based on historical trending.

ALLOWANCE FOR WORKING CAPITAL:

Overview and Calculation by Account:

Chatham-Kent Hydro's working capital allowance is forecast to be $8,668,139 for 2010 and is based on the "15% of specific OM&A accounts formula approach" referred to at page 15 of the Board's Filing Requirements. Chatham-Kent Hydro has provided its calculations by account for each of 2006 Actual, 2007 Actual, 2008 Actual, the 2009 Bridge Year and the 2010 Test Year in Table 1 on the following pages. Chatham-Kent Hydro has provided a spreadsheet setting out Chatham-Kent Hydro's Cost of Power calculations as Appendix A to this Schedule.

Table 2-20
Working Capital Calculation by Account

Expense Description	2006 Actual	Allowance for Working Capital	2007 Actual	Allowance for Working Capital	2008 Actual	Allowance for Working Capital	2009 Bridge	Allowance for Working Capital	2010 Test	Allowance for Working Capital
Power Supply										
4705 - Power Purchased	49,039,932	7,355,990	49,529,573	7,429,436	48,147,972	7,222,196	41,889,709	6,283,456	40,722,897	6,108,435
4708 - Charges WMS	5,537,499	830,625	5,507,216	826,082	5,281,154	792,173	4,538,052	680,708	4,359,335	653,900
4714 - Charges NW	4,417,648	662,647	4,153,219	622,983	3,694,409	554,161	3,791,316	568,697	3,078,724	461,809
4716 - Charges CN	4,439,091	665,864	4,465,155	669,773	3,544,107	531,616	3,192,909	478,936	2,595,180	389,277
4730 - Rural Rate Assistance Expense	-	0	-	0	-	0		0		0
4750 - Low Voltage		0		0		0	243,015	36,452	228,345	34,252
Sub-Total	**63,434,169**	**9,515,125**	**63,655,163**	**9,548,274**	**60,667,641**	**9,100,146**	**53,655,001**	**8,048,250**	**50,984,482**	**7,647,672**
Operation										
5005-Operation Supervision and Engineering	126,478	18,972	121,376	18,206	94,780	14,217	98,227	14,734	164,224	24,634
5010-Load Dispatching	0	0	0	0	0	0	0	0	0	0
5012-Station Buildings and Fixtures Expense	0	0	0	0	0	0	0	0	0	0
5014-Transformer Station Equipment - Operation Labour	0	0	0	0	0	0	0	0	0	0
5015-Transformer Station Equipment - Operation Supplies and Expenses	0	0	0	0	0	0	0	0	0	0
5016-Distribution Station Equipment - Operation Labour	8,405	1,261	56,280	8,442	56,348	8,452	55,365	8,305	107,180	16,077
5017-Distribution Station Equipment - Operation Supplies and Expenses	3,184	478	875	131	6,233	935	5,295	794	6,471	971
5020-Overhead Distribution Lines and Feeders - Operation Labour	102,480	15,372	103,093	15,464	92,120	13,818	98,369	14,755	110,535	16,580
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	36,043	5,406	34,530	5,179	28,808	4,321	31,852	4,778	36,711	5,507
5030-Overhead Subtransmission Feeders - Operation	0	0	0	0	0	0	0	0	0	0
5035-Overhead Distribution Transformers- Operation	39,754	5,963	37,911	5,687	27,505	4,126	50,206	7,531	50,252	7,538
5040-Underground Distribution Lines and Feeders - Operation Labour	137,123	20,568	147,289	22,093	176,507	26,476	159,122	23,868	163,707	24,556
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	38,369	5,755	58,734	8,810	27,878	4,182	22,863	3,429	26,656	3,998
5050-Underground Subtransmission Feeders - Operation	0	0	0	0	0	0	0	0	0	0
5055-Underground Distribution Transformers - Operation	0	0	25	4	26	4	47	7	47	7
5065-Meter Expense	211,305	31,696	242,338	36,351	369,887	55,483	235,006	35,251	345,446	51,817
5070-Customer Premises - Operation Labour	15,507	2,326	17,814	2,672	17,708	2,656	27,777	4,166	27,909	4,186
5075-Customer Premises - Materials and Expenses	5,031	755	5,542	831	1,128	169	2,098	315	2,098	315
5085-Miscellaneous Distribution Expense	0	0	0	0	0	0	0	0	0	0
5096-Other Rent	0	0	0	0	0	0	0	0	0	0
Sub-Total	**723,678**	**108,552**	**825,806**	**123,871**	**898,928**	**134,839**	**786,225**	**117,934**	**1,041,236**	**156,185**

Maintenance

5105-Maintenance Supervision and Engineering	141,378	21,207	136,597	20,490	207,258	31,089	200,912	30,137	315,211	47,282
5110-Maintenance of Buildings and Fixtures - Distribution Stations	0	0	0	0	0	0	0	0	0	0
5112-Maintenance of Transformer Station Equipment	0	0	0	0	0	0	0	0	0	0
5114-Maintenance of Distribution Station Equipment	194,950	29,243	188,150	28,223	147,910	22,187	139,466	20,920	151,068	22,660
5120-Maintenance of Poles, Towers and Fixtures	55,029	8,254	40,176	6,026	65,634	9,845	38,980	5,847	53,155	7,973
5125-Maintenance of Overhead Conductors and Devices	131,731	19,760	134,956	20,243	157,590	23,638	150,495	22,574	190,050	28,508
5130-Maintenance of Overhead Services	133,854	20,078	142,076	21,311	129,867	19,480	118,705	17,806	120,532	18,080
5135-Overhead Distribution Lines and Feeders - Right of Way	170,445	25,567	159,623	23,943	154,264	23,140	170,000	25,500	180,000	27,000
5145-Maintenance of Underground Conduit	2,051	308	3,709	556	3,013	452	3,084	463	3,706	556
5150-Maintenance of Underground Conductors and Devices	8,194	1,229	6,178	927	4,094	614	5,092	764	5,863	879
5155-Maintenance of Underground Services	58,514	8,777	40,174	6,026	61,631	9,245	49,657	7,449	54,106	8,116
5160-Maintenance of Line Transformers	57,303	8,595	34,921	5,238	64,452	9,668	76,075	11,411	91,936	13,790
5172-Sentinel Lights-Materials and Expenses	0	0		0		0		0		0
5175-Maintenance of Meters	28,353	4,253	18,137	2,721	35,315	5,297	23,159	3,474	22,170	3,325
Sub-Total	**981,801**	**147,270**	**904,698**	**135,705**	**1,031,028**	**154,654**	**975,626**	**146,344**	**1,187,798**	**178,170**

Billing and Collections

5305-Supervision	55,980	8,397	65,136	9,770	84,996	12,749	134,027	20,104	137,237	20,586
5310-Meter Reading Expense	98,549	14,782	58,600	8,790	58,014	8,702	43,848	6,577	34,853	5,228
5315-Customer Billing	825,468	123,820	735,468	110,320	860,460	129,069	847,640	127,146	1,025,552	153,833
5320-Collecting	293,703	44,056	286,872	43,031	182,643	27,396	341,446	51,217	416,389	62,458
5325-Collecting- Cash Over and Short	0	0	0	0	0	0	0	0	0	0
5330-Collection Charges	0	0	0	0	0	0	0	0	0	0
5335-Bad Debt Expense	116,777	17,517	142,257	21,339	237,086	35,563	212,806	31,921	212,766	31,915
5340-Miscellaneous Customer Accounts Expenses	0	0	0	0	0	0	0	0	0	0
Sub-Total	**1,390,478**	**208,572**	**1,288,334**	**193,250**	**1,423,199**	**213,480**	**1,579,767**	**236,965**	**1,826,798**	**274,020**

Community Relations

5405-Supervision	0	0	0	0	0	0	0	0	0	0
5410-Community Relations - Sundry	19,323	2,899	29,793	4,469	41,198	6,180	33,123	4,968	44,929	6,739
5415-Energy Conservation	0	0	45,227	6,784	7,775	1,166	0	0	0	0
5420-Community Safety Program	3,888	583	18,108	2,716	4,457	669	5,973	896	9,557	1,434
5510-Demonstrating and Selling Expense	0	0	0	0	0	0	0	0	0	0
5515-Advertising Expense	0	0	0	0	0	0	2,049	307	2,043	306
5520-Miscellaneous Sales Expense	0	0	0	0	0	0	0	0	0	0
Sub-Total	**23,211**	**3,482**	**93,127**	**13,969**	**53,431**	**8,015**	**41,145**	**6,172**	**56,529**	**8,479**

Administrative and General Expenses

5605-Executive Salaries and Expenses	44,934	6,740	72,487	10,873	77,217	11,583	70,521	10,578	73,847	11,077
5610-Management Salaries and Expenses	430,759	64,614	413,289	61,993	446,382	66,957	717,697	107,655	875,544	131,332
5615-General Administrative Salaries and Expenses	186,135	27,920	217,221	32,583	215,196	32,279	148,724	22,309	245,314	36,797
5620-Office Supplies and Expenses	55,519	8,328	65,979	9,897	64,432	9,665	55,962	8,394	59,699	8,955
5630-Outside Services Employed	304,311	45,647	372,388	55,858	360,881	54,132	386,276	57,941	233,633	35,045
5635-Property Insurance	114,060	17,109	94,752	14,213	81,000	12,150	83,186	12,478	84,175	12,626
5640-Injuries and Damages	0	0	0	0	0	0	0	0	0	0
5645-Employee Pensions and Benefits	202,543	30,381	234,815	35,222	234,149	35,122	231,197	34,680	250,137	37,521
5655-Regulatory Expenses	147,937	22,191	168,799	25,320	280,894	42,134	238,662	35,799	339,852	50,978
5660-General Advertising Expenses	0	0	0	0	0	0	0	0	0	0
5665-Miscellaneous General Expenses	0	0	0	0	0	0	0	0	0	0
5670-Rent	0	0	0	0	0	0	0	0	0	0
5675-Maintenance of General Plant	532,148	79,822	527,480	79,122	512,441	76,866	511,162	76,674	528,550	79,283
6205-Charitable Donations		0		0		0		0		0
Sub-Total	**2,018,346**	**302,752**	**2,167,209**	**325,081**	**2,272,590**	**340,889**	**2,443,387**	**366,508**	**2,690,751**	**403,613**

Taxes Other Than Income Taxes

6105-Property Taxes	0		0	0	0	0	0	0	0	0
Sub-Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Total Operating, Maintenance and Administration Expenses	**5,137,513**	**770,627**	**5,279,175**	**791,876**	**5,679,177**	**851,876**	**5,826,150**	**873,923**	**6,803,112**	**1,020,467**
Total	68,571,683	10,285,752	68,934,337	10,340,151	66,346,818	9,952,023	59,481,151	8,922,173	57,787,594	8,668,139

APPENDIX A

COST OF POWER CALCULATION

COST OF POWER CALCULATION:

Electricity - Commodity	**2010 Forecasted**				
Class per Load Forecast	**Metered kWhs**	**2010 Loss Factor**		**2010**	
Residential	199,501,364	1.0443	208,348,066	$0.0607	$12,650,895
General Service < 50 kW	86,923,094	1.0443	90,777,617	$0.0607	$5,512,017
General Service > 50 to 999 kW	183,018,503	1.0443	191,134,288	$0.0607	$11,605,674
Intermediate	134,791,341	1.0443	140,768,538	$0.0607	$8,547,466
Large Use	0	0.0000	0	$0.0607	$0
Streetlights	334,470	1.0443	349,301	$0.0607	$21,210
Sentinel Lights	5,547,412	1.0443	5,793,407	$0.0607	$351,776
Unmetered Scattered Loads	1,041,782	1.0443	1,087,979	$0.0607	$66,062
Standby	31,031,687	1.0443	32,407,758	$0.0607	$1,967,799
TOTAL	**642,189,652**		**670,666,953**		**$40,722,897**

Transmission - Network		**Volume**			
Class per Load Forecast		**Metric**		**2010**	
Residential		kWh	208,348,066	$0.0048	$1,000,071
General Service < 50 kW		kWh	90,777,617	$0.0043	$390,344
General Service > 50 to 999 kW		kW	502,112	$1.7720	$889,742
Intermediate		kW	322,877	$1.8882	$609,657
Large Use		kW	0		$0
Streetlights		kW	1,079	$1.3460	$1,452
Sentinel Lights		kW	18,432	$1.3363	$24,631
Unmetered Scattered Loads		kWh	1,087,979	$0.0043	$4,678
Standby		kW	83,730	$1.8888	$158,149
TOTAL			**301,141,892**		**$3,078,724**

Transmission - Connection		**Volume**			
Class per Load Forecast		**Metric**		**2010**	
Residential		kWh	208,348,066	$0.0041	$854,227
General Service < 50 kW		kWh	90,777,617	$0.0037	$335,877
General Service > 50 to 999 kW		kW	502,112	$1.4556	$730,874
Intermediate		kW	322,877	$1.5942	$514,731
Large Use		kW	0		$0
Streetlights		kW	1,079	$1.1475	$1,238
Sentinel Lights		kW	18,432	$1.1244	$20,725
Unmetered Scattered Loads		kWh	1,087,979	$0.0037	$4,026
Standby		kW	83,730	$1.5942	$133,482
TOTAL			**301,141,892**		**$2,595,180**

Wholesale Market Service					
Class per Load Forecast				**2010**	
Residential			208,348,066	$0.0052	$1,083,410
General Service < 50 kW			90,777,617	$0.0052	$472,044
General Service > 50 to 999 kW			191,134,288	$0.0052	$993,898
Intermediate			140,768,538	$0.0052	$731,996
Large Use			0	$0.0052	$0
Streetlights			349,301	$0.0052	$1,816
Sentinel Lights			5,793,407	$0.0052	$30,126
Unmetered Scattered Loads			1,087,979	$0.0052	$5,657
Standby			32,407,758	$0.0052	$168,520
TOTAL			**670,666,953**		**$3,487,468**

Rural Rate Assistance					
Class per Load Forecast				**2010**	
Residential			208,348,066	$0.0013	$270,852
General Service < 50 kW			90,777,617	$0.0013	$118,011
General Service > 50 to 999 kW			191,134,288	$0.0013	$248,475
Intermediate			140,768,538	$0.0013	$182,999
Large Use			0	$0.0013	$0
Streetlights			349,301	$0.0013	$454
Sentinel Lights			5,793,407	$0.0013	$7,531
Unmetered Scattered Loads			1,087,979	$0.0013	$1,414
Standby			32,407,758	$0.0013	$42,130
TOTAL			**670,666,953**		**$871,867**

	2010
4705-Power Purchased	$40,722,897
4708-Charges-WMS	$3,487,468
4714-Charges-NW	$3,078,724
4716-Charges-CN	$2,595,180
4730-Rural Rate Assistance	$871,867
4750-Low Voltage	$228,345
TOTAL	**50,984,482**

Overview of Service Quality:

Chatham-Kent Hydro has consistently exceeded the OEB's Service Quality Indicators and, as set out in Table 2-19 below, has targeted to maintain its performance at levels equal to or above the OEB's standards.

Table 2-19
CHATHAM-KENT HYDRO INC.'S SERVICE QUALITY INDICATORS
PERFORMANCE FOR 2006, 2007 and 2008

Appointments Met – at the appointed time		
SQI Standard: 90% of the time		
2006 Actual	**2007 Actual**	**2008 Actual**
98.94 %	100.00 %	99.60 %
Telephone Accessibility – answered in person within 30 seconds		
SQI Standard: 65% of the time		
2006 Actual	**2007 Actual**	**2008 Actual**
74.07 %	77.30 %	78.60 %
Underground Cable Locates – within 5 working days		
SQI Standard: 90% of the time		
2006 Actual	**2007 Actual**	**2008 Actual**
97.87 %	98.80 %	90.40 %
Connection of New Services –within 5 working days		
SQI Standard: 90% of the time		
2006 Actual	**2007 Actual**	**2008 Actual**
96.65 %	95.10 %	97.00 %
Emergency Response – Urban within 60 minutes and Rural within 120 minutes		
SQI Standard: 90% of the time		
2006 Actual	**2007 Actual**	**2008 Actual**
92.87 %	92.40 %	92.50 %
Written Responses to Inquiries – within 10 working days		
SQI Standard: 80% of the time		
2006 Actual	**2007 Actual**	**2008 Actual**
100.00 %	100.00 %	100.00 %

Chatham-Kent Hydro has consistently exceeded the OEB's Reliability Performance standards and, as set out in Table 2-20 below, has targeted to maintain its performance at levels equal to or above the OEB's standards.

Table 2-20
CHATHAM-KENT HYDRO INC.'S RELIABILITY PERFORMANCE PERFORMANCE FOR 2006, 2007 and 2008

All Interruptions			
	2006 Actual	**2007 Actual**	**2008 Actual**
SAIDI	2.20	1.84	1.60
SAIFI	2.27	1.58	1.48
CAIDI	.97	1.16	1.08
All Interruptions excluding Loss of Supply			
	2006 Actual	**2007 Actual**	**2008 Actual**
SAIDI	-	.99	1.25
SAIFI	-	.85	1.15
CAIDI	-	1.15	1.09

OVERVIEW OF OPERATING REVENUE:

This Exhibit provides the details of Chatham-Kent Hydro's operating revenue for 2006 Board Approved, 2006 Actual, 2007 Actual, 2008 Actual the 2009 Bridge Year and the 2010 Test Year. This Exhibit also provides a detailed variance analysis by rate class of the operating revenue components. Distribution revenue does not include revenue from commodity sales.

A summary of operating revenues is presented in Table 3-1.

Throughput Revenue:

Information related to Chatham-Kent Hydro's throughput revenue includes details such as weather normalized forecasting methodology, normalized volume based on historical number of customers billed throughout the year and proposed adjustments for Conservation and Demand Management and known economic conditions. Detailed variance analysis on the throughput revenue is set out in Exhibit 3, Tab 2, Schedules 1.

Other Revenue:

Other revenues include Late Payment Charges, Miscellaneous Service Revenues and Retail Services Revenues, to name a few. A summary of these operating revenues together with a materiality analysis of variances is presented in Exhibit 3, Tab 3, Schedules 1 and 2.

Table 3-1
Summary of Operating Revenue

Distribution Revenue	2006 Board Approved	2006 Actual	Variance from 2006 Board Approved	2007 Actual	Variance from 2006 Actual	2008 Actual	Variance from 2007 Actual	2009 Bridge	Variance from 2008 actual	2010 Test	Varance from 2009 Bridge
Residenital	6,548,376	7,900,161	1,351,785	8,036,748	136,587	8,522,664	485,916	6,908,938	(1,613,726)	6,887,599	(21,339)
General Service < 50	1,970,893	2,291,467	320,574	2,156,011	(135,457)	2,198,986	42,975	1,879,696	(319,291)	1,876,182	(3,514)
General Service > 50	1,416,448	1,686,421	269,973	2,263,381	576,960	2,153,004	(110,377)	1,448,018	(704,986)	1,409,221	(38,797)
Intermediate	316,236	1,117,212	800,976	896,896	(220,316)	926,017	29,121	2,271,231	1,345,214	2,297,175	25,944
Large User	616,588	0	(616,588)	0	0	0	0	0	0	0	0
Unmetered scattered Load	0	12,122	12,122	12,395	274	12,322	(73)	13,592	1,270	12,675	(917)
Sentinel Lights	17,201	20,988	3,787	19,083	(1,905)	19,526	443	18,776	(750)	18,016	(760)
Streetlights	115,650	162,627	46,977	121,191	(41,436)	153,084	31,892	118,626	(34,458)	112,056	(6,570)
Standby	0	218,768	218,768	218,768	0	266,554	47,786	141,679	(124,875)	225,256	83,577
Sub-total Distirbution	11,001,393	13,409,767	2,408,374	13,724,473	314,706	14,252,157	527,684	12,800,555	(1,451,602)	12,838,181	37,625
Other Distribution Revenue											
Specific Service Charge	140,963	260,640	119,677	398,075	137,435	435,314	37,239	444,996	9,682	494,368	49,372
Late Payment Charges	195,525	247,177	51,652	250,221	3,043	206,625	(43,595)	170,000	(36,625)	188,861	18,861
Other Distribution Revenue	466,247	370,914	(95,333)	503,626	132,712	362,304	(141,322)	360,988	(1,316)	360,988	0
Other Income and Expenses	439,537	713,647	274,110	407,718	(305,930)	131,959	(275,759)	205,600	73,641	143,233	(62,367)
Sub-total Other Distribution	1,242,272	1,592,379	350,107	1,559,639	(32,740)	1,136,201	(423,437)	1,181,584	45,383	1,187,450	5,866
Total Distribution Revenue	12,243,665	15,002,146	2,758,480	15,284,112	281,967	15,388,358	104,246	13,982,139	(1,406,219)	14,025,631	43,491

Based on Proposed Rates

Distribution Revenue	2006 Board Approved	2006 Actual	Variance from 2006 Board Approved	2007 Actual	Variance from 2006 Actual	2008 Actual	Variance from 2007 Actual	2009 Bridge	Variance from 2008 actual	2010 Test	Varance from 2009 Bridge
Residenital	6,548,376	7,900,161	1,351,785	8,036,748	136,587	8,522,664	485,916	6,908,938	(1,613,726)	7,927,879	1,018,941
General Service < 50	1,970,893	2,291,467	320,574	2,156,011	(135,457)	2,198,986	42,975	1,879,696	(319,291)	2,159,088	279,393
General Service > 50	1,416,448	1,686,421	269,973	2,263,381	576,960	2,153,004	(110,377)	1,448,018	(704,986)	2,510,397	1,062,379
Intermediate	316,236	1,117,212	800,976	896,896	(220,316)	926,017	29,121	2,271,231	1,345,214	1,317,410	(953,821)
Large User	616,588	0	(616,588)	0	0	0	0	0	0	0	0
Unmetered scattered Load	0	12,122	12,122	12,395	274	12,322	(73)	13,592	1,270	292,758	279,166
Sentinel Lights	17,201	20,988	3,787	19,083	(1,905)	19,526	443	18,776	(750)	36,595	17,819
Streetlights	115,650	162,627	46,977	121,191	(41,436)	153,084	31,892	118,626	(34,458)	27,812	(90,814)
Standby	0	218,768	218,768	218,768	0	266,554	47,786	141,679	(124,875)	365,947	224,268
Sub-total Distirbution	11,001,393	13,409,767	2,408,374	13,724,473	314,706	14,252,157	527,684	12,800,555	(1,451,602)	14,637,886	1,837,330
Other Distribution Revenue											
Specific Service Charge	140,963	260,640	119,677	398,075	137,435	435,314	37,239	444,996	9,682	494,368	49,372
Late Payment Charges	195,525	247,177	51,652	250,221	3,043	206,625	(43,595)	170,000	(36,625)	188,861	18,861
Other Distribution Revenue	466,247	370,914	(95,333)	503,626	132,712	362,304	(141,322)	360,988	(1,316)	360,988	0
Other Income and Expenses	439,537	713,647	274,110	407,718	(305,930)	131,959	(275,759)	205,600	73,641	143,233	(62,367)
Sub-total Other Distribution	1,242,272	1,592,379	350,107	1,559,639	(32,740)	1,136,201	(423,437)	1,181,584	45,383	1,187,450	5,866
Total Distribution Revenue	12,243,665	15,002,146	2,758,480	15,284,112	281,967	15,388,358	104,246	13,982,139	(1,406,219)	15,825,336	1,843,196

VARIANCE ANALYSIS ON OPERATING REVENUE:

The distribution revenue in each year has been calculated using the approved rates for those years. As noted above, distribution revenue does not include commodity-related revenue.

A summary of normalized operating revenues is presented in Table 3-1.

2006 Board Approved:

Chatham-Kent Hydro's 2006 Board Approved operating revenue was forecast to be $12,243,665 as shown in Table 3-1. Distribution revenue totaled $11,001,393 or 89.8% of total revenues. Other operating revenue (net) accounts for the remaining revenue of $1,242,272

2006 Actual:

Chatham-Kent Hydro's operating revenue in fiscal 2006 was $15,002,146 as shown in Table 3-1. Distribution revenue totaled $13,409,767 or 89.4% of total revenues. The other operating revenue (net) accounts for the remaining revenue of $1,592,379.

Comparison to 2006 Board Approved:

As shown in Table 3-1, the total operating revenue was $2,758,480 higher than the 2006 Board Approved level forecasted. This increase resulted from higher than forecasted consumption levels, mainly in the Residential rate class, and other distribution revenue also increased in 2006.

2007 Actual:

Chatham-Kent Hydro's operating revenue in fiscal 2007 was $15,284,112, as shown in Table 3-1. Distribution revenue totaled $13,724,473 or 89.8% of total revenues. Other operating revenue (net) accounts for the remaining revenue of $1,559,639.

Comparison to 2006 Actual:

As shown in Table 3-1, the total operating revenue was $281,967 higher than the 2006 actual operating revenue. This increase resulted from an increased in number of General Service greater than 50 kW customers.

2008 Actual Year:

Chatham-Kent Hydro's operating revenue was $15,388,358 in fiscal 2008, as shown in Table 3-1. Distribution revenue totals $14,252,157 or 92.7% of total revenues. Other operating revenue (net) account is the remaining revenue of $1,136,201.

Comparison to 2007 Actual:

As shown in Table 3-1, the total operating revenue was $104,246 higher than the actual year level in fiscal 2007. This increase is the result of a combination of an increase in residential revenue and the decrease in the interest income.

2009 Bridge Year:

Chatham-Kent Hydro's operating revenue is forecast to be $13,982,139 in fiscal 2009, as shown in Table 3-1. Distribution revenue totals $12,800,555 or 91.5% of total revenues. Other operating revenue (net), account is the remaining revenue of $1,181,584.

Comparison to 2008 Actual:

As shown in Table 3-1, the total operating revenue is expected to be $1,406,219 decrease than the actual year level in fiscal 2008. This decrease is the result of reduction in forecasted usage based on the economic conditions of the service area.

2010 Test Year:

Chatham-Kent Hydro's operating revenue at current rates is forecast to be $14,025,631 in fiscal 2010, as shown in Table 3-1. Distribution revenue totals $12,838,181 or 91.5% of total revenues. Other operating revenue (net), account is the remaining revenue of $1,187,450.

Comparison to 2009 Bridge Year:

As shown in Table 3-1, the total operating revenue is expected to be an increase of $43,491 compared to the Bridge Year level in fiscal 2009. This increase is the result of the stabilizing of the economic conditions.

THROUGHPUT REVENUE:

Weather Normalized Load and Customer/Connection Forecast

Chatham-Kent Hydro Inc. has selected the Regression Model that best suits current local economic conditions and where the future market volume is going to be in 2010.

Our overall goal using regression analysis techniques for forecasting was to achieve as high a statistical correspondence between historical consumption and calculated values as possible. This is measured by the r^2 value, which is calculated as part of the regression arithmetic. A perfect match between actual and calculated values would result in an r^2 of 100%. Our initial goal was to achieve a match of 95% or better, on the advice of our consultant. After reviewing previous OEB submissions, we chose the obvious independent variables: degree day, peak/off peak hours, GDP, and population. These variables seemed to produce very favorable r^2 values for other rate submissions.

In our case however, the resultant statistical match was below 90%. A thorough review of the methodology and results indicated that there are unique local conditions that are more influential on consumption then perhaps in other jurisdictions. It was also concluded that our local economy is more loosely coupled with overall provincial economic trends rendering provincial figures for GDP less applicable (or at least not as statistically significant) as would be the case for other LDCs.

Local economic data is only sparsely available for Chatham-Kent. A search of data available from other local sources, such as Chatham-Kent's Economic Development department, did not result in any useful and reliably predictive statistics. Several other variables were tried such as relative humidity, automotive output, and customer growth. Neither of these resulted in any significant improvement in the final results. We eventually concluded that local economic factors are too significant and can't be estimated using available data sources.

We developed the concept of a seasonal and economic adjustment factors. Both factors are an attempt to model the mix of agricultural and manufacturing base in the community, each influenced by seasonal and external manufacturing demands in different ways. Through a trial and error iterative process a new set of variables that repeat annually (and are therefore easily predictable) was developed and used in the analysis. The resulting statistical match climbed over 90% and eventually peaked at the current value of approximately 93%.

There was also the analysis on determining the right level of volume for the Chatham-Kent Service Area, a comparison was conducted between the 6 year average of Heating and Cooling days with 10 year average and 20 year average. In Table 3-2 demonstrates the average Heating and Cooling days.

Table 3-2
Comparison of Heating and Cooling Days

		6 Year Average		10 Year Average		20 Year Average	
Year	Month	HDD	CDD	HDD	CDD	HDD	CDD
2010	Jan	661.3	0	653.23	0	644.93	0
2010	Feb	582.9	0	575.44	0	566.615	0
2010	Mar	481.6	0.1	484.87	0.07	479.85	0.33
2010	Apr	259.6	3	258.21	2.73	278.83	2.96
2010	May	119.7	22.7	114.78	22.98	122.04	23.48
2010	Jun	15.1	107.4	15.47	109.63	17.695	89.635
2010	Jul	0.9	161.8	0.79	167.77	1.12	151.48
2010	Aug	2.1	142.2	2.04	138.58	3.025	126.16
2010	Sep	37.9	58.2	37.87	58.74	50.72	49.25
2010	Oct	200.2	9.6	202.09	8.81	205.34	6.53
2010	Nov	367.1	0	363.24	0	388	0
2010	Dec	594.7	0	591.4	0	579.92	0

Table 3-3 illustrates the related purchases based on the different Heating and Cooling Days using the 6 year, 10 year and 20 year averages.

Table 3-3
Volume based on Heating and Cooling Days

Year	Month	6 Year Average	10 Year Average	20 Year Average
2010	Jan	67,616,407	67,449,243	67,276,242
2010	Feb	61,256,529	61,100,120	60,916,177
2010	Mar	65,927,817	65,994,337	65,921,873
2010	Apr	57,586,081	57,522,475	57,980,724
2010	May	59,161,822	59,098,335	59,311,523
2010	Jun	68,387,200	68,670,312	67,324,110
2010	Jul	73,329,093	74,070,196	72,061,516
2010	Aug	74,751,030	74,297,913	72,781,720
2010	Sep	65,426,791	65,495,217	64,588,859
2010	Oct	60,067,219	60,009,597	59,795,234
2010	Nov	59,976,401	59,895,237	60,411,319
2010	Dec	63,375,419	63,306,636	63,067,354
Total		776,861,807	776,909,617	771,436,651
Difference kWhs			47,811	(5,472,966)
Difference %			0.01%	-0.7%

From the table above the volume difference from the 6 year average and 10 year average heating and cooling days is a 0.01% difference. Compare the 6 year average to the 20 year average heating and cooling days causes the purchases to decrease by 0.7%. From the above information Chatham-Kent Hydro proposes to use the 6 year average heating and cooling days for the Regression Model.

The purpose of this evidence is to present the process used by Chatham-Kent Hydro in preparing the weather normalized load and customer/connection forecast used to design the proposed distribution rates. In summary, Chatham-Kent Hydro reviewed the various processes used by the cost of service applicants and is proposing to adopt a weather normalization forecasting method similar to the one used by Toronto Hydro Electric System Ltd in its application (EB-2007-0680).

A similar method was also approved by the Board for the following 2009 cost of service applicants.

a) Innisfil Hydro Distribution Systems Ltd.

b) Lakeland Power Distribution Ltd.

c) Niagara-on-the-Lake Hydro Inc.

d) Thunder Bay Hydro Electricity Distribution Inc.

e) London Hydro Inc.

In summary, Chatham Kent Hydro has used the same regression analysis methodology used by the distributors mentioned above to determine a prediction model. With regard to the overall process of load forecasting, it is Chatham Kent Hydro's view that in conducting a regression analysis on historical purchases to produce an equation that will predict purchases is appropriate. Chatham Kent Hydro knows by month the exact amount of kWhs purchased from the IESO and others for use by customers of Chatham Kent Hydro. With a regression analysis these purchases can be related to other monthly explanatory variables such as heating degree days and cooling degree days which occur in the same month. The results of regression analysis produces a equation that predicts the purchases based on the explanatory variables. This prediction model is then used as the basis to forecast the total level of weather normalized purchases for Chatham Kent Hydro for the Bridge and Test Year which is converted to billed kWh by rate class. A detailed explanation of the process is provided later on in this evidence.

During the review process of the 2009 cost of service applications, intervenors expressed concerns with the weather normalized load forecasting weather process being proposed by Chatham Kent Hydro. Intevenors suggested the weather normalization should be conducted on an individual rate class basis and the regression analysis would be based on monthly billed kWh by rate class. In Chatham Kent Hydro's view, conducting a regression analysis which relates the monthly billed kWh of a class is to other monthly variables is problematic. The monthly billed amount is not the amount consumed in the month but the amount billed. The amount billed is based on billing cycle meter reading schedules whose reading dates vary and typically are not at month end. The amount billed could include consumption from the month before or even further back. By using a regression analysis to relate rate class billing data to a variable such as heating degree days does not appear to be reasonable, since the resulting regression model would attempt to relate heating degree days in a month to the amount billed in the month, not the amount consumed. In Chatham Kent Hydro's view, variables such as heating degree days impact the amount consumed, and not the amount billed. It is possible to estimate the amount consumed in a month based on the amount bill but until smart meters are fully deployed this would only be an estimate which in Chatham Kent Hydro's view would reduce the accuracy of a regression model that is based on monthly billing data. In addition, Chatham-Kent Hydro does not have as many years of monthly historical billed data by rate class as it does for the amount purchased. As a result, conducting the regression analysis on purchases provides better results since a higher level of historical data increases the accuracy of the regression analysis.

Chatham Kent Hydro understands that to a certain degree the process of developing a load forecast for cost of service rate application is an evolving science for electric distributors in the province. Chatham Kent Hydro expects to include additional improvements to the load forecasting methodology in future cost of service rate applications by taking into consideration data provided by smart meters and how others are conducting load forecasts in future cost of service rate applications. However, based on the Board's approval of this methodology in a number of 2009 applications as well as the discussion that follows, Chatham Kent Hydro submits the load forecasting methodology is reasonable at this time for the purposes of this Application. Tables 3-4, 3-5 and 3-6 below provides a summary of the weather normalized load and customer/connection forecast used in this Application.

Table 3-4
Summary of Load and
Customer/Connection Forecast

Year	Billed	Growth	Percentage Change	Customer/ Connection Count	Growth	Percentage Change
2002	897,023,038			42,824		
2003	864,292,190	-32,730,848	-3.79%	42,923	99	0.23%
2004	893,202,058	28,909,868	3.24%	42,833	-90	-0.21%
2005	908,820,563	15,618,505	1.72%	42,908	75	0.17%
2006	862,509,626	-46,310,937	-5.37%	43,017	109	0.25%
2007	844,556,148	-17,953,478	-2.13%	43,001	-16	-0.04%
2008	815,656,982	-28,899,166	-3.54%	43,251	250	0.58%
2009 (B) (WN)	666,821,225	-148,835,757	-22.32%	43,326	75	0.17%
2010 (T) (WN)	642,189,652	-24,631,573	-3.84%	43,403	77	0.18%

The Billed kWhs from 2002 to 2008 are weather actual and 2009 and 2010 are weather normalized. Chatham-Kent Hydro currently does not have a process to adjust weather actual data to a weather normal basis. However, based on the process outlined in this Exhibit, a process to forecast energy on a weather normalized basis has been developed and used in this Application.

The streetlight, sentinel lights and unmetered scattered loads are measured as connections. On a rate class basis, actual and forecasted billed amount and number of customers are shown in Table 3-5 and customer usage is shown in Table 3-6.

Table 3-5
Billed Energy and Number of Customers by Rate Class

Year	Residential	General Service < 50 kW	General Service > 50 to 999 kW	Intermediate	Streetlights	Sentinel Lights	Unmetered Scattered Loads	Standby	Total
Energy									
2002	253,649,524	112,850,741	320,774,492	169,181,541	8,632,130	506,873	885,330	30,542,407	897,023,038
2003	248,336,123	112,990,352	276,007,457	189,978,099	8,065,495	418,184	885,330	27,611,150	864,292,190
2004	246,887,434	112,454,172	269,650,109	223,651,512	7,885,370	440,186	885,330	31,347,945	893,202,058
2005	255,289,127	107,002,229	261,883,968	238,123,267	7,607,072	413,698	885,330	37,615,872	908,820,563
2006	239,603,216	102,942,601	241,394,305	233,709,128	6,662,770	411,800	885,330	36,900,476	862,509,626
2007	236,072,777	100,856,561	245,541,261	216,626,810	6,663,852	402,663	1,060,728	37,331,496	844,556,148
2008	232,982,274	99,914,752	234,655,904	188,724,594	6,570,411	393,539	1,060,728	51,354,780	815,656,982
2009 (B) (WN)	210,541,450	92,173,911	201,283,895	123,176,932	6,025,655	362,105	1,049,188	32,208,089	666,821,225
2010 (T) (WN)	199,501,364	86,923,094	183,018,503	134,791,341	5,547,412	334,470	1,041,782	31,031,687	642,189,652
Number of Customers/Connections									
2002	28,087	3,282	376	18	10,465	402	193	1	42,824
2003	28,204	3,278	360	20	10,465	402	193	1	42,923
2004	28,200	3,233	360	20	10,465	361	193	1	42,833
2005	28,303	3,186	386	21	10,465	353	193	1	42,908
2006	28,347	3,140	399	21	10,570	346	193	1	43,017
2007	28,391	3,132	405	20	10,510	347	195	1	43,001
2008	28,504	3,097	409	22	10,679	344	194	1	43,250
2009 (B)	28,574	3,067	415	25	10,715	335	194	1	43,326
2010 (T)	28,644	3,038	421	28	10,751	327	194	1	43,403

Table 3-6
Annual Usage per Customer/Connection by Rate Class

Year	Residential	General Service < 50 kW	General Service > 50 to 999 kW	Intermediate	Streetlights	Sentinel Lights	Unmetered Scattered Loads	Standby
Energy usage per Customer/Connection (kWh per Customer/Connection)								
2002	9,031	34,385	853,124	9,398,975	825	1,261	4,587	30,542,407
2003	8,805	34,469	766,687	9,498,905	771	1,040	4,587	27,611,150
2004	8,755	34,783	749,028	11,182,576	753	1,219	4,587	31,347,945
2005	9,020	33,585	678,456	11,339,203	727	1,172	4,587	37,615,872
2006	8,453	32,784	604,998	11,129,006	630	1,190	4,587	36,900,476
2007	8,315	32,202	606,275	10,831,341	634	1,160	5,440	37,331,496
2008	8,174	32,262	573,731	8,578,391	615	1,144	5,468	51,354,780
2009 (B) (WN)	7,368	30,052	485,285	4,977,201	562	1,080	5,404	32,208,089
2010 (T) (WN)	6,965	28,615	435,104	4,885,525	516	1,024	5,361	31,031,687
Annual Growth Rate in Usage per Customer/Connection								
2003	-2.57%	0.25%	-11.27%	1.05%	-7.03%	-21.21%	0.00%	-10.62%
2004	-0.57%	0.90%	-2.36%	15.06%	-2.28%	14.69%	0.00%	11.92%
2005	2.94%	-3.57%	-10.40%	1.38%	-3.66%	-4.04%	0.00%	16.66%
2006	-6.71%	-2.44%	-12.14%	-1.89%	-15.32%	1.53%	0.00%	-1.94%
2007	-1.65%	-1.81%	0.21%	-2.75%	0.58%	-2.56%	15.67%	1.15%
2008	-1.73%	0.19%	-5.67%	-26.26%	-3.05%	-1.43%	0.51%	27.31%
2009 (B)	-10.93%	-7.35%	-18.23%	-72.35%	-9.41%	-5.89%	-1.19%	-59.45%
2010 (T)	-5.79%	-5.02%	-11.53%	-1.88%	-8.99%	-5.49%	-0.80%	-3.79%

LOAD FORECAST AND METHODOLOGY

Chatham-Kent Hydro's weather normalized load forecast is developed in a three-step process. First, a total system weather normalized purchased energy forecast is developed based on a multifactor regression model that incorporates historical load, weather, and economic data. Second, the weather normalized purchased energy forecast is adjusted by the loss factor calculated from the average of 2002 to 2008, to produce a weather normalized billed energy forecast. Finally, the forecast of billed energy by rate class is developed based on a forecast of customer numbers and historical usage patterns per customer. For the rate classes that have weather sensitive load their forecasted billed energy is adjusted to ensure that the total billed energy forecast by rate class is equivalent to the total weather normalized billed energy forecast. The forecast of customers by rate class is determined using time-series econometric methodologies. The forecast is also adjusted for CDM and loss of load from industrial customers who have recently reduced their operations and business that have closed. For those rate classes that use kW for the distribution volumetric billing determinant an adjustment factor is applied to class energy forecast based on the historical relationship between kW and kWh. The following will explain the forecasting process in more detail.

Purchased KWh Load Forecast

The forecast of total system purchased energy is developed using a multifactor regression model with the following independent variables: weather (heating and cooling degree days), economic output (GDP growth),Industrial Production weighting factor, population, unemployment rate, Median age and calendar variables (days in month, seasonal). The regression model uses monthly kWh and monthly values of independent variables from January 2002 to December 2008 to determine the monthly regression coefficients.

The multifactor regression model has determined primary drivers of year-over-year changes in Chatham-Kent Hydro's load growth are economic conditions and weather. Both of these effects are captured within the multifactor regression model.

Chatham-Kent is principally an industrial and agricultural community. As a consequence, total system load contains significant seasonal and industrial variability. Attempts to develop a reliable and accurate load prediction model have been frustrated by this economic bifurcation resulting in opposing and conflicting influences on total energy consumption. Forecasting has also been complicated by the recent economic downturn. As previous years' load tends to be weighted equally with more current years any significant drop-off in consumption is not captured until many months have passed.

The model attempts to incorporate these known complications in several ways. Historical load is used starting in 2002. Most economic data is only available from 2002 as Chatham-Kent is a relatively newly formed municipality and as such statistical data is hard to find.

The current load forecasting model uses multi-variable linear regression with the following independent variables:

1. Heating Degree Days: The sum of the average daily temperatures below 18C. This measure is an indicator of electrical energy required to provide heat for a given month. As Chatham-Kent is the headquarters for Union Gas, and has been well served by a natural gas network for many decades, the amount of electrical energy devoted to heating is believed to be less than for the average community.

2. Cooling Degree Days: The sum of the average daily temperatures above 18C. This measure is an indicator of the electrical energy required to provide cooling for a given month. This number, in particular, is believed to have a far more significant impact on total system load throughout the hottest months of the year. However, as heat is a highly variable component of climate, predicting this value is problematic.

3. Peak Hours: The number of peak consumption hours for each month.

4. Seasonal Weighting Factor: This is a unitless value indicative of the total industrial /agricultural production related to seasonal timing. The values were determined by an iterative process to maximize the R^2 value of the regression analysis.

5. Industrial Production Weighting Factor: Some industrial production is not related to the season or the month but rather to more economical industrial demands and production cycles on a more global scale. This unitless value is an effort to capture this variation and was determined via an iterative process.
6. Population: Total population of the Chatham-Kent service area as per Statistics Canada data.
7. Unemployment Rate: Approximate local unemployment rate. The numbers are for the entire Windsor-Sarnia region and only roughly indicate real local data. Actual Chatham-Kent employment data is unavailable.
8. GDP: Ontario GDP. A measure of economic output. Economic output is related to energy consumption accordingly. For Chatham-Kent this value has little influence on the load forecast. It is believed that provincial GDP data is only roughly coincident with local GDP data.
9. Customers: Total number of customers served with the Chatham-Kent service area.
10. Median Age: Median age of the population of Chatham-Kent as reported by Statistics Canada. It is significant, in that as median age changes, fewer (or more) children are likely to co-exist in each household which impacts total consumption per customer.

The process of developing a model of energy usage involves estimating multifactor models using different input variables to determine the best fit. Using stepwise regression techniques different explanatory variables were tested with the ultimate model being determined both by model statistics and by forecast accuracy. The Statistics of the regression equation on the forecasting the load for 2009 and 2010 is as follows:

Regression Statistics	
Multiple R	0.964
R Square	0.929
Adjusted R Square	0.920
Standard Error	1,814,386.858
Observations	84

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	9	3.17418E+15	3.53E+14	107.13	0.000
Residual	74	2.43608E+14	3.29E+12		
Total	83	3.41778E+15			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	(816,023,640.11)	155,129,043.77	(5.26)	0.00	(1,125,125,002.63)	(506,922,277.59)	(1,125,125,002.63)	(506,922,277.59)
Heating Degree Days	20,843.40	1,845.38	11.29	0.00	17,166.40	24,520.40	17,166.40	24,520.40
Cooling Degree Days	123,729.78	6,416.94	19.28	0.00	110,943.75	136,515.82	110,943.75	136,515.82
Peakhours	34,450.19	12,838.78	2.68	0.01	8,868.37	60,032.01	8,868.37	60,032.01
Seasonal Weighting Factor	3,995,126.88	474,637.13	8.42	0.00	3,049,391.77	4,940,861.99	3,049,391.77	4,940,861.99
Industrial Production Weightii	754,856.91	271,192.96	2.78	0.01	214,493.15	1,295,220.67	214,493.15	1,295,220.67
Population	8,539.24	1,581.99	5.40	0.00	5,387.05	11,691.42	5,387.05	11,691.42
Unemployment Rate	(622,037.48)	272,763.29	(2.28)	0.03	(1,165,530.18)	(78,544.78)	(1,165,530.18)	(78,544.78)
GDP	(137,576.73)	385,893.26	(0.36)	0.72	(906,485.83)	631,332.36	(906,485.83)	631,332.36
Median Age	(766,939.47)	769,855.09	(1.00)	0.32	(2,300,909.21)	767,030.26	(2,300,909.21)	767,030.26

The monthly data used in the regression model and the resulting monthly prediction for the actual and forecasted years are provided in Appendix A.

Weather corrected forecasting, involves projecting forward all known variables including degree heating/cooling data. The following details how each independent variable was forecasted to the end of 2010.

1. Heating Degree Days: Forecasted using the previous 12 month average.
2. Cooling Degree Days: Forecasted using the previous 12 month average.
3. Peak Hours: This is a calculated value that is dependent only on the month and year.
4. Seasonal Weighting Factor: Each month is assigned its own unique value that does not vary from year to year.
5. Industrial Production Weighting Factor: Each month is assigned its own unique value that does not vary from year to year.
6. Population: Population projections are based on Statistics Canada forecasts.

Statistics Canada & Ontario Ministry of Finance Population Growth Forecast

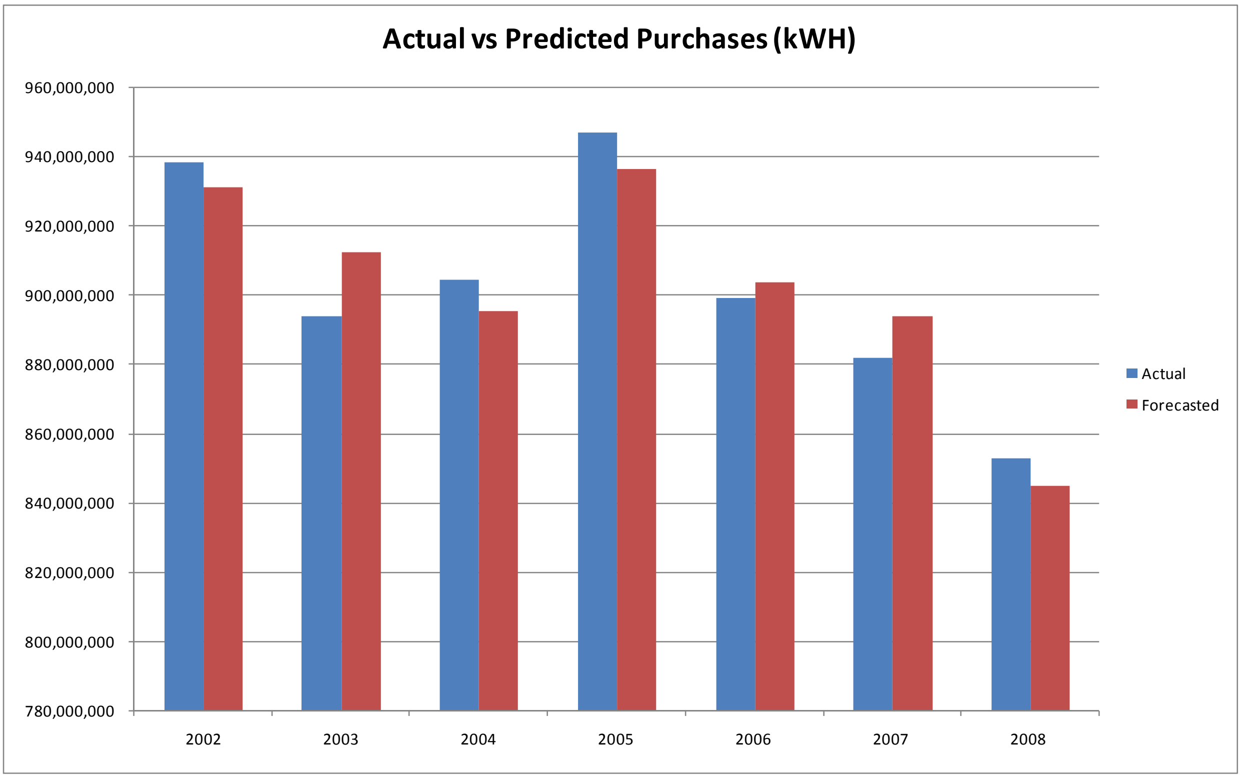
	2006	2007	2008	2009	2010	2011
Bruce	0.36%	0.41%	0.47%	0.50%	0.54%	0.58%
Elgin	0.66%	0.66%	0.71%	0.71%	0.73%	0.73%
Essex	1.27%	1.21%	1.22%	1.19%	1.17%	1.14%
Grey	0.60%	0.65%	0.71%	0.71%	0.75%	0.78%
Huron	0.11%	0.15%	0.19%	0.23%	0.27%	0.29%
Chatham-Kent	-0.34%	-0.29%	-0.23%	-0.19%	-0.15%	-0.12%
Lambton	-0.06%	-0.02%	0.02%	0.03%	0.05%	0.07%
Middlesex	0.88%	0.87%	0.91%	0.89%	0.87%	0.86%
Oxford	0.55%	0.57%	0.61%	0.63%	0.64%	0.66%
Perth	0.70%	0.70%	0.74%	0.73%	0.74%	0.73%

7. Unemployment Rate: Projected forward based on previous years and expected continued downturn in the local economy at least until 2012.

8. GDP: As projected by the Ontario Ministry of Finance.

9. Customers: Extrapolated from previous years data. For 2009 and 2010 it is assumed 40 net new customers would be added in each year.

The annual results of the above prediction formula compared to the actual annual purchases from 2002 to 2008 are shown in the chart below. The prediction formula has a statistical R^2 of 93% which generally indicates the formula has a very good fit to the actual data set.



1 The following table outlines the data that supports the above chart. In addition, the weather
2 normalized forecast of total system purchases for Chatham-Kent Hydro is provided for 2009 and
3 2010.

4 **Table 3-7**
Chatham-Kent Hydro Inc.'s Total System Purchases

Year	Actual	Predicted	% Difference
2002	938,289,237	931,094,934	-0.77%
2003	893,794,600	912,061,000	2.00%
2004	904,175,458	895,326,292	-0.99%
2005	946,838,236	936,088,379	-1.15%
2006	899,106,310	903,700,015	0.51%
2007	881,809,112	893,753,530	1.34%
2008	852,818,080	844,806,883	-0.95%
2009 (WN)		700,348,410	
2010 (WN)		674,625,659	

The forecasted weather normalized amount for 2009 and 2010 is determined by using a forecast of the dependent variables in the prediction formula on a monthly basis. In order to incorporate weather normal conditions, the average monthly heating degree days and cooling degree days which have occurred from 2002 to 2008 is applied in the prediction formula. The details on the average monthly heating degree days and cooling degree days are shown in Appendix A.

Since the prediction formula is based on seven years of historical monthly data it is not able to predict the impact on the forecast for recent events that have caused changes in energy sales. These events include industrial customers that have recently shut-down or reduced operations and CDM programs that have been in place for a relatively short time (i.e. less than an year and a half). Table 3-8 is a comparison of the 2009 predicted purchases against the actual purchases it is provided to demonstrate that the regression analysis does not realize the significant load changes that have occurred.

Table 3-8
2009 Predicted Purchases Compared to Actual Purchases

	Predicted	Actual	Difference	%
January	72,724,570	70,151,166	(2,573,404)	-3.5%
February	62,829,046	61,402,562	(1,426,484)	-2.3%
March	67,217,271	63,603,438	(3,613,833)	-5.4%
April	59,341,806	55,871,387	(3,470,419)	-5.8%
May	60,962,841	53,642,004	(7,320,837)	-12.0%
June	70,579,978	57,547,966	(13,032,012)	-18.5%
July	76,576,209	60,227,287	(16,348,922)	-21.3%
	470,231,721	422,445,810	(47,785,911)	-10.2%

As a result, “manual” adjustments have been made to the forecast to reflect these changes. Table 3-9 shows the predicted purchases before and after the adjustments for those years in which adjustments were made.

Table 3-9
Predicted Purchases Before and After Adjustments

Year	Predicted	Adjustments	Predicted after Adjustments
2008	844,806,883		844,806,883
2009 (B)	802,584,558	-102,236,148	700,348,410
2010 (T)	776,861,807	-102,236,148	674,625,659

The following table outlines the sources of the manual adjustments made to the forecast.

Table 3-10
Manual Adjustment to Forecast

Year	Slow down/ Closures	CDM	Total Adjustments
2008			0
2009 (B)	90,000,104	12,236,044	102,236,148
2010 (T)	90,000,104	12,236,044	102,236,148

Customer effect from Economic Conditions

Chatham-Kent Hydro has encountered a number of companies that have reduced their production or have closed their businesses. These businesses ranged from small businesses to one of our largest customers. This has caused Chatham-Kent Hydro to manually reduce the usage for 2009 and 2010. In the last quarter of 2008 the Chatham-Kent Hydro Service Area was hit harder with economic decline compared to other parts of the province. Therefore there are adjustments to the load by taking the consumption of the customers over 7 years and reducing the volume by the average of those years. In the event that the customers have sold their buildings then we have also adjusted the volume by adding back an annual average usage that the customers have incurred based upon the first 4 months of 2009.

Table 3-11 illustrates the number of customers that have closed down and slowed down and the related changes.

Table 3-11

Customers Impacted from Economic Slowdown

	Number of Customers Shut Down	Number of Customers Slow down	Volume Decrease	Add volume Buildings Purchased	Total
Residential					
General Service					
General Service >50	11	4	48,048,020	4,866,486	43,181,534
Intermediate	1		18,166,823	3,764,683	14,402,141
Large User	1		32,416,430		32,416,430
Standby					
Unmetered Scattered					
Streetlight					
Sentinel light					
Total			98,631,273	8,631,169	90,000,105

Chatham-Kent Hydro has implemented a number of CDM programs. In 2007 Chatham-Kent Hydro partnered with the Ontario Power Authority ("OPA") to augment its existing CDM portfolio. This partnership was particularly effective as many of Chatham-Kent Hydro's conservation activities were focused on customer education. Many successful CDM programs have been and continue to be run in Chatham-Kent Hydro's service territory. The majority of these programs contribute lasting consumption reductions. For programs with lasting consumption reductions, it is assumed that reductions will be permanent. An adjustment to the forecast has been made for each rate class reflecting the lasting energy savings since 2007 and to reflect the impact of the programs to be deployed in 2009 and 2010 resulting from CDM programs initiated since January 2007.

The OPA sponsored Power Savings Blitz ("PSB") targets lighting retrofits in the General Service < 50 kW demand rate class. This program was launched in our service territory in November 2008. In the first 8 months of program operation over 500 retrofits have been completed. Due to the program start, all savings for the program are attributed to 2009. Chatham-Kent Hydro forecast a total of 700 retrofits by the conclusion of 2009. Savings estimates are based on the OPA kWh savings from the retrofit assessment sheet.

The most significant impact to conservation has been the introduction of smart meters and the significant education program surrounding them. Exhibit 10 has a significant amount of information and evidence to support the reduction in load due to smart meters and all conservation programs.

As a result of the conservation programs Chatham-Kent Hydro does not believe that the regression analysis captures all of the conservation impacts since a large amount of conservation has been observed in the later year. Chatham-Kent Hydro estimates that 4% of the residential historical consumption is not captured in the regression analysis. The 4% reduction is an estimate based upon the results of previous programs and conservation education. The conservation adjustments are summarized in Table 3-12.

Table 3-12
Load Adjustment Relating to Conservation

	Year	Residential kWh
	2002	253,649,524
	2003	248,336,123
	2004	246,887,434
	2005	267,121,761
	2006	251,345,806
	2007	236,072,777
	2008	232,973,162
Average		248,055,227
CDM Rate		4%
		9,922,209
General Service less than 50		1,794,773
Total estiamted reduction in consumption		11,716,982
Line losses		1.0443
Total estiamted purchases		12,236,044

Billed kWh Load Forecast

To determine the total weather normalized energy billed forecast, the total system weather normalized purchases forecast is adjusted by an average historical loss factor. As outlined in Loss Factor Calculation Exhibit 8, Tab 1, Schedule 6, Table 8-17, historically the Chatham-Kent Hydro loss factor on average has been 4.43%.

With this average loss factor the total weather normalized billed energy will be 666,821,225 kWhs for 2009 and 642,189,652 kWhs for 2010.

Billed kWh Load Forecast and Customer/Connection Forecast by Rate Class

Since the total weather normalized billed energy amount is known, this amount needs to be distributed by rate class for rate design purposes taking into consideration the customer/connection forecast and expected usage per customer by rate class.

The next step in the forecasting process is to determine a customer/connection forecast. The customer/connection forecast is based on reviewing historical customer/connection data that is available as shown in Table 3-13 below.

Table 3-13
Historical Customer/Connection Data

	Residential	General Service < 50 kW	Service > 50 to 999 kW	Intermediate	Streetlights	Sentinel Lights	Unmetered Scattered Loads	Standby	Total
2002	28,087	3,282	376	18	10,465	402	193	1	42,824
2003	28,204	3,278	360	20	10,465	402	193	1	42,923
2004	28,200	3,233	360	20	10,465	361	193	1	42,833
2005	28,303	3,186	386	21	10,465	353	193	1	42,908
2006	28,347	3,140	399	21	10,570	346	193	1	43,017
2007	28,391	3,132	405	20	10,510	347	195	1	43,001
2008	28,504	3,097	409	22	10,679	344	194	1	43,250

From the historical customer/connection data, the growth rate in customer/connection can be evaluated and is provided in Table 3-14 below. The geometric mean growth rate in number of customers is also provided. The geometric mean approach provides the average growth rate on a compounding basis.

Table 3-14
Growth Rate in Customer/Connections

Year	Residential	General Service < 50 kW	General Service > 50 to 999 kW	Intermediate	Streetlights	Sentinel Lights	Unmetered Scattered Loads	Standby
2002								
2003	0.42%	-0.12%	-4.26%	11.11%	0.00%	0.00%	0.00%	0.00%
2004	-0.01%	-1.37%	0.00%	0.00%	0.00%	-10.20%	0.00%	0.00%
2005	0.37%	-1.45%	7.22%	5.00%	0.00%	-2.22%	0.00%	0.00%
2006	0.16%	-1.44%	3.37%	0.00%	1.00%	-1.98%	0.00%	0.00%
2007	0.16%	-0.25%	1.50%	-4.76%	-0.57%	0.29%	1.04%	0.00%
2008	0.40%	-1.12%	0.99%	10.00%	1.61%	-0.86%	-0.51%	0.00%
Geometic Mean	0.25%	-0.96%	1.41%	3.40%	0.34%	-2.56%	0.09%	0.00%

The resulting geometric mean is applied to the 2008 customer/connection numbers to determine the forecast of customer/connections for 2009 and 2010. Table 3-15 outlines the forecast of customers by rate class for 2009 and 2010.

Table 3-15
Customer/Connection Forecast

Year	Residential	General Service < 50 kW	General Service > 50 to 999 kW	Intermediate	Streetlights	Sentinel Lights	Unmetered Scattered Loads	Standby	Total
Forecast number of Customers/Connection									
2009	28,574	3,067	415	25	10,715	335	194	1	43,326
2010	28,644	3,038	421	28	10,751	327	194	1	43,403

The next step in the process is to review the historical customer/connection usage and to reflect this usage per customer in the forecast. The following Table 3-16 provides the average annual usage per customer by rate class from 2002 to 2008 where data is available.

Table 3-16
Historical Annual Usage per Customer

Year	Residential	General Service < 50 kW	General Service > 50 to 999 kW	Intermediate	Streetlights	Sentinel Lights	Unmetered Scattered Loads	Standby
Energy								
2002	9,031	34,385	853,124	9,398,975	825	1,261	4,587	30,542,407
2003	8,805	34,469	766,687	9,498,905	771	1,040	4,587	27,611,150
2004	8,755	34,783	749,028	11,182,576	753	1,219	4,587	31,347,945
2005	9,020	33,585	678,456	11,339,203	727	1,172	4,587	37,615,872
2006	8,453	32,784	604,998	11,129,006	630	1,190	4,587	36,900,476
2007	8,315	32,202	606,275	10,831,341	634	1,160	5,440	37,331,496
2008	8,174	32,262	573,731	8,578,391	615	1,144	5,468	51,354,780

Usage per customer/connection can only be determined for 2002 and onward since historical billed energy by rate class is only available from 2002. As can been seen from the above table usage per customer/connection essentially declines for all classes after 2005. As stated previously, it is Chatham-Kent Hydro’s view, that this decline is partially due to the CDM programs initiated prior to June 2006.

From the historical usage per customer/connection data the growth rate in usage per customer/connection can be reviewed which is provided on the following Table 3-17. The geometric mean growth rate has also been shown.

Table 3-17
Growth Rate in Usage Per Customer/Connection

Year	Residential	General Service < 50 kW	General Service > 50 to 999 kW	Intermediate	Streetlights	Sentinel Lights	Unmetered Scattered Loads	Standby
Growth Rate in Usage per Customer/Connection								
2002								
2003	-3%	0%	-10%	1%	-7%	-17%	0%	-10%
2004	-1%	1%	-2%	18%	-2%	17%	0%	14%
2005	3%	-3%	-9%	1%	-4%	-4%	0%	20%
2006	-6%	-2%	-11%	-2%	-13%	2%	0%	-2%
2007	-2%	-2%	0%	-3%	1%	-3%	19%	1%
2008	-2%	0%	-5%	-21%	-3%	-1%	1%	38%
Geometic Mean	-2%	-1%	-6%	-2%	-5%	-2%	3%	9%

For the forecast of usage per customer/connection the historical geometric mean was used for all rate classes except for the Streetlights and Standby classes.

For Streetlights, since the historical pattern in usage per connection was not consistent, the 2008 usage per customer/connection was assumed to be held constant for 2009 and 2010.

For the Standby class the average consumption for 2002 to 2007 was used for the forecasted kWhs in 2009 and 2010. In 2008 Standby customer did not generate as much power as previously which resulted in an increase of 14,023,284 kWhs consumed in the year for a 37.5% increase. Without an adjustment the regression analysis had a large increase for this class which is not realizable. Chatham-Kent Hydro submits that a better estimate is the average of the 6 previous years.

Table 3-18
Non-Normalized Forecast Annual kWh Usage per Customer/Connection

Year	Residential	General Service < 50 kW	General Service > 50 to 999 kW	Intermediate	Streetlights	Sentinel Lights	Unmetered Scattered Loads	Standby
Forecast Annual kWh Usage per Customers/Connection								
2009	8,039	31,921	537,021	8,448,768	586	1,126	5,630	33,558,224
2010	7,906	31,584	502,659	8,321,104	558	1,108	5,797	33,558,224

With the preceding information the non-normalized weather billed energy forecast can be determined by applying the forecast number of customer/connection from Table 3-13 by the forecast of annual usage per customer/connection from Table 3-18. The resulting non-normalized weather billed energy forecast is shown in Table 3-19 below.

Table 3-19
Non-Normalized Weather Billed Energy Forecast

Year	Residential	General Service < 50 kW	General Service > 50 to 999 kW	Intermediate	Streetlights	Sentinel Lights	Unmetered Scattered Loads	Standby	Total
Non-normalized weather billed energy forecast									
2009	229,705,301	97,907,768	222,742,674	209,092,094	6,278,245	377,285	1,093,169	33,558,224	800,754,759
2010	226,474,420	95,941,097	211,434,266	229,578,750	5,999,071	361,702	1,126,601	33,558,224	804,474,132

The non-normalized weather billed energy forecast has been determined but this need to be aligned with the total weather normalized billed energy forecast and then adjusted for the manual adjustments previously identified in this Exhibit.

The difference between the non-normal billed energy and the weather normalized billed energy from the regression analysis, weather adjustment, is provided in Table 3-20.

Table 3-20
Weather Adjustment

	2009	2010
Non-normal billed energy	800,754,759	804,474,132
Normal billed energy	768,538,311	743,906,738
Difference	-32,216,448	-60,567,394

Chatham-Kent Hydro is assigning the weather difference to more than just weather sensitive classes and is not using the Hydro One weather sensitive allocation. Chatham-Kent Hydro is proposing that this difference is for more than just weather and is a reflection of weather and economic impacts. The allocation to the various rate classes is provided in Table 3-21.

Table 3-21

Weather and Economic Sensitivity by Rate Class

Residential	General Service < 50 kW	General Service > 50 to 999 kW	Intermediate	Streetlights	Sentinel Lights	Unmetered Scattered Loads	Standby
Weather and Economic Sensitivity							
28.69%	12.23%	27.82%	26.11%	0.78%	0.05%	0.14%	4.19%
28.15%	11.93%	26.28%	28.54%	0.75%	0.04%	0.14%	4.17%

As a result, the difference between the non-normalized and normalized forecast has been assigned on a prorated basis to each rate class based upon their percentage of the total billed energy.

The impact of using the Hydro One weather sensitivity allocation would reduce the level of consumption on the residential and general service < 50 kW class below a level that is reasonable. The following Table 3-22 summarizes the difference in the allocation proposed and the Hydro One allocation and the resulting 2010 billed energy for the residential and small general service classes.

Table 3-22
Consumption Using the Hydro One Weather Sensitivity Allocation

	Residential	General Serive < 50
Hydro One Weather Allocation	51%	22%
Weather and Economic Sensitivty	31,057,224	13,156,736
Proposed Weather Economic Sensitivty Adjustment	17,050,847	7,223,231
Difference	14,006,377	5,933,505
Proposed Consumption	199,501,364	86,923,094
Consumpiton using Hydro One Weather	185,494,987	80,989,588

Therefore Chatham-Kent Hydro is proposing to allocate the weather and economic adjustment to all rate classes based upon their respective percentage of total volume.

Table 3-23 outlines how the weather and economic sensitive rate classes have been adjusted to align the non-normalized forecast with the normalized forecast. In addition, the impact of the manual adjustments by rate class is also included to show how the weather normalized billed energy forecast after adjustments have been determined. The manual adjustments are at the billed level which excludes losses.

Table 3-23
Alignment of Non-Normal to Weather Normal Forecast

Year	Residential	General Service < 50 kW	General Service > 50 to 999 kW	Intermediate	Streetlights	Sentinel Lights	Unmetered Scattered Loads	Standby	Total
Non-normalized Weather Billed Energy Forecast									
2009	229,705,301	97,907,768	222,742,674	209,092,094	6,278,245	377,285	1,093,169	33,558,224	800,754,759
2010	226,474,420	95,941,097	211,434,266	229,578,750	5,999,071	361,702	1,126,601	33,558,224	804,474,132
Adjustment for Weather and Economic Sensitivty									-
2009	(9,241,642)	(3,939,084)	(8,961,517)	(8,412,319)	(252,590)	(15,179)	(43,981)	(1,350,135)	(32,216,448)
2010	(17,050,847)	(7,223,231)	(15,918,501)	(17,284,567)	(451,659)	(27,232)	(84,820)	(2,526,538)	(60,567,394)
Manual Adjustment to Billed Energy Forecast									-
2009	(9,922,209)	(1,794,773)	(12,497,262)	(77,502,843)	-	-	-	-	(101,717,086)
2010	(9,922,209)	(1,794,773)	(12,497,262)	(77,502,843)	-	-	-	-	(101,717,086)
Weather Normalized Billed Energy Forecast									-
2009	210,541,450	92,173,911	201,283,895	123,176,932	6,025,655	362,105	1,049,188	32,208,089	666,821,225
2010	199,501,364	86,923,094	183,018,503	134,791,341	5,547,412	334,470	1,041,782	31,031,687	642,189,652

Billed kW Load Forecast

There are five rate classes that charge volumetric distribution on a per kW basis. These include General Service > 50 to 999 kW, Intermediate, Streetlights, Sentinel Lights and Standby. As a result, the energy forecast for these classes needs to be converted to a kW basis for rate setting purposes. The forecast of kW for these classes is based on a review of the historical ratio of kW to kWhs and applying the average ratio to the forecasted kWh to produce the required kW.

The following table outlines the annual demand units by applicable rate class for the years that data is available (i.e. 2002 to 2008).

Table 3-24
Historical Annual kW per Applicable Rate Class

Year	General Service > 50 to 999 kW	Intermediate	Streetlights	Sentinel Lights	Standby
2002	716,816	493,128	22,225	1,361	80,836
2003	702,415	511,287	22,715	1,216	68,757
2004	687,658	552,774	22,715	1,071	88,440
2005	669,694	581,551	22,714	1,149	99,597
2006	627,671	591,430	20,133	1,771	90,767
2007	608,972	579,905	27,153	1,118	94,533
2008	623,613	517,747	19,576	1,104	107,627

The following is the historical ratio of kW/kWh as well as the average ratio from 2002 to 2008.

Table 3-25
Historical kW/KWh Ratio per Applicable Rate Class

Year	General Service > 50 to 999 kW	Intermediate	Streetlights	Sentinel Lights	Standby
2002	0.22%	0.29%	0.26%	0.27%	0.26%
2003	0.25%	0.27%	0.28%	0.29%	0.25%
2004	0.26%	0.25%	0.29%	0.24%	0.28%
2005	0.26%	0.24%	0.30%	0.28%	0.26%
2006	0.26%	0.25%	0.30%	0.43%	0.25%
2007	0.25%	0.27%	0.41%	0.28%	0.25%
2008	0.27%	0.27%	0.30%	0.28%	0.21%
Average	0.25%	0.26%	0.31%	0.30%	0.26%

The average ratio was applied to the weather normalized billed energy forecast in Table 3-21 to provide the forecast of kW by rate class as shown below.

The following Table 3-26 outlines the forecast of kW for the applicable rate classes.

Table 3-26
kW Forecast by Applicable Rate Class

Year	General Service > 50 to 999 kW	Intermediate	Streetlights	Sentinel Lights	Standby
2009	502,112	322,877	18,432	1,079	83,730
2010	456,548	353,322	16,969	997	80,671

Summary of Forecast Data

	2006 EDR	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Weather Normal	2010 Weather Normal
Actual kWh Purchases		904,175,458	946,838,236	899,106,310	881,809,112	852,818,080		
Predicted kWh Purchases		895,326,292	936,088,379	903,700,015	893,753,530	844,806,883	802,584,558	776,861,807
Adjustments not in model							-102,236,148	-102,236,148
Revised Predicted kWh Purchases							700,348,410	674,625,659
% Difference		-1.0%	-1.1%	0.5%	1.4%	-0.9%		
Billed kWh	879,314,686	893,202,058	908,820,563	862,509,626	844,556,148	815,656,982	666,821,225	642,189,652
By Class								
Residential								
Customers	28,200	28,200	28,303	28,347	28,391	28,504	28,574	28,644
kWh	249,952,782	246,887,434	255,289,127	239,603,216	236,072,777	232,982,274	210,541,450	199,501,364
General Service < 50 kW								
Customers	3,291	3,233	3,186	3,140	3,132	3,097	3,067	3,038
kWh	112,582,193	112,454,172	107,002,229	102,942,601	100,856,561	99,914,752	92,173,911	86,923,094
General Service > 50 to 999 kW								
Customers	375	360	386	399	405	409	415	421
kWh	391,671,066	269,650,109	261,883,968	241,394,305	245,541,261	234,655,904	201,283,895	183,018,503
kW	1,013,282	687,658	669,694	627,671	608,972	623,613	502,112	456,548
Intermediate								
Customers	4	20	21	21	20	22	25	28
kWh	72,845,904	223,651,512	238,123,267	233,709,128	216,626,810	188,724,594	123,176,932	134,791,341
kW	156,920	552,774	581,551	591,430	579,905	517,747	322,877	353,322
Large Use								
Customers	2	0	0	0	0	0	0	0
kWh	43,644,776	0	0	0	0	0	0	0
kW	118,399	0	0	0	0	0	0	0
Streetlights								
Customers	10,465	10,465	10,465	10,570	10,510	10,679	10,715	10,751
kWh	8,194,332	7,885,370	7,607,072	6,662,770	6,663,852	6,570,411	6,025,655	5,547,412
kW	22,552	22,715	22,714	20,133	27,153	19,576	18,432	16,969
Sentinel Lights								
Connections	361	361	353	346	347	344	335	327
kWh	423,632	440,186	413,698	411,800	402,663	393,539	362,105	334,470
kW	1,128	1,071	1,149	1,771	1,118	1,104	1,079	997
Unmetered Scattered Loads								
Connections		193	193	193	195	194	194	194
kWh		885,330	885,330	885,330	1,060,728	1,060,728	1,049,188	1,041,782
Standby								
Connections		1	1	1	1	1	1	1
kWh		31,347,945	37,615,872	36,900,476	37,331,496	51,354,780	32,208,089	31,031,687
kW		88,440	99,597	90,767	94,533	107,627	83,730	80,671
Total								
Customer/Connections	42,698	42,833	42,908	43,017	43,001	43,250	43,326	43,403
kWh	879,314,685	893,202,058	908,820,563	862,509,626	844,556,148	815,656,982	666,821,225	642,189,652
kW from applicable classes	1,312,281	1,352,658	1,374,705	1,331,772	1,311,681	1,269,667	928,230	908,507

APPENDIX A

MONTHLY DATA USED FOR REGRESSION ANALYSIS

Appendix A

Year	Month	No	KWH	Heating Degree Days	Cooling Degree Days	Peakhours	Seasonal Weighting Factor	Industrial Production Weighting Factor	Population	Unemployment Rate	GDP	Median Age	Predicted kWH
2002	Jan	1	75,539,423	545.30	0.00	352	0	2	107,355	7.7	121.5	35.50	76,975,862
2002	Feb	2	68,515,032	494.80	0.00	320	-1	2	107,369	8.7	121.9	35.61	70,184,635
2002	Mar	3	73,639,815	513.90	0.00	320	0	3	107,383	9.2	122.2	35.73	75,005,529
2002	Apr	4	70,425,715	273.30	15.10	352	-0.75	4	107,397	8.2	122.6	35.84	71,329,414
2002	May	5	72,864,570	185.10	12.50	352	0	3	107,411	7.5	122.9	35.95	71,822,329
2002	Jun	6	79,716,033	16.50	118.30	320	0	3	107,425	7.2	123.3	36.07	80,456,681
2002	Jul	7	93,049,284	0.00	201.20	352	0	2	107,439	7.6	123.7	36.18	90,458,268
2002	Aug	8	91,281,708	0.00	149.20	336	1	2	107,453	7.7	124.0	36.30	87,400,422
2002	Sep	9	85,671,396	17.10	97.90	320	0.75	4	107,467	7	124.4	36.41	81,764,997
2002	Oct	10	78,002,634	255.90	12.60	352	0.25	4	107,481	6	124.8	36.53	75,904,256
2002	Nov	11	75,569,055	417.50	0.00	336	-0.25	3	107,495	6	125.1	36.64	74,402,213
2002	Dec	12	74,014,572	610.40	0.00	320	-0.25	0	107,509	6.3	125.5	36.76	75,390,328
2003	Jan	1	80,158,611	759.20	0.00	352	0	2	107,523	6.7	125.7	36.87	81,865,351
2003	Feb	2	73,538,697	656.20	0.00	320	-1	2	107,537	7.4	125.8	36.98	74,195,835
2003	Mar	3	74,987,208	524.10	0.00	336	0	3	107,551	8.1	126.0	37.10	76,334,181
2003	Apr	4	68,131,035	303.30	2.70	336	-0.75	4	107,565	8.2	126.1	37.21	69,772,327
2003	May	5	68,381,673	147.60	0.20	336	0	3	107,579	7.5	126.2	37.33	68,907,874
2003	Jun	6	73,186,791	30.30	64.20	336	0	3	107,593	6.8	126.4	37.44	74,827,019
2003	Jul	7	81,942,993	0.00	144.60	352	0	2	107,607	6.9	126.5	37.56	83,877,756
2003	Aug	8	80,915,733	0.00	143.10	320	1	2	107,621	6.8	126.7	37.67	86,658,912
2003	Sep	9	75,167,748	50.30	37.60	336	0.75	4	107,635	6.9	126.8	37.79	75,676,327
2003	Oct	10	72,475,980	225.60	1.00	352	0.25	4	107,649	6.4	127.0	37.90	73,666,528
2003	Nov	11	71,081,556	338.80	0.00	320	-0.25	3	107,663	6.5	127.1	38.02	71,988,729
2003	Dec	12	73,826,575	541.80	0.00	336	-0.25	0	107,677	6.9	127.3	38.13	74,290,160
2004	Jan	1	79,684,648	762.90	0.00	336	0	2	107,691	7.5	127.5	38.24	81,029,574
2004	Feb	2	72,900,352	579.40	0.00	320	-1	2	107,705	7.8	127.8	38.36	72,463,050
2004	Mar	3	75,667,416	429.30	0.00	368	0	3	107,719	8	128.1	38.47	75,613,290
2004	Apr	4	68,680,718	251.70	4.40	336	-0.75	4	107,733	8.2	128.3	38.59	68,981,675
2004	May	5	70,763,440	101.60	28.10	320	0	3	107,747	8	128.6	38.70	70,584,512
2004	Jun	6	76,247,526	21.40	62.00	352	0	3	107,761	8	128.9	38.82	74,210,520
2004	Jul	7	79,986,462	2.20	122.00	336	0	2	107,775	8.5	129.1	38.93	79,619,418
2004	Aug	8	80,648,262	6.10	74.20	336	1	2	107,789	8.9	129.4	39.05	77,527,877
2004	Sep	9	79,026,081	23.00	59.70	336	0.75	4	107,803	8.3	129.7	39.16	76,963,615
2004	Oct	10	72,549,672	190.90	0.50	320	0.25	4	107,817	7.8	129.9	39.27	70,884,638
2004	Nov	11	72,369,445	354.00	0.00	352	-0.25	3	107,831	7.6	130.2	39.39	72,697,152
2004	Dec	12	75,651,436	593.50	0.00	336	-0.25	0	107,845	7.8	130.5	39.50	74,750,971
2005	Jan	1	79,711,033	700.40	0.00	320	0	2	107,859	8.2	130.7	39.62	78,666,771
2005	Feb	2	72,086,002	572.00	0.00	320	-1	2	107,873	8.2	131.0	39.73	71,985,451
2005	Mar	3	78,211,488	545.30	0.00	352	0	3	107,887	8.4	131.3	39.85	77,149,956
2005	Apr	4	69,000,350	242.50	1.40	336	-0.75	4	107,901	7.9	131.6	39.96	68,532,998
2005	May	5	70,417,800	143.40	5.70	336	0	3	107,915	7.9	131.9	40.08	69,234,083
2005	Jun	6	87,906,300	4.40	166.90	352	0	3	107,929	7.7	132.2	40.19	86,941,932
2005	Jul	7	89,932,560	0.00	194.70	320	0	2	107,943	7.7	132.5	40.31	88,418,440
2005	Aug	8	94,440,230	0.10	185.50	352	1	2	107,957	7.7	132.8	40.42	92,370,684
2005	Sep	9	81,092,320	15.20	82.20	336	0.75	4	107,971	7.5	133.1	40.53	79,990,696
2005	Oct	10	74,394,333	182.80	19.00	320	0.25	4	107,985	7.1	133.4	40.65	73,344,389
2005	Nov	11	73,123,230	346.20	0.00	352	-0.25	3	107,999	6.6	133.7	40.76	73,056,797
2005	Dec	12	76,522,590	659.70	0.00	320	-0.25	0	108,013	6.3	134.0	40.88	76,396,181
2006	Jan	1	76,765,830	494.70	0.00	336	0	2	108,027	7.5	134.3	40.99	75,276,716
2006	Feb	2	71,300,830	538.00	0.00	320	-1	2	108,041	8	134.5	41.11	71,301,242
2006	Mar	3	76,123,120	461.40	0.00	368	0	3	108,055	8.6	134.8	41.22	75,742,672
2006	Apr	4	66,029,130	219.50	1.10	304	-0.75	4	108,069	7.9	135.1	41.34	66,804,254
2006	May	5	72,285,180	105.90	40.60	352	0	3	108,083	7.9	135.4	41.45	73,214,799
2006	Jun	6	76,116,070	8.80	85.70	352	0	3	108,097	7.7	135.6	41.56	76,894,685
2006	Jul	7	87,124,080	0.00	197.40	320	0	2	108,111	8.4	135.9	41.68	88,226,972
2006	Aug	8	86,693,010	0.00	147.40	352	1	2	108,125	8.6	136.2	41.79	87,006,547
2006	Sep	9	71,803,266	52.10	22.30	320	0.75	4	108,139	8.5	136.5	41.91	72,069,764
2006	Oct	10	70,311,840	251.30	2.30	336	0.25	4	108,153	7.4	136.8	42.02	72,999,056
2006	Nov	11	72,024,057	356.80	0.00	352	-0.25	3	108,167	6.9	137.0	42.14	73,009,068
2006	Dec	12	72,529,897	460.40	0.00	304	-0.25	0	108,177	7	137.3	42.25	71,154,241

2007	Jan	1	75,943,576	602.40	0.00	352	0	2	108,151	8.6	137.6	42.37	76,922,270
2007	Feb	2	73,489,679	706.10	0.00	320	-1	2	108,125	9	137.8	42.48	73,390,594
2007	Mar	3	73,780,831	429.30	0.20	352	0	3	108,099	9.6	138.1	42.60	72,780,958
2007	Apr	4	66,320,469	285.20	0.90	320	-0.75	4	108,072	9	138.3	42.71	66,539,834
2007	May	5	68,636,519	87.20	46.00	352	0	3	108,046	9.1	138.6	42.82	70,937,138
2007	Jun	6	76,584,776	8.10	132.20	336	0	3	108,020	9.2	138.8	42.94	79,006,163
2007	Jul	7	77,111,267	1.30	148.20	336	0	2	107,994	9.2	139.1	43.05	79,745,177
2007	Aug	8	85,216,617	4.40	167.40	352	1	2	107,968	9	139.3	43.17	86,497,400
2007	Sep	9	73,536,545	25.40	76.40	304	0.75	4	107,942	8.1	139.6	43.28	74,744,527
2007	Oct	10	71,397,719	111.20	42.30	352	0.25	4	107,916	6.8	139.8	43.40	72,434,967
2007	Nov	11	69,283,467	400.30	0.00	352	-0.25	3	107,889	6.3	140.1	43.51	70,445,434
2007	Dec	12	70,507,648	595.00	0.00	304	-0.25	0	107,863	6.2	140.3	43.63	70,309,069
2008	Jan	1	75,226,388	611.20	0.00	352	0	2	107,843	7.6	140.3	43.74	73,669,879
2008	Feb	2	71,282,776	629.30	0.00	320	-1	2	107,822	7.9	140.3	43.85	68,505,090
2008	Mar	3	73,304,135	541.60	0.00	304	0	3	107,801	8.6	140.2	43.97	70,182,566
2008	Apr	4	66,441,873	223.80	1.30	352	-0.75	4	107,781	8.1	140.2	44.08	63,184,607
2008	May	5	66,716,840	143.20	11.60	336	0	3	107,760	8.3	140.1	44.20	64,087,007
2008	Jun	6	76,146,317	3.20	123.90	336	0	3	107,739	8.2	140.1	44.31	74,868,070
2008	Jul	7	83,277,874	0.30	188.60	352	0	2	107,719	8.8	140.0	44.43	81,978,144
2008	Aug	8	75,973,258	0.90	144.80	320	1	2	107,698	9	140.0	44.54	79,081,676
2008	Sep	9	68,765,247	12.20	65.00	336	0.75	4	107,677	8.7	139.9	44.66	70,434,391
2008	Oct	10	63,416,229	220.70	3.30	352	0.25	4	107,657	7.8	139.9	44.77	66,001,659
2008	Nov	11	64,406,943	413.30	0.00	304	-0.25	3	107,636	7.7	139.8	45.00	64,918,217
2008	Dec	12	67,860,200	632.0	0.0	336	-0.25	0	107,615	8.1	139.8	45	67,895,575
2009	Jan	1		799.1	0.0	336	0	2	107,598	9.8	139.5	45	72,724,570
2009	Feb	2		575.4	0.0	304	-1	2	107,581	9.85	139.2	45	62,829,046
2009	Mar	3		484.9	0.1	352	0	3	107,564	9.9	138.9	45	67,217,271
2009	Apr	4		258.2	2.7	320	-0.75	4	107,547	9.95	138.6	45	59,341,806
2009	May	5		114.8	23.0	320	0	3	107,530	10	138.3	45	60,962,841
2009	Jun	6		15.5	109.6	352	0	3	107,513	10.05	138.0	45	70,579,978
2009	Jul	7		0.8	167.8	352	0	2	107,496	10.1	137.7	45	76,576,209
2009	Aug	8		2.0	138.6	320	1	2	107,479	10.15	137.4	45	75,746,646
2009	Sep	9		37.9	58.7	336	0.75	4	107,462	10.2	137.2	45	67,540,266
2009	Oct	10		202.1	8.8	336	0.25	4	107,445	10.25	136.9	45	62,650,944
2009	Nov	11		363.2	0.0	320	-0.25	3	107,428	10.3	136.6	45	61,479,258
2009	Dec	12		591.4	0.0	352	-0.25	0	107,411	10.35	136.3	45	64,935,723
2010	Jan	1		661.3	0.0	320	0	2	107,397	10.4	136.5	45	67,616,407
2010	Feb	2		582.9	0.0	304	-1	2	107,384	10.45	136.8	45	61,256,529
2010	Mar	3		481.6	0.1	368	0	3	107,370	10.5	137.1	45	65,927,817
2010	Apr	4		259.6	3.0	320	-0.75	4	107,357	10.55	137.3	45	57,586,081
2010	May	5		119.7	22.7	320	0	3	107,344	10.6	137.6	45	59,161,822
2010	Jun	6		15.1	107.4	352	0	3	107,330	10.65	137.8	45	68,387,200
2010	Jul	7		0.9	161.8	336	0	2	107,317	10.7	138.1	45	73,329,093
2010	Aug	8		2.1	142.2	336	1	2	107,303	10.75	138.4	45	74,751,030
2010	Sep	9		37.9	58.2	336	0.75	4	107,290	10.8	138.6	45	65,426,791
2010	Oct	10		200.2	9.6	320	0.25	4	107,276	10.85	138.9	45	60,067,219
2010	Nov	11		367.1	0.0	336	-0.25	3	107,263	10.9	139.2	45	59,976,401
2010	Dec	12		594.7	0.0	368	-0.25	0	107,250	10.95	139.4	45	63,375,419

Other Distribution Revenue

Chatham-Kent Hydro provides other services to customers and customers are charged rates for those services. The revenue from these services reduces the revenue requirement that is to be reviewed in the distribution service charge and volume rates.

Table 3-27 provides the total other distribution revenue by USoA for 2006 to 2010.

Table 3-28 provides the other distribution revenue by year along with the variance for each year.

Table 3-27
Summary of Other Distribution Revenue

Uniform System of Account #	Description	2006 Actual	2007 Actual	2008 Actual	2009 Bridge Actual	2010 Test Existing Rates
4235	**Specific Service Charges**	**260,640**	**398,075**	**435,314**	**444,996**	**494,368**
4225	**Late Payment Charges**	**247,177**	**250,221**	**206,625**	**170,000**	**188,861**
	Other Distribution Revenue					
4082	RS Revenue	69,144	178,784	63,697	65,004	65,004
4084	Sev Tx Requests	3,724	3,105	1,773	1,996	1,996
4090	Electric Services Incidential to Energy Sales	-	-	-	-	-
4205	Interdepartmental Rents	156,996	156,996	156,996	156,996	156,996
4210	Rent from Electric Property	128,880	154,213	130,592	126,996	126,996
4215	Other Utility Opeating Income	-	-	-	-	-
4220	Other Electric Revenue	12,170	10,528	9,246	9,996	9,996
4240	Provision for Rate Refunds	-	-	-	-	-
4345	Government Assist Directly Credited to Income	-	-	-	-	-
	Total Other Distribution Revenue	**370,914**	**503,626**	**362,304**	**360,988**	**360,988**
	Other Income and Expenses					
4305	Regulatory Debits	-	-	-	-	-
4310	Regulatory Credits	-	-	-	34,000	-
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	130,722	63,083	35,721	39,996	40,000
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	(13,405)	(20,108)	-	-	-
4385	Expenses of Non-Utility Operations	-	-	-	-	-
4390	Miscellaneous Non-Operating Income	67,136	35,051	26,835	30,996	30,996
4395	Rate-Payer Benefit Including Interest	-	-	-	-	-
4398	Foreign Exchange Gains and Losses, Including Amortization	-	-	-	-	-
4405	Interest and Dividend Income	529,194	329,691	69,402	100,608	72,237
	Total Other Income and Expenses	**713,647**	**407,718**	**131,959**	**205,600**	**143,233**
	Specific Service Charges	260,640	398,075	435,314	444,996	494,368
	Late Payment Charges	247,177	250,221	206,625	170,000	188,861
	Other Distribution Revenue	370,914	503,626	362,304	360,988	360,988
	Other Income and Expenses	713,647	407,718	131,959	205,600	143,233
	Total	1,592,379	1,559,639	1,136,201	1,181,584	1,187,450

Table 3-28
Other Distribution Revenue
Account Breakdown

Description	2006 Actual	2007 Actual	Variance	2008 Actual	Variance	2009 Bridge Actual	Variance	2010 Test Existing Rates	Variance
4082 -Retailer Services Rvenue									
Monthly Fixed Charge	2,100	2,780	680	3,240	460	3,306	66	3,306	-
Standard Charge	100	500	400	-	(500)		-		-
Monthly Variable Charge	42,805	43,938	1,133	38,334	(5,604)	39,120	786	39,120	-
Bill Ready Billing Charge	24,139	24,709	569	22,124	(2,584)	22,578	453	22,578	-
Retailer Consolidated Credit			-	(1)	(1)		1		-
SSS Admin Charges	-	106,858	106,858		(106,858)		-		-
Total	69,144	178,784	109,640	63,697	(115,087)	65,004	1,307	65,004	-
4084 - Service TX Requests									
Request Fees	1,518	1,869	351	804	453	905	101	905	-
Processing Fees	2,207	1,237	(970)	969	1,939	1,091	122	1,091	-
Total	3,724	3,105	(619)	1,773	2,392	1,996	224	1,996	-
4205 - Interdepartmental Rents									
Rental 320 Qeen Street	156,996	156,996	-	156,996	-	156,996	-	156,996	-
4210 - Rent from Electric Property									
Rent office to lawyer	17,550	14,850	(2,700)		(14,850)		-		-
Rent Bldg Space to Corix	3,750	22,500	18,750	22,500	-	22,500	-	22,500	-
Transformer Rental	1,875	150	(1,725)		(150)		-		-
Joint Use Pole Revenue	102,492	116,713	14,221	108,092	(8,621)	104,496	(3,596)	104,496	-
Meter Board Rental	3,213	-	(3,213)		-		-		-
Total	128,880	154,213	25,333	130,592	(23,621)	126,996	(3,596)	126,996	-
4220 - Other Electric Revenue									
Arrears Certificate charges	5,152	7,316	2,164	5,385	(1,931)	5,822	437	5,822	-
Private Locate Charges	3,525	2,963	(563)	3,550	588	3,838	288	3,838	-
Write Up Deposits and AR	2,450		(2,450)		-		-		-
Employee Reimbursements	892	143	(749)		(143)		-		-
Lawyers Letters	150	106	(44)	311	205	336	25	336	-
Total	12,170	10,528	(1,642)	9,246	(1,282)	9,996	750	9,996	-
4225 - Late Payment	247,177	250,221	3,044	206,625					

4235 - Misc Service Revenue									
NSF Fees	7,099	8,745	1,647	8,880	135	9,078	198	10,085	1,007
Profit sale of Mat'l / Services	27,247	38,391	11,144	139,602	101,211	142,707	3,105	158,540	15,833
Occupancy Charges	144,321	168,184	23,863	158,109	(10,075)	161,625	3,517	179,558	17,932
Reconnection Charges	81,974	182,755	100,781	126,723	(56,032)	129,542	2,819	143,914	14,373
Temporary Service Fee			-	2,000	2,000	2,044	44	2,271	227
Total	260,640	398,075	137,435	435,314	35,239	444,996	9,638	494,368	49,145
4310 - Regulatory Credits						34,000	34,000		(34,000)
4360 - Loss on Disposition of Property									
Surplus Vehicles Sold	49,767	41,200	(8,567)	21,287	(19,913)	23,834	2,547	23,836	2
Surplus Office Eqpt Sold		(434)	(434)		434		-		-
Surplus Buildings Sold	80,956	22,318	(58,638)	14,435	(7,883)	16,162	1,727	16,164	2
Total	130,722	63,083	(67,639)	35,721	(27,362)	39,996	4,275	40,000	4
4380 - Expenses Non Utility									
Write off 10% Transition Costs	(13,405)	(20,108)	(20,108)	-	(20,108)	-	(20,108)	-	(20,108)
4390 - Non Operating Income									
Sale of Scrap	63,928	35,051	(28,876)	26,835	(8,216)	30,996	4,161	30,996	-
Prior year GST reclaimed on			-		-		-		-
Travel & Meal Exp	3,208		(3,208)		-		-		-
Total	67,136	35,051	(32,084)	26,835	(8,216)	30,996	4,161	30,996	-
4405-Interest and Dividend Income									
Bank interest	150,051	27,551	(122,501)	78,838	51,288	100,608	21,770	72,237	(28,371)
Intercompany loan interest	64,087	24,480	(39,607)	1,682	(22,798)	-	(1,682)		-
Interest on overpayment of pils			-	30,984	30,984		(30,984)		-
Interest Income - Transition cost		9,082	9,082	10,690	1,608		(10,690)		-
Interest Income/Expense RSVA	315,056	268,578	(46,478)	(52,792)	(321,370)		52,792		-
Total	529,194	329,691	(199,503)	69,402	(260,289)	100,608	31,206	72,237	(28,371)

VARIANCE ANALYSIS ON OTHER DISTRIBUTION REVENUE:

Preamble:

The Materiality threshold used to analyze Other Distribution Revenue was the threshold used for OM&A costs, being 0.5 per cent of revenue requirement as set out in Table 3-29 below. The OM&A cost threshold was used because other distribution revenues, like OM&A costs, are recorded in Income Statement accounts.

Table 3-29
Rate Base Materiality

Description	2006 OEB Approved	2006 Actual	2007 Actual Year	2008 Actual Year	2009 Bridge Year	2010 Test Year
Rate Base	$50,309,522	$51,813,558	$54,003,463	$55,634,596	$55,490,686	$56,073,568
Cost Capital	8.02%	8.02%	8.02%	7.95%	7.89%	7.52%
Return on Rate Base	$4,034,824	$4,155,447	$4,331,078	$4,425,583	$4,377,809	$4,219,200
Distribution Expense	$8,723,462	$8,107,926	$8,594,813	$9,274,947	$9,527,916	$10,618,473
PILS	$1,572,932	$1,349,735	$1,405,223	$1,207,671	$1,096,204	$987,663
Revenue Requirement	$14,331,218	$13,613,108	$14,331,114	$14,908,201	$15,001,929	$15,825,336
Materiality Cal .5%	$71,656	$68,066	$71,656	$74,541	$75,010	$79,127

To allow for a detailed review of materiality on Other Distribution Revenue, Chatham-Kent Hydro has selected the materiality threshold of $79,127. Chatham-Kent Hydro has provided explanations for the following variances, which exceed the materiality threshold. The following variances exceed the materiality threshold.

Table 3-30
Other Revenue Variances

Description	2006 Actual	2007 Actual	Variance	2008 Actual	Variance	2009 Bridge Actual	Variance	2010 Test Existing Rates	Variance
4082-RS Rev	69,144	178,784	109,640	63,697	(115,087)	65,004	1,307	65,004	-
4084-Serv Tx Requests	3,724	3,105	(619)	1,773	(1,333)	1,996	224	1,996	-
4090-Electric Services Incidental to Energy Sales	-	-	-	-	-	-	-	-	-
4205-Interdepartmental Rents	156,996	156,996	-	156,996	-	156,996	-	156,996	-
4210-Rent from Electric Property	128,880	154,213	25,333	130,592	(23,621)	126,996	(3,596)	126,996	-
4215-Other Utility Operating Income	-	-	-	-	-	-	-	-	-
4220-Other Electric Revenues	12,170	10,528	(1,642)	9,246	(1,282)	9,996	750	9,996	-
4225-Late Payment Charges	247,177	250,221	3,043	206,625	(43,595)	170,000	(36,625)	188,861	18,861
4230-Sales of Water and Water Power	-	-	-	-	-	-	-	-	-
4235-Miscellaneous Service Revenues	260,640	398,075	137,435	435,314	37,239	444,996	9,682	494,368	49,372
4240-Provision for Rate Refunds	-	-	-	-	-	-	-	-	-
4245-Government Assistance Directly Credited to Income	-	-	-	-	-	-	-	-	-
4305-Regulatory Debits	-	-	-	-	-	-	-	-	-
4310-Regulatory Credits	-	-	-	-	-	34,000	34,000	-	(34,000)
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	130,722	63,083	(67,639)	35,721	(27,362)	39,996	4,275	40,000	4
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	(13,405)	(20,108)	(6,703)		20,108		-		-
4385-Expenses of Non-Utility Operations	-	-	-	-	-	-	-	-	-
4390-Miscellaneous Non-Operating Income	67,136	35,051	(32,084)	26,835	(8,216)	30,996	4,161	30,996	-
4395-Rate-Payer Benefit Including Interest	-	-	-	-	-	-	-	-	-
4398-Foreign Exchange Gains and Losses, Including Amortization	-	-	-	-	-	-	-	-	-
4405-Interest and Dividend Income	529,194	329,691	(199,503)	69,402	(260,289)	100,608	31,206	72,237	(28,371)
Total Other Revenue	1,592,379	1,559,639	(32,740)	1,136,201	(423,437)	1,181,584	45,383	1,187,450	5,866
Specific Service Charge	260,640	398,075	137,435	435,314	37,239	444,996	9,682	494,368	49,372
Late Payment Charges	247,177	250,221	3,043	206,625	(43,595)	170,000	(36,625)	188,861	18,861
Other Distribution Revenue	370,914	503,626	132,712	362,304	(141,322)	360,988	(1,316)	360,988	-
Other Income and Expenses	713,647	407,718	(305,930)	131,959	(275,759)	205,600	73,641	143,233	(62,367)
Total	1,592,379	1,559,639	(32,740)	1,136,201	(423,437)	1,181,584	45,383	1,187,450	5,866

Variance Analysis on Other Distribution Revenue :

Retail Services Revenue – 4082

2006	2007	Variance
69,144	178,784	109,640

The increase to Retail Service revenue is due to inclusion of $ 106,857 of SSS Administration Revenue in this account in 2007. In 2006 the SSS Administration Revenue of $ 110,530 was included in account 4080 which is the current account for this revenue.

Retail Services Revenue – 4082

2007	2008	Variance
178,784	63,697	(115,087)

The decrease to Retail Service revenue is due to exclusion of $ 108,499, of SSS Administration Revenue as it is reported in account 4080 in 2008. In 2007 the SSS Administration Revenue of $106,857 was included in account 4082 which was incorrect as this revenue should be in 4080.

Miscellaneous Service Revenue – 4235

2006	2007	Variance
260,640	398,075	137,435

The increase to the Miscellaneous Service Revenue is due to the increase in the service charge for the Occupancy charge and the Reconnection Charge in the middle of 2006. The rate of the Occupancy charge has increased from $8.80 to $30 and the Reconnection Charge increased from $17.60 to $65.

Interest and Dividend Income-4405

2006	2007	Variance
529,194	329,691	(199,503)

The decrease in the Interest and Dividend Income is due to mainly the decrease in bank interest caused by lower interest rates and lower cash balances.

Interest and Dividend Income-4405

2007	2008	Variance
329,691	69,402	(260,289)

The decrease in Interest and Dividend Income from 2007 to 2008 by $260,289 was mainly the decrease in bank interest caused by lower interest rates and lower cash balances.

OVERVIEW OF OPERATING COSTS:

Chatham-Kent Hydro Consistently Has Low Operating Costs

Chatham-Kent Hydro’s focus on lowering costs:

Chatham-Kent Hydro has always strived to provide a safe and reliable system while managing the impacts on its customers. In 2001 when Chatham-Kent Hydro filed its first rate application (EB-2001-0033) before the OEB it elected to have a profit model rather than a maximum profit model. This decision was made to assist the customers through the many changes that were going to affect them when deregulation was introduced to the Ontario electricity industry market.

Chatham-Kent Hydro continued to manage the cost impacts to the customers when it selected it’s smart meter solution in 2006. Chatham-Kent Hydro prepared a full cost analysis of the smart meter solution and has been approved on two occasions for full recovery of smart meter costs installed up to December 31, 2007. One component of the smart meter solution chosen that reduces the impact to the customers is that the solution allowed for retrofitting of newer meters. This has significantly reduced the stranded meter costs to approximately $126,000 or less than $4 per customer.

Chatham-Kent Hydro has been extremely prudent in its IT infrastructure costs in the past and continues to do so while still being able to deliver the services required for smart meters and TOU billing while ensuring data security and reliability. Chatham-Kent Hydro has a service level agreement with Chatham-Kent Utility Services, an affiliate, to provide all customer care, administration, regulatory and finance activities. Chatham-Kent Utility Services has been able to update the customer information system (“CIS”), integrate with the Meter Data Management Repository (“MDMR”), and implement a new financial system for minimal costs. Since Chatham-Kent Utility Services provides billing services to Chatham-Kent PUC and administrative services to Middlesex Power Distribution Company, another affiliate, a significant amount of the costs are allocated to other companies and do not impact the customers of Chatham-Kent Hydro.

OEB's distributor cost comparator ranking:

The OEB has undertaken a lengthy process of reviewing, comparing and ranking distributor costs. The purpose of the cost comparison is to assist the OEB in regulating the approximately 80 distributors in setting their rates and in providing a stretch factor for 3rd Generation Incentive Rate Mechanism ("IRM").

Through the many analyses that were performed by the OEB staff and their consultant Pacific Economics Group ("PEG"), Chatham-Kent Hydro has been ranked as one of the lowest cost distributors in Ontario. If Chatham-Kent Hydro were filing this Application under the 3rd generation IRM it would be classified in Group 1 for the lowest stretch factor. The benchmark evaluation for Distributors in Group 1 is;

> "Statistically superior on the econometric benchmarking model and in the top quartiles on the unit cost benchmarking model" (EB-2007-0673, Addendum to the Supplemental Report of the Board, Page 1, Table 1, January 28, 2009)

Chatham-Kent Hydro is therefore considered to be statistically superior and in the lowest cost quartile of distributors.

Another report provided by PEG is Sensitivity Analysis on Efficiency Ranking and Cohorts for the 2009 Rate Year: Update (Exhibit 4, Tab 1, Schedule 1, Appendix A). This report has identified in many cases that Chatham-Kent Hydro has managed its costs to be a leader in Ontario; some of the instances are:

- Chatham-Kent Hydro is placed into their group, Mid-size Southern Medium-High Undergrounding (Table 1, Page 7)
- Chatham-Kent Hydro is ranked number 1 in its peer group for Unit OM&A Cost Indexes (Table 2, Page 9)
- Chatham-Kent Hydro is ranked number 2 of all Ontario distributors for Updated Performance Rankings Based on Econometric Benchmarks (Table 3, Page 10)

- Chatham-Kent Hydro is ranked number 4 of all Ontario distributors for Updated Performance Rankings Based on Unit Cost Indexes (Table 4, Page 11)
- Chatham-Kent Hydro is put into Group 1 for Stretch Factor Results: 2007 data Updated (Table 5, Page 12)
- Chatham-Kent Hydro maintains the number 2 ranked distributor of all Ontario distributors for Updated Performance Rankings Based on Econometric Benchmarks (Renfrew off the Canadian Shield) (Table 6, Page 13)
- Chatham-Kent Hydro is ranked number 3 for Updated Performance Rankings Based on Econometric Benchmarks (26% allocation for LV charges) (Table 7, Page 14)
- Chatham-Kent Hydro is ranked number 4 for Updated Performance Rankings Based on Unit Costs Indexes (26% Allocation for LV charges) (Table 8, Page 15)
- Chatham-Kent Hydro again is ranked in Group 1 for Stretch Factor Results: 2007 data Update (26% Allocation for LV charges) (Table 9, Page 16)
- Chatham-Kent Hydro is ranked number 2 for Updated Performance Rankings Based on Econometric Benchmarks (26% allocation for LV charges divided by 2.35) (Table 10, Page 17)
- Chatham-Kent Hydro is ranked number 4 for Updated Performance Rankings Based on Unit Costs Indexes (26% Allocation for LV charges divided by 2.35) (Table 11, Page 18)
- Chatham-Kent Hydro would maintain in Group 1 for Stretch Factor Results: 2007 data Update (26% Allocation for LV charges divided by 2.35) (Table 12, Page 19)

PEG has clearly identified that Chatham-Kent Hydro manages costs very well and is a “superior” utility.

APPENDIX A
PEG REPORT

Pacific Economics Group, LLC
Economic and Litigation Consulting

SENSITIVITY ANALYSIS ON EFFICIENCY RANKING AND COHORTS FOR THE 2009 RATE YEAR: UPDATE

In July 2008, Pacific Economics Group (PEG) updated its benchmarking evaluations of the operations, maintenance and administrative (OM&A) costs of Ontario's electricity distributors to include 2007 data. We computed updated econometric benchmarks and unit cost benchmarks. These benchmarking evaluations were used to divide the Ontario industry into three efficiency "cohorts" for the purpose of assigning stretch factors to distributors for the 2009 rate year using a methodology described in the July 14, 2008 Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors. The Board issued the results of our work on July 22, 2008.

Subsequent to the release of the September 17, 2008 Supplemental Report of the Board, Board staff asked PEG to undertake a sensitivity analysis of our July 2008 results to address two potential issues. The first was the sensitivity of benchmarking results where a firm may be incorrectly identified as being on the Canadian Shield; specifically, for the purposes of this test, Renfrew Hydro. The second was the treatment of charges billed by Hydro One to distributors "embedded" within its network for the use of low voltage (LV) facilities. In both cases, our benchmarking models were identical to those used in our original March 20, 2008 report and our July 2008 update. Any changes in results would therefore reflect the impact of changes in distributor data only and not any changes in benchmarking techniques. The results of these sensitivity tests were released publicly on November 21, 2008.

As part of the consultation on our November 2008 benchmarking results, PEG was asked to present updated versions of the tables which detail our proposed peer groups

CAPITOL SQUARE OFFICE
22 EAST MIFFLIN ST.
MADISON, WI 53703
Phone: 608.257.1522 Fax: 608.257.1540

and the unit cost indexes for each individual distributor within each peer group. This information was previously presented in Tables 5 and 6, respectively, in our March 2008 report. In responding to this request, PEG noticed a data processing error in the 2007 update (*i.e.* for some companies, the unit cost benchmarks that were computed were based on 2004-2006 data rather than 2005-2007 data). This error affects both the 2007 benchmarking update as well as any tests of the sensitivity of these results to LV charge allocation and whether firms are incorrectly identified as being on the Canadian shield. PEG has therefore produced a new set of benchmarking results that corrects this data processing error. These tables are presented here, and they supersede the Tables previously presented by PEG in July 2008 (the update to include 2007 data) and November 2008 (the sensitivity tests). This memorandum will describe the results of these analyses, which do not materially impact the conclusions of our previous (November 2008) memorandum.

2007 Update

The results of the 2007 update are attached. Table One presents PEG's proposed peer groups; this is an update of what was Table 5 in the March 2008 report. The peer groups have not been altered since that report. Table Two presents the OM&A unit cost indexes for all distributors and all peer groups; this is an update of what was Table 6 in the March 2008 report. Table Three presents the econometric benchmarking results that include 2007 data. Table Four presents the unit cost benchmarking results; these benchmarks are calculated using 2005-2007 data for each distributor. Table Five presents the stretch factor assignments for each distributor using the methodology approved by the Board.

The Canadian Shield Sensitivity Test

With respect to the Canadian Shield sensitivity, Staff selected Renfrew Hydro since there was a possibility that it could have been misclassified based on the physiography reference maps used. Our review of Ontario geography and Renfrew's service territory indicated that there was some uncertainty about whether Renfrew should or should not have been categorized as serving territory on the Canadian Shield. We therefore investigated the sensitivity of our benchmarking results to this uncertainty by estimating an econometric model in which Renfrew was classified as being "off" rather than "on" the Canadian Shield (*i.e.* the value of the Canadian Shield dummy variable for Renfrew was changed from a 1 to a zero). It should be noted that this sensitivity test affected the econometric benchmarking results only because the unit cost benchmarking results do not depend on the Canadian Shield variable.

It should also be noted that, even though this sensitivity test did not lead to changes in the econometric model itself, using different data for even a single company can lead to changes in the coefficients that are estimated for the independent variables in an econometric model. Carrying out this test did affect the coefficients. After making the change in Renfrew's data for the Canadian Shield variable, the coefficients in PEG's econometric model were very similar, although not identical, to what were obtained earlier and presented in our March 2008 report.

The results of the Renfrew Canadian Shield variable sensitivity test are summarized in Table 6. The groups of "statistically superior" and "statistically inferior" cost performers are demarcated by the bold lines in the table. It can be seen that there are 15 statistically superior distributors (*i.e.* those distributors above the first bold line), 12 statistically inferior distributors (*i.e.* those distributors below the second bold line), and the remaining 56 distributors are statistically average cost performers. In our July 2008 update, there were 17 statistically superior cost performers, 13 statistically inferior cost performers, and 53 statistically average cost distributors. Thus this sensitivity test moved two distributors (Kingston Electricity Distribution and Horizon Utilities) from statistically superior to average cost performance, and one distributor (Fort Frances Power) from statistically inferior to average cost performance. This change in the econometric benchmarks would cause Kingston and Horizon to move from the top to the middle efficiency cohort, and Fort Frances from the bottom to the middle efficiency cohort.[1]

---

1 As described in the July 14 Report of the Board, a company will be in efficiency cohort 1 if it is statistically superior on the econometric benchmarking model and in the top quartile on the unit cost benchmarking model. A company will be in efficiency cohort 3 if it is statistically inferior on the econometric benchmarking model and in the bottom quartile on the unit cost benchmarking model. All other companies will be in efficiency cohort 2.

In all three cases, the companies that moved were just on the edge of being classified in one cohort vis-à-vis another in our July 2008 study. The new Renfrew data used to re-estimate the econometric model led to small changes in estimated coefficients, and standard errors, which were nevertheless material enough to move these three distributors from one identified cohort into another. The classification for Renfrew itself was not impacted by this sensitivity test; the company was in the top efficiency cohort in the July 2008 update and in our current results, although the difference between its actual and predicted cost widened from -19.3% in July to -24.8% with the new data.

Low Voltage Charges

The second set of sensitivity tests concerned Hydro One's charges to distributors embedded within its territory for the use of low voltage (LV) facilities. A number of embedded distributors are currently charged by Hydro One for the use of its LV assets, but these charges are not reported as O&M costs in the distributors' RRR filings which were used as the basis for PEG's benchmarking results. This accounting treatment may lead to a lack of comparability among sampled companies, since the reported OM&A for non-embedded distributors in the Province do include the costs of LV facilities, which the non-embedded firms own, operate and maintain themselves.

Hydro One does not segregate its charges for LV facilities into the associated capital and O&M costs so, to control for these costs in OM&A benchmarking, it was necessary to develop proxies for the O&M component of Hydro One's charges. OEB Staff developed two separate proxies for these O&M costs, using data from Hydro One's 2006 and 2008 electricity distribution rate (EDR) proceedings. The first proxy was equal to 26% of LV charges to each distributor. The second proxy was equal to 26% of LV charges for each distributor, divided by 2.354. Further details on these proxies are

---

The forthcoming Tables 9 and 12 display the efficiency cohorts under two different sensitivity tests, for two different measures of LV costs. For both Table 9 and Table 12, the ordering of firms in the top and bottom cohorts is identical to that presented for the econometric rankings in the associated Tables Seven and Ten, respectively, although it will be noted that not all firms identified as being statistically superior or inferior necessarily achieve top or bottom cohort performance. The rank ordering of companies within an efficiency cohort should also not itself be interpreted as evidence of relative performance *i.e.* the first firm appearing in the top efficiency cohort in Table 12 is not necessarily the "most" efficient, and the last firm appearing in the bottom cohort in Table 12 is not necessarily the "least" efficient, distributor in Ontario.

provided as part of the accompanying letter to this note. For both proxies, the proxy O&M costs were added to the OM&A costs which were benchmarked originally for each embedded distributor. After the proxy O&M costs were added in, PEG re-estimated the econometric model, re-computed unit cost indexes, and re-determined the efficiency cohorts for all distributors in the sample (again, separately for each of the proxy O&M costs associated with LV assets).

The results of the sensitivity tests for the first LV proxy (26% of LV charges) are presented in Tables 7, 8 and 9. Table 7 presents the updated econometric benchmarks, Table 8 the updated unit cost benchmarks, and Table 9 the updated efficiency cohort/stretch factor assignments. Comparing our July 2008 results (presented above) with the results of the sensitivity test for the first LV proxy, PEG finds that efficiency cohort classifications have changed for four of the 83 distributors. Hydro 2000 was in the top cohort in our July 2008 update but moved to the middle cohort when these proxy LV charges are included in the analysis. Eastern Ontario Power, Centre Wellington and Niagara Falls Hydro move from the bottom cohort to the middle cohort. Overall, with this sensitivity test, there are 10 distributors in the top efficiency cohort, 8 distributors in the bottom cohort, and 65 distributors in the middle cohort.

The results of the sensitivity tests for the second LV proxy (26% of LV charges, divided by 2.354) are presented in Tables 10, 11 and 12. Table 10 presents the updated econometric benchmarks, Table 11 the updated unit cost benchmarks, and Table 12 the updated efficiency cohort/stretch factor assignments. Comparing the results of the second sensitivity test for the LV proxy to the July 2008 results, PEG finds that efficiency cohort classifications have changed for two of the 83 distributors. Hydro 2000 moves from the top cohort in our July 2008 to the middle cohort in the current results. Centre Wellington Hydro moves from the bottom cohort to the middle cohort. Overall, with this sensitivity test, there are 10 distibutors in the top efficiency cohort, 10 distributors in the bottom cohort, and 63 distributors in the middle cohort.

Concluding Comments

Overall, PEG believes that these sensitivity analyses show that the efficiency cohorts identified in our July 2008 update are robust. Our sensitivity tests show that relatively few distributors move from one efficiency cohort to another based on changes in accounting for LV charges or for whether or not Renfrew is classified as being on the Canadian Shield. These factors have a relatively small impact on any given firm's efficiency ranking. A principal reason is that LV costs and changes in Renfrew's Canadian Shield classification have little impact on the estimated coefficients for customer numbers, kWh, and km of line in our econometric model, and these variables continue to be the major drivers of distributors' OM&A costs. PEG's benchmarking models also control for labour prices and dimensions of capital cost (system undergrounding and asset age). Our previous econometric research also investigated whether distributors' ownership of high voltage transmission assets impacted OM&A cost performance, but we found that there was no statistically significant relationship between this variable and distributors' OM&A costs. However, PEG believes that further research on this, and on related issues, is warranted in the total cost benchmarking analysis to be undertaken.

Table 1

PEG Proposed Peer Groups for Ontario LDCs

Peer Group Designation	Distributor	Customers[1,2,3,4]	% Undergrounding[1,5,6,7,8]	Canadian Shield	Customer Growth/Output Index[1,9]
Small Northern Low Undergrounding	Atikokan Hydro	1,711	0.5%	Yes	-1,470
Small Northern Low Undergrounding	Chapleau Public Utilities	1,338	3.7%	Yes	-2,346
Small Northern Low Undergrounding	Espanola Regional Hydro Distribution	3,316	8.0%	Yes	691
Small Northern Low Undergrounding	Fort Frances Power	3,864	9.5%	Yes	650
Small Northern Low Undergrounding	Great Lakes Power	11,522	0.1%	Yes	236
Small Northern Low Undergrounding	Northern Ontario Wires	6,112	1.4%	Yes	-772
Small Northern Low Undergrounding	Parry Sound Power	3,365	8.6%	Yes	716
Small Northern Low Undergrounding	Renfrew Hydro	4,149	3.6%	Yes	323
Small Northern Low Undergrounding	Sioux Lookout Hydro	2,754	2.8%	Yes	105
Small Northern Medium Undergrounding	Hearst Power Distribution	2,772	16.2%	Yes	209
Small Northern Medium Undergrounding	Kenora Hydro Electric	5,642	10.2%	Yes	226
Small Northern Medium Undergrounding	Lakeland Power Distribution	9,135	19.7%	Yes	789
Small Northern Medium Undergrounding	Ottawa River Power	10,230	13.0%	Yes	869
Mid-Size Northern	Greater Sudbury Hydro & West Nippissing	46,451	20.1%	Yes	90
Mid-Size Northern	North Bay Hydro Distribution	23,642	15.6%	Yes	408
Mid-Size Northern	PUC Distribution	32,512	15.7%	Yes	255
Mid-Size Northern	Thunder Bay Hydro Electricity Distribution	49,421	19.9%	Yes	428
Large Northern	Hydro One Networks	1,173,360	3.5%	Yes	855
Small Southern Low & Medium Undergrounding	Brant County Power	9,339	13.1%	No	2,164
Small Southern Low & Medium Undergrounding	Clinton Power	1,639	19.0%	No	331
Small Southern Low & Medium Undergrounding	Dutton Hydro	600	14.3%	No	2,755
Small Southern Low & Medium Undergrounding	Eastern Ontario Power	3,552	11.2%	No	313
Small Southern Low & Medium Undergrounding	Grand Valley Energy	677	11.1%	No	1,203
Small Southern Low & Medium Undergrounding	Hydro 2000	1,159	14.3%	No	1,106
Small Southern Low & Medium Undergrounding	Hydro Hawkesbury	5,428	13.8%	No	2,044
Small Southern Low & Medium Undergrounding	Lakefront Utilities	9,057	16.7%	No	1,967
Small Southern Low & Medium Undergrounding	Port Colborne	9,159	4.5%	No	391
Small Southern Low & Medium Undergrounding	Rideau St. Lawrence Distribution	5,864	10.3%	No	197
Small Southern Low & Medium Undergrounding	Wellington North Power	3,486	12.3%	No	857
Small Southern Medium-High Undergrounding	Middlesex Power Distribution	6,957	23.6%	No	1,809
Small Southern Medium-High Undergrounding	Midland Power Utility	6,709	31.3%	No	1,751
Small Southern Medium-High Undergrounding	Newbury Power	199	25.0%	No	1,168
Small Southern Medium-High Undergrounding	Tillsonburg Hydro	6,571	33.3%	No	1,596
Small Southern Medium-High Undergrounding	West Coast Huron Energy	3,853	20.0%	No	1,002
Small Southern Medium-High Undergrounding	West Perth Power	2,034	30.6%	No	1,530
Small Southern Medium-High Undergrounding with Rapid Growth[10]	Centre Wellington Hydro	6,239	47.3%	No	3,522
Small Southern Medium-High Undergrounding with Rapid Growth	Cooperative Hydro Embrun	1,882	44.4%	No	6,605
Small Southern Medium-High Undergrounding with Rapid Growth	Grimsby Power	9,792	24.3%	No	3,588
Small Southern Medium-High Undergrounding with Rapid Growth	Niagara-on-the-Lake Hydro	7,778	26.7%	No	2,800
Small Southern Medium-High Undergrounding with Rapid Growth	Orangeville Hydro	10,134	41.5%	No	3,582
Mid-size Southern Low & Medium Undergrounding	Fort Erie	15,494	8.4%	No	503
Mid-size Southern Low & Medium Undergrounding	Haldimand County Hydro	20,698	4.7%	No	780
Mid-size Southern Low & Medium Undergrounding	Innisfil Hydro Distribution Systems	14,120	18.2%	No	2,244
Mid-size Southern Low & Medium Undergrounding	Norfolk Power Distribution	18,641	12.5%	No	3,174
Mid-size Southern Low & Medium Undergrounding	Orillia Power Distribution	12,648	18.9%	No	1,199
Mid-size Southern Low & Medium Undergrounding	Peninsula West Utilities	15,491	7.9%	No	1,639
Mid-size Southern Medium-High Undergrounding	Bluewater Power Distribution	35,906	22.7%	No	837
Mid-size Southern Medium-High Undergrounding	Chatham-Kent Hydro	32,007	27.4%	No	401
Mid-size Southern Medium-High Undergrounding	COLLUS Power	14,325	33.9%	No	2,761
Mid-size Southern Medium-High Undergrounding	E.L.K. Energy	10,719	38.4%	No	2,233
Mid-size Southern Medium-High Undergrounding	Erie Thames Powerlines	14,181	19.1%	No	1,468
Mid-size Southern Medium-High Undergrounding	Essex Powerlines	27,789	50.3%	No	2,809
Mid-size Southern Medium-High Undergrounding	Festival Hydro	19,262	32.8%	No	1,605
Mid-size Southern Medium-High Undergrounding	Kingston Electricity Distribution	26,632	30.5%	No	-68
Mid-size Southern Medium-High Undergrounding	Niagara Falls Hydro	34,704	40.4%	No	1,225
Mid-size Southern Medium-High Undergrounding	Peterborough Distribution	34,161	29.5%	No	1,371
Mid-size Southern Medium-High Undergrounding	St. Thomas Energy	15,919	33.3%	No	2,591
Mid-size Southern Medium-High Undergrounding	Wasaga Distribution	11,311	45.4%	No	6,308
Mid-size Southern Medium-High Undergrounding	Welland Hydro-Electric System	21,389	24.9%	No	770
Mid-size Southern Medium-High Undergrounding	Westario Power	21,297	29.0%	No	1,188
Mid-size Southern Medium-High Undergrounding	Woodstock Hydro Services	14,441	43.3%	No	1,730
Large City Southern Medium-High Undergrounding	ENWIN Powerlines	84,757	36.2%	No	1,332
Large City Southern Medium-High Undergrounding	Hydro Ottawa	287,006	49.5%	No	2,653
Large City Southern Medium-High Undergrounding	Toronto Hydro-Electric System	679,913	45.5%	No	457
Large City Southern Medium-High Undergrounding	Veridian Connections	109,225	32.9%	No	2,837
Large City Southern High Undergrounding	Enersource Hydro Mississauga	183,715	65.3%	No	2,511
Large City Southern High Undergrounding	Horizon Utilities	232,493	55.0%	No	1,302
Large City Southern High Undergrounding	Hydro One Brampton Networks	126,026	70.4%	No	5,800
Large City Southern High Undergrounding	London Hydro	142,105	51.2%	No	2,265
Large City Southern High Undergrounding	PowerStream	236,220	69.3%	No	4,617
Mid-size GTA Medium-High & High Undergrounding	Barrie Hydro Distribution	68,535	54.9%	No	5,188
Mid-size GTA Medium-High & High Undergrounding	Brantford Power	37,108	44.3%	No	2,160
Mid-size GTA Medium-High & High Undergrounding	Burlington Hydro	61,776	40.2%	No	3,192
Mid-size GTA Medium-High & High Undergrounding	Cambridge and North Dumfries Hydro	48,944	33.9%	No	2,712
Mid-size GTA Medium-High & High Undergrounding	Guelph Hydro Electric Systems	47,720	58.6%	No	3,331
Mid-size GTA Medium-High & High Undergrounding	Halton Hills Hydro	20,078	34.4%	No	2,533
Mid-size GTA Medium-High & High Undergrounding	Kitchener-Wilmot Hydro	82,599	43.3%	No	2,730
Mid-size GTA Medium-High & High Undergrounding	Milton Hydro Distribution	22,811	35.2%	No	6,256
Mid-size GTA Medium-High & High Undergrounding	Newmarket Hydro & Tay Hydro	31,193	43.9%	No	2,746
Mid-size GTA Medium-High & High Undergrounding	Oakville Hydro Electricity Distribution	59,883	61.0%	No	4,067
Mid-size GTA Medium-High & High Undergrounding	Oshawa PUC Networks	50,980	46.2%	No	1,643
Mid-size GTA Medium-High & High Undergrounding	Waterloo North Hydro	49,558	31.5%	No	2,932
Mid-size GTA Medium-High & High Undergrounding	Whitby Hydro Electric	38,278	51.9%	No	5,447

[1] Latest year of available data.
[2] Small is defined as less than 10,000 customers with the exception of Great Lakes Power and Ottawa River Power, who have more than 10,000 customers but are defined as "small."
[3] Mid-size is defined as between 10,000 and 82,000 customers.
[4] Large is defined as more than 82,000 customers.
[5] Low undergrounding is defined as 0% to 10%.
[6] Medium undergrounding is between 10% and 20%.
[7] Medium-high undergrounding is between 20% and 50%.
[8] High undergrounding is over 50%.
[9] Rapid growth is defined as a value for (Customer Growth/Output Index) that exceeds 2,000.
[10] Centre Wellington is in the GTA but no GTA peer group is appropriate.

Table 2

Unit OM&A Cost Indexes

	2002	2003	2004	2005	2006	2007	Average of Last 3 Available Years[2]	Average / Group Average[2] [A]	Percentage Differences[2] [A - 1]	Implied Cost Surplus (Savings) per year[2]
Small Northern Low Undergrounding										
Renfrew Hydro	0.928	0.996	0.921	0.809	0.999	1.094	0.967	**0.584**	-41.6%	-$350,347
Espanola Regional Hydro Distribution	1.410	1.171	1.092	1.155	1.495	1.483	1.378	**0.832**	-16.8%	-$156,347
Northern Ontario Wires	1.375	1.223	1.369	1.192	1.270	1.374	1.279	**0.772**	-22.8%	-$395,437
Parry Sound Power	1.013	1.200	1.214	1.275	1.333	1.303	1.303	**0.787**	-21.3%	-$215,508
Fort Frances Power	1.197	1.213	1.236	1.305	1.346	1.442	1.365	**0.824**	-17.6%	-$192,252
Sioux Lookout Hydro	1.086	0.877	1.259	1.359	1.390	1.528	1.426	**0.861**	-13.9%	-$149,138
Atikokan Hydro	1.443	2.729	1.758	1.618	1.619	2.022	1.753	**1.058**	5.8%	$40,163
Chapleau Public Utilities	1.615	1.668	1.720	1.907	1.833	2.380	2.040	**1.231**	23.1%	$128,185
Great Lakes Power	2.983	2.924	3.116	3.308	3.412	3.476	3.399	**2.052**	105.2%	$8,371,020
GROUP AVERAGE							**1.657**			
Small Northern Medium Undergrounding										
Hearst Power Distribution	0.630	0.609	0.764	0.745	0.826	0.868	0.813	**0.799**	-20.1%	-$127,595
Lakeland Power Distribution	1.076	1.296	0.905	0.909	1.083	0.977	0.990	**0.972**	-2.8%	-$58,301
Ottawa River Power	0.940	1.043	1.020	0.989	1.070	1.200	1.087	**1.067**	6.7%	$141,026
Kenora Hydro Electric	1.098	1.117	1.155	1.114	1.149	1.284	1.183	**1.162**	16.2%	$208,696
GROUP AVERAGE							**1.018**			
Mid-Size Northern										
North Bay Hydro Distribution	1.126	1.005	0.991	0.878	1.147	1.007	1.010	**0.906**	-9.4%	-$487,201
PUC Distribution	0.866	0.937	1.070	1.046	1.028	1.166	1.080	**0.969**	-3.1%	-$225,144
Thunder Bay Hydro Electricity Distribution	1.087	1.178	1.130	1.016	1.070	1.179	1.088	**0.976**	-2.4%	-$262,212
Greater Sudbury Hydro & West Nippissing	1.034	0.996	1.121	1.003	1.069	1.769	1.280	**1.149**	14.9%	$1,743,696
GROUP AVERAGE							**1.115**			
Large Northern										
Hydro One Networks	n/a	1.015	0.969	1.042	1.252	1.465	1.253	**NA**	NA	NA
GROUP AVERAGE							**1.253**			
Small Southern Low & Medium Undergrounding										
Hydro Hawkesbury	0.495	0.517	0.473	0.568	0.537	0.581	0.562	**0.398**	-60.2%	-$450,834
Lakefront Utilities	0.669	0.594	0.681	0.807	0.876	0.890	0.858	**0.608**	-39.2%	-$710,739
Hydro 2000	0.572	0.649	0.648	1.164	0.930	0.989	1.028	**0.728**	-27.2%	-$65,796
Rideau St. Lawrence Distribution	1.029	1.060	1.058	1.157	1.198	1.257	1.204	**0.853**	-14.7%	-$200,189
Wellington North Power	1.179	1.077	1.121	1.170	1.237	1.213	1.207	**0.855**	-14.5%	-$143,409
Brant County Power	1.259	1.441	1.504	1.507	1.633	0.688	1.276	**0.904**	-9.6%	-$260,269
Clinton Power	1.244	1.302	1.119	1.229	1.599	1.795	1.541	**1.092**	9.2%	$42,543
Eastern Ontario Power	n/a	1.736	1.297	1.565	1.936	1.826	1.776	**1.258**	25.8%	$348,530
Dutton Hydro	1.310	1.428	2.325	1.592	1.538	n/a	1.818	**1.288**	28.8%	$49,469
Grand Valley Energy	1.623	1.461	1.600	1.814	2.294	2.012	2.040	**1.445**	44.5%	$98,248
Port Colborne	0.781	0.856	0.938	2.143	2.149	2.353	2.215	**1.570**	57.0%	$2,406,782
GROUP AVERAGE							**1.411**			
Small Southern Medium-High Undergrounding										
Middlesex Power Distribution	0.952	1.097	0.899	1.070	0.898	0.886	0.952	**0.842**	-15.8%	-$230,272
West Perth Power	1.087	1.129	1.044	0.886	1.137	1.103	1.042	**0.923**	-7.7%	-$38,634
Midland Power Utility	1.102	1.069	1.049	0.974	1.089	1.065	1.042	**0.923**	-7.7%	-$133,315
Tillsonburg Hydro	0.793	1.437	1.425	1.618	0.966	0.955	1.180	**1.044**	4.4%	$67,583
Newbury Power	n/a	n/a	1.320	1.030	1.216	1.477	1.241	**1.099**	9.9%	$4,889
West Coast Huron Energy	1.124	1.122	1.096	1.376	1.414	1.170	1.320	**1.169**	16.9%	$225,336
GROUP AVERAGE							**1.129**			
Small Southern Medium-High Undergrounding with Rapid Growth										
Grimsby Power	0.731	0.745	0.819	0.856	0.823	0.898	0.859	**0.876**	-12.4%	-$192,942
Orangeville Hydro	0.836	0.894	0.830	0.844	0.826	0.907	0.859	**0.876**	-12.4%	-$224,279
Niagara-on-the-Lake Hydro	0.885	0.830	0.915	0.838	0.929	1.028	0.932	**0.950**	-5.0%	-$79,402
Centre Wellington Hydro	1.196	1.146	1.083	1.079	1.095	1.109	1.094	**1.116**	11.6%	$171,344
Cooperative Hydro Embrun	0.979	1.056	0.945	1.112	1.128	1.237	1.159	**1.182**	18.2%	$67,523
GROUP AVERAGE							**0.981**			
Mid-Size Southern Low & Medium Undergrounding										
Norfolk Power Distribution	1.162	1.126	1.062	1.046	1.033	1.223	1.101	**0.894**	-10.6%	-$447,089
Peninsula West Utilities	1.090	1.133	1.184	1.295	1.174	0.871	1.114	**0.905**	-9.5%	-$376,880
Innisfil Hydro Distribution Systems	1.039	1.210	1.261	1.057	1.135	1.212	1.135	**0.922**	-7.8%	-$229,937
Orillia Power Distribution	0.934	1.041	1.074	1.200	1.174	1.264	1.213	**0.985**	-1.5%	-$50,688
Haldimand County Hydro	n/a	n/a	n/a	1.163	1.247	1.576	1.328	**1.079**	7.9%	$478,050
Fort Erie	1.437	1.281	1.299	1.357	1.510	1.619	1.496	**1.215**	21.5%	$979,789
GROUP AVERAGE							**1.231**			

[1] Last three years of available data.
[2] Lower values imply better performance.

Unit OM&A Cost Indexes

	2002	2003	2004	2005	2006	2007	Average of Last 3 Available Years[2]	Average / Group Average[2] [A]	Percentage Differences[2] [A - 1]
Mid-Size Southern Medium-High Undergrounding									
Chatham-Kent Hydro	0.668	0.665	0.700	0.690	0.702	0.721	0.704	**0.724**	-27.6%
Festival Hydro	0.754	0.709	0.724	0.698	0.782	0.774	0.752	**0.773**	-22.7%
Peterborough Distribution	0.794	0.739	0.802	0.778	0.884	0.914	0.859	**0.883**	-11.7%
Welland Hydro-Electric System	0.817	0.907	0.981	0.841	0.789	1.016	0.882	**0.907**	-9.3%
COLLUS Power	0.834	0.796	0.844	0.847	1.024	1.063	0.978	**1.005**	0.5%
E.L.K. Energy	0.960	1.011	0.856	0.579	0.846	0.873	0.766	**0.787**	-21.3%
Woodstock Hydro Services	0.831	0.898	0.923	0.932	0.969	1.008	0.969	**0.997**	-0.3%
Wasaga Distribution	0.843	0.892	0.971	1.070	1.147	1.114	1.110	**1.142**	14.2%
St. Thomas Energy	0.784	0.818	0.882	0.962	1.099	1.041	1.034	**1.063**	6.3%
Kingston Electricity Distribution	0.911	1.004	0.993	0.917	0.832	0.827	0.859	**0.883**	-11.7%
Niagara Falls Hydro	0.985	1.019	1.017	1.065	1.093	1.152	1.103	**1.135**	13.5%
Westario Power	0.988	1.140	1.165	1.017	1.003	0.958	0.993	**1.021**	2.1%
Bluewater Power Distribution	n/a	1.045	1.014	1.034	1.108	1.048	1.063	**1.093**	9.3%
Essex Powerlines	1.055	0.958	1.068	1.177	1.166	1.079	1.141	**1.173**	17.3%
Erie Thames Powerlines	1.054	1.248	1.277	1.323	1.270	1.534	1.376	**1.415**	41.5%
GROUP AVERAGE							**0.973**		
Large City Southern Medium-High Undergrounding									
Hydro Ottawa	0.838	0.760	0.641	0.595	0.723	0.695	0.671	**0.760**	-24.0%
Veridian Connections	0.951	1.122	0.930	0.829	0.875	0.774	0.826	**0.937**	-6.3%
Toronto Hydro-Electric System	0.844	0.876	0.905	0.850	0.846	0.915	0.870	**0.987**	-1.3%
ENWIN Powerlines	1.213	1.080	1.083	0.996	1.045	1.442	1.161	**1.316**	31.6%
GROUP AVERAGE							**0.882**		
Large City Southern High Undergrounding									
Hydro One Brampton Networks	0.574	0.563	0.518	0.514	0.561	0.526	0.534	**0.742**	-25.8%
Horizon Utilities	0.601	0.695	0.623	0.744	0.660	0.746	0.717	**0.997**	-0.3%
London Hydro	0.737	0.724	0.718	0.721	0.792	0.827	0.780	**1.084**	8.4%
PowerStream	0.634	0.725	0.751	0.772	0.703	0.765	0.747	**1.039**	3.9%
Enersource Hydro Mississauga	n/a	n/a	0.746	0.776	0.819	0.861	0.819	**1.138**	13.8%
GROUP AVERAGE							**0.719**		
Mid-Size GTA Medium-High Undergrounding									
Barrie Hydro Distribution	0.607	0.740	0.650	0.547	0.604	0.601	0.584	**0.739**	-26.1%
Cambridge and North Dumfries Hydro	0.617	0.609	0.657	0.594	0.597	0.685	0.625	**0.791**	-20.9%
Kitchener-Wilmot Hydro	0.599	0.615	0.613	0.626	0.690	0.703	0.673	**0.852**	-14.8%
Guelph Hydro Electric Systems	0.736	0.825	0.771	0.731	0.737	0.844	0.771	**0.976**	-2.4%
Waterloo North Hydro	0.836	0.812	0.813	0.766	0.785	0.760	0.770	**0.975**	-2.5%
Oshawa PUC Networks	0.920	0.989	0.971	0.725	0.741	0.796	0.754	**0.954**	-4.6%
Milton Hydro Distribution	0.859	0.815	0.796	0.808	0.792	0.805	0.801	**1.014**	1.4%
Burlington Hydro	0.738	0.771	0.797	0.782	0.858	0.889	0.843	**1.067**	6.7%
Newmarket Hydro & Tay Hydro	0.841	0.949	0.921	0.859	0.859	0.846	0.855	**1.082**	8.2%
Oakville Hydro Electricity Distribution	0.773	0.858	0.858	0.814	0.884	0.826	0.841	**1.065**	6.5%
Halton Hills Hydro	0.995	0.896	0.918	0.850	1.015	0.910	0.925	**1.171**	17.1%
Brantford Power	0.727	0.833	0.889	0.870	0.775	0.951	0.865	**1.095**	9.5%
Whitby Hydro Electric	0.927	1.002	0.898	0.916	0.966	1.007	0.963	**1.219**	21.9%
GROUP AVERAGE							**0.790**		
AVERAGE: ALL COMPANIES	**0.977**	**1.034**	**1.031**	**1.046**	**1.098**	**1.140**	**1.100**	**1.000**	**0.000**

[1] Last three years of available data.
[2] Lower values imply better performance.

Table 3

Updated Performance Rankings Based on Econometric Benchmarks

This table replaces the table on page 4 of PEG's "Efficiency Ranking & Cohorts for the 2009 Rate Year" issued on July 22, 2008.

	Years Benchmarked	Actual/Predicted[1]	Deviation Percentage [A-1][1]	P-Value	Rank[1]
Hydro Hawkesbury	2005-2007	**0.643**	-0.357	0.000	1
Chatham-Kent Hydro	2005-2007	**0.691**	-0.309	0.001	2
Northern Ontario Wires	2005-2007	**0.711**	-0.289	0.001	3
Cambridge and North Dumfries Hydro	2005-2007	**0.715**	-0.285	0.002	4
E.L.K. Energy	2005-2007	**0.729**	-0.271	0.003	5
Grimsby Power	2005-2007	**0.764**	-0.236	0.008	6
Oshawa PUC Networks	2005-2007	**0.787**	-0.213	0.017	7
Lakeland Power Distribution	2005-2007	**0.789**	-0.211	0.018	8
Hydro One Brampton Networks	2005-2007	**0.793**	-0.207	0.020	9
Kitchener-Wilmot Hydro	2005-2007	**0.805**	-0.195	0.027	10
Renfrew Hydro	2005-2007	**0.807**	-0.193	0.028	11
Barrie Hydro Distribution	2005-2007	**0.814**	-0.186	0.034	12
Festival Hydro	2005-2007	**0.822**	-0.178	0.041	13
Welland Hydro-Electric System	2005-2007	**0.834**	-0.166	0.054	14
Hydro 2000	2005-2007	**0.840**	-0.160	0.060	15
Kingston Electricity Distribution	2005-2007	**0.860**	-0.140	0.090	16
Horizon Utilities	2005-2007	**0.864**	-0.136	0.098	17
Hydro Ottawa	2005-2007	**0.873**	-0.127	0.113	18
Lakefront Utilities	2005-2007	**0.874**	-0.126	0.115	19
Peninsula West Utilities	2005-2007	**0.878**	-0.122	0.123	20
Waterloo North Hydro	2005-2007	**0.880**	-0.120	0.127	21
Niagara-on-the-Lake Hydro	2005-2007	**0.894**	-0.106	0.158	22
Rideau St. Lawrence Distribution	2005-2007	**0.899**	-0.101	0.173	23
Kenora Hydro Electric	2005-2007	**0.904**	-0.096	0.185	24
Innisfil Hydro Distribution Systems	2005-2007	**0.908**	-0.092	0.194	25
Halton Hills Hydro	2005-2007	**0.914**	-0.086	0.212	26
Peterborough Distribution	2005-2007	**0.914**	-0.086	0.213	27
North Bay Hydro Distribution	2005-2007	**0.919**	-0.081	0.226	28
Atikokan Hydro	2005-2007	**0.927**	-0.073	0.250	29
Hearst Power Distribution	2005-2007	**0.932**	-0.068	0.265	30
Newmarket & Tay Hydro Electric	2005-2007	**0.933**	-0.067	0.268	31
Orangeville Hydro	2005-2007	**0.938**	-0.062	0.283	32
Enersource Hydro Mississauga	2005-2007	**0.958**	-0.042	0.351	33
Espanola Regional Hydro Distribution	2005-2007	**0.962**	-0.038	0.367	34
PUC Distribution	2005-2007	**0.966**	-0.034	0.378	35
Wellington North Power	2005-2007	**0.967**	-0.033	0.384	36
Middlesex Power Distribution	2005-2007	**0.970**	-0.030	0.392	37
Newbury Power	2005-2007	**0.977**	-0.023	0.416	38
Wasaga Distribution	2005-2007	**0.984**	-0.016	0.445	39
Veridian Connections	2005-2007	**0.991**	-0.009	0.469	40
Hydro One Networks	2005-2007	**0.996**	-0.004	0.485	41
Burlington Hydro	2005-2007	**1.008**	0.008	0.472	42
Brantford Power	2005-2007	**1.011**	0.011	0.461	43
Haldimand County Hydro	2005-2007	**1.016**	0.016	0.444	44
Westario Power	2005-2007	**1.017**	0.017	0.441	45
Tillsonburg Hydro	2005-2007	**1.019**	0.019	0.435	46
Toronto Hydro-Electric System	2005-2007	**1.021**	0.021	0.427	47
London Hydro	2005-2007	**1.028**	0.028	0.404	48
Woodstock Hydro Services	2005-2007	**1.037**	0.037	0.373	49
Ottawa River Power	2005-2007	**1.044**	0.044	0.350	50
Milton Hydro Distribution	2005-2007	**1.047**	0.047	0.342	51
Norfolk Power Distribution	2005-2007	**1.050**	0.050	0.332	52
Bluewater Power Distribution	2005-2007	**1.050**	0.050	0.331	53
Thunder Bay Hydro Electricity Distribution	2005-2007	**1.053**	0.053	0.324	54
Grand Valley Energy	2005-2007	**1.056**	0.056	0.314	55
Parry Sound Power	2005-2007	**1.063**	0.063	0.293	56
West Perth Power	2005-2007	**1.064**	0.064	0.290	57
COLLUS Power	2005-2007	**1.073**	0.073	0.265	58
Oakville Hydro Electricity Distribution	2005-2007	**1.077**	0.077	0.255	59
Cooperative Hydro Embrun	2005-2007	**1.080**	0.080	0.248	60
Clinton Power	2005-2007	**1.083**	0.083	0.238	61
Brant County Power	2005-2007	**1.087**	0.087	0.230	62
Orillia Power Distribution	2005-2007	**1.087**	0.087	0.229	63
St. Thomas Energy	2005-2007	**1.088**	0.088	0.228	64
Dutton Hydro	2004-2006	**1.096**	0.096	0.208	65
Sioux Lookout Hydro	2005-2007	**1.101**	0.101	0.197	66
Fort Erie (CNP)	2005-2007	**1.115**	0.115	0.167	67
Powerstream	2005-2007	**1.121**	0.121	0.155	68
Greater Sudbury-West Nipissing	2005-2007	**1.123**	0.123	0.151	69
Guelph Hydro Electric Systems	2005-2007	**1.131**	0.131	0.137	70
Fort Frances Power	2005-2007	**1.158**	0.158	0.097	71
Eastern Ontario Power (CNP)	2005-2007	**1.173**	0.173	0.079	72
Niagara Falls Hydro	2005-2007	**1.183**	0.183	0.068	73
Midland Power Utility	2005-2007	**1.202**	0.202	0.051	74
Centre Wellington Hydro	2005-2007	**1.203**	0.203	0.051	75
ENWIN Powerlines	2005-2007	**1.232**	0.232	0.032	76
Essex Powerlines	2005-2007	**1.247**	0.247	0.025	77
Whitby Hydro Electric	2005-2007	**1.261**	0.261	0.020	78
Chapleau Public Utilities	2005-2007	**1.328**	0.328	0.006	79
Erie Thames Powerlines	2005-2007	**1.365**	0.365	0.003	80
West Coast Huron Energy	2005-2007	**1.385**	0.385	0.002	81
Great Lakes Power	2005-2007	**1.441**	0.441	0.001	82
Port Colborne (CNP)	2005-2007	**1.515**	0.515	0.000	83

[1] Lower values imply better performance.

Table 4

Updated Performance Rankings Based on Unit Cost Indexes

This table replaces the table on page 5 of PEG's "Efficiency Ranking & Cohorts for the 2009 Rate Year" issued on July 22, 2008.

	Average / Group Average[1] [A]	Percentage Differences[1] [A - 1]	Efficiency Ranking[1]
Hydro Hawkesbury	**0.398**	-60.2%	1
Renfrew Hydro	**0.584**	-41.6%	2
Lakefront Utilities	**0.608**	-39.2%	3
Chatham-Kent Hydro	**0.724**	-27.6%	4
Hydro 2000	**0.728**	-27.2%	5
Barrie Hydro Distribution	**0.739**	-26.1%	6
Hydro One Brampton Networks	**0.742**	-25.8%	7
Hydro Ottawa	**0.760**	-24.0%	8
Northern Ontario Wires	**0.772**	-22.8%	9
Festival Hydro	**0.773**	-22.7%	10
Parry Sound Power	**0.787**	-21.3%	11
E.L.K. Energy	**0.787**	-21.3%	12
Cambridge and North Dumfries Hydro	**0.791**	-20.9%	13
Hearst Power Distribution	**0.799**	-20.1%	14
Fort Frances Power	**0.824**	-17.6%	15
Espanola Regional Hydro Distribution	**0.832**	-16.8%	16
Middlesex Power Distribution	**0.842**	-15.8%	17
Kitchener-Wilmot Hydro	**0.852**	-14.8%	18
Rideau St. Lawrence Distribution	**0.853**	-14.7%	19
Wellington North Power	**0.855**	-14.5%	20
Sioux Lookout Hydro	**0.861**	-13.9%	21
Grimsby Power	**0.876**	-12.4%	22
Orangeville Hydro	**0.876**	-12.4%	23
Peterborough Distribution	**0.883**	-11.7%	24
Kingston Electricity Distribution	**0.883**	-11.7%	25
Norfolk Power Distribution	**0.894**	-10.6%	26
Brant County Power	**0.904**	-9.6%	27
Peninsula West Utilities	**0.905**	-9.5%	28
North Bay Hydro Distribution	**0.906**	-9.4%	29
Welland Hydro-Electric System	**0.907**	-9.3%	30
Innisfil Hydro Distribution Systems	**0.922**	-7.8%	31
West Perth Power	**0.923**	-7.7%	32
Midland Power Utility	**0.923**	-7.7%	33
Veridian Connections	**0.937**	-6.3%	34
Niagara-on-the-Lake Hydro	**0.950**	-5.0%	35
Oshawa PUC Networks	**0.954**	-4.6%	36
PUC Distribution	**0.969**	-3.1%	37
Lakeland Power Distribution	**0.972**	-2.8%	38
Waterloo North Hydro	**0.975**	-2.5%	39
Guelph Hydro Electric Systems	**0.976**	-2.4%	40
Thunder Bay Hydro Electricity Distribution	**0.976**	-2.4%	41
Orillia Power Distribution	**0.985**	-1.5%	42
Toronto Hydro-Electric System	**0.987**	-1.3%	43
Woodstock Hydro Services	**0.997**	-0.3%	44
Horizon Utilities	**0.997**	-0.3%	45
COLLUS Power	**1.005**	0.5%	46
Milton Hydro Distribution	**1.014**	1.4%	47
Westario Power	**1.021**	2.1%	48
PowerStream	**1.039**	3.9%	49
Tillsonburg Hydro	**1.044**	4.4%	50
Atikokan Hydro	**1.058**	5.8%	51
St. Thomas Energy	**1.063**	6.3%	52
Oakville Hydro Electricity Distribution	**1.065**	6.5%	53
Burlington Hydro	**1.067**	6.7%	54
Ottawa River Power	**1.067**	6.7%	55
Haldimand County Hydro	**1.079**	7.9%	56
Newmarket Hydro & Tay Hydro	**1.082**	8.2%	57
London Hydro	**1.084**	8.4%	58
Clinton Power	**1.092**	9.2%	59
Bluewater Power Distribution	**1.093**	9.3%	60
Brantford Power	**1.095**	9.5%	61
Newbury Power	**1.099**	9.9%	62
Centre Wellington Hydro	**1.116**	11.6%	63
Niagara Falls Hydro	**1.135**	13.5%	64
Enersource Hydro Mississauga	**1.138**	13.8%	65
Wasaga Distribution	**1.142**	14.2%	66
Greater Sudbury Hydro & West Nippissing	**1.149**	14.9%	67
Kenora Hydro Electric	**1.162**	16.2%	68
West Coast Huron Energy	**1.169**	16.9%	69
Halton Hills Hydro	**1.171**	17.1%	70
Essex Powerlines	**1.173**	17.3%	71
Cooperative Hydro Embrun	**1.182**	18.2%	72
Fort Erie	**1.215**	21.5%	73
Whitby Hydro Electric	**1.219**	21.9%	74
Chapleau Public Utilities	**1.231**	23.1%	75
Eastern Ontario Power	**1.258**	25.8%	76
Dutton Hydro	**1.288**	28.8%	77
ENWIN Powerlines	**1.316**	31.6%	78
Erie Thames Powerlines	**1.415**	41.5%	79
Grand Valley Energy	**1.445**	44.5%	80
Port Colborne	**1.570**	57.0%	81
Great Lakes Power	**2.052**	105.2%	82

1 Lower values imply better performance.
2 Hydro One Networks has no peer group and is not included in this analysis.

Table 5

Stretch Factor Results: 2007 Data Update

This table replaces the table on page 6 of PEG's "Efficiency Ranking & Cohorts for the 2009 Rate Year" issued on July 22, 2008.

Company	Group	Stretch Factor
Hydro Hawkesbury	1	0.20%
Chatham-Kent Hydro	1	0.20%
Northern Ontario Wires	1	0.20%
Cambridge and North Dumfries Hydro	1	0.20%
E.L.K. Energy	1	0.20%
Hydro One Brampton Networks	1	0.20%
Kitchener-Wilmot Hydro	1	0.20%
Renfrew Hydro	1	0.20%
Barrie Hydro Distribution	1	0.20%
Festival Hydro	1	0.20%
Hydro 2000	1	0.20%
Grimsby Power	2	0.40%
Oshawa PUC Networks	2	0.40%
Lakeland Power Distribution	2	0.40%
Welland Hydro-Electric System	2	0.40%
Kingston Electricity Distribution	2	0.40%
Horizon Utilities	2	0.40%
Hydro Ottawa	2	0.40%
Lakefront Utilities	2	0.40%
Peninsula West Utilities	2	0.40%
Waterloo North Hydro	2	0.40%
Niagara-on-the-Lake Hydro	2	0.40%
Rideau St. Lawrence Distribution	2	0.40%
Kenora Hydro Electric	2	0.40%
Innisfil Hydro Distribution Systems	2	0.40%
Halton Hills Hydro	2	0.40%
Peterborough Distribution	2	0.40%
North Bay Hydro Distribution	2	0.40%
Atikokan Hydro	2	0.40%
Hearst Power Distribution	2	0.40%
Newmarket & Tay Hydro Electric	2	0.40%
Orangeville Hydro	2	0.40%
Enersource Hydro Mississauga	2	0.40%
Espanola Regional Hydro Distribution	2	0.40%
PUC Distribution	2	0.40%
Wellington North Power	2	0.40%
Middlesex Power Distribution	2	0.40%
Newbury Power	2	0.40%
Wasaga Distribution	2	0.40%
Veridian Connections	2	0.40%
Hydro One Networks	2	0.40%
Burlington Hydro	2	0.40%
Brantford Power	2	0.40%
Haldimand County Hydro	2	0.40%
Westario Power	2	0.40%
Tillsonburg Hydro	2	0.40%
Toronto Hydro-Electric System	2	0.40%
London Hydro	2	0.40%
Woodstock Hydro Services	2	0.40%
Ottawa River Power	2	0.40%
Milton Hydro Distribution	2	0.40%
Norfolk Power Distribution	2	0.40%
Bluewater Power Distribution	2	0.40%
Thunder Bay Hydro Electricity Distribution	2	0.40%
Grand Valley Energy	2	0.40%
Parry Sound Power	2	0.40%
West Perth Power	2	0.40%
COLLUS Power	2	0.40%
Oakville Hydro Electricity Distribution	2	0.40%
Cooperative Hydro Embrun	2	0.40%
Clinton Power	2	0.40%
Brant County Power	2	0.40%
Orillia Power Distribution	2	0.40%
St. Thomas Energy	2	0.40%
Dutton Hydro	2	0.40%
Sioux Lookout Hydro	2	0.40%
Fort Erie (CNP)	2	0.40%
Powerstream	2	0.40%
Greater Sudbury-West Nipissing	2	0.40%
Guelph Hydro Electric Systems	2	0.40%
Fort Frances Power	2	0.40%
Midland Power Utility	2	0.40%
Eastern Ontario Power (CNP)	3	0.60%
Niagara Falls Hydro	3	0.60%
Centre Wellington Hydro	3	0.60%
ENWIN Powerlines	3	0.60%
Essex Powerlines	3	0.60%
Whitby Hydro Electric	3	0.60%
Chapleau Public Utilities	3	0.60%
Erie Thames Powerlines	3	0.60%
West Coast Huron Energy	3	0.60%
Great Lakes Power	3	0.60%
Port Colborne (CNP)	3	0.60%

Table 6

Updated Performance Rankings Based on Econometric Benchmarks (Renfrew off the Canadian Shield)

	Years Benchmarked	Actual/Predicted[1]	Deviation Percentage [A-1][1]	P-Value	Rank[1]
Hydro Hawkesbury	2005-2007	**0.644**	-0.356	0.000	1
Chatham-Kent Hydro	2005-2007	**0.694**	-0.306	0.001	2
Northern Ontario Wires	2005-2007	**0.714**	-0.286	0.001	3
Cambridge and North Dumfries Hydro	2005-2007	**0.718**	-0.282	0.002	4
E.L.K. Energy	2005-2007	**0.733**	-0.267	0.003	5
Renfrew Hydro	2005-2007	**0.752**	-0.248	0.006	6
Grimsby Power	2005-2007	**0.769**	-0.231	0.010	7
Oshawa PUC Networks	2005-2007	**0.781**	-0.219	0.014	8
Lakeland Power Distribution	2005-2007	**0.787**	-0.213	0.017	9
Hydro One Brampton Networks	2005-2007	**0.792**	-0.208	0.019	10
Kitchener-Wilmot Hydro	2005-2007	**0.804**	-0.196	0.027	11
Barrie Hydro Distribution	2005-2007	**0.810**	-0.190	0.031	12
Festival Hydro	2005-2007	**0.827**	-0.173	0.046	13
Welland Hydro-Electric System	2005-2007	**0.839**	-0.161	0.060	14
Hydro 2000	2005-2007	**0.845**	-0.155	0.068	15
Kingston Electricity Distribution	2005-2007	**0.868**	-0.132	0.105	16
Horizon Utilities	2005-2007	**0.872**	-0.128	0.113	17
Hydro Ottawa	2005-2007	**0.873**	-0.127	0.114	18
Kenora Hydro Electric	2005-2007	**0.875**	-0.125	0.118	19
Peninsula West Utilities	2005-2007	**0.877**	-0.123	0.123	20
Waterloo North Hydro	2005-2007	**0.878**	-0.122	0.125	21
Lakefront Utilities	2005-2007	**0.878**	-0.122	0.125	22
Hearst Power Distribution	2005-2007	**0.891**	-0.109	0.154	23
Niagara-on-the-Lake Hydro	2005-2007	**0.898**	-0.102	0.170	24
Rideau St. Lawrence Distribution	2005-2007	**0.906**	-0.094	0.190	25
Halton Hills Hydro	2005-2007	**0.908**	-0.092	0.196	26
Innisfil Hydro Distribution Systems	2005-2007	**0.911**	-0.089	0.204	27
North Bay Hydro Distribution	2005-2007	**0.916**	-0.084	0.217	28
Peterborough Distribution	2005-2007	**0.919**	-0.081	0.228	29
Atikokan Hydro	2005-2007	**0.922**	-0.078	0.237	30
Newmarket & Tay Hydro Electric	2005-2007	**0.930**	-0.070	0.260	31
Orangeville Hydro	2005-2007	**0.940**	-0.060	0.291	32
Espanola Regional Hydro Distribution	2005-2007	**0.946**	-0.054	0.310	33
Enersource Hydro Mississauga	2005-2007	**0.956**	-0.044	0.344	34
PUC Distribution	2005-2007	**0.965**	-0.035	0.377	35
Middlesex Power Distribution	2005-2007	**0.973**	-0.027	0.405	36
Newbury Power	2005-2007	**0.982**	-0.018	0.436	37
Wasaga Distribution	2005-2007	**0.984**	-0.016	0.444	38
Wellington North Power	2005-2007	**0.991**	-0.009	0.468	39
Veridian Connections	2005-2007	**0.995**	-0.005	0.483	40
Burlington Hydro	2005-2007	**1.007**	0.007	0.474	41
Haldimand County Hydro	2005-2007	**1.012**	0.012	0.457	42
Ottawa River Power	2005-2007	**1.015**	0.015	0.448	43
Brantford Power	2005-2007	**1.018**	0.018	0.438	44
Toronto Hydro-Electric System	2005-2007	**1.019**	0.019	0.433	45
Westario Power	2005-2007	**1.022**	0.022	0.424	46
London Hydro	2005-2007	**1.026**	0.026	0.411	47
Tillsonburg Hydro	2005-2007	**1.027**	0.027	0.406	48
Hydro One Networks	2005-2007	**1.037**	0.037	0.375	49
Parry Sound Power	2005-2007	**1.038**	0.038	0.372	50
Woodstock Hydro Services	2005-2007	**1.043**	0.043	0.356	51
Milton Hydro Distribution	2005-2007	**1.043**	0.043	0.354	52
Norfolk Power Distribution	2005-2007	**1.051**	0.051	0.329	53
Thunder Bay Hydro Electricity Distribution	2005-2007	**1.057**	0.057	0.313	54
Bluewater Power Distribution	2005-2007	**1.059**	0.059	0.305	55
Grand Valley Energy	2005-2007	**1.060**	0.060	0.302	56
West Perth Power	2005-2007	**1.066**	0.066	0.285	57
Oakville Hydro Electricity Distribution	2005-2007	**1.075**	0.075	0.260	58
COLLUS Power	2005-2007	**1.076**	0.076	0.257	59
Cooperative Hydro Embrun	2005-2007	**1.077**	0.077	0.254	60
Clinton Power	2005-2007	**1.084**	0.084	0.236	61
St. Thomas Energy	2005-2007	**1.092**	0.092	0.218	62
Dutton Hydro	2004-2006	**1.092**	0.092	0.217	63
Brant County Power	2005-2007	**1.096**	0.096	0.207	64
Sioux Lookout Hydro	2005-2007	**1.097**	0.097	0.206	65
Orillia Power Distribution	2005-2007	**1.098**	0.098	0.204	66
Powerstream	2005-2007	**1.110**	0.110	0.178	67
Greater Sudbury-West Nipissing	2005-2007	**1.126**	0.126	0.147	68
Fort Erie (CNP)	2005-2007	**1.127**	0.127	0.145	69
Guelph Hydro Electric Systems	2005-2007	**1.129**	0.129	0.141	70
Fort Frances Power	2005-2007	**1.129**	0.129	0.141	71
Niagara Falls Hydro	2005-2007	**1.185**	0.185	0.066	72
Eastern Ontario Power (CNP)	2005-2007	**1.198**	0.198	0.055	73
Centre Wellington Hydro	2005-2007	**1.205**	0.205	0.049	74
Midland Power Utility	2005-2007	**1.207**	0.207	0.048	75
Essex Powerlines	2005-2007	**1.253**	0.253	0.023	76
ENWIN Powerlines	2005-2007	**1.253**	0.253	0.023	77
Whitby Hydro Electric	2005-2007	**1.257**	0.257	0.021	78
Chapleau Public Utilities	2005-2007	**1.273**	0.273	0.017	79
Erie Thames Powerlines	2005-2007	**1.376**	0.376	0.002	80
West Coast Huron Energy	2005-2007	**1.392**	0.392	0.002	81
Great Lakes Power	2005-2007	**1.475**	0.475	0.000	82
Port Colborne (CNP)	2005-2007	**1.540**	0.540	0.000	83

[1] Lower values imply better performance.

This table replaces Table 1 in PEG's "Sensitivity Analysis on Efficiency Ranking & Cohorts for the 2009 Rate Year" issued on November 21, 2008.

Table 7

Updated Performance Rankings Based on Econometric Benchmarks (26% allocation for LV charges)

This table replaces Table 2 in PEG's "Sensitivity Analysis on Efficiency Ranking & Cohorts for the 2009 Rate Year" issued on November 21, 2008.

	Years Benchmarked	Actual/Predicted[1]	Deviation Percentage [A-1][1]	P-Value	Rank[1]
Hydro Hawkesbury	2005-2007	**0.657**	-0.343	0.000	1
Northern Ontario Wires	2005-2007	**0.712**	-0.288	0.001	2
Chatham-Kent Hydro	2005-2007	**0.713**	-0.287	0.001	3
Cambridge and North Dumfries Hydro	2005-2007	**0.718**	-0.282	0.001	4
Grimsby Power	2005-2007	**0.754**	-0.246	0.005	5
E.L.K. Energy	2005-2007	**0.764**	-0.236	0.007	6
Oshawa PUC Networks	2005-2007	**0.773**	-0.227	0.009	7
Hydro One Brampton Networks	2005-2007	**0.790**	-0.210	0.015	8
Kitchener-Wilmot Hydro	2005-2007	**0.800**	-0.200	0.020	9
Renfrew Hydro	2005-2007	**0.811**	-0.189	0.026	10
Welland Hydro-Electric System	2005-2007	**0.825**	-0.175	0.037	11
Lakeland Power Distribution	2005-2007	**0.826**	-0.174	0.038	12
Festival Hydro	2005-2007	**0.827**	-0.173	0.039	13
Barrie Hydro Distribution	2005-2007	**0.841**	-0.159	0.055	14
Horizon Utilities	2005-2007	**0.865**	-0.135	0.090	15
Niagara-on-the-Lake Hydro	2005-2007	**0.865**	-0.135	0.090	16
Waterloo North Hydro	2005-2007	**0.873**	-0.127	0.105	17
Hydro Ottawa	2005-2007	**0.875**	-0.125	0.109	18
Atikokan Hydro	2005-2007	**0.877**	-0.123	0.113	19
Kingston Electricity Distribution	2005-2007	**0.879**	-0.121	0.115	20
Kenora Hydro Electric	2005-2007	**0.883**	-0.117	0.124	21
Peninsula West Utilities	2005-2007	**0.896**	-0.104	0.154	22
Lakefront Utilities	2005-2007	**0.909**	-0.091	0.189	23
Hydro 2000	2005-2007	**0.910**	-0.090	0.190	24
North Bay Hydro Distribution	2005-2007	**0.911**	-0.089	0.193	25
Newmarket & Tay Hydro Electric	2005-2007	**0.918**	-0.082	0.214	26
Rideau St. Lawrence Distribution	2005-2007	**0.919**	-0.081	0.217	27
Innisfil Hydro Distribution Systems	2005-2007	**0.925**	-0.075	0.236	28
Hearst Power Distribution	2005-2007	**0.926**	-0.074	0.237	29
Peterborough Distribution	2005-2007	**0.926**	-0.074	0.239	30
Halton Hills Hydro	2005-2007	**0.926**	-0.074	0.240	31
Espanola Regional Hydro Distribution	2005-2007	**0.957**	-0.043	0.343	32
Wellington North Power	2005-2007	**0.958**	-0.042	0.347	33
PUC Distribution	2005-2007	**0.961**	-0.039	0.358	34
Newbury Power	2005-2007	**0.963**	-0.037	0.363	35
Orangeville Hydro	2005-2007	**0.966**	-0.034	0.374	36
Middlesex Power Distribution	2005-2007	**0.969**	-0.031	0.387	37
Enersource Hydro Mississauga	2005-2007	**0.979**	-0.021	0.424	38
Tillsonburg Hydro	2005-2007	**0.985**	-0.015	0.443	39
Hydro One Networks	2005-2007	**0.988**	-0.012	0.456	40
Wasaga Distribution	2005-2007	**0.988**	-0.012	0.456	41
Haldimand County Hydro	2005-2007	**1.001**	0.001	0.498	42
Burlington Hydro	2005-2007	**1.004**	0.004	0.485	43
Toronto Hydro-Electric System	2005-2007	**1.004**	0.004	0.484	44
Brantford Power	2005-2007	**1.007**	0.007	0.472	45
Veridian Connections	2005-2007	**1.011**	0.011	0.460	46
Woodstock Hydro Services	2005-2007	**1.017**	0.017	0.437	47
London Hydro	2005-2007	**1.022**	0.022	0.419	48
Milton Hydro Distribution	2005-2007	**1.031**	0.031	0.387	49
Westario Power	2005-2007	**1.045**	0.045	0.343	50
Norfolk Power Distribution	2005-2007	**1.045**	0.045	0.340	51
Cooperative Hydro Embrun	2005-2007	**1.047**	0.047	0.334	52
Bluewater Power Distribution	2005-2007	**1.050**	0.050	0.326	53
Grand Valley Energy	2005-2007	**1.050**	0.050	0.324	54
Thunder Bay Hydro Electricity Distribution	2005-2007	**1.051**	0.051	0.324	55
Ottawa River Power	2005-2007	**1.060**	0.060	0.293	56
West Perth Power	2005-2007	**1.064**	0.064	0.282	57
Brant County Power	2005-2007	**1.068**	0.068	0.270	58
Parry Sound Power	2005-2007	**1.070**	0.070	0.267	59
St. Thomas Energy	2005-2007	**1.073**	0.073	0.258	60
Oakville Hydro Electricity Distribution	2005-2007	**1.078**	0.078	0.243	61
Fort Erie (CNP)	2005-2007	**1.097**	0.097	0.196	62
Dutton Hydro	2004-2006	**1.101**	0.101	0.187	63
COLLUS Power	2005-2007	**1.103**	0.103	0.182	64
Orillia Power Distribution	2005-2007	**1.104**	0.104	0.181	65
Powerstream	2005-2007	**1.117**	0.117	0.153	66
Fort Frances Power	2005-2007	**1.124**	0.124	0.139	67
Guelph Hydro Electric Systems	2005-2007	**1.125**	0.125	0.138	68
Greater Sudbury-West Nipissing	2005-2007	**1.127**	0.127	0.133	69
Clinton Power	2005-2007	**1.133**	0.133	0.123	70
Eastern Ontario Power (CNP)	2005-2007	**1.141**	0.141	0.111	71
Sioux Lookout Hydro	2005-2007	**1.144**	0.144	0.107	72
Niagara Falls Hydro	2005-2007	**1.169**	0.169	0.074	73
Centre Wellington Hydro	2005-2007	**1.181**	0.181	0.061	74
Midland Power Utility	2005-2007	**1.229**	0.229	0.028	75
ENWIN Powerlines	2005-2007	**1.234**	0.234	0.026	76
Whitby Hydro Electric	2005-2007	**1.257**	0.257	0.017	77
Essex Powerlines	2005-2007	**1.272**	0.272	0.013	78
Chapleau Public Utilities	2005-2007	**1.280**	0.280	0.011	79
West Coast Huron Energy	2005-2007	**1.340**	0.340	0.003	80
Erie Thames Powerlines	2005-2007	**1.388**	0.388	0.001	81
Great Lakes Power	2005-2007	**1.402**	0.402	0.001	82
Port Colborne (CNP)	2005-2007	**1.484**	0.484	0.000	83

[1] Lower values imply better performance.

Table 8

Updated Performance Rankings Based on Unit Cost Indexes (26% Allocation for LV charges)

This table replaces Table 3 in PEG's "Sensitivity Analysis on Efficiency Ranking & Cohorts for the 2009 Rate Year" issued on November 21, 2008.

	Average / Group Average[1] [A]	Percentage Differences[1] [A - 1]	Efficiency Ranking[1]
Hydro Hawkesbury	**0.402**	-59.8%	1
Renfrew Hydro	**0.602**	-39.8%	2
Lakefront Utilities	**0.616**	-38.4%	3
Chatham-Kent Hydro	**0.735**	-26.5%	4
Hydro One Brampton Networks	**0.740**	-26.0%	5
Hydro Ottawa	**0.759**	-24.1%	6
Barrie Hydro Distribution	**0.763**	-23.7%	7
Festival Hydro	**0.769**	-23.1%	8
Northern Ontario Wires	**0.774**	-22.6%	9
Cambridge and North Dumfries Hydro	**0.793**	-20.7%	10
Hearst Power Distribution	**0.801**	-19.9%	11
Hydro 2000	**0.804**	-19.6%	12
Parry Sound Power	**0.809**	-19.1%	13
Fort Frances Power	**0.815**	-18.5%	14
E.L.K. Energy	**0.825**	-17.5%	15
Middlesex Power Distribution	**0.830**	-17.0%	16
Wellington North Power	**0.836**	-16.4%	17
Kitchener-Wilmot Hydro	**0.844**	-15.6%	18
Espanola Regional Hydro Distribution	**0.845**	-15.5%	19
Rideau St. Lawrence Distribution	**0.852**	-14.8%	20
Brant County Power	**0.862**	-13.8%	21
Grimsby Power	**0.867**	-13.3%	22
Peterborough Distribution	**0.880**	-12.0%	23
Welland Hydro-Electric System	**0.885**	-11.5%	24
Norfolk Power Distribution	**0.889**	-11.1%	25
Kingston Electricity Distribution	**0.890**	-11.0%	26
Orangeville Hydro	**0.903**	-9.7%	27
North Bay Hydro Distribution	**0.906**	-9.4%	28
Sioux Lookout Hydro	**0.909**	-9.1%	29
Peninsula West Utilities	**0.919**	-8.1%	30
Niagara-on-the-Lake Hydro	**0.924**	-7.6%	31
West Perth Power	**0.933**	-6.7%	32
Midland Power Utility	**0.935**	-6.5%	33
Oshawa PUC Networks	**0.939**	-6.1%	34
Innisfil Hydro Distribution Systems	**0.939**	-6.1%	35
Veridian Connections	**0.950**	-5.0%	36
Waterloo North Hydro	**0.965**	-3.5%	37
PUC Distribution	**0.968**	-3.2%	38
Thunder Bay Hydro Electricity Distribution	**0.973**	-2.7%	39
Guelph Hydro Electric Systems	**0.973**	-2.7%	40
Woodstock Hydro Services	**0.976**	-2.4%	41
Toronto Hydro-Electric System	**0.978**	-2.2%	42
Tillsonburg Hydro	**0.997**	-0.3%	43
Horizon Utilities	**0.998**	-0.2%	44
Lakeland Power Distribution	**0.999**	-0.1%	45
Orillia Power Distribution	**1.004**	0.4%	46
Milton Hydro Distribution	**1.012**	1.2%	47
COLLUS Power	**1.027**	2.7%	48
Atikokan Hydro	**1.035**	3.5%	49
PowerStream	**1.039**	3.9%	50
Westario Power	**1.041**	4.1%	51
St. Thomas Energy	**1.041**	4.1%	52
Haldimand County Hydro	**1.056**	5.6%	53
Burlington Hydro	**1.063**	6.3%	54
Oakville Hydro Electricity Distribution	**1.069**	6.9%	55
Newmarket Hydro & Tay Hydro	**1.070**	7.0%	56
Bluewater Power Distribution	**1.074**	7.4%	57
Ottawa River Power	**1.074**	7.4%	58
London Hydro	**1.079**	7.9%	59
Brantford Power	**1.095**	9.5%	60
Niagara Falls Hydro	**1.106**	10.6%	61
Centre Wellington Hydro	**1.112**	11.2%	62
Kenora Hydro Electric	**1.125**	12.5%	63
West Coast Huron Energy	**1.128**	12.8%	64
Wasaga Distribution	**1.135**	13.5%	65
Clinton Power	**1.144**	14.4%	66
Enersource Hydro Mississauga	**1.145**	14.5%	67
Greater Sudbury Hydro & West Nippissing	**1.153**	15.3%	68
Newbury Power	**1.177**	17.7%	69
Essex Powerlines	**1.188**	18.8%	70
Halton Hills Hydro	**1.193**	19.3%	71
Fort Erie	**1.193**	19.3%	72
Cooperative Hydro Embrun	**1.195**	19.5%	73
Eastern Ontario Power	**1.204**	20.4%	74
Whitby Hydro Electric	**1.222**	22.2%	75
Chapleau Public Utilities	**1.240**	24.0%	76
ENWIN Powerlines	**1.313**	31.3%	77
Dutton Hydro	**1.327**	32.7%	78
Erie Thames Powerlines	**1.427**	42.7%	79
Grand Valley Energy	**1.467**	46.7%	80
Port Colborne	**1.486**	48.6%	81
Great Lakes Power	**1.972**	97.2%	82

1 Lower values imply better performance.
2 Hydro One Networks has no peer group and is not included in this analysis.

Table 9

Stretch Factor Results: 2007 Data Update (26% Allocation for LV Charges)

This table replaces Table 4 in PEG's "Sensitivity Analysis on Efficiency Ranking & Cohorts for the 2009 Rate Year" issued on November 21, 2008.

Company	Group	Stretch Factor
Hydro Hawkesbury	1	0.20%
Northern Ontario Wires	1	0.20%
Chatham-Kent Hydro	1	0.20%
Cambridge and North Dumfries Hydro	1	0.20%
E.L.K. Energy	1	0.20%
Hydro One Brampton Networks	1	0.20%
Kitchener-Wilmot Hydro	1	0.20%
Renfrew Hydro	1	0.20%
Festival Hydro	1	0.20%
Barrie Hydro Distribution	1	0.20%
Grimsby Power	2	0.40%
Oshawa PUC Networks	2	0.40%
Welland Hydro-Electric System	2	0.40%
Lakeland Power Distribution	2	0.40%
Horizon Utilities	2	0.40%
Niagara-on-the-Lake Hydro	2	0.40%
Waterloo North Hydro	2	0.40%
Hydro Ottawa	2	0.40%
Atikokan Hydro	2	0.40%
Kingston Electricity Distribution	2	0.40%
Kenora Hydro Electric	2	0.40%
Peninsula West Utilities	2	0.40%
Lakefront Utilities	2	0.40%
Hydro 2000	2	0.40%
North Bay Hydro Distribution	2	0.40%
Newmarket & Tay Hydro Electric	2	0.40%
Rideau St. Lawrence Distribution	2	0.40%
Innisfil Hydro Distribution Systems	2	0.40%
Hearst Power Distribution	2	0.40%
Peterborough Distribution	2	0.40%
Halton Hills Hydro	2	0.40%
Espanola Regional Hydro Distribution	2	0.40%
Wellington North Power	2	0.40%
PUC Distribution	2	0.40%
Newbury Power	2	0.40%
Orangeville Hydro	2	0.40%
Middlesex Power Distribution	2	0.40%
Enersource Hydro Mississauga	2	0.40%
Tillsonburg Hydro	2	0.40%
Hydro One Networks	2	0.40%
Wasaga Distribution	2	0.40%
Haldimand County Hydro	2	0.40%
Burlington Hydro	2	0.40%
Toronto Hydro-Electric System	2	0.40%
Brantford Power	2	0.40%
Veridian Connections	2	0.40%
Woodstock Hydro Services	2	0.40%
London Hydro	2	0.40%
Milton Hydro Distribution	2	0.40%
Westario Power	2	0.40%
Norfolk Power Distribution	2	0.40%
Cooperative Hydro Embrun	2	0.40%
Bluewater Power Distribution	2	0.40%
Grand Valley Energy	2	0.40%
Thunder Bay Hydro Electricity Distribution	2	0.40%
Ottawa River Power	2	0.40%
West Perth Power	2	0.40%
Brant County Power	2	0.40%
Parry Sound Power	2	0.40%
St. Thomas Energy	2	0.40%
Oakville Hydro Electricity Distribution	2	0.40%
Fort Erie (CNP)	2	0.40%
Dutton Hydro	2	0.40%
COLLUS Power	2	0.40%
Orillia Power Distribution	2	0.40%
Powerstream	2	0.40%
Fort Frances Power	2	0.40%
Guelph Hydro Electric Systems	2	0.40%
Greater Sudbury-West Nipissing	2	0.40%
Clinton Power	2	0.40%
Eastern Ontario Power (CNP)	2	0.40%
Sioux Lookout Hydro	2	0.40%
Niagara Falls Hydro	2	0.40%
Centre Wellington Hydro	2	0.40%
Midland Power Utility	2	0.40%
ENWIN Powerlines	3	0.60%
Whitby Hydro Electric	3	0.60%
Essex Powerlines	3	0.60%
Chapleau Public Utilities	3	0.60%
West Coast Huron Energy	3	0.60%
Erie Thames Powerlines	3	0.60%
Great Lakes Power	3	0.60%
Port Colborne (CNP)	3	0.60%

This table replaces Table 5 in PEG's "Sensitivity Analysis on Efficiency Ranking & Cohorts for the 2009 Rate Year" issued on November 21, 2008.

Table 10

Updated Performance Rankings Based on Econometric Benchmarks (26% allocation for LV charges divided by 2.35)

	Years Benchmarked	Actual/Predicted[1]	Deviation Percentage [A-1][1]	P-Value	Rank[1]
Hydro Hawkesbury	2005-2007	**0.648**	-0.352	0.000	1
Chatham-Kent Hydro	2005-2007	**0.700**	-0.300	0.001	2
Northern Ontario Wires	2005-2007	**0.712**	-0.288	0.001	3
Cambridge and North Dumfries Hydro	2005-2007	**0.716**	-0.284	0.001	4
E.L.K. Energy	2005-2007	**0.743**	-0.257	0.004	5
Grimsby Power	2005-2007	**0.759**	-0.241	0.006	6
Oshawa PUC Networks	2005-2007	**0.781**	-0.219	0.013	7
Hydro One Brampton Networks	2005-2007	**0.792**	-0.208	0.017	8
Kitchener-Wilmot Hydro	2005-2007	**0.803**	-0.197	0.024	9
Lakeland Power Distribution	2005-2007	**0.804**	-0.196	0.024	10
Renfrew Hydro	2005-2007	**0.810**	-0.190	0.028	11
Festival Hydro	2005-2007	**0.822**	-0.178	0.038	12
Barrie Hydro Distribution	2005-2007	**0.826**	-0.174	0.042	13
Welland Hydro-Electric System	2005-2007	**0.829**	-0.171	0.045	14
Horizon Utilities	2005-2007	**0.865**	-0.135	0.094	15
Kingston Electricity Distribution	2005-2007	**0.866**	-0.134	0.096	16
Hydro 2000	2005-2007	**0.870**	-0.130	0.103	17
Hydro Ottawa	2005-2007	**0.876**	-0.124	0.114	18
Waterloo North Hydro	2005-2007	**0.877**	-0.123	0.117	19
Niagara-on-the-Lake Hydro	2005-2007	**0.880**	-0.120	0.123	20
Peninsula West Utilities	2005-2007	**0.886**	-0.114	0.136	21
Lakefront Utilities	2005-2007	**0.888**	-0.112	0.141	22
Kenora Hydro Electric	2005-2007	**0.895**	-0.105	0.157	23
Rideau St. Lawrence Distribution	2005-2007	**0.907**	-0.093	0.187	24
Atikokan Hydro	2005-2007	**0.908**	-0.092	0.191	25
North Bay Hydro Distribution	2005-2007	**0.914**	-0.086	0.208	26
Innisfil Hydro Distribution Systems	2005-2007	**0.915**	-0.085	0.209	27
Peterborough Distribution	2005-2007	**0.918**	-0.082	0.219	28
Halton Hills Hydro	2005-2007	**0.918**	-0.082	0.219	29
Newmarket & Tay Hydro Electric	2005-2007	**0.926**	-0.074	0.242	30
Hearst Power Distribution	2005-2007	**0.930**	-0.070	0.255	31
Orangeville Hydro	2005-2007	**0.949**	-0.051	0.317	32
Espanola Regional Hydro Distribution	2005-2007	**0.960**	-0.040	0.356	33
Wellington North Power	2005-2007	**0.962**	-0.038	0.362	34
PUC Distribution	2005-2007	**0.962**	-0.038	0.364	35
Enersource Hydro Mississauga	2005-2007	**0.966**	-0.034	0.377	36
Middlesex Power Distribution	2005-2007	**0.968**	-0.032	0.384	37
Newbury Power	2005-2007	**0.970**	-0.030	0.391	38
Wasaga Distribution	2005-2007	**0.986**	-0.014	0.448	39
Veridian Connections	2005-2007	**1.001**	0.001	0.496	40
Tillsonburg Hydro	2005-2007	**1.002**	0.002	0.491	41
Burlington Hydro	2005-2007	**1.006**	0.006	0.478	42
Hydro One Networks	2005-2007	**1.007**	0.007	0.476	43
Brantford Power	2005-2007	**1.008**	0.008	0.472	44
Haldimand County Hydro	2005-2007	**1.010**	0.010	0.463	45
Toronto Hydro-Electric System	2005-2007	**1.015**	0.015	0.445	46
London Hydro	2005-2007	**1.026**	0.026	0.409	47
Westario Power	2005-2007	**1.027**	0.027	0.405	48
Woodstock Hydro Services	2005-2007	**1.027**	0.027	0.403	49
Milton Hydro Distribution	2005-2007	**1.040**	0.040	0.361	50
Norfolk Power Distribution	2005-2007	**1.048**	0.048	0.334	51
Bluewater Power Distribution	2005-2007	**1.049**	0.049	0.333	52
Thunder Bay Hydro Electricity Distribution	2005-2007	**1.050**	0.050	0.328	53
Grand Valley Energy	2005-2007	**1.051**	0.051	0.327	54
Ottawa River Power	2005-2007	**1.051**	0.051	0.325	55
West Perth Power	2005-2007	**1.062**	0.062	0.292	56
Cooperative Hydro Embrun	2005-2007	**1.064**	0.064	0.286	57
Parry Sound Power	2005-2007	**1.066**	0.066	0.280	58
Oakville Hydro Electricity Distribution	2005-2007	**1.077**	0.077	0.251	59
Brant County Power	2005-2007	**1.078**	0.078	0.247	60
St. Thomas Energy	2005-2007	**1.080**	0.080	0.244	61
COLLUS Power	2005-2007	**1.084**	0.084	0.232	62
Orillia Power Distribution	2005-2007	**1.093**	0.093	0.210	63
Dutton Hydro	2004-2006	**1.096**	0.096	0.201	64
Clinton Power	2005-2007	**1.103**	0.103	0.186	65
Fort Erie (CNP)	2005-2007	**1.107**	0.107	0.178	66
Powerstream	2005-2007	**1.121**	0.121	0.151	67
Sioux Lookout Hydro	2005-2007	**1.121**	0.121	0.151	68
Greater Sudbury-West Nipissing	2005-2007	**1.124**	0.124	0.145	69
Guelph Hydro Electric Systems	2005-2007	**1.127**	0.127	0.139	70
Fort Frances Power	2005-2007	**1.144**	0.144	0.112	71
Eastern Ontario Power (CNP)	2005-2007	**1.158**	0.158	0.092	72
Niagara Falls Hydro	2005-2007	**1.175**	0.175	0.072	73
Centre Wellington Hydro	2005-2007	**1.191**	0.191	0.056	74
Midland Power Utility	2005-2007	**1.211**	0.211	0.041	75
ENWIN Powerlines	2005-2007	**1.232**	0.232	0.029	76
Essex Powerlines	2005-2007	**1.257**	0.257	0.019	77
Whitby Hydro Electric	2005-2007	**1.260**	0.260	0.018	78
Chapleau Public Utilities	2005-2007	**1.310**	0.310	0.007	79
West Coast Huron Energy	2005-2007	**1.363**	0.363	0.003	80
Erie Thames Powerlines	2005-2007	**1.373**	0.373	0.002	81
Great Lakes Power	2005-2007	**1.432**	0.432	0.001	82
Port Colborne (CNP)	2005-2007	**1.502**	0.502	0.000	83

[1] Lower values imply better performance.

Table 11

Updated Performance Rankings Based on Unit Cost Indexes (26% allocation for LV charges divided by 2.35)

This table replaces Table 6 in PEG's "Sensitivity Analysis on Efficiency Ranking & Cohorts for the 2009 Rate Year" issued on November 21, 2008.

	Average / Group Average[1] [A]	Percentage Differences[1] [A - 1]	Efficiency Ranking[1]
Hydro Hawkesbury	**0.399**	-60.1%	1
Renfrew Hydro	**0.592**	-40.8%	2
Lakefront Utilities	**0.610**	-39.0%	3
Chatham-Kent Hydro	**0.728**	-27.2%	4
Hydro One Brampton Networks	**0.741**	-25.9%	5
Barrie Hydro Distribution	**0.750**	-25.0%	6
Hydro Ottawa	**0.760**	-24.0%	7
Hydro 2000	**0.762**	-23.8%	8
Festival Hydro	**0.771**	-22.9%	9
Northern Ontario Wires	**0.772**	-22.8%	10
Cambridge and North Dumfries Hydro	**0.791**	-20.9%	11
Parry Sound Power	**0.796**	-20.4%	12
Hearst Power Distribution	**0.799**	-20.1%	13
E.L.K. Energy	**0.804**	-19.6%	14
Fort Frances Power	**0.820**	-18.0%	15
Middlesex Power Distribution	**0.836**	-16.4%	16
Espanola Regional Hydro Distribution	**0.838**	-16.2%	17
Wellington North Power	**0.846**	-15.4%	18
Kitchener-Wilmot Hydro	**0.848**	-15.2%	19
Rideau St. Lawrence Distribution	**0.852**	-14.8%	20
Grimsby Power	**0.872**	-12.8%	21
Sioux Lookout Hydro	**0.880**	-12.0%	22
Peterborough Distribution	**0.881**	-11.9%	23
Brant County Power	**0.884**	-11.6%	24
Kingston Electricity Distribution	**0.886**	-11.4%	25
Orangeville Hydro	**0.887**	-11.3%	26
Norfolk Power Distribution	**0.892**	-10.8%	27
Welland Hydro-Electric System	**0.897**	-10.3%	28
North Bay Hydro Distribution	**0.906**	-9.4%	29
Peninsula West Utilities	**0.910**	-9.0%	30
Midland Power Utility	**0.927**	-7.3%	31
West Perth Power	**0.927**	-7.3%	32
Innisfil Hydro Distribution Systems	**0.930**	-7.0%	33
Niagara-on-the-Lake Hydro	**0.938**	-6.2%	34
Veridian Connections	**0.944**	-5.6%	35
Oshawa PUC Networks	**0.948**	-5.2%	36
PUC Distribution	**0.969**	-3.1%	37
Waterloo North Hydro	**0.971**	-2.9%	38
Guelph Hydro Electric Systems	**0.974**	-2.6%	39
Thunder Bay Hydro Electricity Distribution	**0.974**	-2.6%	40
Toronto Hydro-Electric System	**0.981**	-1.9%	41
Lakeland Power Distribution	**0.983**	-1.7%	42
Woodstock Hydro Services	**0.988**	-1.2%	43
Orillia Power Distribution	**0.993**	-0.7%	44
Horizon Utilities	**0.997**	-0.3%	45
Milton Hydro Distribution	**1.014**	1.4%	46
COLLUS Power	**1.015**	1.5%	47
Tillsonburg Hydro	**1.024**	2.4%	48
Westario Power	**1.030**	3.0%	49
PowerStream	**1.038**	3.8%	50
Atikokan Hydro	**1.049**	4.9%	51
St. Thomas Energy	**1.054**	5.4%	52
Burlington Hydro	**1.065**	6.5%	53
Oakville Hydro Electricity Distribution	**1.066**	6.6%	54
Haldimand County Hydro	**1.069**	6.9%	55
Ottawa River Power	**1.071**	7.1%	56
Newmarket Hydro & Tay Hydro	**1.077**	7.7%	57
London Hydro	**1.083**	8.3%	58
Bluewater Power Distribution	**1.083**	8.3%	59
Brantford Power	**1.096**	9.6%	60
Centre Wellington Hydro	**1.114**	11.4%	61
Clinton Power	**1.115**	11.5%	62
Niagara Falls Hydro	**1.121**	12.1%	63
Newbury Power	**1.137**	13.7%	64
Enersource Hydro Mississauga	**1.140**	14.0%	65
Wasaga Distribution	**1.142**	14.2%	66
Kenora Hydro Electric	**1.147**	14.7%	67
West Coast Huron Energy	**1.149**	14.9%	68
Greater Sudbury Hydro & West Nippissing	**1.151**	15.1%	69
Essex Powerlines	**1.180**	18.0%	70
Halton Hills Hydro	**1.181**	18.1%	71
Cooperative Hydro Embrun	**1.190**	19.0%	72
Fort Erie	**1.206**	20.6%	73
Whitby Hydro Electric	**1.221**	22.1%	74
Eastern Ontario Power	**1.234**	23.4%	75
Chapleau Public Utilities	**1.237**	23.7%	76
Dutton Hydro	**1.309**	30.9%	77
ENWIN Powerlines	**1.315**	31.5%	78
Erie Thames Powerlines	**1.420**	42.0%	79
Grand Valley Energy	**1.459**	45.9%	80
Port Colborne	**1.531**	53.1%	81
Great Lakes Power	**2.016**	101.6%	82

[1] Lower values imply better performance.

[2] Hydro One Networks has no peer group and is not included in this analysis.

Table 12

Stretch Factor Results: 2007 Data Update (26% allocation of LV charges divided by 2.35)

Company	Group	Stretch Factor
Hydro Hawkesbury	1	0.20%
Chatham-Kent Hydro	1	0.20%
Northern Ontario Wires	1	0.20%
Cambridge and North Dumfries Hydro	1	0.20%
E.L.K. Energy	1	0.20%
Hydro One Brampton Networks	1	0.20%
Kitchener-Wilmot Hydro	1	0.20%
Renfrew Hydro	1	0.20%
Festival Hydro	1	0.20%
Barrie Hydro Distribution	1	0.20%
Grimsby Power	2	0.40%
Oshawa PUC Networks	2	0.40%
Lakeland Power Distribution	2	0.40%
Welland Hydro-Electric System	2	0.40%
Horizon Utilities	2	0.40%
Kingston Electricity Distribution	2	0.40%
Hydro 2000	2	0.40%
Hydro Ottawa	2	0.40%
Waterloo North Hydro	2	0.40%
Niagara-on-the-Lake Hydro	2	0.40%
Peninsula West Utilities	2	0.40%
Lakefront Utilities	2	0.40%
Kenora Hydro Electric	2	0.40%
Rideau St. Lawrence Distribution	2	0.40%
Atikokan Hydro	2	0.40%
North Bay Hydro Distribution	2	0.40%
Innisfil Hydro Distribution Systems	2	0.40%
Peterborough Distribution	2	0.40%
Halton Hills Hydro	2	0.40%
Newmarket & Tay Hydro Electric	2	0.40%
Hearst Power Distribution	2	0.40%
Orangeville Hydro	2	0.40%
Espanola Regional Hydro Distribution	2	0.40%
Wellington North Power	2	0.40%
PUC Distribution	2	0.40%
Enersource Hydro Mississauga	2	0.40%
Middlesex Power Distribution	2	0.40%
Newbury Power	2	0.40%
Wasaga Distribution	2	0.40%
Veridian Connections	2	0.40%
Tillsonburg Hydro	2	0.40%
Burlington Hydro	2	0.40%
Hydro One Networks	2	0.40%
Brantford Power	2	0.40%
Haldimand County Hydro	2	0.40%
Toronto Hydro-Electric System	2	0.40%
London Hydro	2	0.40%
Westario Power	2	0.40%
Woodstock Hydro Services	2	0.40%
Milton Hydro Distribution	2	0.40%
Norfolk Power Distribution	2	0.40%
Bluewater Power Distribution	2	0.40%
Thunder Bay Hydro Electricity Distribution	2	0.40%
Grand Valley Energy	2	0.40%
Ottawa River Power	2	0.40%
West Perth Power	2	0.40%
Cooperative Hydro Embrun	2	0.40%
Parry Sound Power	2	0.40%
Oakville Hydro Electricity Distribution	2	0.40%
Brant County Power	2	0.40%
St. Thomas Energy	2	0.40%
COLLUS Power	2	0.40%
Orillia Power Distribution	2	0.40%
Dutton Hydro	2	0.40%
Clinton Power	2	0.40%
Fort Erie (CNP)	2	0.40%
Powerstream	2	0.40%
Sioux Lookout Hydro	2	0.40%
Greater Sudbury-West Nipissing	2	0.40%
Guelph Hydro Electric Systems	2	0.40%
Fort Frances Power	2	0.40%
Centre Wellington Hydro	2	0.40%
Midland Power Utility	2	0.40%
Eastern Ontario Power (CNP)	3	0.60%
Niagara Falls Hydro	3	0.60%
ENWIN Powerlines	3	0.60%
Essex Powerlines	3	0.60%
Whitby Hydro Electric	3	0.60%
Chapleau Public Utilities	3	0.60%
West Coast Huron Energy	3	0.60%
Erie Thames Powerlines	3	0.60%
Great Lakes Power	3	0.60%
Port Colborne (CNP)	3	0.60%

This table replaces Table 7 in PEG's "Sensitivity Analysis on Efficiency Ranking & Cohorts for the 2009 Rate Year" issued on November 21, 2008.

Operating, Maintenance and Administration (OM&A) Costs:

Overview:

The operating costs presented in this Exhibit represent the annual expenditures required to maintain Chatham-Kent Hydro's distribution operations. Chatham-Kent Hydro follows the OEB's Accounting Procedures Handbook (the "APH") in distinguishing work performed between operations and maintenance. In Table 4-1 below Chatham-Kent Hydro has provided a summary of its operating costs for 2006 Board Approved, 2006 Actual, 2007 Actual, 2008 Actual, 2009 Bridge Year and the 2010 Test Year. Also provided is the yearly variance amount for analysis, prepared in accordance with the Filing Requirements.

Table 4-1
Summary of Operating Costs

Description	2006 Board Approved	2006 Actual	Variance	2007 Actual	Variance	2008 Actual	Variance	2009 Bridge	Variance	2010 Test	Variance
OM&A expenses											
Operation	799,526	723,678	(75,848)	825,806	102,129	898,928	73,122	786,225	(112,703)	1,041,236	255,010
Maintenance	861,403	981,801	120,398	904,698	(77,102)	1,031,028	126,329	975,626	(55,402)	1,187,798	212,172
Billing and Collections	1,478,645	1,390,478	(88,167)	1,288,334	(102,144)	1,423,199	134,865	1,579,767	156,568	1,826,798	247,030
Community Relations	23,011	23,211	200	93,127	69,916	53,431	(39,696)	41,145	(12,285)	56,529	15,384
Administrative and General Expenses	2,743,514	2,018,346	(725,168)	2,167,209	148,863	2,272,590	105,382	2,443,387	170,796	2,690,751	247,365
Total Controllables	5,906,099	5,137,513	(768,586)	5,279,175	141,661	5,679,177	400,002	5,826,150	146,974	6,803,112	976,961
Property Tax	0	0	0	0	0	0	0	0	0	0	-
Amortization Expenses	2,817,363	2,970,412	153,049	3,315,639	345,226	3,595,770	280,132	3,701,765	105,995	3,815,361	113,596
Total Operating Costs	8,723,462	8,107,926	(615,536)	8,594,813	486,887	9,274,947	680,134	9,527,916	252,969	10,618,473	1,090,557
Variance				141,661		400,002		146,974		976,961	
Percent Change (year over year)				2.76%		7.58%		2.59%		16.77%	
Percent Change Test year vs 2008 Actuals			19.79%								
Percent Change Test year VS. Last Board Approved Rebasing Year			15.19%								
Average for 2006 to 2008			5.27%								
Compound Annual Growth Rate (for 2006 to 2008)			5.1%								

Table 4-2
OMA Cost per Customer and FTEE

Description	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test
Number of Customers	31,972	32,013	32,097	32,146	32,195
Total OMA	5,137,513	5,279,175	5,679,177	5,826,150	6,803,112
OMA cost per Customer	161	165	177	181	211
Number of FTEEs	39	38	38	38	44
FTEEs/Customer	0.0012	0.0012	0.0012	0.0012	0.0014
OMA cost per FTEE	133,442	138,926	149,452	153,320	154,616
Administrative Expenditures	2,018,346	2,167,209	2,272,590	2,443,387	2,690,751
Administrative cost per customer	63	68	71	76	84

In table 4-2 in calculating the number of customers, streetlight, sentinel light, unmetered scattered load was based on the number of customers not the number of connections.

The Controllable costs in 2010 increase by $897,013 ($6,803,172- $5,906,099) or 13.2% from the 2006 Board Approved. The 2006 Board Approved is based upon 2004 costs therefore there are six years of inflation from that time. Table 4-3 summarizes the inflation for the period;

Table 4-3
Inflation

Year	%
2005	2.2%
2006	1.8%
2007	1.8%
2008	2.3%
2009	0.5%
2010	1.4%
Total	10.0%

The inflation rate from 2005 to 2008 is from Statistics Canada (Appendix B) and the forecasted inflation rate is from CIBC World Markets Inc (Appendix C).

After taking into account the inflation over six years Chatham-Kent Hydro's Controllable costs increase by only 3% or an additional 0.5% per year.

Chatham-Kent Hydro currently is one of the lowest cost Distributors in Ontario as provided above and in Table 4-4. Chatham-Kent Hydro will continue to be a low cost Distributor. At the 2010 cost level Chatham-Kent Hydro would be at approximately the average of the peer group, $211 for 2010 to $208 for the average (2005 to 2007). The LDCs in the peer group would have also incurred inflationary pressures, regulatory challenges and staff planning for current and future retirements. Chatham-Kent Hydro therefore suggests that it continues to be a low cost LDC in Ontario and will most likely maintain the same ranking.

The executive, management and supervisory staff along with some hourly engineering and stores staff provide service to Middlesex Power Distribution Corporation ("MPDC"). MPDC is an affiliate of Chatham-Kent Energy and was purchased in 2005. The expenditures allocated to MPDC are either based on an estimate of time spent or the number of customers depending upon the cost drivers. The hourly staff's costs are allocated based upon actual hours worked. By having this relationship with MPDC the revenue requirement for Chatham-Kent Hydro and the costs to its customers are reduced.

Table 4-4
OEB Comparison of Distributor Costs (EB-2008-026)
Updated December 4, 2008

Mid-Size Southern Medium-High Undergrounding	Average	2007	2006	2005
E.L.K. Energy Inc.	**$155**	$182	$171	$113
Wasaga Distribution Inc.	**$157**	$159	$159	$152
Chatham-Kent Hydro Inc.	**$162**	$164	$161	$162
Peterborough Distribution Incorporated	**$181**	$192	$186	$166
Festival Hydro Inc.	**$182**	$185	$189	$171
Welland Hydro-Electric System Corp.	**$183**	$209	$162	$178
Kingston Electricity Distribution Limited	**$189**	$182	$181	$204
Westario Power Inc.	**$203**	$196	$205	$206
COLLUS Power Corp.	**$211**	$225	$220	$187
St. Thomas Energy Inc.	**$216**	$214	$229	$205
Essex Powerlines Corporation	**$221**	$206	$222	$236
Woodstock Hydro Services Inc.	**$223**	$228	$223	$218
Niagara Falls Hydro Inc.	**$247**	$255	$245	$240
Bluewater Power Distribution Corporation	**$261**	$256	$270	$258
Erie Thames Powerlines Corporation	**$329**	$356	$308	$324
Group Average	**$208**			

Detailed information with respect to OM&A costs and variances, arranged by USoA account, is provided at Exhibit 4, Tab 2, Schedule 2.

The variance used to determine the OM&A accounts requiring analysis has been prescribed by the Filing Requirements as 0.5% of Revenue Requirement. Chatham-Kent Hydro has adopted a variance analysis threshold of $79,127 being the variances among the years under review.

OM&A Costs:

OM&A costs in this Exhibit represent Chatham-Kent Hydro's integrated set of asset maintenance and customer activity needs to meet public and employee safety objectives; to comply with the Distribution System Code, environmental requirements and government direction; and to maintain distribution business service quality and reliability at targeted performance levels. OM&A costs also include providing services to customers connected to

Chatham-Kent Hydro's distribution system, and meeting the requirements of the OEB's Standard Supply Service Code and Retail Settlement Code.

The proposed OM&A cost expenditures for the 2010 Test Year are the result of a business planning and work prioritization process that ensures that the most appropriate, cost effective solutions are put in place.

Chatham-Kent Hydro is proposing recovery of 2010 Test Year OM&A costs, including amortization but excluding PILs and Interest totaling $10,618,473.

OM&A Budgeting Process Used by Chatham-Kent Hydro:

The operating budget is prepared annually by management and is reviewed and approved by the President, CFO and CEO. The budget is then presented to the Board for approval. The budget is prepared before the start of each fiscal year. Once approved, it does not change, but provides a plan against which actual results may be evaluated.

The operating budget is a component of the overall budget process described in Exhibit 1, Tab 2, Schedule 2.

Operating Work plans:

Each department Manager provides input for the preparation of the departmental budget. The following directives are provided to each manager and director:

- Outside expenses for all department budgets are built using previous year actual, current year forecast and current year budget as the base;
- Significant variances in spending from prior years must be explained and documented; and

- Review the headcount of the department for accuracy and outline any changes.

Income Tax, Large Corporation Tax and Ontario Capital Taxes:

Chatham-Kent Hydro is subject to the payment of PILs under Section 93 of the *Electricity Act, 1998*, as amended. The Applicant does not pay Section 89 proxy taxes, and is exempt from the payment of income and capital taxes under the *Income Tax Act (Canada)* and the Ontario *Corporations Tax Act*. Table 4-5 below provides a summary of 2006 OEB Approved, 2006, 2007 and 2008 income taxes included in audited statements, 2009 Bridge Year estimate using current rates, and 2010 Test Year income taxes based on revised rates. A copy of the 2008 Federal T2 and Ontario C23 tax return has been provided in Exhibit 4, Tab 1, Schedule 1, Appendix A. Income Tax amounts included in the 2008 financial statements are based on estimates and will differ from the actual tax return. The difference between actual and estimate will be recorded in 2009 financial statements.

Table 4-5
Summary of Income Taxes

Description	2006 Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test
Income Taxes	1,432,241	1,893,376	1,427,557	864,426	876,644	956,858
Large Corporation Tax	0	0	0	0	0	0
Ontario Capital Tax	140,691	140,691	145,394	145,400	91,104	30,805
Total Taxes	1,572,932	2,034,067	1,572,951	1,009,826	967,748	987,663

DEPARTMENTAL AND CORPORATE OM&A ACTIVITIES:

OPERATIONS & MAINTENANCE

The expenses for this department include all costs relating to the operation (5000-5095) and maintenance (5105-5195) of the Chatham-Kent Hydro electrical system. This includes both direct labor costs and non-capital material spending to support both scheduled and reactive maintenance events. In addition, costs are allocated from support departments to cover the costs of Labour Burden, Engineering, Stores, Administration, IT, and Transportation Fleet.

Chatham-Kent Hydro's maintenance strategy is, to the extent possible, to minimize reactive and emergency-type work through an effective planned maintenance program (including predictive and preventative actions).

Chatham-Kent Hydro's customer responsiveness and system reliability are monitored continually to ensure that its maintenance strategy is effective. This effort is coordinated with Chatham-Kent Hydro's capital project work, so that where maintenance programs have identified matters the correction of which require capital investments, Chatham-Kent Hydro may adjust its capital spending priorities to address those matters.

Predictive Maintenance:

Predictive maintenance activities involve the testing of elements of the Chatham-Kent Hydro distribution system. These activities include infrared thermography testing, transformer oil analysis, planned visual inspections and pole testing. These evaluation tools are all administered using a grid system with appropriate frequency levels. Any identified deficiencies found are prioritized and addressed within a suitable time frame.

Preventative Maintenance:

Preventative maintenance activities include inspection, servicing and repair of network components. This includes overhead and pad-mounted load break switch maintenance, insulator washing and cleaning/inspection of underground vaults. Also included are regular inspection and repair of substation components, relays, and ancillary equipment. The work is performed using a combination of time and condition based methodologies.

Emergency Maintenance:

This item includes unexpected system repairs to the electrical system that must be addressed immediately. The costs include those related to repairs caused by storm damage, emergency tree trimming and on-call premiums. Chatham-Kent Hydro constantly evaluates its maintenance data to adjust predictive and preventative actions. The ultimate objective is to reduce this emergency maintenance.

Service Work:

The majority of costs related to this work pertain to service upgrades requested by customers, and requests to provide safety coverage for work (overhead line cover ups). This includes service disconnections and reconnections by Chatham-Kent Hydro for all service classes; assisting pre-approved contractors; the making of final connections after Electrical Safety Authority ("ESA") inspection for service upgrades; and changes of service locations.

Network Control Operations:

Network operating costs are related to the 24-hour monitoring and operation of the distribution system through Chatham-Kent Hydro's control room. The control room is staffed only on weekdays, during regular business hours. An answering service company has been contracted to contact "on call" lineperson and supervisory staff in the event of service problems after normal business hours. The control room is linked to the distribution system by a data communication network and information is processed by a Supervisory Control and Data Acquisition ("SCADA") system. Real-time breaker status, and voltage and current readings from the Hydro One transformer stations and Chatham-Kent Hydro substations, are sent to the control room and displayed on the SCADA system.

The control room operators continuously monitor the system and dispatch repair crews to manage equipment failures and provide work protection for the crews doing work on the system.

Metering:

This department is responsible for the installation, testing, and commissioning of new and existing simple and complex metering installations. Testing of complex metering installations ensures the accuracy of the installation and verifies meter multipliers for billing purposes.

Revenue Protection is another key activity performed by Metering, by proactively investigating potential diversion and theft of power.

This department also provides an underground locate service to anyone requesting verification of underground cable locations.

Substation Services:

Substation services activities address the maintenance of all equipment at Chatham-Kent Hydro's 14 substations. This includes both labor costs and non-capital material spending to support both scheduled and emergency maintenance events. As with the maintenance activities, Chatham-Kent Hydro's substation maintenance strategy focuses on minimizing, to the extent possible, emergency-type work by improving the effectiveness of Chatham-Kent Hydro's planned maintenance program (including predictive and preventative actions) for its substations.

ENGINEERING DEPARTMENT

Engineering is responsible for keeping asset related data up to date on electronic Geographic Information System ("GIS"). This system will be used for asset management activities, troubleshooting system problems in the control room, delivering underground utility locating services for excavating contractors and for design and construction activities including new capital projects and customer connections. Engineering also delivers drafting services to the design technicians for capital projects and provides distribution system asset information to many departments within Chatham-Kent Hydro. Engineering costs are allocated to operations, maintenance, capital, and Third Party receivable accounts based on direct labor costs. A standard overhead percentage is set at the beginning of the year and adjusted to actual at year end.

STORES/WAREHOUSE

Stores staff is accountable for managing the procurement, control, and movement of materials within Chatham-Kent Hydro's service centre. This would include monitoring inventory levels, issuing material receipts, material issues, and material returns as required. The cost of the stores department is allocated to all departmental, capital, Chatham-Kent Hydro receivable, and Third Party receivable accounts as an overhead cost based on direct material costs. A standard overhead percentage is set at the beginning of the year and adjusted to actual at year end.

TRANSPORTATION FLEET

The Transportation fleet costs are for the maintenance and control of approximately 20 fleet vehicles. Its objectives include maintenance of vehicle reliability and safety, and the minimization of vehicle down time. Vehicle costs are allocated to operations, maintenance, capital, Chatham-Kent Hydro receivable, and Third Party receivable accounts based on the number of hours used in those functions. The vehicles are put into two vehicle classes and an estimated standard hourly cost/hr is set for each class. Costs are adjusted to actual at year end.

LABOUR BURDEN/ HEALTH AND SAFETY

This department collects the cost of all employee benefits and payroll taxes such as EI, CPP, EHT, WSIB, and group insurances. Costs are allocated to all departments, capital, Chatham-Kent Hydro receivable and Third Party receivable amounts based on direct labour. An overhead rate is set at the beginning of each year and adjusted to actual at year end.

In addition, the cost of Health and Safety is included in this department. Costs include Health & Safety program supplies as well labour costs associated with safety meetings. Chatham-Kent Hydro is committed to maximizing productivity and reducing risk of injury by initiating safety and health measures that focus on preventative actions. The commitment to safety and health is significant, and involves documenting unsafe behaviors, monitoring conformance to established standards and policies, determining the effectiveness of safety training and monitoring the resolution of safety recommendations/audits; commitment to continuous improvement in training; and identifying and correcting root causes for system deficiencies.

Chatham-Kent Hydro is a member of E&USA and takes part in their education and training programs. Chatham-Kent Hydro has been working though E&USA's "Quest for Zero" lost time accident program. Chatham-Kent Hydro has been awarded the Bronze, Silver and most recently the Gold award for health and safety excellence. Chatham-Kent Hydro had been awarded the President's award for achieving 250,000 working hours without a lost time injury.

CUSTOMER SERVICE

The Customer Service activities are provided by Chatham-Kent Utility Services, an affiliate of Chatham-Kent Hydro. Chatham-Kent Hydro is responsible for the customer care activities for the approximately 32,200 customers in Chatham-Kent Hydro's service area. These activities include meter reading, billing, call centre, collections, wholesale settlement, managing the transactions with retailers, and other back office functions. Chatham-Kent Hydro, in partnership with Chatham-Kent Utility Services aspires to achieve customer service excellence in its processes and customer programs. The costs associated with the Customer Service department are collected in accounts 5305 to 5515.

Meter Reading : 5310

Meter reading services in the past were contracted by Chatham-Kent Utility Services to a non-affiliated third party under a service contract agreement. On average the contractor reads approximately 18,300 electric service meters each month as the residential and small general service classes are predominantly bi-monthly billed.

Chatham-Kent Hydro has fully deployed smart meters to the residential class and therefore in 2009 has begun to read the meters for billing purposes using the smart meter solution which has reduced the cost in meter reading. For 2010 the meter reading costs will be provided by Chatham-Kent Utility Services and are only provided an annual manual meter read. The manual meter read will provide for visual verification and testing of the meters.

Billing : 5315

Billing is predominantly bi-monthly with the demand customers on monthly billing, Chatham-Kent Hydro issues 244,800 invoices annually to customers. On average this total includes 24,000 final bills for customers moving within or outside of Chatham-Kent Hydro's service territory. An annual billing schedule is created based on the meter reading schedule to ensure timely billing of services. The billing functions include the VEE processes; EBT and retailer settlement functions for 12 retailers that have signed up approximately 6,000 customers; account adjustments; processing meter changes; and other various account related field service orders and mailing services. Chatham-Kent Hydro offers customers a number of payment options including an equal payment plan, electronic payment, bank, credit card and a preauthorized payment plan.

In 2010, Chatham-Kent Hydro is preparing to move to monthly billing for the residential customers due to the Low-income Energy Assistance Plan and at the request of some social agencies in the Chatham-Kent Hydro service territory (Exhibit 4, Tab 2, Appendix E and F).

Collections: 5320

Collections involve a combination of activities, including processing payments made from customers at the office, through the mail, bank and other electronic methods. The activities also include the collection of overdue active accounts, security deposits and final bills for service termination. Credit risk is a concern for Chatham-Kent Hydro with 2010 credit loss forecast at $200,000 and $12,760 for third party collection assistance. The credit loss is based on an approximately 20% increase from 3 year average of the bad debt that has been incurred. In an effort to minimize credit losses, Chatham-Kent Hydro enforces a prudent credit policy in accordance with the Distribution System Code. Active overdue accounts are collected by in-house staff through notices, letters and direct telephone contact is made by manual phone calls and the Integrated Voice Recognition (IVR) automated phone system after regular hours. Final bill collections are turned over to a collection agency 30 days after the final due date.

The collections activities have significantly increased over the past few years due to the economic challenges in our community. These activities are expected to continue over the next few years.

Bad Debt Expense: 5335

Bad debt expense has increased since the 2006 Board Approved amount was established. The economic challenges in our service area have affected bad debts. There have been more residential bad debts and the most significant impact has been in the general service class. Chatham-Kent Hydro has experienced write offs in this class at levels that have never been experienced previously.

Community Relations: 5410

Chatham-Kent Hydro is committed to providing consumer information and responses, in a timely and proactive manner, on electricity distribution and related issues. Chatham-Kent Hydro maintains a presence in the communities it serves, where Chatham-Kent Hydro staff is available to answer customer questions in a friendly environment.

Since LDCs are the "face-to-the-customer" for the electricity industry, Chatham-Kent Hydro has an important role to play in educating the public about electricity safety and energy conservation.

Education – Electricity Safety: 5420

Chatham-Kent Hydro supports elementary schools in the Chatham-Kent Service Area by providing electricity safety sessions for students in grades one through eight. These highly interactive one-hour sessions educate children in the dangers of electricity. Chatham-Kent Hydro uses the Electrical Safety & Conservation Company to assist in the presentations.

Chatham-Kent Hydro is also a sponsor and a participant of the Children's Safety Village. The Children's' Safety Village is a community based education center that educates not only children but also all residents on safety awareness issues that they may encounter on a daily basis.

Chatham-Kent Hydro's support has been in building a home that demonstrates the safety issues with electricity, providing employee time in presenting safety program to the children and providing financial support to all programs.

Education – Energy Conservation: 5410

Building a conservation culture in Chatham-Kent continues to be an important objective for Chatham-Kent Hydro as it is very active in the community promoting conservation initiatives, attending a number of community events each year, distributing compact florescent light bulbs and energy conservation handbooks. Chatham-Kent Hydro continues to participate with the OPA in administering programs directed at Energy Conservation.

Chatham-Kent Hydro has been involved in a number of CDM programs throughout the Chatham-Kent Service Area. One of its missions as a utility is to provide the consumers with in-depth education on how to conserve to assist them in reducing their level of consumption. Throughout 2006 Chatham-Kent Hydro provided its customers in the service area with 5 presentations on the advantages of Smart Meters. This entailed presentations to Maple Senior Centre, Chatham Kent Health Alliance Environment Expo, Home Builders Meeting, Teachers Resource Fair and Union Gas Town Hall Meeting. In 2007 Chatham-Kent Hydro hosted several presentations on the tools that are available to consumers to monitor their usage and take advantage of off-peak energy consumption. Also in 2007 Chatham-Kent Hydro was involved in the Ask the Expert hosted on CFCO radio which provided consumers with Energy saving tips. In 2008 and the beginning of 2009 Chatham-Kent Hydro provided a number of presentations on tips to conserve as well as tools available on the internet to monitor their consumption.

Chatham-Kent Hydro has developed a children's program to educate them on energy conservation. The program is provided to children in grade five and is supported by an educational workbook and the children's website www.ckenergykids.com.

ADMINISTRATIVE AND GENERAL EXPENSES

Administrative and general expenses include expenses incurred in connection with the general administration of the utility's operations. Within Chatham-Kent Hydro, the following functional areas are considered to be part of general administration and, as such, all expenses incurred within these functional areas are accounted for as administrative and general expenses:

- Executive Management (5605);
- Finance and Regulatory Services (5610);

- Information Technology Services (5615);

Executive Salaries and Expenses: 5605

The President & Chief Executive Officer is responsible for all aspects of Chatham-Kent Hydro. The Chief Financial and Regulatory Officer is responsible for the financial and regulatory well being. Also included in this category is the Executive Assistant to the President. Expenses include salaries and all related expenses for all employees within the above noted functional areas.

Management Salaries and Expenses: 5610

This account has been capturing three different categories of costs:

Executive Salaries and Expenses:

The President & Chief Executive Officer, the Chief Financial and Regulatory Officer and the President of Chatham-Kent Utility Services are allocated to this account. Only the portion of salaries and expenses that relates to service provided to and benefit Chatham-Kent Hydro customers are allocated. Expenses include salaries and all related expenses for all employees within the above noted functional areas.

Financial Services:

The Finance department is responsible for the preparation of statutory, management and Board of Directors financial reporting in accordance with GAAP; implement all changes necessary to be compliant under International Financial Regulatory Standards; all daily accounting functions, including accounts payable, accounts receivable, and general accounting; treasury functions including cash management, risk management, accounting systems and internal control processes; preparation of consolidated budgets and forecasts; and supporting tax compliance. Expenses include salaries and all related expenses associated with the accounting staff.

Regulatory Services:

The Regulatory Services department is responsible for all regulatory reporting and compliance with applicable codes and legislation governing Chatham-Kent Hydro. Regulatory reporting includes development and preparation of rate filings, performance reporting, and compliance. Expenses include salary and related costs associated with the Regulatory Analyst.

General Administrative Salaries and Expenses: 5615

The Executive Assistant to the Chief Executive Officer's salary and related expenses are recorded in this account.

Office Supplies and Expenses: 5620

Office supplies and expenses incurred in connection with the general administration of the utility's operations which are assignable to specific administrative or general departments and are not specifically provided for in other accounts. This includes the expenses of the various administrative and general departments, the salaries and wages of which are included in account 5615, General Administration Salaries and Expenses.

Outside Service Employed: 5630

Outside Services Employed include, but are not limited to, consulting and professional fees of accountants and auditors, information technology, actuaries, legal services, public relations counsel and tax consultants.

Property Insurance: 5635

Insurance protects the utility against losses and damages to owned or leased property used in its utility operations. It shall also include the cost of labour and related supplies and expenses incurred in property insurance activities.

Employee Post-Retirement Benefits: 5645

Employee Post-Retirement Benefits include annual expenses for post-retirement benefits provided to eligible Chatham-Kent Hydro retirees in accordance with company policy and as provided in the collective bargaining agreement between Chatham-Kent Hydro and its union. The future liability for post retirement benefits of the current retirees is also recorded in this account. The annual expense and liability are determined in accordance with Section 3461 of the CICA Handbook and supported by an actuarial valuation that is completed every three years.

Regulatory Expenses: 5655

Regulatory Expenses include those expenses incurred in connection with Decisions and Orders on Cost Awards for hearings, proceedings, technical sessions, and other matters before the OEB or other regulatory bodies, including annual assessment fees paid to a regulatory body. Annual fees assessed by the OEB are included in this expenditure category. This account will also include the salaries and benefits of regulatory and accounting staff that report the many regulatory proceedings before the OEB. Chatham-Kent Hydro has been and will continue to be a active participant in regulatory matters that impact the energy industry in Ontario. This expense also includes the recovery of the 2010 cost of service application over a four year period.

Maintenance of General Plant: 5675

Maintenance cost for administrative and general functions of labour, materials used and expenses incurred in the maintenance of property.

APPENDIX B

STATISTICS CANADA – CPI

Related tables: Consumer price indexes.

Consumer Price Index, by province
(Ontario)

	2004	2005	2006	2007	2008
	2002=100				
Ont.					
All-items	**104.6**	**106.9**	**108.8**	**110.8**	**113.3**
Food	103.6	106.7	109.0	111.8	116.0
Shelter	105.6	109.0	112.5	114.4	118.4
Household operations, furnishings and equipment	101.5	101.7	102.0	103.3	105.0
Clothing and footwear	98.0	96.2	93.2	93.5	92.2
Transportation	107.8	112.1	114.9	117.2	119.6
Health and personal care	102.3	104.3	105.8	107.3	109.2
Recreation, education and reading	100.2	99.3	99.0	101.0	101.6
Alcoholic beverages and tobacco products	118.2	123.1	126.5	129.8	131.7
Special aggregates					
All-items excluding food	104.7	106.9	108.7	110.5	112.8
All-items excluding energy	104.0	105.6	107.0	109.1	110.9
	% change from previous year				
All-items	**1.9**	**2.2**	**1.8**	**1.8**	**2.3**
Food	2.0	3.0	2.2	2.6	3.8
Shelter	2.7	3.2	3.2	1.7	3.5
Household operations, furnishings and equipment	0.5	0.2	0.3	1.3	1.6
Clothing and footwear	0.3	-1.8	-3.1	0.3	-1.4
Transportation	1.8	4.0	2.5	2.0	2.0
Health and personal care	1.1	2.0	1.4	1.4	1.8
Recreation, education and reading	0.3	-0.9	-0.3	2.0	0.6
Alcoholic beverages and tobacco products	7.6	4.1	2.8	2.6	1.5
Special aggregates					
All-items excluding food	1.8	2.1	1.7	1.7	2.1
All-items excluding energy	1.5	1.5	1.3	2.0	1.6

Note: Annual average indexes are obtained by averaging the indexes for the 12 months of the calendar year.
Source: Statistics Canada, CANSIM, table (for fee) 326-0021 and Catalogue nos. 62-001-X and 62-010-X.
Last modified: 2009-07-30.

To learn more about the Consumer Price Index, see Your Guide to the Consumer Price Index.

Find information related to this table (CANSIM table(s); Definitions, data sources and methods; *The Daily*; publications; and related Summary tables).

Date Modified: 2009-07-30

APPENDIX C

CIBC WORLD MARKETS – PROVINCIAL FORECAST

PROVINCIAL FORECAST

June 22, 2009

Provincial Growth: Bottom Hit, Where to Next?

by Warren Lovely

Economics

Avery Shenfeld
(416) 594-7356
avery.shenfeld@cibc.ca

Benjamin Tal
(416) 956-3698
benjamin.tal@cibc.ca

Peter Buchanan
(416) 594-7354
peter.buchanan@cibc.ca

Warren Lovely
(416) 594- 8041
warren.lovely@cibc.ca

Meny Grauman
(416) 956-6527
meny.grauman@cibc.ca

Krishen Rangasamy
(416) 956-3219
krishen.rangasamy@cibc.ca

It's taken a year-and-a-half of downward revisions, but a bottom has finally formed in the outlook for Canadian economic growth. The consensus forecast for real GDP has recently coalesced around a 2½% contraction for 2009, as compared to the 2½% expansion anticipated a little more than a year ago (Chart 1). Ugly yes, but on par with the hit to Canadian GDP sustained during each of the last two major North American recessions.

Relative to national forecasts that get tweaked at least once a month, provincial outlooks aren't updated with the same frequency. So whether it's relative to official government projections or private sector calls put on the books during brighter days, provincial growth forecasts for 2009 are in many cases still a little optimistic (Chart 2). The same holds for 2010, where we see the economy walking before it runs, advancing at a modest 1½% pace and disappointing provincial Finance Ministers and the majority of private sector prognosticators who currently envision a 2%-plus recovery.

Recession More Broadly Based

While provincial performance is hardly uniform, today's global economic downturn has nonetheless left a mark on every region of the country. At the most macro level, CIBC anticipates all provinces, save Saskatchewan, will be subject to an outright decline in real GDP this year (Table 1). Such a slump would be more broadly based than in either of the past two recessions. Back in the early-1980s, Atlantic Canada was spared the recession's painful grip, while a 1991 contraction was borne largely by Ontario, Québec and Manitoba, with half of the provinces avoiding decline.

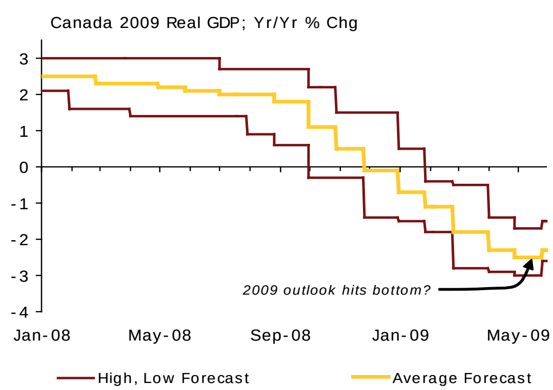
And in a notable departure from previous recessions, Canada is sustaining less economic damage than the US. Canada's provinces and municipalities have, by extension, absorbed a less debilitating hit compared to most US states and cities, where job losses, home foreclosures and government budget pressures are considerably more pronounced.

Trading Places in Central Canada

Ontario's 3.3% real GDP contraction accounts for a disproportionate share of Canada's 2009 stumble. While that builds on 2008 weakness, the two-year real GDP decline, at 3.7%, would still be less acute than the cumulative 5.6% retreat of the early 1990s.

Chart 1

Consensus Forecast Revised Lower



Source: Consensus Economics

Chart 2

Budget Growth Forecasts Now Look Too High

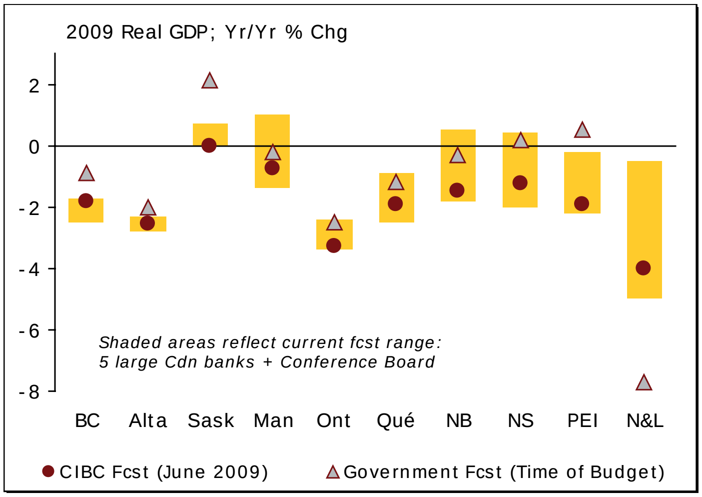
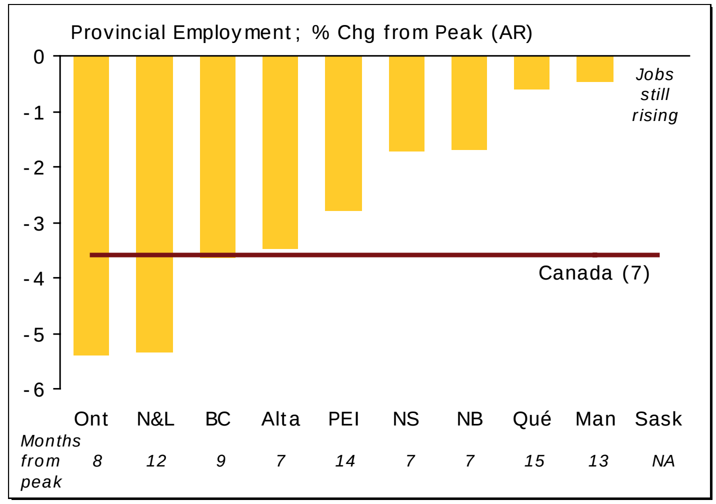


Chart 3

Ontario Has Seen Largest Job Loss



A government-sponsored auto bailout protects Canada's relative standing, but pronounced weakness in that high-profile industry has left its mark. Despite enduring a less painful adjustment, non-auto manufacturers can expect only a tentative near-term recovery, as American consumers adapt to shrinking payrolls, tighter credit and an increasing energy drag. A resurgent C$ and trade protectionism fears add further clouds to the outlook.

Factory job losses tell the tale; Ontario manufacturing employment has plunged fully 30% from a late-2002 peak, and through Spring 2009, was continuing to fall at a 15% annual rate. As non-manufacturing sectors shed their earlier resilience, no province has seen a steeper decline in total employment relative to the recent cyclical peak (Chart 3), blunting wage growth and crimping consumer confidence.

A necessary emphasis on cost containment will leave private business striving for productivity gains, signaling further headcount reductions ahead. Additional job losses won't be limited to Ontario, mind you, nor would they be out of line with the path provincial employment followed during prior recessions (Chart 4). More positively, government stimulus efforts—monetary and fiscal, federal and provincial—will key a resumption of positive growth in 2010 and beyond, forestalling a repeat of the early- to mid-1990s jobless recovery.

Come 2010, Ontario still looks to be trailing Québec in real GDP growth (Chart 5). Québec's outperformance represents a notable reversal from the 1990s and early 2000s, and reflects a more diversified manufacturing base, lighter job losses and a less severe housing

Table 1

Real GDP Outlook

%	Actual 2008	CIBC Forecasts 2009	CIBC Forecasts 2010	Reference: Past Recessions 1982	Reference: Past Recessions 1991
BC	-0.3	-1.8	2.0	-6.1	0.2
Alta	-0.2	-2.5	1.8	-3.2	0.5
Sask	4.4	0.0	2.2	-1.9	1.1
Man	2.4	-0.7	1.7	-2.6	-3.4
Ont	-0.4	-3.3	1.3	-2.7	-3.9
Qué	1.0	-1.9	1.6	-3.6	-2.7
NB	0.0	-1.5	1.7	1.9	0.0
NS	2.0	-1.2	1.8	3.7	-0.9
PEI	0.9	-1.9	1.0	0.9	-0.3
N&L	-0.1	-4.0	2.5	1.0	0.5
CDA	0.4	-2.5	1.5	-2.9	-2.1
US	*1.1*	*-3.1*	*1.7*	*-1.9*	*-0.2*

Note: Shading denotes annual decline in provincial real GDP

Chart 4

Ontario Job Losses vs. Past Recessions

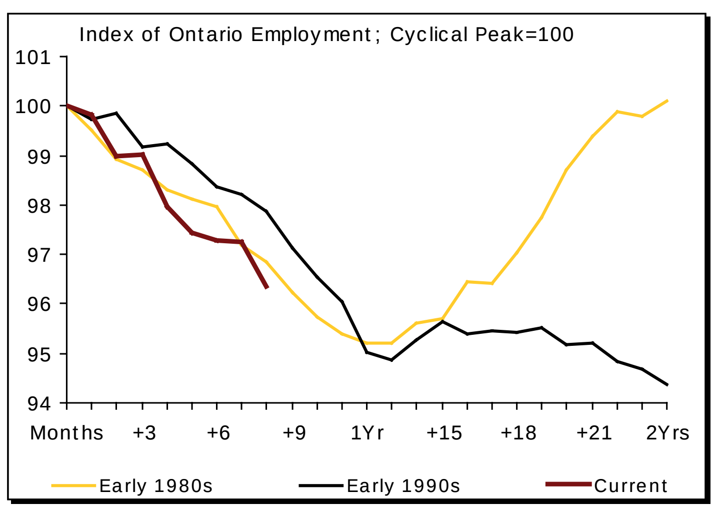


Chart 5

Québec Outperforms in Central Canada

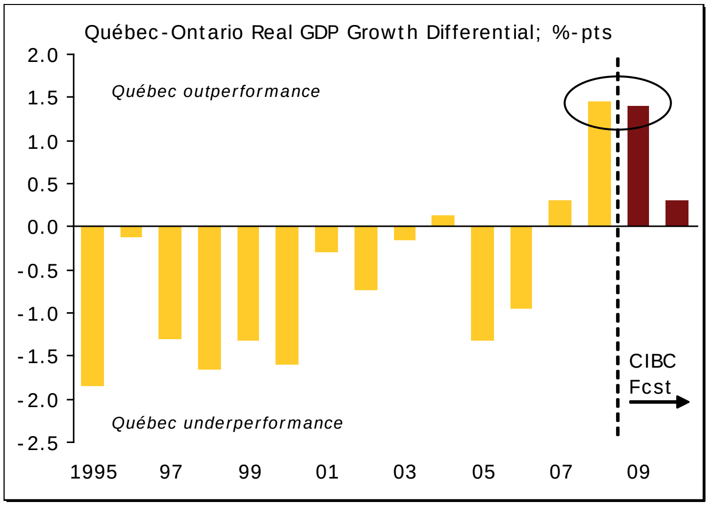
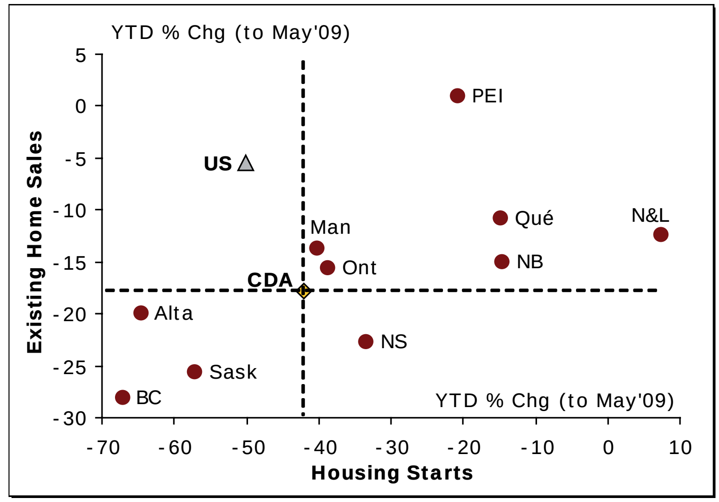


Chart 6

East Beats West in Housing



pullback. An accelerated infrastructure program, including development of the province's key renewable energy assets, has paid timely dividends, while a relative improvement in tax competitiveness aims to encourage private investment.

Capital Projects Colour Atlantic Canada Prospects

Further East, New Brunswick and Nova Scotia will see less pronounced weakness in 2009 real GDP growth, consistent with relatively healthier labour and housing markets. In New Brunswick, capital investment is cementing that province's role as a key North American energy hub, while dramatic tax reform should lure business and support the province's drive towards self sufficiency.

Nova Scotia's diverse economy has seen growth in key service industries, including financial services, with resource development (including the much-anticipated Deep Panuke project) a plus.

Notwithstanding a 2009 production pullback, confidence is riding high in Newfoundland and Labrador. Improved job prospects have snapped a once-dominant pattern of out-migration, while resource-related income growth has delivered decisive outperformance in consumer spending and key housing market metrics (Chart 6).

Western Housing Correcting

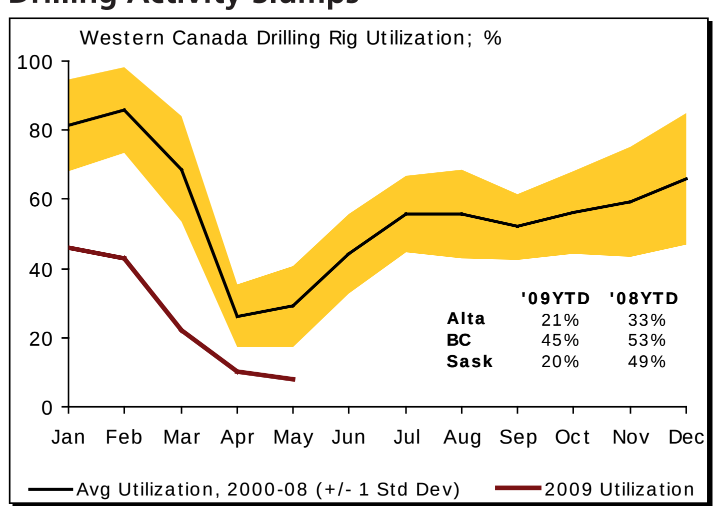
As a global downturn savaged markets for some of Canada's key commodities, parts of Western Canada saw their previous boom violently halted. This has been most obvious in the energy industry, where projects have been delayed/shelved and drilling activity has slumped well-below 'normal' levels (Chart 7).

In Alberta and British Columbia, businesses have retrenched, job losses have climbed and housing markets have cracked. Witness pronounced declines in new and resale market activity. A dramatic pullback in housing construction, while an obvious drag on current economic activity, will ultimately staunch declines in house prices (Chart 8).

More recent commodity strength, if sustained, would be an obvious plus, particularly for Alberta and Saskatchewan, which are levered to oil. Prices for natural gas, the

Chart 7

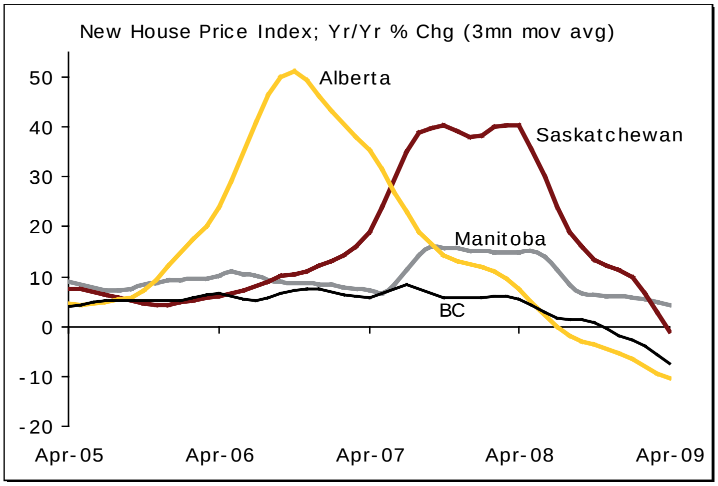
Drilling Activity Slumps



Source: CAODC

Chart 8

House Prices Give Back Some Earlier Gains



predominant source of energy activity and royalties for BC, have languished in comparison. But the US housing market is bottoming—a relief for BC's embattled forestry industry—and the province can expect a modest boost from the 2010 Olympic Games.

For 2009, Saskatchewan remains Canada's fastest-growing province, and should see its relative outperformance continue in 2010. House prices are no longer vaulting ahead, but the province's still-solid jobs market is attracting would-be hires from other parts of the country and buoying Saskatchewan's potential growth rate. Income growth remains unparalleled and government stimulus efforts are hitting their mark.

Economic activity in Manitoba, meanwhile, has held its own, consistent with the province's track record of relatively stable growth. A diverse factory sector has weathered the US economic collapse, leaving labour and housing markets in better shape than most. Like Québec, the province is well positioned to benefit from an increasing focus on renewable energy, owing to the ongoing development of its vast hydro-electric potential.

Table 2

Provincial Economic Forecast

	Employment Yr/Yr % Chg			Unemployment Rate %			Retail Sales Yr/Yr % Chg			Housing Starts 000s Units			CPI Yr/Yr % Chg		
	2008A	2009F	2010F	2008A	2009F	2010F	2008A	2009F	2010F	2008A	2009F	2010F	2008A	2009F	2010F
BC	2.1	-2.4	0.9	4.6	7.6	8.1	0.3	-6.2	4.5	34.3	13.0	19.0	2.1	0.3	1.6
Alta	2.7	-0.8	0.6	3.6	6.3	6.9	-0.1	-7.9	4.2	29.0	13.0	18.5	3.2	-0.3	1.4
Sask	2.2	1.9	1.1	4.1	5.0	5.4	10.6	-2.6	5.0	6.8	3.1	4.0	3.2	0.9	1.9
Man	1.7	0.1	0.7	4.2	5.0	5.6	7.2	-2.7	4.0	5.6	3.4	4.5	2.2	0.6	1.5
Ont	1.4	-2.6	0.3	6.5	9.2	9.9	3.5	-2.9	3.4	75.6	48.4	53.5	2.3	0.5	1.4
Qué	0.8	-0.6	0.5	7.2	8.6	9.4	5.1	-2.7	3.6	47.9	41.5	46.0	2.1	0.5	1.5
NB	0.9	-0.1	0.6	8.6	9.1	9.8	5.9	-2.3	3.7	4.2	3.7	3.9	1.7	0.1	1.6
NS	1.2	0.0	0.8	7.7	9.1	9.6	4.2	-1.0	3.8	4.3	3.3	4.0	3.0	-0.4	1.5
PEI	1.3	-2.2	0.6	10.8	12.6	12.9	5.6	1.0	3.5	0.7	0.6	0.7	3.4	-0.4	1.4
N&L	1.5	-3.0	0.9	13.3	15.0	15.3	7.6	1.3	4.2	3.2	3.1	3.3	2.9	0.4	1.7
CDA	1.5	-1.6	0.5	6.1	8.3	9.0	3.4	-3.8	3.8	211	133	157	2.4	0.3	1.5

OM&A Detailed Costs

Materiality thresholds for rate base related costs and expenditures, being 0.5 per cent of revenue requirement in accordance with the OEB's updated Filing Requirements are set out in Table 4-6.

Table 4-6
Rate Base Materiality

Description	2006 OEB Approved	2006 Actual	2007 Actual Year	2008 Actual Year	2009 Bridge Year	2010 Test Year
Rate Base	$50,309,522	$51,813,558	$54,003,463	$55,634,596	$55,490,686	$56,073,568
Cost Capital	8.02%	8.02%	8.02%	7.95%	7.89%	7.52%
Return on Rate Base	$4,034,824	$4,155,447	$4,331,078	$4,425,583	$4,377,809	$4,219,200
Distribution Expense	$8,723,462	$8,107,926	$8,594,813	$9,274,947	$9,527,916	$10,618,473
PILS	$1,572,932	$1,349,735	$1,405,223	$1,207,671	$1,096,204	$987,663
Revenue Requirement	$14,331,218	$13,613,108	$14,331,114	$14,908,201	$15,001,929	$15,825,336
Materiality Cal .5%	$71,656	$68,066	$71,656	$74,541	$75,010	$79,127

The analyses for those variances over the materiality threshold in the above table 4-6, are highlighted in yellow in the following schedules.

Chatham-Kent Hydro is providing the detailed OM&A costs by USoA in Table 4-7, for 2006 Board Approved, 2006 Actual to 2008 Actual, 2009 Bridge Year and 2010 Test Year. Also included in the table is the percentage of change year over year.

Page 5 of this schedule provides greater details of the regulatory costs.

Table 4-7
OM & A Detailed Cost

Expense Description	2006 Board Approved	2006 Actual	Variance from 2006 Board Approved	Percentage Change (%)	2007 Actual	Variance from 2006 Actual	Percentage Change (%)	2008 Actual	Variance from 2007 Actual	Percentage Change (%)	2009 Bridge	Variance from 2008 Actual	Percentage Change (%)	2010 Test	Variance from 2009 Bridge	Percentage Change (%)
Operation																
5005-Operation Supervision and Engineering	143,807	126,478	(17,329)	-12.05%	121,376	(5,102)	-4.03%	94,780	(26,596)	-21.91%	98,227	3,447	3.64%	164,224	65,997	67.19%
5010-Load Dispatching		0	0	0.00%	0	0	0.00%	0	0	0.00%	0	0	0.00%	0	0	0.00%
5012-Station Buildings and Fixtures Expense		0	0	0.00%	0	0	0.00%	0	0	0.00%	0	0	0.00%	0	0	0.00%
5014-Transformer Station Equipment - Operation Labour		0	0	0.00%	0	0	0.00%	0	0	0.00%	0	0	0.00%	0	0	0.00%
5015-Transformer Station Equipment - Operation Supplies and Expenses		0	0	0.00%	0	0	0.00%	0	0	0.00%	0	0	0.00%	0	0	0.00%
5016-Distribution Station Equipment - Operation Labour	2,068	8,405	6,337	306.41%	56,280	47,875	569.64%	56,348	68	0.12%	55,365	(983)	-1.74%	107,180	51,815	93.59%
5017-Distribution Station Equipment - Operation Supplies and Expenses	5,890	3,184	(2,706)	-45.95%	875	(2,309)	-72.53%	6,233	5,359	612.72%	5,295	(939)	-15.06%	6,471	1,177	22.23%
5020-Overhead Distribution Lines and Feeders - Operation Labour	112,180	102,480	(9,700)	-8.65%	103,093	613	0.60%	92,120	(10,973)	-10.64%	98,369	6,249	6.78%	110,535	12,167	12.37%
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	36,883	36,043	(840)	-2.28%	34,530	(1,513)	-4.20%	28,808	(5,722)	-16.57%	31,852	3,044	10.57%	36,711	4,859	15.26%
5030-Overhead Subtransmission Feeders - Operation		0	0	0.00%	0	0	0.00%	0	0	0.00%	0	0	0.00%	0	0	0.00%
5035-Overhead Distribution Transformers- Operation	68,840	39,754	(29,086)	-42.25%	37,911	(1,844)	-4.64%	27,505	(10,406)	-27.45%	50,206	22,701	82.53%	50,252	46	0.09%
5040-Underground Distribution Lines and Feeders - Operation Labour	155,038	137,123	(17,915)	-11.56%	147,289	10,166	7.41%	176,507	29,218	19.84%	159,122	(17,385)	-9.85%	163,707	4,585	2.88%
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	63,632	38,369	(25,263)	-39.70%	58,734	20,366	53.08%	27,878	(30,856)	-52.54%	22,863	(5,015)	-17.99%	26,656	3,792	16.59%
5050-Underground Subtransmission Feeders - Operation		0	0	0.00%	0	0	0.00%	0	0	0.00%	0	0	0.00%	0	0	0.00%
5055-Underground Distribution Transformers - Operation	804	0	(804)	-100.00%	25	25	0.00%	26	1	3.63%	47	21	83.61%	47	0	0.00%
5065-Meter Expense	193,124	211,305	18,181	9.41%	242,338	31,034	14.69%	369,887	127,549	52.63%	235,006	(134,882)	-36.47%	345,446	110,440	46.99%
5070-Customer Premises - Operation Labour	13,570	15,507	1,937	14.27%	17,814	2,307	14.88%	17,708	(105)	-0.59%	27,777	10,068	56.86%	27,909	132	0.48%
5075-Customer Premises - Materials and Expenses	3,690	5,031	1,341	36.35%	5,542	510	10.14%	1,128	(4,414)	-79.65%	2,098	971	86.08%	2,098	0	0.00%
5085-Miscellaneous Distribution Expense		0	0	0.00%	0	0	0.00%	0	0	0.00%	0	0	0.00%	0	0	0.00%
5096-Other Rent		0	0	0.00%	0	0	0.00%	0	0	0.00%	0	0	0.00%	0	0	0.00%
Sub-Total	**799,526**	**723,678**	**(75,848)**		**825,806**	**102,129**		**898,928**	**73,122**		**786,225**	**(112,703)**		**1,041,236**	**255,010**	

Maintenance

5105-Maintenance Supervision and Engineering	147,804	141,378	(6,426)	-4.35%	136,597	(4,781)	-3.38%	207,258	70,661	51.73%	200,912	(6,346)	-3.06%	315,211	114,299	56.89%
5110-Maintenance of Buildings and Fixtures - Distribution Stations		0	0	0.00%	0	0	0.00%	0	0	0.00%	0	0	0.00%	0	0	0.00%
5112-Maintenance of Transformer Station Equipment		0	0	0.00%	0	0	0.00%	0	0	0.00%	0	0	0.00%	0	0	0.00%
5114-Maintenance of Distribution Station Equipment	161,821	194,950	33,129	20.47%	188,150	(6,800)	-3.49%	147,910	(40,240)	-21.39%	139,466	(8,444)	-5.71%	151,068	11,602	8.32%
5120-Maintenance of Poles, Towers and Fixtures	44,352	55,029	10,677	24.07%	40,176	(14,852)	-26.99%	65,634	25,458	63.37%	38,980	(26,654)	-40.61%	53,155	14,175	36.36%
5125-Maintenance of Overhead Conductors and Devices	101,344	131,731	30,387	29.98%	134,956	3,226	2.45%	157,590	22,633	16.77%	150,495	(7,095)	-4.50%	190,050	39,555	26.28%
5130-Maintenance of Overhead Services	121,515	133,854	12,339	10.15%	142,076	8,222	6.14%	129,867	(12,209)	-8.59%	118,705	(11,162)	-8.60%	120,532	1,827	1.54%
5135-Overhead Distribution Lines and Feeders - Right of Way	168,586	170,445	1,859	1.10%	159,623	(10,821)	-6.35%	154,264	(5,359)	-3.36%	170,000	15,736	10.20%	180,000	10,000	5.88%
5145-Maintenance of Underground Conduit	3,992	2,051	(1,941)	-48.63%	3,709	1,658	80.86%	3,013	(696)	-18.78%	3,084	71	2.36%	3,706	622	20.18%
5150-Maintenance of Underground Conductors and Devices	13,466	8,194	(5,272)	-39.15%	6,178	(2,015)	-24.60%	4,094	(2,085)	-33.75%	5,092	999	24.40%	5,863	770	15.13%
5155-Maintenance of Underground Services	28,209	58,514	30,305	107.43%	40,174	(18,340)	-31.34%	61,631	21,457	53.41%	49,657	(11,973)	-19.43%	54,106	4,449	8.96%
5160-Maintenance of Line Transformers	53,652	57,303	3,651	6.80%	34,921	(22,382)	-39.06%	64,452	29,531	84.57%	76,075	11,623	18.03%	91,936	15,861	20.85%
5172-Sentinel Lights-Materials and Expenses		0	0	0.00%		0	0.00%		0	0.00%			0.00%			0.00%
5175-Maintenance of Meters	16,662	28,353	11,691	70.17%	18,137	(10,217)	-36.03%	35,315	17,178	94.72%	23,159	(12,156)	-34.42%	22,170	(990)	-4.27%
Sub-Total	**861,403**	**981,801**	**120,398**		**904,698**	**(77,102)**		**1,031,028**	**126,329**		**975,626**	**(55,402)**		**1,187,798**	**212,172**	

Billing and Collections

5305-Supervision	54,562	55,980	1,418	2.60%	65,136	9,156	16.36%	84,996	19,860	30.49%	134,027	49,031	57.69%	137,237	3,210	2.40%
5310-Meter Reading Expense	98,403	98,549	146	0.15%	58,600	(39,949)	-40.54%	58,014	(586)	-1.00%	43,848	(14,166)	-24.42%	34,853	(8,995)	-20.51%
5315-Customer Billing	865,907	825,468	(40,439)	-4.67%	735,468	(90,000)	-10.90%	860,460	124,992	16.99%	847,640	(12,820)	-1.49%	1,025,552	177,912	20.99%
5320-Collecting	322,189	293,703	(28,486)	-8.84%	286,872	(6,831)	-2.33%	182,643	(104,229)	-36.33%	341,446	158,803	86.95%	416,389	74,943	21.95%
5325-Collecting- Cash Over and Short	188	0	(188)	-100.00%	0	0	0.00%	0	0	0.00%	0	0	0.00%	0	0	0.00%
5330-Collection Charges		0	0	0.00%	0	0	0.00%	0	0	0.00%	0	0	0.00%	0	0	0.00%
5335-Bad Debt Expense	137,396	116,777	(20,619)	-15.01%	142,257	25,480	21.82%	237,086	94,829	66.66%	212,806	(24,280)	-10.24%	212,766	(40)	-0.02%
5340-Miscellaneous Customer Accounts Expenses		0	0	0.00%	0	0	0.00%	0	0	0.00%	0	0	0.00%	0	0	0.00%
Sub-Total	**1,478,645**	**1,390,478**	**(88,167)**		**1,288,334**	**(102,144)**		**1,423,199**	**134,865**		**1,579,767**	**156,568**		**1,826,798**	**247,030**	

Community Relations

5405-Supervision		0	0	0.00%	0	0	0.00%	0	0	0.00%	0	0	0.00%	0	0	0.00%
5410-Community Relations - Sundry	20,696	19,323	(1,373)	-6.63%	29,793	10,469	54.18%	41,198	11,405	38.28%	33,123	(8,075)	-19.60%	44,929	11,806	35.64%
5415-Energy Conservation		0	0	0.00%	45,227	45,227	0.00%	7,775	(37,452)	-82.81%	0	(7,775)	0.00%	0	0	0.00%
5420-Community Safety Program	142	3,888	3,746	2637.94%	18,108	14,220	365.74%	4,457	(13,650)	-75.38%	5,973	1,516	34.01%	9,557	3,584	60.00%
5510-Demonstrating and Selling Expense		0	0	0.00%	0	0	0.00%	0	0	0.00%	0	0	0.00%	0	0	0.00%
5515-Advertising Expense	2,173	0	(2,173)	-100.00%	0	0	0.00%	0	0	0.00%	2,049	2,049	#DIV/0!	2,043	(6)	-0.29%
5520-Miscellaneous Sales Expense		0	0	0.00%	0	0	0.00%	0	0	0.00%	0	0	0.00%	0	0	0.00%
Sub-Total	**23,011**	**23,211**	**200**		**93,127**	**69,916**		**53,431**	**(39,696)**		**41,145**	**(12,285)**		**56,529**	**15,384**	

Administrative and General Expenses

5605-Executive Salaries and Expenses		44,934	44,934	100.00%	72,487	27,553	61.32%	77,217	4,730	6.53%	70,521	(6,696)	-8.67%	73,847	3,326	4.72%
5610-Management Salaries and Expenses	377,394	430,759	53,365	14.14%	413,289	(17,470)	-4.06%	446,382	33,092	8.01%	717,697	271,315	60.78%	875,544	157,847	21.99%
5615-General Administrative Salaries and Expenses	175,436	186,135	10,699	6.10%	217,221	31,085	16.70%	215,196	(2,025)	-0.93%	148,724	(66,472)	-30.89%	245,314	96,590	64.95%
5620-Office Supplies and Expenses	43,391	55,519	12,128	27.95%	65,979	10,460	18.84%	64,432	(1,547)	-2.34%	55,962	(8,470)	-13.15%	59,699	3,737	6.68%
5630-Outside Services Employed	268,397	304,311	35,914	13.38%	372,388	68,077	22.37%	360,881	(11,507)	-3.09%	386,276	25,395	7.04%	233,633	(152,643)	-39.52%
5635-Property Insurance	83,600	114,060	30,460	36.44%	94,752	(19,308)	-16.93%	81,000	(13,752)	-14.51%	83,186	2,186	2.70%	84,175	989	1.19%
5640-Injuries and Damages	88,070	0	(88,070)	-100.00%	0	0	0.00%	0	0	0.00%	0	0	0.00%	0	0	0.00%
5645-Employee Pensions and Benefits	290,415	202,543	(87,873)	-30.26%	234,815	32,273	15.93%	234,149	(667)	-0.28%	231,197	(2,952)	-1.26%	250,137	18,940	8.19%
5655-Regulatory Expenses	300,000	147,937	(152,063)	-50.69%	168,799	20,861	14.10%	280,894	112,095	66.41%	238,662	(42,232)	-15.03%	339,852	101,190	42.40%
5660-General Advertising Expenses		0	0	0.00%	0	0	0.00%	0	0	0.00%	0	0	0.00%	0	0	0.00%
5665-Miscellaneous General Expenses	615,576	0	(615,576)	-100.00%	0	0	0.00%	0	0	0.00%	0	0	0.00%	0	0	0.00%
5670-Rent		0	0	0.00%	0	0	0.00%	0	0	0.00%	0	0	0.00%	0	0	0.00%
5675-Maintenance of General Plant	501,235	532,148	30,913	6.17%	527,480	(4,667)	-0.88%	512,441	(15,039)	-2.85%	511,162	(1,279)	-0.25%	528,550	17,389	3.40%
6205-Charitable Donations			0	100.00%		0	0.00%		0	0.00%		0	0.00%		0	0.00%
Sub-Total	**2,743,514**	**2,018,346**	**(725,168)**		**2,167,209**	**148,863**		**2,272,590**	**105,382**		**2,443,387**	**170,796**		**2,690,751**	**247,365**	

Taxes Other Than Income Taxes

6105-Property Taxes	0	0	0	0.00%	0	0	0.00%	0	0	0.00%	0	0	0.00%	0	0	0.00%
Sub-Total	**0**	**0**	**0**		**0**	**0**		**0**	**0**		**0**	**0**		**0**	**0**	
Total Operating, Maintenance and Administration Expenses	**5,906,099**	**5,137,513**	**(768,586)**		**5,279,175**	**141,661**		**5,679,177**	**400,002**		**5,826,150**	**146,974**		**6,803,112**	**976,961**	

Amortization Expenses

5705-Amortization Expense - Property, Plant, and Equipment	2,817,363	2,970,412	153,049	5.43%	3,315,639	345,226	11.62%	3,595,770	280,132	8.45%	3,701,765	105,995	2.95%	3,815,361	113,596	3.07%
Sub-Total	**2,817,363**	**2,970,412**	**153,049**		**3,315,639**	**345,226**		**3,595,770**	**280,132**		**3,701,765**	**105,995**		**3,815,361**	**113,596**	
Total Distribution Expense Before Income Taxes	8,723,462	8,107,926	(615,536)	-7.06%	8,594,813	486,887	6.01%	9,274,947	680,134	7.91%	9,527,916		0.00%	10,618,473		0.00%

Regulatory Cost Schedule

Description	USoA Account	UsoA Account Balance	Ongoing or One Time cost	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	% Change in bridge vs 2008	2010 Test	% Change in 2010 vs 2009
1. OEB Annual Assessment	5655		Ongoing	$ 74,415	$ 87,516	$ 85,549	$ 85,884	0.39%	$ 85,884	0.00%
2. OEB Hearing Assessments	5655		Ongoing	$ 1,109	$ 1,754		$ 6,000	100.00%	$ 6,067	1.11%
3. OEB Section 30 Costs	5655		Ongoing			$ 996				
4. Expert Witness cost for regulatory matters	5655									
5. Legal costs for regulatory matters	5655		One Time						$ 30,000	100.00%
6. Consutants costs for regulatory matters	5655		One Time						$ 20,000	100.00%
7. Operating expenses associated with staff resources allocated to regulatory matters	5655		Ongoing	$ 18,996	$ 31,032	$ 135,900	$ 139,977	3.00%	$ 177,100	20.96%
8. Operating expenses associated with other resources allocated to regulatory matters	5655		Ongoing	$ 44						
9. Other regulatory agency fees or assessments	5655		Ongoing	$ 40,874	$ 34,182	$ 39,916	$ 800	-98.00%	$ 800	0.00%
10. Any other cost for regulatory matters	5655		Ongoing	$ 12,500	$ 14,315	$ 13,750				
11. Intervenor costs	5655		One Time			$ 4,782	$ 6,000	25.47%	$ 20,000	70.00%
Total				$ 147,937	$ 168,799	$ 280,894	$ 238,661		$ 339,852	

Note:
In years 2006 to 2008 EDA annual fees and Standard and Poor expenditures were recorded in the Regulatory Expense account should have been recorded in Acct 5630 Outside Service, which the cost for these cost were recorded correctly in 2009 and 2010.

VARIANCE ANALYSIS ON OM&A COSTS:

Chatham-Kent Hydro has provided a detailed OM&A cost table covering the periods from 2006 Board Approved, 2006 Actual, 2007 Actual, 2008 Actual, 2009 Bridge Year and 2010 Test Year including the variances year over year in Table 4-7, above. Before moving to a variance analysis for each account that exceeds the materiality threshold, a summary of total OM&A expenses (excluding depreciation) is presented below along with an analysis of the total movement from 2006 Actual to 2010 Test Year.

The following table identifies key cost drivers from 2006 to 2010 Test year

Table 4-8
Summary of Cost Drivers

Description	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test
OM&A expenses					
Opening Balance	5,906,099	5,137,513	5,279,175	5,679,177	5,826,150
O&M	37,000	76,000	77,000	(172,000)	470,000
B&C	(60,000)	(105,000)	125,000	120,000	172,000
Community Relations	-	70,000	-	-	15,000
Adminsitrative	(786,600)	103,000	-	80,000	245,700
Inflation	236,219	92,475	121,421	28,396	74,006
Miscellaneous	(195,205)	(94,814)	76,581	90,577	256
Closing Balance	5,137,513	5,279,175	5,679,177	5,826,150	6,803,112

2006 Cost Drivers

a) O&M

i. Additional station maintenance cost to prepare for decommissioning

b) B&C

i. Outsourcing bill printing and mailing (-$40,000)

ii. Significant bad debts were recorded on balance sheet for future recovery as Z factor which was denied in EB-2007- 0517 (-$20,000)

c) Administrative

i. Low voltage charges recorded in cost of power however were included in administration costs for Board Approved costs (-$615,600)

ii. Regulatory costs for OEB fees and ongoing costs were lower than expected (-$83,000)

iii. Pension costs lower due to updated actuarial estimate which was offset by an increase in actual expenses (-$88,000)

d) Inflation

i. Stats Can inflation rate for 2005 and 2006 was 4.0% ([$5,906,099-615,000]*4% =$236,219)

2007 Cost Drivers

a) O&M

i. Additional station maintenance cost to prepare for decommissioning (+$41,000)

ii. Meter costs increase due to approval of smart meter costs in combined hearing, EB-2007- 0063 which is offset by a reimbursement from Hydro One for wholesale meter maintenance (+75,000)

iii. Less transformer and underground activities (-$40,000)

b) B&C

iv. Meter reading reduction due to improved contract pricing and more costs allocated to water meter reading (-$40,000)

i. Improved pricing from service providers for Electronic Billing Transactions, wholesale settlement and full year of contracting out bill printing and mailing (-$90,000)

ii. Bad debts not being allocated to the balance sheet (+$25,000)

c) Community relations

i. Conservation programs as part of the 3rd traunche funding and support for the Children's Safety Village (+$70,000)

d) Administration

i. Outside services for (+$70,000)

ii. Pension cost increases (+$33,000)

e) Inflation

i. Stats Can inflation rate for 2007 was 1.8% ($5,137,513*1.8% = $92,475)

2008 Cost Drivers

a) O&M

i. Meter expense due to wholesale meter costs and no rebate from Hydro One (+$117,000)

ii. Station maintenance is lower as the decommissioning was completed (-$40,000)

iii. Additional overhead maintenance resulting in increased costs for the poles, towers, conductors and transformers (+$77,000)

b) B&C

i. Bad debt increase due to not obtaining approval for Z factor in EB -2007- (+$125,000)

c) Inflation

i. Stats Can inflation rate for 2007 was 2.3% ($5,279,175*2.3% =$121,421)

2009 Cost Drivers

a) O&M

i. Meter expense does not have any costs for a smart meter application similar to costs included in 2007 and 2008(-$172,000)

b) B&C

i. Additional data management staff for smart meter, MDMR and TOU billing activities (+$80,000)

ii. Additional collection activates by staff, upgrade of phone system(Integrated Voice Recognition) and collection letters (+$40,000)

c) Administration

i. Activities for 80,000

d) Inflation

i. CIBC forecasts inflation rate for 2009 was 0.5% ($5,679,177*0.5% =$28,396)

2010 Cost Drivers

a) O&M

i. Additional staff – (6) additional staff members (+$300,000)

ii. Full year costs for 2 apprentice lineman hired in 2009 (+$80,000)

iii. Meter maintenance costs for maintain smart meters (+90,000)

b) B&C

i. Move to monthly billing from bi-monthly billing (+$142,000)

ii. Upgrade of CIS (+$30,000)

c) Community Relations

i. Increased support of Children’s Safety Village (+$15,000)

d) Administration

i. Additional services in accounting and regulatory (+$110,700)

ii. New financial system (+$75,000)

iii. Enhanced network security to ensure security for CIS upgrade, smart meter data (+$40,000)

iv. New document management and record keeping system (+$20,000)

e) Inflation

i. CIBC forecasts inflation for 2010 at 1.4% ($5,826,150*1.4%= $74,006)

Variance Analysis:

As mentioned above, the variance analysis has triggered a threshold of $79,127 which represents the lowest 0.5% of Chatham-Kent Hydro's revenue requirement. Chatham-Kent Hydro has reviewed the variance of each OEB USoA account to determine where explanations are necessary. The amount over the threshold has been highlighted and an explanation of each variance is presented in the following section.

2006 Actual versus 2006 Board Approved:

5640 Injuries and Damage

Injuries and Damage costs decreased by $88,070 compared to the 2006 Board Approved amount. In the 2006 EDR the adjustment for the increase in Property Insurance was recorded on the wrong line - it should have been recorded on Account 5635 Property Insurance.

5645 Employee Pensions and Benefits

The cost has decreased by $87,873 compared to the 2006 Board Approved amount. In the 2006 EDR there was an adjustment of $112,163 to increase the expenditure to accommodate the increase in OMERS cost of $31,163 and Employee future benefit accrual which had been overstated to the actual.

5655 Regulatory Expense

The cost has decreased by $152,063 compared to the 2006 Board Approved amount. The 2006 EDR application had an adjustment of $109,630 to take into account the increase in OEB annual fees and introduction of Electrical Safety Association fees. The EDA costs were incorrectly charged to this account and should have been charged to 5630 Outside Services. An invoice for the Standard and Poor represents the cost for the actuarial report on retiree benefit liabilities which is performed every three years was also recorded in this account and should have been charged to 5630 Outside Services.

5665 Miscellaneous General Expense

The cost has decreased by $615,576 compared to the 2006 Board Approved amount. The decrease in costs is related to two items; first, Executive and Salary Expense were included in this account in the 2006 Board Approved but are actually recorded in account 5605; second, Low Voltage costs were also recorded in this amount for the 2006 Board Approved but are actually recorded in the cost of power expenditures.

5705 Amortization Expense

Actual depreciation expense in 2006 was $153,049 over the 2006 Board Approved levels. The 2006 Board Approved amount is based on 2004 Actual with some Tier 1 adjustments.

2007 Actual versus 2006 Actual:

5315 Customer Billing

In 2007 Actual compared to 2006 Actual the expenditures decreased by $90,000. The contract for Wholesale Settlement decreased by $10,000 from the previous year along with a reduction in meter reading costs and outsourcing bill printing and mailing activities.

5705 Amortization Expense

The increase in depreciation expense is related to the 2007 Capital Expenditures.

2008 Actual versus 2007 Actual:

5065 Meter Expense

The 2008 Actual has increased by $127,549 compared to 2007 Actual, which is due to the increase of Smart Meter Maintenance costs for the completion of the residential smart meter deployment project.

5315 Customer Billing

The 2008 Actual has increased by $124,992 compared to 2007 Actual. In 2008 there was an analysis conducted to verify the allocation of labor resources which caused a shift in expenditures allocation between the customer billing and Collections.

5320 Collecting

The 2008 Actual has decreased by $104,229 compared to 2007 Actual. As stated above in the context of customer billing this allocation had caused the expenditures from 2008 to 2007 to decrease.

5335 Bad Debt Expense`

The 2008 Actual has increased by $94,829 compared to 2007 Actual. There was an increase in bad debt expense in 2008 actual compared to 2007 actual due to a deferred amount relating to a customer that had closed and from who in Chatham-Kent Hydro would not be recovering any arrears. This bad debt was submitted to the OEB for recovery as part of Chatham-Kent Hydro 2007 IRM application but the amount was denied, therefore it was expensed in the following year.

5655 Regulatory Expense

The 2008 actual has increased by $112,095 compared to 2007 Actual due to the additional staff resources for the Smart Meter Proceeding EB-2007-0063.

5705 Amortization Expense

The increase in depreciation expense is the result of 2009 Capital Expenditures.

2009 Bridge Year versus 2008 Actual:

5065 Meter Expense

In 2009 Bridge Year compared to 2008 Actual the expenditure has decreased by $134,882 due to the reduction in smart meter maintenance costs.

5320 Collecting

Total expenditures have increased by $158,803 in 2009 Bridge compared to 2008 actual due to the hiring of additional staff and IVR phone system to manage the collection activities.

5610 Management Salaries and Expenses

The variance increase of $271,315 for 2009 Bridge compared to 2008 Actual is due to the change in capitalizing labor. Management was not involved in as many capital projects in 2009, therefore a higher percentage of management salaries was expensed.

5705 Amortization Expense

The increase in depreciation expense is the result of 2009 Capital Expenditures.

2010 Test Year versus 2009 Bridge Year:

5065 Meter Expense

The expenditure has increased by $110,440 from the 2009 Bridge Year to the 2010 Test Year due to the increase in the smart meter maintenance costs during the switching of the meters for the General Service.

5105 Maintenance Supervision and Engineering

There is a variance of $114,299 between the 2010 Test year and 2009 Bridge year, due to the additional hiring of Supervisor and 2 Engineering Apprentices.

5315 Customer Billing

Expenditures will increase by $177,912 in the 2010 Test Year compared to the 2009 Bridge Year due to the move to monthly billing from bi-monthly billing for the residential and small general customer classes. See Appendix B for details.

5610 Management Salaries and Expenses

The increase of $157,847 from the 2009 Bridge Year to the 2010 Test Year is due to the increase in personnel in accounting to meet the accounting changes for International Financial Reporting Standards. This also includes costs for a new financial system of $40,000.

5615 General administrative Salaries and Expenses

Expenditures have increased by $96,590 from the 2009 Bridge Year to the 2010 Test Year due to the increase in information technology upgrades to increase the security of the network which is required for the flow of smart meter data along with a new electronic documentation management system.

5630 Outside Services Employed

The variance between 2009 Bridge Year and 2010 Test year has decrease by $152,643 due to the costs are being recorded in regulatory and administration.

5655 Regulatory Expense

The expenditure in the 2010 Test Year has increased by $101,190 compared to the 2009 Test Year with additional costs for this Application and for an increase in personnel. Only a portion of the total cost is charged to Chatham-Kent Hydro; the remainder is shared with Middlesex Power Distribution Corporation. Costs related to managing the regulatory changes for LEAP, smart meters and Time-of-use billing roll out and various activities that may arise. Chatham-Kent Hydro has been and will continue to be a strong and continuous voice from the mid-size LDCs on regulatory issues and will require these costs to benefit the customers.

5705 Amortization Expense

The increase in depreciation expense is the result of 2009 Capital Expenditures.

Variance 2010 Test year to 2006 Actual and 2008 Actual

To provide additional information regarding the 2010 Test Year OM&A costs being proposed Chatham-Kent Hydro has provided Table 4-9 which compares the 2010 costs to the 2006 actual costs and the latest actual full year of costs, 2008. A variance analysis of the changes follows.

Table 4-9
OM&A 2010 Compared to 2006 and 2008

Expense Description	2006 Actual	2010 Test	Variance from 2010 Test Year	Percentage Change (%)	2008 Actual	2010 Test	Variance from 2010 Test Year	Percentage Change (%)
Operation								
5005-Operation Supervision and Engineering	126,478	164,224	37,746	22.98%	94,780	164,224	69,444	42.29%
5010-Load Dispatching	0	0	0	0.00%	0	0	0	0.00%
5012-Station Buildings and Fixtures Expense	0	0	0	0.00%	0	0	0	0.00%
5014-Transformer Station Equipment - Operation Labour	0	0	0	0.00%	0	0	0	0.00%
5015-Transformer Station Equipment - Operation Supplies and Expenses	0	0	0	0.00%	0	0	0	0.00%
5016-Distribution Station Equipment - Operation Labour	8,405	107,180	98,776	92.16%	56,348	107,180	50,832	47.43%
5017-Distribution Station Equipment - Operation Supplies and Expenses	3,184	6,471	3,288	50.80%	6,233	6,471	238	3.68%
5020-Overhead Distribution Lines and Feeders - Operation Labour	102,480	110,535	8,056	7.29%	92,120	110,535	18,415	16.66%
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	36,043	36,711	668	1.82%	28,808	36,711	7,903	21.53%
5030-Overhead Subtransmission Feeders - Operation	0	0	0	0.00%	0	0	0	0.00%
5035-Overhead Distribution Transformers- Operation	39,754	50,252	10,497	20.89%	27,505	50,252	22,747	45.27%
5040-Underground Distribution Lines and Feeders - Operation Labour	137,123	163,707	26,584	16.24%	176,507	163,707	(12,800)	-7.82%
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	38,369	26,656	(11,713)	-43.94%	27,878	26,656	(1,223)	-4.59%
5050-Underground Subtransmission Feeders - Operation	0	0	0	0.00%	0	0	0	0.00%
5055-Underground Distribution Transformers - Operation	0	47	47	100.00%	26	47	21	45.54%
5065-Meter Expense	211,305	345,446	134,141	38.83%	369,887	345,446	(24,442)	-7.08%
5070-Customer Premises - Operation Labour	15,507	27,909	12,402	44.44%	17,708	27,909	10,200	36.55%
5075-Customer Premises - Materials and Expenses	5,031	2,098	(2,933)	-139.81%	1,128	2,098	971	46.26%
5085-Miscellaneous Distribution Expense	0	0	0	0.00%	0	0	0	0.00%
5096-Other Rent	0	0	0	0.00%	0	0	0	0.00%
Sub-Total	**723,678**	**1,041,236**	**317,558**		**898,928**	**1,041,236**	**142,307**	
Maintenance								
5105-Maintenance Supervision and Engineering	141,378	315,211	173,833	55.15%	207,258	315,211	107,953	34.25%
5110-Maintenance of Buildings and Fixtures - Distribution Stations	0	0	0	0.00%	0	0	0	0.00%
5112-Maintenance of Transformer Station Equipment	0	0	0	0.00%	0	0	0	0.00%
5114-Maintenance of Distribution Station Equipment	194,950	151,068	(43,882)	-29.05%	147,910	151,068	3,158	2.09%
5120-Maintenance of Poles, Towers and Fixtures	55,029	53,155	(1,873)	-3.52%	65,634	53,155	(12,479)	-23.48%
5125-Maintenance of Overhead Conductors and Devices	131,731	190,050	58,320	30.69%	157,590	190,050	32,460	17.08%
5130-Maintenance of Overhead Services	133,854	120,532	(13,322)	-11.05%	129,867	120,532	(9,335)	-7.74%
5135-Overhead Distribution Lines and Feeders - Right of Way	170,445	180,000	9,555	5.31%	154,264	180,000	25,736	14.30%
5145-Maintenance of Underground Conduit	2,051	3,706	1,655	44.67%	3,013	3,706	694	18.71%
5150-Maintenance of Underground Conductors and Devices	8,194	5,863	(2,331)	-39.76%	4,094	5,863	1,769	30.18%
5155-Maintenance of Underground Services	58,514	54,106	(4,407)	-8.15%	61,631	54,106	(7,524)	-13.91%
5160-Maintenance of Line Transformers	57,303	91,936	34,633	37.67%	64,452	91,936	27,484	29.89%
5172-Sentinel Lights-Materials and Expenses	0	0	0	0.00%		0	0	0.00%
5175-Maintenance of Meters	28,353	22,170	(6,184)	-27.89%	35,315	22,170	(13,145)	-59.29%
Sub-Total	**981,801**	**1,187,798**	**205,997**		**1,031,028**	**1,187,798**	**156,770**	

Billing and Collections								
5305-Supervision	55,980	137,237	81,257	59.21%	84,996	137,237	52,241	38.07%
5310-Meter Reading Expense	98,549	34,853	(63,696)	-182.76%	58,014	34,853	(23,161)	-66.45%
5315-Customer Billing	825,468	1,025,552	200,084	19.51%	860,460	1,025,552	165,092	16.10%
5320-Collecting	293,703	416,389	122,686	29.46%	182,643	416,389	233,746	56.14%
5325-Collecting- Cash Over and Short	0	0	0	0.00%	0	0	0	0.00%
5330-Collection Charges	0	0	0	0.00%	0	0	0	0.00%
5335-Bad Debt Expense	116,777	212,766	95,989	45.11%	237,086	212,766	(24,320)	-11.43%
5340-Miscellaneous Customer Accounts Expenses	0	0	0	0.00%	0	0	0	0.00%
Sub-Total	**1,390,478**	**1,826,798**	**436,320**		**1,423,199**	**1,826,798**	**403,598**	
Community Relations								
5405-Supervision	0	0	0	0.00%	0	0	0	0.00%
5410-Community Relations - Sundry	19,323	44,929	25,605	56.99%	41,198	44,929	3,731	8.30%
5415-Energy Conservation	0	0	0	0.00%	7,775	0	(7,775)	#DIV/0!
5420-Community Safety Program	3,888	9,557	5,669	59.32%	4,457	9,557	5,100	53.36%
5510-Demonstrating and Selling Expense	0	0	0	0.00%	0	0	0	0.00%
5515-Advertising Expense	0	2,043	2,043	100.00%	0	2,043	2,043	0.00%
5520-Miscellaneous Sales Expense	0	0	0	0.00%	0	0	0	0.00%
Sub-Total	**23,211**	**56,529**	**33,318**		**53,431**	**56,529**	**3,098**	
Administrative and General Expenses								
5605-Executive Salaries and Expenses	44,934	73,847	28,914	100.00%	77,217	73,847	(3,370)	-4.56%
5610-Management Salaries and Expenses	430,759	875,544	444,785	50.80%	446,382	875,544	429,162	49.02%
5615-General Administrative Salaries and Expenses	186,135	245,314	59,179	24.12%	215,196	245,314	30,118	12.28%
5620-Office Supplies and Expenses	55,519	59,699	4,180	7.00%	64,432	59,699	(4,733)	-7.93%
5630-Outside Services Employed	304,311	233,633	(70,678)	-30.25%	360,881	233,633	(127,248)	-54.46%
5635-Property Insurance	114,060	84,175	(29,885)	-35.50%	81,000	84,175	3,175	3.77%
5640-Injuries and Damages	0	0	0	#DIV/0!	0	0	0	0.00%
5645-Employee Pensions and Benefits	202,543	250,137	47,595	19.03%	234,149	250,137	15,989	6.39%
5655-Regulatory Expenses	147,937	339,852	191,914	56.47%	280,894	339,852	58,958	17.35%
5660-General Advertising Expenses	0	0	0	100.00%	0	0	0	0.00%
5665-Miscellaneous General Expenses	0	0	0	#DIV/0!	0	0	0	0.00%
5670-Rent	0	0	0	100.00%	0	0	0	0.00%
5675-Maintenance of General Plant	532,148	528,550	(3,597)	-0.68%	512,441	528,550	16,110	3.05%
6205-Charitable Donations			0	100.00%			0	0.00%
Sub-Total	**2,018,346**	**2,690,751**	**672,406**		**2,272,590**	**2,690,751**	**418,161**	
Taxes Other Than Income Taxes								
6105-Property Taxes	0	0	0	0.00%	0	0	0	0.00%
Sub-Total	**0**	**0**	**0**		**0**	**0**	**0**	
Total Operating, Maintenance and Administration Expenses	**5,137,513**	**6,803,112**	**1,665,598**		**5,679,177**	**6,803,112**	**1,123,935**	
Amortization Expenses								
5705-Amortization Expense - Property, Plant, and Equipment	2,970,412	3,815,361	844,949	29.99%	3,595,770	3,815,361	219,591	5.76%
Sub-Total	**2,970,412**	**3,815,361**	**844,949**		**3,595,770**	**3,815,361**	**219,591**	
Total Distribution Expense Before Income Taxes	8,107,926	10,618,473	(615,536)	-7.06%	9,274,947	10,618,473	1,343,526	15.40%

2010 Test Year versus 2006 Actual Year:

5016 Distribution Station Equipment – Operation Labour

The cost has increased by $98,776 comparing 2006 Actual to 2010 Test Year, due to an additional supervisor in 2007, and another 2 additional employees that will be hired in 2010 which a portion of their salary will be allocated.

5065 Meter Expense

This expense has increased by $134,141 from 2006 Actual to the 2010 Test Year. Cost have increased in 2010 smart meter maintenance due to the switching of the meters for the General Service.

5105 Maintenance Supervision and Engineering

The cost between 2006 Actual and 2010 Test Year is an increase of $173,833. This is due to the additional supervisor and 2 engineering technicians that are included in the 2010 budget.

5305 Supervision – Billing and Collecting

The cost between 2006 Actual and 2010 Test Year is an increase of $81,257. In the 2010 budget there is an additional Supervisor Salary reclassified to Billing and Collection. In 2006 only a portion of the cost of one supervisor was allocated to Billing and Collecting. In 2010, there is a portion of 3 employee salaries allocated to this account.

5315 Customer Billing

The cost between 2006 Actual and 2010 Test year is an increase of $200,084. This is due to the additional personnel and the change from Bi-monthly billing to Monthly billing as stated in Appendix A.

5320 Collecting

The cost between 2006 Actual and 2010 Test Year is an increase of $122,686. This is due to the additional personnel for time of use billing and the change from Bi-monthly billing to monthly billing and the implementing DSC changes, as stated in Appendix A.

5335 Bad Debt Expense

The cost between 2006 Actual and 2010 Test Year is an increase of $95,989. This increase will result from the economic environment which will have an effect on the level of bad debt.

5610 Management Salaries and Expenses

The cost between 2006 Actual and 2010 Test Year is an increase of $444,785.   The increase in the expense is caused by the requirements of meeting the International Financial Reporting Standards ("IFRS") such that more staff time is required to meet the financial reporting requirements. This is offset by a decrease in outside services employed.

5630 Outside Services Employed

The cost between 2006 Actual and 2010 Test Year is a decreased of $70,678. In 2010 more work will be done in- house to meet IFRS requirements.

5655 Regulatory Expense

The cost between 2006 Actual and 2010 Test year is an increase of $191,914. The additional costs are related to this 2010 Cost of Service rate application, in 2010 an additional personnel hired that is shared with Middlesex Power Distribution Corporation in managing the regulatory changes for LEAP, smart meters and Time-of –use billing roll out and various activities that may arise.

5705 Amortization Expense

The cost between 2006 Actual and 2010 Test Year is an increase of $844,949. This is dealing with the additional capital expenditures to maintain a safe and reliable distribution system while meeting all regulatory guidelines.

2010 Test Year versus 2008 Actual Year:

5105 Maintenance Supervision and Engineering

The variance between 2008 Actual and 2010 Test Year is an increase of $107,953. This is due to additional supervisor and 2 engineering technicians above the employees in 2008.

5315 Customer Billing

The variance between 2008 Actual and 2010 Test Year is an increase of $165,092. As previously mentioned is the change from bi-monthly billing to monthly billing and related expenses that will cause the increase over our the current expenditures.

5320 Collecting

The variance between 2008 Actual and 2010 Test Year is an increase of $233,745. The increase is due to higher base debts along with some increases experienced in 5315 Customer Billing.

5610 Management Salaries and Expenses

The variance between 2008 Actual and 2010 Test Year is an increase of $429,162. The increase is due to the fact that meeting International Financial Reporting Standards ("IFRS") has required the allocation of additional staff time from management and Chief Financial Officer. This increase in costs is offset by a decrease in outside services employed.

5630 Outside Services Employed

The variance between 2008 Actual and 2010 Test Year is a decrease of $127,248. This is due to bringing more services in house as a requirement to meet IFRS.

5705 Amortization Expense

The cost between 2008 Actual and 2010 Test Year is an increase of $219,591. This reflects an increase in capital expenditures to provide a safe and reliable distribution system.

APPENDIX D

SUMMARY OF MONTHLY BILLING/COLLECTING

Monthly Billing and Collecting Analysis

Chatham-Kent Hydro is planning on moving to monthly billing in 2010. Currently Chatham-Kent Hydro is billing the Residential and Small General Service classes bi-monthly. The reason for the move to monthly billing is to assist the customers in managing their bills better and reduce the deposits that are required from customers.

While Chatham-Kent Hydro does have many payment options for customers such as pre-authorized payment and budget, there continues to be a challenge for a large number of customers in managing their bi-monthly bill.

Monthly billing is strongly supported by the community and in particular the social agencies that assist the low income energy users. Ontario Works and The Salvation Army have requested that Chatham-Kent Hydro move to monthly billing (Appendix E and F).

While assisting customers in budgeting their monthly payments another benefit is that deposits required from customers will be lower. The calculation to determine the deposit amount is based upon the total amount of the bill, and since bi-monthly bills are higher the deposit will therefore be higher. Another benefit to the change is that Chatham-Kent Hydro will be able to refund approximately $500,000 of deposits to its customers. At this time of economic challenges these funds would be put to good use in the hands of Chatham-Kent Hydro's customers.

Since the billing services are provided by Chatham-Kent Utility Services, which also provides billing services to the Chatham-Kent PUC, less than 50% of the additional costs will be recovered from the Chatham-Kent Hydro customers.

The costs to Chatham-Kent Hydro will be $142,381 per year for an impact of less than $0.38 per customer. Detailed calculations follow:

1

1. Postage and Supplies				
# of bi-monthly customers	30,877			
# of monthly billed	1,354			
# of total customers	32,231			
# of finals	30,562			
Postage Rate (incl hash mark discount)	0.55	2009 rate plus $.01		
Stationary cost per bill (envelope,paper,etc.)	0.050568	2008 cost factor increase to 2010 by 5%		
Bi-monthly	6			
Monthly	12			
Currently Bi-Monthly billing	Annual Cost	Monthly Billing	Annual Cost	
Hard Costs	2008		2010	
Postage	$ 167,293	Additional cost by bi-monhly x 6 x postage	$ 101,894	postage
Stationary, ie. Envelopes, paper, etc.	$ 25,433	Additional cost by bi-monhly x 6 x supplies	$ 9,368	supplies
		2008 cost with 5% Cost increase	$ 175,658	postage
		2008 cost with 5% Cost increase	$ 26,705	supplies
*** These numbers include costs that relate to water only.*		** for 2010 monthly billing to start May 1st.		
Third party bill printing service	$ 15,000	2008 cost with 5% increase	$ 19,728	
Sub-total	$ 207,726		$ 333,353	
		2010 increase vs 2008	$ 125,627	
2. Staffing				
Staff	Change to support Monthly Billing		Increase in Annual Cost	
Billing	Add 2 staff for billing		$ 86,604	
Customer Service Rep	Add 1 staff for customer service		$ 43,302	
Collections	Add 1 staff for collections		$ 43,302	
Cashier	Add 1 staff for cashier functions		$ 43,302	
Total labour costs			$ 216,510	
Efficicencies expected from CIS upgrade in 2009	Less 1 staff member		-$ 43,302	
Net labour costs			$ 173,208	
3. Gross Costs				
Total Increase in gross costs			$ 298,835	
4. Costs allocated to Chatham-Kent Hydro				
Function	%		$	
Supplies	50.0%		$ 62,813	
Billing	46.5%		$ 40,271	
Customer Service	45.5%		$ 19,702	
Collections	45.5%		$ 19,702	
Cashier	45.5%		$ 19,702	
Efficiencies	45.8%		-$ 19,811	
Increase in monthly billing costs			$ 142,381	

2

APPENDIX E
LETTER FROM SALVATION ARMY

The Salvation Army
Canada & Bermuda Territory
Ontario Great Lakes Division

Chatham-Kent Ministries

Chatham Community & Family Services
42 Harvey Street, P.O. Box 715
Chatham, ON N7M 5K8
Telephone: (519) 354-1430
Fax: (519) 354-1919

Giving Hope Today

RECEIVED
JUL 17 2019

Jim Hogan
Chatham Kent Utility Services
320 Queen St.
PO Box 70
Chatham, ON N7M 5K2

Dear Jim:

I am writing a letter to support your plan to start with monthly Hydro bills. Working everyday with low to non income single persons and families, I feel it would benefit them and make it easier for them to budget instead of receiving a bill every two months.

Here at the Salvation Army, we have a Trustee program that aids people with budgeting and paying their expenses. If clients are not on a budget we have with the help of your staff, figured out what a monthly budget amount would be and we are now sending an amount every month towards their account.

During the present economic times of this community the needs are rising. It is becoming very difficult finding housing that includes utilities. I know in the past if I assist with a bill I will also try and arrange a monthly payment schedule with your office so that we try to avoid problems in the future. I strongly encourage clients to put money on their utility bill every month. I don't have many repeats to the program.

I strongly feel that a monthly billing would benefit people to assist them paying their bill.

I personally would like to thank your staff, Lynda and Erin for all their help and assistance.

If you have any other questions or concerns please feel free to contact me.

Sincerely Yours,

Rhonda Dickson

Rhonda Dickson
Chatham Salvation Army
Housing Support Services
519-354-1430

APPENDIX F
LETTER FROM ONTARIO WORKS

MUNICIPALITY OF CHATHAM-KENT
435 GRAND AVE., WEST • P.O. BOX 1230 • CHATHAM, ONTARIO • N7M 5L8

July 16, 2009

RECEIVED
JUL 2 0 2019

Mr. Jim Hogan, Chief Financial Officer
Chatham-Kent Energy
PO Box 70
320 Queen Street
CHATHAM, ON N7M 5K2

Dear Mr. Hogan,

RE: Change to Monthly Billing

I am writing in support of Chatham-Kent Energy's intention to move from a bi-monthly to a monthly billing system, particularly as it relates to customers receiving social assistance through Ontario Works.

Ontario Works funding is very limited, and as such, recipients have not been able to keep up with the increasing costs associated with shelter. A monthly billing system will assist clients with their budgeting process. There are a number of benefits for Ontario Works recipients, including:

- ✓ Simplicity of the system
- ✓ Monthly billing is consistent with monthly OW cheque production
- ✓ Timeliness of payment for usage
- ✓ Anticipate fewer situations of arrears
- ✓ If client arrears occurs, the amounts owing will be more manageable

I believe a monthly billing system will also be helpful for low income customers as they juggle their monthly finances. Hopefully, we will see a reduction in the number of clients requiring help from Energy Bank funding, or at least a reduction in the amount they request.

We look forward to our continued partnership to support vulnerable residents in our community.

Yours truly,

Val Colasanti /jo

V. J. Colasanti, Director
Ontario Works
Health and Family Services
Municipality of Chatham-Kent

VJC:jo

CHARGES TO AFFILIATES FOR SERVICES PROVIDED:

Introduction:

A summary of charges to affiliates for services provided in 2006 Actual, 2007 Actual, and 2008 Actual together with the projections for the 2009 Bridge Year and 2010 Test Year, are shown in the following Tables 4-10 to 4-16.

Chatham-Kent Hydro currently performs streetlight maintenance for the Municipality of Chatham-Kent. In addition, Chatham-Kent Hydro is also involved in Sentinel Light rentals to third party customers. Chatham-Kent Hydro provides certain services to Municipality of Chatham-Kent in respect of these activities. Actual cost including labour, labour burden, stores material and burden, along with vehicle costs are charged to Chatham-Kent Hydro. In addition, billings to the Municipality of Chatham-Kent include a 10% profit mark up.

As a result of recent changes to the Affiliate Relationships Code, Chatham-Kent Hydro is reviewing its provision of services to Municipality of Chatham-Kent in respect of Street Light Maintenance and Sentinel Lights.

There are currently no shared services with the Corporation of the Municipality of Chatham-Kent. Revenue from the rental agreement is included Other Operating Revenue-Rent from Electric Property (4210) and detailed in Exhibit 3, Tab 3, Schedules 1 & 2.

Summary of Charges to Affiliates for Services Provided:

Table 4-10
Shared Services/Corporate Cost Allocation

Year 2006

Name of Company		Service Offered	Pricing Methodology	Price for the Service ($)	Cost for the Service ($)	Percentage Allocation
From	To					
CK Utility Service	CK Hydro	Customer Service	Hours/No of bills/related Costs		1,434,594	50.06%
CK Utility Service	CK Hydro	General Financial Service	Hours/No of bills/related Costs		1,322,305	75.89%
CK Utility Service	CK Hydro	IFRS	Hours/related cost		-	0.00%
CK Utility Service	CK Hydro	Regulatory Service	Based on hours		96,021	100.00%
CK Hydro	Municpality	Streetlight Maintenance	Actual Cost	181,619		100%
CK Hydro	Middlesex Power	Management Charges	Based on hours	35,656		100%
CK Hydro	Middlesex Power	Inventory Staff Charge Out	Based on hours	-		0%
CK Hydro	Middlesex Power	Engineering and Other Service	Actual hours/cost	9,839		100%
CK Hydro	CK Utility Service	Rent	Square Footage	140,484		100%
Ck Hydro	CK Energy	Rent	Square Footage	16,512		100%
CK Hydro	Municpality	Street Light Conversion	Actual Cost	30,953		100%
CK Utility Service	CK Hydro	Board of Directors Costs			9,661	100.00%

Table 4-11
Shared Services/Corporate Cost Allocation

Year 2007

Name of Company		Service	Pricing	Price for the	Cost for the	Percentage
From	To	Offered	Methodology	Service ($)	Service ($)	Allocation
CK Utility Service	CK Hydro	Customer Service	Hours/No of bills/related Costs		1,461,622	49.06%
CK Utility Service	CK Hydro	General Financial Service	Hours/No of bills/related Costs		1,390,109	79.68%
CK Utility Service	CK Hydro	IFRS	Hours/related cost		-	0.00%
CK Utility Service	CK Hydro	Regulatory Service	Based on hours		116,107	100.00%
CK Hydro	Municpality	Streetlight Maintenance	Actual Cost	121,725	-	100%
CK Hydro	Middlesex Power	Management Charges	Based on hours	36,432	-	100%
CK Hydro	Middlesex Power	Inventory Staff Charge Out	Based on hours	10,860	-	100%
CK Hydro	Middlesex Power	Engineering and Other Service	Actual hours/cost	14,318	-	100%
CK Hydro	CK Utility Service	Rent	Square Footage	140,484	-	100%
Ck Hydro	CK Energy	Rent	Square Footage	16,512	-	100%
CK Hydro	Municpality	Street Light Conversion	Actual Cost	-	-	0%
CK Utility Service	CK Hydro	Board of Directors Costs			9,758	100.00%

Table 4-12
Shared Services/Corporate Cost Allocation

Year 2008

Name of Company		Service	Pricing	Price for the	Cost for the	Percentage
From	To	Offered	Methodology	Service ($)	Service ($)	Allocation
CK Utility Service	CK Hydro	Customer Service	Hours/No of bills/related Costs		1,347,056	46.72%
CK Utility Service	CK Hydro	General Financial Service	Hours/No of bills/related Costs		1,563,287	80.66%
CK Utility Service	CK Hydro	IFRS	Hours/related cost		809	100.00%
CK Utility Service	CK Hydro	Regulatory Service	Based on hours		100,996	100.00%
CK Hydro	Municpality	Streetlight Maintenance	Actual Cost	198,791	-	100%
CK Hydro	Middlesex Power	Management Charges	Based on hours	64,211	-	100%
CK Hydro	Middlesex Power	Inventory Staff Charge Out	Based on hours	13,200	-	100%
CK Hydro	Middlesex Power	Engineering and Other Service	Actual hours/cost	62,845	-	100%
CK Hydro	CK Utility Service	Rent	Square Footage	140,484	-	100%
Ck Hydro	CK Energy	Rent	Square Footage	16,512	-	100%
CK Hydro	Municpality	Street Light Conversion	Actual Cost	-	-	0%
CK Utility Service	CK Hydro	Board of Directors Costs			9,099	100.00%

Table 4-13
Shared Services/Corporate Cost Allocation

Year 2009

Name of Company		Service	Pricing	Price for the	Cost for the	Percentage
From	To	Offered	Methodology	Service ($)	Service ($)	Allocation
CK Utility Service	CK Hydro	Customer Service	Hours/No of bills/related Costs		1,542,868	47.62%
CK Utility Service	CK Hydro	General Financial Service	Hours/No of bills/related Costs		1,675,658	69.70%
CK Utility Service	CK Hydro	IFRS	Hours/related cost		80,000	100.00%
CK Utility Service	CK Hydro	Regulatory Service	Based on hours		83,374	75.97%
CK Hydro	Municpality	Streetlight Maintenance	Actual Cost	187,893	-	100%
CK Hydro	Middlesex Power	Management Charges	Based on hours	64,824	-	100%
CK Hydro	Middlesex Power	Inventory Staff Charge Out	Based on hours	13,200	-	100%
CK Hydro	Middlesex Power	Engineering and Other Service	Actual hours/cost	66,655	-	100%
CK Hydro	CK Utility Service	Rent	Square Footage	140,484	-	100%
Ck Hydro	CK Energy	Rent	Square Footage	16,512	-	100%
CK Hydro	Municpality	Street Light Conversion	Actual Cost	-	-	0%
CK Utility Service	CK Hydro	Board of Directors Costs			9,250	100.00%

Table 4-14
Shared Services/Corporate Cost Allocation

Year 2010

Name of Company		Service	Pricing	Price for the	Cost for the	Percentage
From	To	Offered	Methodology	Service ($)	Service ($)	Allocation
CK Utility Service	CK Hydro	Customer Service	Hours/No of bills/related Costs		1,722,815	46.66%
CK Utility Service	CK Hydro	General Financial Service	Hours/No of bills/related Costs		1,820,181	72.99%
CK Utility Service	CK Hydro	IFRS	Hours/related cost		50,000	100.00%
CK Utility Service	CK Hydro	Regulatory Service	Based on hours		120,617	75.00%
CK Hydro	Municpality	Streetlight Maintenance	Actual Cost	172,507	-	100%
CK Hydro	Middlesex Power	Management Charges	Based on hours	66,120		100%
CK Hydro	Middlesex Power	Inventory Staff Charge Out	Based on hours	13,200		100%
CK Hydro	Middlesex Power	Engineering and Other Service	Actual hours/cost	67,589		100%
CK Hydro	CK Utility Service	Rent	Square Footage	140,484		100%
Ck Hydro	CK Energy	Rent	Square Footage	16,512		100%
CK Hydro	Municpality	Street Light Conversion	Actual Cost	-		0%
CK Utility Service	CK Hydro	Board of Directors Costs			9,250	100.00%

Table 4-15
Shared Services/Corporate cost Allocation

2006 Actual vs 2010 Test Year

Name of Company		Service	2006 Actual		2010 Test Year	
From	To	Offered	Price for the Service ($)	Cost for the Service ($)	Price for the Service ($)	Cost for the Service ($)
CK Utility Service	CK Hydro	Customer Service	-	1,434,594	-	1,722,815
				-	-	-
CK Utility Service	CK Hydro	General Financial Service	-	1,322,305	-	1,820,181
			-	-	-	-
CK Utility Service	CK Hydro	IFRS	-	-	-	50,000
			-	-	-	-
CK Utility Service	CK Hydro	Regulatory Service	-	96,021	-	120,617
			-	-	-	-
CK Hydro	Municpality	Streetlight Maintenance	181,619	-	172,507	-
			-	-	-	-
CK Hydro	Middlesex Power	Management Charges	35,656	-	66,120	-
			-	-	-	-
CK Hydro	Middlesex Power	Inventory Staff Charge Out	-	-	13,200	-
			-	-	-	-
CK Hydro	Middlesex Power	Engineering and Other Servi	9,839	-	67,589	-
			-	-	-	-
CK Hydro	CK Utility Service	Rent	140,484	-	140,484	-
			-	-	-	-
Ck Hydro	CK Energy	Rent	16,512	-	16,512	-
			-	-	-	-
CK Hydro	Municpality	Street Light Conversion	30,953	-	-	-
CK Utility Service	CK Hydro	Board of Directors Costs	-	9,661	-	9,250

The cost between 2006 Actual and 2010 Test for Customer Service is an increase of $288,221, which is due to the increase in the personnel and the change to monthly billing. The cost of Chatham-Kent Utility Service providing the meter reading service instead of outside service has increased the shared service cost. The actual meter reading cost will decrease through this arrangement oppose to a third party providing the service.

The cost between 2006 Actual and 2010 Test for General Financial Service is an increase of $497,465 is due to the increase in personnel and change in management salary allocation for 2010.

Table 4-16
Shared Service/Corporate Cost Allocation

2008 Actual vs 2010 Test Year

			2008 Actual		2010 Test Year	
Name of Company		Service	Price for the	Cost for the	Price for the	Cost for the
From	To	Offered	Service ($)	Service ($)	Service ($)	Service ($)
CK Utility Service	CK Hydro	Customer Service	-	1,347,056	-	1,722,815
			-	-	-	-
CK Utility Service	CK Hydro	General Financial Service	-	1,563,287	-	1,820,181
			-	-	-	-
CK Utility Service	CK Hydro	IFRS	-	809	-	50,000
			-	-	-	-
CK Utility Service	CK Hydro	Regulatory Service	-	100,996	-	120,617
			-	-	-	-
CK Hydro	Municpality	Streetlight Maintenance	198,791	-	172,507	-
			-	-	-	-
CK Hydro	Middlesex Power	Management Charges	64,211	-	66,120	-
			-	-	-	-
CK Hydro	Middlesex Power	Inventory Staff Charge Out	13,200	-	13,200	-
			-	-	-	-
CK Hydro	Middlesex Power	Engineering and Other Servi	62,845	-	67,589	-
			-	-	-	-
CK Hydro	CK Utility Service	Rent	140,484	-	140,484	-
			-	-	-	-
Ck Hydro	CK Energy	Rent	16,512	-	16,512	-
			-	-	-	-
CK Hydro	Municpality	Street Light Conversion	-	-	-	-
CK Utility Service	CK Hydro	Board of Directors Costs	-	9,099	-	9,250

The cost between 2006 Actual and 2010 Test for Customer Service increased by $375,759, is due to the increase in the personnel and the change to the monthly billing. The cost of Chatham-Kent Utility Service providing the meter reading service instead of outside service has increased the shared service cost. The actual meter reading cost will decrease through this arrangement oppose to a third party providing the service.

The cost between 2006 Actual and 2010 Test for General Financial Service is an increase of $257,045 due to the increase in personnel and change in management salary allocation for 2010.

Purchase of Services from Non-Affiliates:

Chatham-Kent Hydro obtains many services from third parties; the requirement was to provide an annual cost summary of any non- affiliate service cost that was above the materiality level of 79,127 (that is the 0.5% of revenue requirement). The amount recorded for 2006 to 2008 is based on the actual expenditures, as for 2009 and 2010 the amounts are based on the capital jobs budgeted and the additional consultation fees for this 2010 cost of service rate application. The table below sets out the services beyond the threshold amount.

Table 4-17
Summary of Purchases from third party over threshold

Name	Activity	Priced by	2006 Amount	2007 Amount	2008 Amount	2009 Amount	2010 Amount
Badger Daylighting	Digging Holes	Standard Rate pe hole	82,082		111,055	81,997	95,000
Westhoek	New Garage	Hours and Material	176,195				
Pachecos	Underground Work	Hours and Material		127,299			
Borden Ladner Gervais	Consultant	Hours and Material					160,000
		Total	258,277	127,299	111,055	81,997	255,000

EMPLOYEE COMPENSATION, INCENTIVE PLAN EXPENSES, PENSION EXPENSE AND POST RETIREMENT BENEFITS:

Overview:

Chatham-Kent Hydro is facing the same challenges as other LDCs throughout the electricity distribution sector. In the next five years, 14 employees or 38% of Chatham-Kent Hydro's employees will be eligible for retirement, and more will be eligible within 10 years. Chatham-Kent Hydro's total employee average age is in the late 40's, with a skilled trade average being the highest, consistent with the national electricity distribution sector at 43.0 years.

Succession Planning

Eligible Retirees between 2008-2013

Effective succession planning must also be implemented as the average age of Chatham-Kent Hydro's employees is 48 and many have OMERS early retirement options. This will require hiring apprentices prior to the mass retirement of the employees in the trades areas to manage the attrition of trades staff and to maintain the ability to provide service to Chatham-Kent Hydro's customers.

As indicated in Table 4-18 staff members have retired/resigned and have currently not been replaced while 3 others are currently eligible for retirement. Over the 5 years of the internal budget plan 8 more will become eligible resulting in the potential that 14 or 38% of the staff of Chatham-Kent Hydro will need to be replaced.

Table 4-18
Upcoming Retirements

Number	Position	Early Retirement Date	Status
Line Staff			
1	Line Subforemen	2006	Retired in 2008 – not replaced
1	Power Line Maintainer	2007	Currently employed
1	Power Line Maintainer	2008	Resigned – not replaced
1	Manager of Health Safety & Maintenance	2008	Retired – replaced internally
1	Power Line Maintainer	2009	
1	Power Line Maintainer	2011	
1	Manager of Construction Projects	2013	
1	Line Sub-foremen	2013	
Engineering/Metering			
1	Operations Assistant	2007	Currently employed
1	Engineering Technologist	2011	
1	Meter Technologist	2012	
1	Maintenance Technician	2012	
1	Engineering Technician	2013	
Stores			
1	Stockroom Technician	2006	Currently employed

The challenge Chatham-Kent Hydro faces is effectively bridging the gap in maintaining sufficient talent to meet the current needs of the utility while planning for the ‘new’ future. Table 4-19 below illustrates Chatham-Kent Hydro’s current employee demographics by employee type.

Table 4-19
Chatham-Kent Hydro Employee Demographics

Department	Employees	Avg Age	Avg years of Service
Management	7	43	14
Operations	15	47	18
Engineering	7	49	15
Metering	4	49	24
Stores	2	51	21

Effective workforce planning will be a significant initiative going forward. Chatham-Kent Hydro recognized the need to develop a strategy to replace linepersons as a result of two retirements in 2009 and an aging workforce. As a result of the required four year training program, these apprentice positions must be introduced on a timely basis. Chatham-Kent Hydro hired two apprentice linepersons in early 2009.

Change In Workforce Year Over Year:

Table 4-19, provided later in this schedule shows Chatham-Kent Hydro's FTE headcount for 2006 Actual (39), 2007 Actual (38), 2008 Actual (38), 2009 Bridge Year (38), and 2010 Test Year (44).

2007 Actual versus 2006 Actual

The FTE employees decreased from 38 to 37 in 2007. One lineperson retired in 2007 and was not replaced.

2010 Test Year versus 2009 Bridge Year

The FTE employees will increase from 39 to 44 in 2010. Four of the six additions are related to linepersons as follows:

FTE 2009 Actual/Board Approved	39
2010 Apprentices	2
Meter Technicians	1
Engineering/Operations Technician	1
Operations Supervisor	1
FTE 2010 Test Year	44

As indicated previously, Chatham-Kent Hydro must continue to move forward with the training of new linemen in order to have a skilled workforce in place prior to retirement of certified linemen in the next five years. The third addition to headcount in 2010 is the addition of a Meter Technician/Inspector in the Engineering Department and additional Operations Supervisor.

Chatham-Kent Hydro's Compensation/Performance System

Union

Chatham-Kent Hydro's unionized staff are represented by the IBEW Local 636. Formal contract negotiations occurred between November 2008 and June 2009 which resulted in a new three year collective agreement effective January 31, 2008. The settlement included annual wage increases of less than 3% per year beginning in 2009 and included minimal changes to the benefits provided. Chatham-Kent Hydro's pay rates are competitive with other LDCs in the Southwest Ontario Region.

Executive

The Executive staff member is entitled to an incentive program, which is the same program that was detailed in EB-2005-0350, as follows:

> "The executive would receive a % of the base salary while the management staff would get a fixed dollar amount.
>
> 1. Performance Measures
>
> In order to receive an incentive there are a number of measures that must be met. The measures are the following;
>
> - Meet the regulated return on equity.
> - Not exceed operation and maintenance expenses.
> - Not exceed capital budgets.
> - Meet service quality targets.
> - Strong health and safety record.
> - There are also some individual targets.

All targets are considered to be for the benefit of the rate payers. Meeting the targets of net income operation, maintenance expense and capital expenditures will ensure that Chatham-Kent Hydro is providing a safe and reliable distribution system. By having a reasonable net income this will ensure that money can be reinvested into the system while ensuring borrowing costs will be lower.

The service quality targets are to ensure that customers receive service that is at or exceeds the OEB standards.

Health and safety is very important to customers as well. Included in health and safety are environmental targets. By providing the services with safe standards is of value to the customers.

The personal targets will ensure that the employees will be current in their education and training. Better qualified staff will be able to provide better service to the customers.

The Board of Directors has developed the incentive pay program by using a consultant to provide guidance in designing the program as well as to provide comparatives to other companies inside and outside the electricity sector. All payments are reviewed and approved by the Board of Directors' compensation committee.

Management

The management staff are also eligible for some incentive pay and their targets are set to ensure that meet personal and corporate goals. Some of the main targets relate to health and safety, service quality and meeting regulatory changes. The incentive pay is a fixed dollar amount and not a percentage of salary.

Benefits

A comprehensive and competitive benefits package exists which includes medical insurance, life insurance, vacation and a company-sponsored retirement plan. The plans are designed to address the health and welfare needs of the employee population with similar plans for both union and management employees.

Retiree benefits are in two categories, retirees who retired prior to 1999 and those who retired after 1999. The retirees that left prior to 1999 have life time benefits as that was the benefit plan in place at that time. Chatham-Kent Hydro amalgamated 11 electric utilities in 1999 and in the first contract negotiations were able to agree with IBEW Local 636 to change the retirees benefits from life time to age 65 for all future retirees. This was a significant cost reduction for Chatham-Kent Hydro.

Employee Compensation and Benefits:

Chatham-Kent Hydro's employee complement, compensation and benefits are set out in Table 4-20, below.

Table 4-20
Chatham-Kent Hydro – Employee Complement and Compensation

Number of Employees (FTEs including Part-Time)	**2006**	**2007**	**2008**	**2009**	**2010**
Executive					
Management	6.5	6	7	7	9
Non-Union	1	1	1	1	1
Union	31	31	30	30	34
Total	39	38	38	38	44

Number of Part Time Employees	**2006**	**2007**	**2008**	**2009**	**2010**
Executive					
Management					
Non-Union	1	1	1	1	1
Union					
Total	1	1	1	1	1

Total Salary and Wages	**2006**	**2007**	**2008**	**2009**	**2010**
Executive					
Management	588,995	530,191	676,696	667,905	881,164
Non-Union	21,270	31,231	21,100	23,800	23,800
Union	2,069,559	2,094,449	2,223,585	2,114,457	2,339,642
Total	2,679,824	2,655,871	2,921,381	2,806,162	3,244,606

Total Benefits	**2006**	**2007**	**2008**	**2009**	**2010**
Executive					
Management	128,864	123,849	149,113	152,164	200,749
Non-Union	4,653	7,295	4,805	4,046	4,046
Union	452,791	489,252	511,408	481,721	533,023
Total	586,308	620,396	665,326	637,931	737,818

Total Compensation (Salary,Wages & Benefits)	**2006**	**2007**	**2008**	**2009**	**2010**
Executive					
Management	717,859	654,040	825,809	820,069	1,081,913
Non-Union	25,923	38,526	25,905	27,846	27,846
Union	2,522,350	2,583,701	2,734,993	2,596,178	2,872,665
Total	3,266,132	3,276,267	3,586,707	3,444,093	3,982,424

Compensation - Average Yearly Base Wages	**2006**	**2007**	**2008**	**2009**	**2010**
Executive					
Management	587,262	530,191	663,126	667,905	881,164
Non-Union	21,255	30,246	21,092	23,800	23,800
Union	1,907,909	1,948,211	1,995,498	1,935,799	2,160,984

Compensation - Average Yearly Overtime	**2006**	**2007**	**2008**	**2009**	**2010**
Executive					
Management	1,733		13,570	0	0
Non-Union	15	985	8		
Union	161,650	146,238	228,087	178,658	178,658

Compensation - Average Yearly Incentive	**2006**	**2007**	**2008**	**2009**	**2010**
Executive					
Management					
Non-Union					
Union					

Compensation - Average Yearly Benefits	**2006**	**2007**	**2008**	**2009**	**2010**
Executive					
Management	128,864	123,849	149,113	152,164	200,749
Non-Union	4,653	7,295	4,805	4,046	4,046
Union	452,791	489,252	511,408	481,721	533,023

	2006	**2007**	**2008**	**2009**	**2010**
Total Compensation	3,266,132	3,276,267	3,586,707	3,444,093	3,982,424
Total Compensation Charged to OM&A	1,331,679	1,252,596	1,361,213	1,308,755	1,513,321
Total Compensation Capitalized	1,711,454	1,855,949	1,729,456	1,790,928	2,070,860
Total Compensation Charged to Recoverable jobs	222,999	167,722	496,038	344,410	398,243

OMERS Pension Expense and Post Retiree Benefits

OMERS Pension Expense

Chatham-Kent Hydro's employees are members of the Ontario Municipal Employees Retirement System ("OMERS"). Accordingly, Chatham-Kent Hydro has provided the OMERS pension premium information for 2006 Actual, 2007 Actual, 2008 Actual, 2009 Bridge Year, and the 2010 Test Year in Table 4-21 below.

Table 4-21
Pension Premium Information

Pension	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test
Premiums Paid	187,390	184,132	191,617	191,617	191,617
Adjustments					
Pension Expense	187,390	184,132	191,617	191,617	191,617

Post-Retirement Benefits - Liability:

Chatham-Kent Hydro has provided post-retirement benefits accounting information as required and has included the change in Post-Retirement expense for 2006 Actual, 2007 Actual, 2008 Actual, 2009 Bridge Year, and 2010 Test Year, in Table 4-22 below.

Post-Retirement Benefits - Premiums:

Chatham-Kent Hydro pays certain health, dental, and life insurance benefits on behalf of its retired employees. Actual premiums paid for 2006 Actual, 2007 Actual, 2008 Actual, 2009 Bridge Year, and 2010 Test Year, are shown in Table 4-22 below.

Table 4-22
Post-Retirement Benefit Information

Pension	2006 Actual	2007 Actual	2008 Actual	2009 Bridge
Premiums Paid	195,000	219,000	219,000	231,180
Change in Account	31,148	49,200	57,656	59,385
Post-Retirement Benefit Expense	226,148	268,200	276,656	290,565

DEPRECIATION, AMORTIZATION AND DEPLETION:

Amortization on capital assets is calculated as follows:

- Chatham-Kent Hydro uses the pooling of assets for all fixed assets with the exception of Computer Equipment/Software, Automotive Equipment, Furniture & Equipment, Communication Equipment, and Capital Tools. Amortization is calculated on a straight line basis over the estimated remaining useful life of the assets at the end of the previous year; plus:

- Normally a full year's amortization is taken on capital additions during the current year. For this rate application Chatham-Kent Hydro used the half year rule for calculating depreciation expense for the 2010 Test Year.

Depreciation Schedules for 2006 to 2010 are provided in Tables 4-23 to 4-27.

Table 4-23
Depreciation Expense

Year 2006

OEB	Description	2006 Opening Balance (A)	LESS Fully Depreciated (B)	Net For Deprecatian (C) = (A)-(B)	2006 Additions (D)	Total For Deprecation (E) = (C) + 0.5 X (D) OR (E) = (C) + (D)	Years (F)	2006 Depreciation Expense (G) = (E)/(F)
1805	Land	181,059.04		-	-	-		
1806	Land Rights	-		-		-		
1808	Buildings and Fixtures	486,580		486,580		486,580	26	18,678
1810	Leasehold Improvements	-		-		-		
1815	Transformer Station Equipment - Primary > 50 kV	-		-		-		
1820	Distribution Station Equipment - Primary <50 kV	748,900		748,900		748,900	23	32,531
1825	Storage Battery Equipment	-		-		-		
1830	Poles, Towers and Fixtures	2,466,857		2,466,857	788,893	3,255,749	25	130,230
1835	Overhead Conductors and Devices	16,261,198		16,261,198	876,812	17,138,011	20	863,130
1840	Underground Conduit	967,848		967,848	62,455	1,030,303	25	41,212
1845	Underground Conductors and Devices	12,843,559		12,843,559	731,457	13,575,016	18	754,434
1850	Line Transformers	11,858,568		11,858,568	717,354	12,575,923	20	620,768
1855	Services	2,273,554		2,273,554	417,753	2,691,307	25	107,652
1860	Meters	2,460,276		2,460,276	496,620	2,956,897	20	147,298
1861	Smart Meters	-		-		-		
1865	Other Installations on Customer's Premises	-		-				
1905	Land	205,766		-	358,875	-		
1906	Land Rights	-		-				
1908	Buildings and Fixtures	2,967,829		2,967,829	240,303	3,208,132	35	90,764
1910	Leasehold Improvements	-		-		-		
1915	Office Furniture and Equipment	91,964		91,964	14,638	99,282	12	8,573
1920	Computer Equipment - Hardware	306,236		306,236		306,236	19	16,435
1920	Computer - Hardware post Mar 22/04	27,331		27,331	28,000	41,331	5	8,266
1920	Computer - Hardware post Mar19/07	-		-		-		
1925	Computer Software	5,995		5,995	6,739	-		
1930	Transportation Equipment **	1,754,146	1,754,146	-	312,975	-		
1935	Stores Equipment	-		-		-		
1940	Tools, Shop and Garage Equipment	526,281		526,281	16,861	534,711	11	50,323
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	653,619		653,619	88,832	742,450	9	79,562
1985	Sentinel Lighting Rentals	-		-		-		
1990	Other Tangible Property	1,440,321		1,440,321	174,338	1,614,659	12	134,771
1995	Contributions and Grants	- 2,885,841		- 2,885,841	- 452,865	- 3,338,707	25	- 134,216
	Total	55,642,045	1,754,146	53,501,074	4,880,041	57,666,781		2,970,412

Table 4-24
Depreciation Expense

Year 2007

OEB	Description	2007 Opening Balance (A)	LESS Fully Depreciated (B)	Net For Deprecatian (C) = (A)-(B)	2007 Additions (D)	Total For Deprecation (E) = (C) + 0.5 X (D) OR (E) = (C) + (D)	Years (F)	2007 Depreciation Expense (G) = (E)/(F)
1805	Land	169,868		-		-		
1806	Land Rights	-		-		-		
1808	Buildings and Fixtures	471,972		471,972		471,972	31	15,172
1810	Leasehold Improvements	-		-		-		
1815	Transformer Station Equipment - Primary > 50 kV	-		-		-		
1820	Distribution Station Equipment - Primary <50 kV	748,900		748,900	18,973	767,873	23	33,511
1825	Storage Battery Equipment	-		-		-		
1830	Poles, Towers and Fixtures	3,255,749		3,255,749	456,056	3,711,805	25	148,472
1835	Overhead Conductors and Devices	17,138,011		17,138,011	769,779	17,907,789	20	876,315
1840	Underground Conduit	1,030,303		1,030,303	80,208	1,110,511	25	44,420
1845	Underground Conductors and Devices	13,575,016		13,575,016	362,694	13,937,710	18	768,942
1850	Line Transformers	12,575,923		12,575,923	1,042,557	13,618,480	21	662,319
1855	Services	2,691,307		2,691,307	315,104	3,006,411	25	120,256
1860	Meters	2,956,897		2,956,897	62,833	3,019,729	21	140,764
1861	Smart Meters	-		-	2,577,598	1,288,799	6	204,551
1865	Other Installations on Customer's Premises	-		-				
1905	Land	564,641		-	3,870	-		
1906	Land Rights	-		-				
1908	Buildings and Fixtures	3,208,132		3,208,132	48,365	3,256,497	35	91,995
1910	Leasehold Improvements	-		-		-		
1915	Office Furniture and Equipment	106,601		106,601		106,601	12	9,059
1920	Computer Equipment - Hardware	298,310		298,310		298,310	26	11,666
1920	Computer - Hardware post Mar 22/04	55,331		55,331		55,331	5	11,066
1920	Computer - Hardware post Mar19/07	-		-	123,954	61,977	3	19,379
1925	Computer Software	12,734		12,734	256,644	141,057	2	71,318
1930	Transportation Equipment **	2,056,130	2,056,130	-	333,864	-		
1935	Stores Equipment	-		-		-		
1940	Tools, Shop and Garage Equipment	543,142		543,142	43,140	564,712	16	34,725
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	742,450		742,450	25,060	767,510	14	54,124
1985	Sentinel Lighting Rentals	-		-		-		
1990	Other Tangible Property	1,614,659		1,614,659	61,705	1,676,364	12	140,325
1995	Contributions and Grants	- 3,338,707		- 3,338,707	- 213,142	- 3,551,848	25	- 142,742
	Total	60,477,369	2,056,130	57,686,730	6,369,261	62,217,589		3,315,639

Table 4-25
Depreciation Expense
Year 2008

OEB	Description	2,008.00 Opening Balance (A)	LESS Fully Depreciated (B)	Net For Deprecatian (C) = (A)-(B)	2,008.00 Additions (D)	Total For Deprecation (E) = (C) + 0.5 X (D) OR (E) = (C) + (D)	Years (F)	2,008.00 Depreciation Expense (G) = (E)/(F)
1,805.00	Land	119,868		-		-		
1,806.00	Land Rights	-		-		-		
1,808.00	Buildings and Fixtures	339,972		339,972		339,972	23	14,813
1,810.00	Leasehold Improvements	-		-		-		
1,815.00	Transformer Station Equipment - Primary > 50 kV	-		-		-		
1,820.00	Distribution Station Equipment - Primary <50 kV	753,463		753,463	83,230	836,693	24	35,535
1,825.00	Storage Battery Equipment	-		-		-		
1,830.00	Poles, Towers and Fixtures	3,711,805		3,711,805	515,834	4,227,639	25	169,106
1,835.00	Overhead Conductors and Devices	17,907,789		17,907,789	865,152	18,772,941	21	900,706
1,840.00	Underground Conduit	1,110,511		1,110,511	93,729	1,204,240	25	48,170
1,845.00	Underground Conductors and Devices	13,937,710		13,937,710	678,494	14,616,203	18	796,081
1,850.00	Line Transformers	13,618,480		13,618,480	741,454	14,359,934	21	691,787
1,855.00	Services	3,006,411		3,006,411	348,135	3,354,546	25	134,182
1,860.00	Meters	2,816,325		2,816,325	- 28,993	2,787,332	20	139,606
1,861.00	Smart Meters	2,577,598		2,577,598	1,633,216	3,394,206	10	335,161
1,865.00	Other Installations on Customer's Premises	-		-				
1,905.00	Land	568,511		-		-		
1,906.00	Land Rights	-		-				
1,908.00	Buildings and Fixtures	3,256,497		3,256,497	78,084	3,334,581	33	99,613
1,910.00	Leasehold Improvements	-		-		-		
1,915.00	Office Furniture and Equipment	105,183		105,183	19,243	114,805	11	10,063
1,920.00	Computer Equipment - Hardware	298,067		298,067		298,067	52	5,685
1,920.00	Computer - Hardware post Mar 22/04	55,331		55,331		55,331	5	11,066
1,920.00	Computer - Hardware post Mar19/07	123,954		123,954	45,865	146,886	4	34,054
1,925.00	Computer Software	269,379		269,379	210,284	374,521	4	102,812
1,930.00	Transportation Equipment **	2,341,913	2,341,913	-	213,221	-		
1,935.00	Stores Equipment	-		-		-		
1,940.00	Tools, Shop and Garage Equipment	586,282		586,282	52,331	612,447	24	25,645
1,945.00	Measurement and Testing Equipment	-		-		-		
1,950.00	Power Operated Equipment	-		-		-		
1,955.00	Communication Equipment	-		-		-		
1,960.00	Miscellaneous Equipment	-		-		-		
1,970.00	Load Management Controls - Customer Premises	-		-		-		
1,975.00	Load Management Controls - Utility Premises	-		-		-		
1,980.00	System Supervisory Equipment	767,510		767,510	20,218	787,728	15	52,562
1,985.00	Sentinel Lighting Rentals	-		-		-		
1,990.00	Other Tangible Property	1,676,364		1,676,364	74,063	1,750,427	12	145,262
1,995.00	Contributions and Grants	- 3,551,848		- 3,551,848	- 334,905	- 3,886,753	25	- 156,138
	Total	66,397,074	2,341,913	63,366,782	5,308,654	67,481,745		3,595,770

Table 4-26
Depreciation Expense

Year 2009

OEB	Description	2,009.00 Opening Balance (A)	LESS Fully Depreciated (B)	Net For Deprecatian (C) = (A)-(B)	2,009.00 Additions (D)	Total For Deprecation (E) = (C) + 0.5 X (D) OR (E) = (C) + (D)	Years (F)	2,009.00 Depreciation Expense (G) = (E)/(F)
1,805.00	Land	117,846		-		-		
1,806.00	Land Rights	-		-		-		
1,808.00	Buildings and Fixtures	339,972		339,972		339,972	25	13,591
1,810.00	Leasehold Improvements	-		-		-		
1,815.00	Transformer Station Equipment - Primary > 50 kV	-		-		-		
1,820.00	Distribution Station Equipment - Primary <50 kV	836,693		836,693		836,693	24	35,536
1,825.00	Storage Battery Equipment	-		-		-		
1,830.00	Poles, Towers and Fixtures	4,227,639		4,227,639	519,294	4,746,932	25	189,877
1,835.00	Overhead Conductors and Devices	18,772,941		18,772,941	855,653	19,628,594	21	915,617
1,840.00	Underground Conduit	1,204,240		1,204,240	74,215	1,278,455	25	51,139
1,845.00	Underground Conductors and Devices	14,616,203		14,616,203	565,628	15,181,831	19	818,708
1,850.00	Line Transformers	14,359,934		14,359,934	987,823	15,347,757	21	732,602
1,855.00	Services	3,354,546		3,354,546	400,929	3,755,475	25	150,219
1,860.00	Meters	2,787,332		2,787,332	29,278	2,816,610	20	140,776
1,861.00	Smart Meters	4,210,814		4,210,814		4,210,814	11	375,787
1,865.00	Other Installations on Customer's Premises	-		-				
1,905.00	Land	568,511		-	200,000	-		
1,906.00	Land Rights	-		-				
1,908.00	Buildings and Fixtures	3,334,581		3,334,581	138,500	3,473,081	31	110,929
1,910.00	Leasehold Improvements	-		-		-		
1,915.00	Office Furniture and Equipment	124,426		124,426	7,500	128,176	11	11,499
1,920.00	Computer Equipment - Hardware	298,067		298,067		298,067	376	794
1,920.00	Computer - Hardware post Mar 22/04	55,331		55,331		55,331	6	9,854
1,920.00	Computer - Hardware post Mar19/07	169,819		169,819	63,000	201,319	17	11,651
1,925.00	Computer Software	479,663		479,663	130,000	544,663	8	66,787
1,930.00	Transportation Equipment **	2,519,106	2,519,106	-	362,000			
1,935.00	Stores Equipment	-		-		-		
1,940.00	Tools, Shop and Garage Equipment	638,613		638,613	47,000	662,113	23	28,190
1,945.00	Measurement and Testing Equipment	-		-		-		
1,950.00	Power Operated Equipment	-		-		-		
1,955.00	Communication Equipment	-		-		-		
1,960.00	Miscellaneous Equipment	-		-		-		
1,970.00	Load Management Controls - Customer Premises	-		-		-		
1,975.00	Load Management Controls - Utility Premises	-		-		-		
1,980.00	System Supervisory Equipment	787,728		787,728	40,000	827,728	15	55,023
1,985.00	Sentinel Lighting Rentals	-		-		-		
1,990.00	Other Tangible Property	1,750,427		1,750,427	76,572	1,826,998	12	150,325
1,995.00	Contributions and Grants	- 3,886,753		- 3,886,753	- 275,000	- 4,161,753	25	- 167,138
	Total	71,667,677	2,519,106	68,462,214	4,222,390	71,998,854		3,701,765

Table 4-27
Depreciation Expense
Year 2010

OEB	Description	2010 Opening Balance (A)	LESS Fully Depreciated (B)	Net For Deprecatian (C) = (A)-(B)	2010 Additions (D)	Total For Deprecation (E) = (C) + 0.5 X (D) OR (E) = (C) + (D)	Years (F)	2010 Depreciation Expense (G) = (E)/(F)
1805	Land	117,846		-		-		
1806	Land Rights	-		-		-		
1808	Buildings and Fixtures	339,972		339,972	65,000	404,972	25	16,191
1810	Leasehold Improvements	-		-		-		
1815	Transformer Station Equipment - Primary > 50 kV	-		-		-		
1820	Distribution Station Equipment - Primary <50 kV	836,693		836,693	100,000	936,693	24	38,555
1825	Storage Battery Equipment	-		-		-		
1830	Poles, Towers and Fixtures	4,746,932		4,746,932	584,444	5,331,377	25	213,255
1835	Overhead Conductors and Devices	19,628,594		19,628,594	678,418	20,307,012	22	927,277
1840	Underground Conduit	1,278,455		1,278,455	241,438	1,519,893	25	60,796
1845	Underground Conductors and Devices	15,181,831		15,181,831	838,840	16,020,671	19	852,282
1850	Line Transformers	15,347,757		15,347,757	1,059,560	16,407,317	21	768,983
1855	Services	3,755,475		3,755,475	423,737	4,179,211	25	167,168
1860	Meters	2,816,610		2,816,610	29,499	2,846,109	20	141,970
1861	Smart Meters	4,210,814		4,210,814		4,210,814	13	331,925
1865	Other Installations on Customer's Premises	-		-				
1905	Land	768,511		-	25,000	-		
1906	Land Rights	-		-				
1908	Buildings and Fixtures	3,473,081		3,473,081	478,000	3,951,081	33	121,529
1910	Leasehold Improvements	-		-		-		
1915	Office Furniture and Equipment	131,926		131,926	12,000	137,926	15	9,472
1920	Computer Equipment - Hardware	298,067	298,067	-		-		
1920	Computer - Hardware post Mar 22/04	55,331		55,331		55,331	8	7,122
1920	Computer - Hardware post Mar19/07	232,819		232,819	56,000	260,819	11	23,551
1925	Computer Software	609,663		609,663		609,663	8	79,287
1930	Transportation Equipment **	2,881,106	2,881,106	-	780,000			
1935	Stores Equipment	-		-		-		
1940	Tools, Shop and Garage Equipment	685,613		685,613	299,000	835,113	20	41,085
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	827,728		827,728	40,000	867,728	18	47,330
1985	Sentinel Lighting Rentals	-		-		-		
1990	Other Tangible Property	1,826,998		1,826,998	81,595	1,908,593	13	145,722
1995	Contributions and Grants	- 4,161,753		- 4,161,753	- 275,000	- 4,436,753	25	- 178,138
	Total	75,890,067	3,179,172	71,824,538	5,517,531	76,353,569		3,815,361

TAX CALCULATIONS:

Chatham-Kent Hydro's detailed tax calculations using the most recent tax rates are provided in the following Table 4-28.

Table 4-28
Tax Calculations

						Wires Only
Regulatory Taxable Income						$ 2,129,780
Ontario Income Taxes						
Income tax payable	**Ontario income tax**	13.00%	B	$ 276,871	C = A * B	
Small business credit	Ontario Small Business Threshold	$ 500,000	D			
	Rate reduction	-8.50%	E	-$ 42,500	F = D * E	
Surtax		$ 1,000,000	G = A - D			
	Ontario surtax claw-back	4.25%	H	$ 42,500	I = G * H	
Ontario Income tax						$ 276,871
Combined Tax Rate and PILs	Effective Ontario Tax Rate			13.00%	K = J / A	
	Federal tax rate			18.00%	L	
	Combined tax rate					31.00%
Total Income Taxes						**$ 660,232**
Investment Tax Credits						
Miscellaneous Tax Credits						
Total Tax Credits						$ -
Corporate PILs/Income Tax Provision for Test Year						**$ 660,232**
Corporate PILs/Income Tax Provision Gross Up				69.00%	S = 1 - M	**$ 296,626**
Income Tax (grossed-up)						**$ 956,858**
Ontario Capital Tax (not grossed-up)						**$ 30,805**
Tax Provision for Test Year Rate Recovery						**$ 987,663**

CAPITAL COST ALLOWANCE (CCA):

Chatham-Kent Hydro is providing Capital Cost Allowance continuity schedules for the 2009 Bridge Year (Table 4-29) and the 2010 Test Year (Table 4-30) as follows:

Table 4-29
2009 Bridge Year Capital Cost Allowance

Class	Class Description	UCC Test Year Opening Balance	Additions	Disposals	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Test Year CCA	UCC End of Bridge Year
1	Distribution System - post 1987	$ 37,632,279	$ -	$ -	$ 37,632,279	$ -	$ 37,632,279	4%	$ 1,505,291	$ 36,126,988
2	Distribution System - pre 1988	$ -	$ -	$ -	$ -	$ -	$ -	6%	$ -	$ -
8	General Office/Stores Equip	$ 635,340	$ 170,000	$ -	$ 805,340	$ 85,000	$ 720,340	20%	$ 144,068	$ 661,272
10	Computer Hardware/ Vehicles	$ 779,843	$ 362,000	$ -	$ 1,141,843	$ 181,000	$ 960,843	30%	$ 288,253	$ 853,590
10.1	Certain Automobiles	$ -	$ -	$ -	$ -	$ -	$ -	30%	$ -	$ -
12	Computer Software	$ 124,375	$ 130,000	$ -	$ 254,375	$ 65,000	$ 189,375	100%	$ 189,375	$ 65,000
13 1	Lease # 1	$ -	$ -	$ -	$ -	$ -	$ -	5	$ -	$ -
13 2	Lease #2	$ -	$ -	$ -	$ -	$ -	$ -	4	$ -	$ -
13 3	Lease # 3	$ -	$ -	$ -	$ -	$ -	$ -	3	$ -	$ -
13 4	Lease # 4	$ -	$ -	$ -	$ -	$ -	$ -	4	$ -	$ -
14	Franchise	$ -	$ -	$ -	$ -	$ -	$ -	7	$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	$ 235,037	$ -	$ -	$ 235,037	$ -	$ 235,037	8%	$ 18,803	$ 216,234
43.1	Certain Energy-Efficient Electrical Generating Equipment	$ -	$ -	$ -	$ -	$ -	$ -	30%	$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04	$ 50,983	$ -	$ -	$ 50,983	$ -	$ 50,983	45%	$ 22,942	$ 28,041
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ 164,488	$ -	$ -	$ 164,488	$ -	$ 164,488	30%	$ 49,346	$ 115,142
47	Distribution System - post February 2005	$ 14,998,239	$ 3,234,390	$ -	$ 18,232,629	$ 1,617,195	$ 16,615,434	8%	$ 1,329,235	$ 16,903,394
50	Data Network Infrastructure Equipment - post Mar 2007	$ 39,695	$ 63,000	$ -	$ 102,695	$ 31,500	$ 71,195	55%	$ 39,157	$ 63,538
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
	TOTAL	**$ 54,660,279**	**$ 3,959,390**	**$ -**	**$ 58,619,669**	**$ 1,979,695**	**$ 56,639,974**		**$ 3,586,471**	**$ 55,033,198**

Table 4-30
2010 Test Year Capital Cost Allowance

Class	Class Description	UCC Test Year Opening Balance	Additions	Disposals	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Test Year CCA	UCC End of Test Year
1	Distribution System - post 1987	$ 36,126,988	$ -	$ -	$ 36,126,988	$ -	$ 36,126,988	4%	$ 1,445,080	$ 34,681,908
2	Distribution System - pre 1988	$ -	$ -	$ -	$ -	$ -	$ -	6%	$ -	$ -
8	General Office/Stores Equip	$ 661,272	$ 1,079,000	$ -	$ 1,740,272	$ 539,500	$ 1,200,772	20%	$ 240,154	$ 1,500,118
10	Computer Hardware/ Vehicles	$ 853,590	$ 478,000	$ -	$ 1,331,590	$ 239,000	$ 1,092,590	30%	$ 327,777	$ 1,003,813
10.1	Certain Automobiles	$ -	$ -	$ -	$ -	$ -	$ -	30%	$ -	$ -
12	Computer Software	$ 65,000	$ -	$ -	$ 65,000	$ -	$ 65,000	100%	$ 65,000	$ -
13 1	Lease # 1	$ -	$ -	$ -	$ -	$ -	$ -	0	$ -	$ -
13 2	Lease #2	$ -	$ -	$ -	$ -	$ -	$ -	0	$ -	$ -
13 3	Lease # 3	$ -	$ -	$ -	$ -	$ -	$ -	0	$ -	$ -
13 4	Lease # 4	$ -	$ -	$ -	$ -	$ -	$ -	0	$ -	$ -
14	Franchise	$ -	$ -	$ -	$ -	$ -	$ -	0	$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	$ 216,234	$ -	$ -	$ 216,234	$ -	$ 216,234	8%	$ 17,299	$ 198,935
43.1	Certain Energy-Efficient Electrical Generating Equipment	$ -	$ -	$ -	$ -	$ -	$ -	30%	$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04	$ 28,041	$ -	$ -	$ 28,041	$ -	$ 28,041	45%	$ 12,618	$ 15,422
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ 115,142	$ -	$ -	$ 115,142	$ -	$ 115,142	30%	$ 34,542	$ 80,599
47	Distribution System - post February 2005	$ 16,903,394	$ 3,802,531	$ -	$ 20,705,925	$ 1,901,266	$ 18,804,660	8%	$ 1,504,373	$ 19,201,552
50	Data Network Infrastructure Equipment - post Mar 2007	$ 63,538	$ 56,000	$ -	$ 119,538	$ 28,000	$ 91,538	55%	$ 50,346	$ 69,192
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
	TOTAL	$ 55,033,198	$ 5,415,531	$ -	$ 60,448,729	$ 2,707,766	$ 57,740,964		$ 3,697,189	$ 56,751,540

APPENDIX G

2008 FEDERAL AND ONTARIO TAX RETURN

Canada Revenue Agency | Agence du revenu du Canada

BUSINESS CONSENT FORM

Complete 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. **Send this completed form to your tax centre**. You can also give or cancel consent by providing the requested information online through My Business Account at **www.cra.gc.ca/mybusinessaccount**.

Note: Read all instructions on the last page before completing this form.

Part 1 – Business Information – Complete this part to identify your business (all fields have to be completed)

Business Name: CHATHAM-KENT HYDRO INC.

Business Number: 894290014 Telephone Number: (519) 352-6300

Part 2 – Authorize a representative

If you are giving consent for an individual, enter that person's full name or if you are giving consent to a firm, enter the name of the firm and the BN. If you want us to deal with a specific individual in that firm, enter **both** the individual's name and the name of the firm. If you do not identify an individual of the firm then you are giving us consent to deal with anyone from that firm.

Name of Individual:

Name of Firm:

Telephone Number: Extension: **BN:**

Authorize online access

You can authorize your representative to deal with us through our online services for representatives. You have to provide the RepID of the individual or the Business Number of the firm indicated above. The name of the firm provided above must be the same name that is registered with the Represent a Client service at **www.cra.gc.ca/representatives**. If the firm names differ then online access will not be granted. Our online services do not have a year specific option, so your representative will have access to all years.

RepID: (for above individual) **OR** **BN:** The BN must be registered with the Represent a Client service to be an online representative.

Part 3 – Which Accounts and Which Years?

i) Accounts – Select which accounts the above individual or firm is authorized to access (check only box A or B).

A. [X] This authorization applies to all BN accounts and all years. **Note: online access is available for box A only.**

Expiry date:

OR

B. [ ] This authorization applies only to the BN accounts and periods listed in Part 3ii.

Authorization level: check one box

[ ] Disclose information only

OR

[ ] Disclose information **and** make changes to your BN account(s)

BUSINESS CONSENT FORM (RC59 continued)

ii) Details of accounts and fiscal periods – Complete this area if you checked box "B" in Part 3 i) on the first page.

If you checked box B in part 3i, you have to provide at least one program identifier (see Instructions on the last page). You can then check the "all accounts" box for that program identifier or enter a specific account number. Provide the authorization level ("1" to disclose information or "2" to disclose information and make changes). You can also check the "All years" box to allow unlimited tax year access or enter a specific fiscal period **(specific period authorization is not available for online access)**. You can also enter an expiry date to automatically cancel authorization. If additional authorizations or more than four program identifiers are needed complete another RC59.

Program identifier	All accounts		Specific account	Authorization level	All years		Specific fiscal period (not available for online access)	Expiry date
		or				or		
		or				or		
		or				or		
		or				or		

Part 4 – Cancel one or more existing authorizations – Complete this section **only** to cancel existing authorization(s)

☐ **A.** Cancel **all** authorizations.

☐ **B.** Cancel authorization for the individual or firm identified below.

Name of Individual: ____________________

Name of Firm: ____________________

Part 5 – Certification

This form must be signed by an authorized person of the business such as a proprietor of a proprietorship, a partner of a partnership, a director of a corporation, an officer of a non profit organization or a trustee of an estate.
By signing and dating this form, you authorize the CRA to deal with the individual or firm listed in Part 2 of this form and/or cancel the authorizations listed in Part 4.

First name: DAVE

Last name: KENNEY

Title: PRESIDENT

Sign here ► ____________________ Date __________

WE WILL NOT PROCESS THIS FORM UNLESS IT IS SIGNED AND DATED BY AN AUTHORIZED PERSON OF THE BUSINESS.

T2-RETURN AND SCHEDULE INFORMATION

Name: **CHATHAM-KENT HYDRO INC.**

BN: 89429 0014 RC 0001 **Taxation Year End:** **2008-12-31**

For agency use
[055]

This page must be attached to your return and sent to the Canada Revenue Agency

Name: **CHATHAM-KENT HYDRO INC.**

BN: 89429 0014 RC 0001 **Taxation Year End: 2008-12-31**

For agency use
[055]

[001] 89429 0014 RC 0001
[060] 2008 01 01
[061] 2008 12 31
[099] EP10

B

XXXXXXXXXXX

[002] CHATHAM-KENT HYDRO INC.

[003] 2
[004] ____________

XXXXXXXXXXX

[010]@ 2
[011] ____________
[012] ____________
[015] ____________
[016] ____________
[017] ____________
[018] ____________

For agency use
[091] ____________
[092] ____________
[093] ____________

[020]@ 2
[021] ____________
[022] ____________
[023] ____________
[025] ____________
[026] ____________
[027] ____________
[028] ____________

For agency use
[094] ____________
[095] ____________
[096] ____________
[100] ____________

Name: CHATHAM-KENT HYDRO INC.

BN: 89429 0014 RC 0001 **Taxation Year End:** 2008-12-31

[030]@	2
[031]	
[032]	
[035]	
[036]	
[037]	
[038]	
	XXXXXXXXXXX

[040]	1	[164]		[216]	
[043]		[165]		[217]	
[063]	2	[166]		[218]	
[065]		[167]		[220]	
[066]	2	[168]		[221]	
[067]	2	[169]		[227]	
[070]	2	[170]		[231]	
[071]	2	[171]		[232]	
[072]	2	[172]		[233]	1
[076]	2	[173]	1	[234]	1
[078]	2	[201]	1	[236]	
[080]	1	[202]		[237]	
[081]		[203]		[238]	
[082]	2	[204]		[242]	
[085]	4	[205]		[243]	
[150]	1	[206]		[244]	
[151]		[207]		[249]	
[160]	1	[208]		[250]	
[161]		[210]		[253]	
[162]		[212]		[254]	
[163]		[213]		[255]	

Name: **CHATHAM-KENT HYDRO INC.**

BN: 89429 0014 RC 0001 **Taxation Year End: 2008-12-31**

[256]		**[910]**	
[258]		**[914]**	
[259]		**[918]**	
[260]		**[990]**	1
[261]			**XXXXXXXXXXX**
[262]			
[263]		**[280]**	2
[264]		**[281]**	2
[265]		**[282]**	
[266]		**[283]**	
[267]		**[284]**	ELECTRICAL DISTRIB.
[268]		**[286]**	
[269]		**[288]**	
[291]	2	**[285]**	100
[292]	2	**[287]**	
[293]		**[289]**	
[294]		**[950]**	KENNEY
[295]		**[951]**	DAVE
[370]		**[954]**	PRESIDENT
[435]		**[955]**	
[438]		**[956]**	519 352 6300
[624]		**[957]**	2
[646]		**[958]**	JIM HOGAN
[750]	ON	**[959]**	519 352 6300
[801]			**XXXXXXXXXXX**
[894]			
[896]	2		
[898]			

Name: **CHATHAM-KENT HYDRO INC.**

BN: 89429 0014 RC 0001 **Taxation Year End:** **2008-12-31**

[300]	7 020 809	**[440]**		**[652]**	
[311]		**[445]**		**[700]**	
[312]		**[450]**			**XXXXXXXXXXX**
[313]		**[600]**			
[314]		**[632]**		**[704]**	
[315]		**[636]**		**[708]**	
[320]		**[780]**		**[710]**	
[325]			**XXXXXXXXXXX**	**[716]**	
[331]				**[720]**	
[332]		**[460]**		**[724]**	
[333]		**[465]**		**[727]**	
[334]		**[480]**		**[728]**	
[335]		**[485]**		**[760]**	
[340]		**[712]**		**[765]**	
[350]			**XXXXXXXXXXX**	**[770]**	
[355]					**XXXXXXXXXXX**
[360]	7 020 809	**[550]**			
	XXXXXXXXXXX	**[602]**		**[784]**	
		[604]		**[788]**	
[400]	7 020 809	**[608]**		**[792]**	
[405]		**[616]**		**[796]**	
[410]	400 000	**[620]**		**[797]**	
[425]		**[628]**		**[800]**	
[430]		**[638]**		**[808]**	
	XXXXXXXXXXX	**[639]**		**[812]**	
		[640]		**[840]**	
[415]	39 240	**[644]**		**[890]**	
	XXXXXXXXXXX	**[648]**			**XXXXXXXXXXX**

Name: **CHATHAM-KENT HYDRO INC.**

BN: 89429 0014 RC 0001 **Taxation Year End: 2008-12-31**

Certification

I, DAVE KENNEY 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]	7 020 809
Part I tax payable [line 200700]	0
Part I.3 tax payable [line 200704]	0
Part II surtax payable [line 200708]	0
Part III.1 tax payable [line 200710]	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 XIII.1 tax payable [line 200727]	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.

PRESIDENT

Date | Signature of an authorized signing officer of the corporation | Position, office or rank

T2-RETURN AND SCHEDULE INFORMATION

Name: **CHATHAM-KENT HYDRO INC.**

BN: 89429 0014 RC 0001 **Taxation Year End:** **2008-12-31**

[600]	
[601]	
[602]	
[603]	
[604]	
[700]	
[701]	
[702]	
[703]	
[704]	
	XXXXXXXXXXX

[101]	1 009 826	[118]		[203]	
[102]		[119]		[204]	
[103]		[120]		[205]	
[104]	3 595 770	[121]		[206]	
[105]		[122]		[207]	
[106]		[123]		[208]	
[107]		[124]		[209]	
[108]		[125]		[210]	
[109]		[126]		[211]	
[110]		[127]		[212]	
[111]		[128]		[213]	
[112]		[199]		[214]	
[113]		[500]	4 605 596	[215]	
[114]			XXXXXXXXXXX	[216]	
[115]				[217]	
[116]		[201]		[218]	
[117]		[202]		[219]	

Name: CHATHAM-KENT HYDRO INC.

BN: 89429 0014 RC 0001 **Taxation Year End:** 2008-12-31

[220]		[300]		[401]	
[221]		[301]		[402]	
[222]		[302]		[403]	
[223]		[303]		[404]	
[224]		[304]		[405]	
[225]		[305]		[406]	
[226]		[306]		[407]	
[227]		[307]		[408]	
[228]		[308]		[409]	
[229]		[309]		[410]	
[230]		[310]		[411]	
[231]		[311]		[413]	
[232]		[312]		[414]	
[233]		[313]		[416]	
[234]		[314]		[417]	
[235]		[315]		[499]	
[236]		[316]		[510]	
[237]		[340]			XXXXXXXXXXX
[238]		[341]			
[290]		[342]			
[291]		[343]			
[292]		[344]			
[293]		[345]			
[294]		[346]			
	XXXXXXXXXXX	[390]			
		[391]			
		[392]			
		[393]			
		[394]			
			XXXXXXXXXXX		

Name: **CHATHAM-KENT HYDRO INC.**

BN: 89429 0014 RC 0001 **Taxation Year End: 2008-12-31**

[300]

1. 89428 6012 RC 0001
2. 86356 0967 RC 0001
3. 86633 7058 RC 0001
4. 86570 1635 RC 0001 *

[400]

1. 1
2. 3
3. 1
4. 3 *

XXXXXXXXXXX

[100]

1. CHATHAM-KENT ENERGY INC.
2. CHATHAM-KENT UTILITY SERVICES INC.
3. THE CORPORATION OF THE MUNICIPALITY OF CHATHAM-KENT
4. MIDDLESEX POWER DISTRIBUTION CORPORATION *

[200]

1. ____________
2. ____________
3. ____________
4. ____________ *

[500]

1. ____________
2. ____________
3. ____________
4. ____________ *

[550]

1. ____________
2. ____________
3. ____________
4. ____________ *

T2-RETURN AND SCHEDULE INFORMATION

Name: **CHATHAM-KENT HYDRO INC.**

BN: 89429 0014 RC 0001 **Taxation Year End: 2008-12-31**

[600]
1. ______________
2. ______________
3. ______________
4. ______________ *

[650]
1. ______________
2. ______________
3. ______________
4. ______________ *

[700]
1. ______________
2. ______________
3. ______________
4. ______________ *

XXXXXXXXXXX

T2-RETURN AND SCHEDULE INFORMATION

Name: CHATHAM-KENT HYDRO INC.

BN: 89429 0014 RC 0001 **Taxation Year End: 2008-12-31**

[025] ______________

[050] 2008

[075] 2

[200]
1. 89429 0014 RC 0001
2. 89428 6012 RC 0001
3. 86356 0967 RC 0001
4. 86633 7058 RC 0001
5. 86570 1635 RC 0001 *

[300]
1. 1
2. 1
3. 1
4. 1
5. 1 *

XXXXXXXXXXX

[350]
1. 100
2. ______________
3. ______________
4. ______________
5. ______________ *

XXXXXXXXXXX

[400]
1. 400 000
2. ______________
3. ______________
4. ______________
5. ______________ *

XXXXXXXXXXX

Name: **CHATHAM-KENT HYDRO INC.**

BN: 89429 0014 RC 0001 **Taxation Year End: 2008-12-31**

[100]

1. CHATHAM-KENT HYDRO INC.
2. CHATHAM-KENT ENERGY INC.
3. CHATHAM-KENT UTILITY SERVICES INC.
4. THE CORPORATION OF THE MUNICIPALITY OF CHATHAM-KENT
5. MIDDLESEX POWER DISTRIBUTION CORPORATION *

XXXXXXXXXXX

T2-RETURN AND SCHEDULE INFORMATION

Name: **CHATHAM-KENT HYDRO INC.**

BN: 89429 0014 RC 0001 **Taxation Year End: 2008-12-31**

[100] 1. CHATHAM-KENT ENERGY INC. *

[200] 1. 89428 6012 RC 0001 *

[300] 1. ________________ *

[350] 1. ________________ *

[400] 1. 100 *

[500] 1. ________________ *

XXXXXXXXXXX

T2-RETURN AND SCHEDULE INFORMATION **100**

Name: **CHATHAM-KENT HYDRO INC.**

BN: 89429 0014 RC 0001 **Taxation Year End: 2008-12-31**

[3640]	68 966 761
	XXXXXXXXXXX
[1000]	6 340 035
[1060]	12 370 782
[1066]	109 388
[1120]	676 263
[1400]	383 262
[1484]	91 079
[1599]	19 970 809
[1774]	305 533
[1900]	71 188 015
[1901]	# 25 062 852
[2008]	71 493 548
[2009]	# 25 062 852
[2420]	2 565 256
[2589]	2 565 256
[2599]	68 966 761
	XXXXXXXXXXX
[2600]	
[2620]	9 036 529
[2860]	2 248 214
[2960]	1 116 267
[3139]	12 401 010
[3140]	3 463 476
[3300]	23 523 326
[3320]	873 565
[3450]	27 860 367
[3499]	40 261 377
	XXXXXXXXXXX

[3500]	23 523 425
[3600]	5 181 959
[3620]	28 705 384
	XXXXXXXXXXX
[3660]	3 916 746
[3680]	2 415 213
[3700]	# 1 150 000
[3849]	5 181 959
	XXXXXXXXXXX

Name: **CHATHAM-KENT HYDRO INC.**

BN: 89429 0014 RC 0001 **Taxation Year End:** **2008-12-31**

[0001] __________

[0002] __________

XXXXXXXXXXX

[0003] __________

XXXXXXXXXXX

[8519]	13 571 648	**[8810]**	1 416 110
[9369]	3 425 039	**[9270]**	2 475 778
[9899]		**[9284]**	2 117 686
[9970]	3 425 039	**[9367]**	11 591 230
[9975]		**[9368]**	72 776 918
[9976]			**XXXXXXXXXXX**
[9980]			
[9985]		**[9370]**	
[9990]	1 009 826	**[9659]**	0
[9995]			**XXXXXXXXXXX**
[9999]	2 415 213		
	XXXXXXXXXXX	**[9660]**	
		[9898]	0
[8000]	74 757 336		**XXXXXXXXXXX**
[8089]	74 757 336		
[8230]	1 444 621		
[8299]	76 201 957		
	XXXXXXXXXXX		
[8300]			
[8320]	61 185 688		
[8518]	61 185 688		
[8670]	3 595 770		
[8710]	1 985 886		

Name: **CHATHAM-KENT HYDRO INC.**

BN: 89429 0014 RC 0001 **Taxation Year End:** **2008-12-31**

[095]	1
[097]	2
[198]	1
[099]	2
[101]	1
[102]	2
[103]	2
[104]	2
[105]	2
[106]	1
[107]	1
[108]	2
[110]	

XXXXXXXXXXX

Canada Revenue Agency / Agence du revenu du Canada

T2 CORPORATION INCOME TAX RETURN

200

EXEMPT FROM TAX

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 Ontario (for tax years ending before 2009), Quebec, 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 federal *Income Tax Act*. This return may contain changes that had not yet become law at the time of printing.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or the *T2 Corporation – Income Tax Guide*.

Identification

Business Number (BN) 001 89429 0014 RC0001

Corporation's name

002 CHATHAM-KENT HYDRO INC.

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.)

011 320 QUEEN STREET

012 P.O. BOX 70

City: 015 CHATHAM

Province, territory, or state: 016 ON

Country (other than Canada): 017

Postal code/Zip code: 018 N7M 5K2

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

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.)

031 320 QUEEN STREET

032 P.O. BOX 70

City: 035 CHATHAM

Province,territory, or state: 036 ON

Country (other than Canada): 037

Postal code/Zip code: 038 N7M 5K2

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

To which tax year does this return apply?

Tax year start 060 2008-01-01 (YYYY MM DD)

Tax year-end 061 2008-12-31 (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

Is the date on line 061 a deemed tax year-end in accordance with subsection 249(3.1)? . . . . 066 1 Yes [ ] 2 No [X]

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.

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

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 [X] Exempt under other paragraphs of section 149

Do not use this area

091	092	093	094	095	096
100					

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	X	9
Is the corporation an associated CCPC?	160	X	23
Is the corporation an associated CCPC 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; gifts of cultural or ecological property; or gifts of medicine?	202		2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203		3
Is the corporation claiming any type of losses?	204		4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205		5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) is the corporation claiming the refundable portion of Part I tax?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208		8
Does the corporation have any property that is eligible capital property?	210		10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming reserves of any kind?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231		31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232		T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	
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? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

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
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265		55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268		53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54

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 ☐ 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	ELECTRICAL DISTRIB.	285	100.000 %
286		287	%
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
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293		

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible 294 ______ YYYY MM DD

If the corporation's major business activity is construction, did you have any sub-contractors during the tax year? 295 1 Yes ☐ 2 No ☐

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.	300		7,020,809	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			
Gifts of medicine from Schedule 2	315			
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320			
Part VI.1 tax deduction *	325			
Non-capital losses of previous tax years from Schedule 4	331			
Net capital losses of previous tax years from Schedule 4	332			
Restricted farm losses of previous tax years from Schedule 4	333			
Farm losses of previous tax years from Schedule 4	334			
Limited partnership losses of previous tax years from Schedule 4	335			
Taxable capital gains or taxable dividends allocated from a central credit union	340			
Prospector's and grubstaker's shares	350			
Subtotal				B
Subtotal (amount A **minus** amount B) (if negative, enter "0")			7,020,809	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355			D
Taxable income (amount C **plus** amount D)	360		7,020,809	
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	7,020,809	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.

300,000	x	Number of days in the tax year in 2006 / Number of days in the tax year	/ 366	=		1
400,000	x	Number of days in the tax year after 2006 / Number of days in the tax year	366 / 366	=	400,000	2
		Add amounts at lines 1 and 2			400,000	4

Business limit (see notes 1 and 2 below)	410	400,000	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	400,000	x	415 *** 39,240 D / 11,250	=	1,395,200	E
Reduced business limit (amount C **minus** amount E) (if negative, enter "0")				425		F

Small business deduction

Amount A, B, C, or F whichever is the least		x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	/ 366	x 16 %	=	5
Amount A, B, C, or F whichever is the least		x	Number of days in the tax year after December 31, 2007, and before January 1, 2009 / Number of days in the tax year	366 / 366	x 17 %	=	6
Amount A, B, C, or F whichever is the least		x	Number of days in the tax year after December 31, 2008 / Number of days in the tax year	/ 366	x 17 %	=	7

Total of amounts 5, 6, and 7 – enter 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 previous 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 previous 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 2006 / Number of days in the tax year	/ 366	x 5 %	=	I
Amount H		x	Number of days in the tax year in 2007 / Number of days in the tax year	/ 366	x 7 %	=	J

Note: Resource deduction is no longer available for tax years starting after December 31, 2006.

Resource deduction – Total of amounts I and J Enter amount K on line 10.	438		K

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 from Schedule 17		E	
Amount from line 400, 405, 410, or 425, whichever is the least		F	
Aggregate investment income from line 440		G	
Total of amounts B, C, D, E, F, and G		►	H
Amount A **minus** amount H (if negative, enter "0")			I

Amount I		x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	/ 366	x	7 %	=	J
Amount I		x	Number of days in the tax year after December 31, 2007, and before January 1, 2009 / Number of days in the tax year	366 / 366	x	8.5 %	=	K
Amount I		x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year	/ 366	x	9 %	=	L
Amount I		x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year	/ 366	x	10 %	=	L1

General tax reduction for Canadian-controlled private corporations – Total of amounts J, K, L, and L1 . . . M
Enter amount M on line 638.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, or a mutual fund corporation, and for tax years starting after May 1, 2006, any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from line 360 (for tax years starting after May 1, 2006, amount Z)			N
Amount Z1 from Part 9 of Schedule 27		O	
Amount QQ from Part 13 of Schedule 27		P	
Taxable resource income from line 435		Q	
Amount used to calculate the credit union deduction from Schedule 17		R	
Total of amounts O, P, Q, and R		►	S
Amount N **minus** amount S (if negative, enter "0")			T

Amount T		x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	/ 366	x	7 %	=	U
Amount T		x	Number of days in the tax year after December 31, 2007, and before January 1, 2009 / Number of days in the tax year	366 / 366	x	8.5 %	=	V
Amount T		x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year	/ 366	x	9 %	=	W
Amount T		x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year	/ 366	x	10 %	=	W1

General tax reduction – Total of amounts U, V, W, and W1 . . . X
Enter amount X on line 639.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7	440		x 26 2 / 3 % =		A
Foreign non-business income tax credit from line 632					
Deduct:					
Foreign investment income from Schedule 7	445		x 9 1 / 3 % =		
			(if negative, enter "0")	▶	B
Amount A **minus** amount B (if negative, enter "0")					C
Taxable income from line 360			7,020,809		
Deduct:					
Amount from 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 =			
		▶	7,020,809		
			x 26 2 / 3 % =	1,872,216	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 previous 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 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 – Taxable income (line 360 or amount Z, whichever applies) **multiplied** by 38.00 % . . . . **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 Number of days in the tax year before January 1, 2008 ______ / Number of days in the tax year 366 x 4 % = **600** ______ B

* The corporate surtax is zero effective January 1, 2008.

Recapture of investment tax credit from 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	7,020,809		
Deduct:			
Amount from line 400, 405, 410, or 425, whichever is the least			
Net amount	7,020,809 ▶	7,020,809	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 Schedule 27	**616**		
Investment corporation deduction	**620**		
Taxed capital gains **624** ______			
Additional deduction – credit unions from Schedule 17	**628**		
Federal foreign non-business income tax credit from Schedule 21	**632**		
Federal foreign business income tax credit from Schedule 21	**636**		
Resource deduction from line 438			10
General tax reduction for CCPCs from amount M	**638**		
General tax reduction from amount X	**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 . . . . . ______ G
Enter amount G on line 700.

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 III.1 tax payable from Schedule 55	710	
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 Ontario [for tax years ending before 2009], Quebec, 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	
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 ☒

Certification

I, 950 KENNEY (Last name in block letters) 951 DAVE (First name in block letters) 954 PRESIDENT (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 Date (yyyy/mm/dd) Signature of the authorized signing officer of the corporation 956 (519) 352-6300 Telephone number

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

958 JIM HOGAN (Name in block letters) 959 (519) 352-6300 Telephone number

Language of correspondence – Langue de correspondance

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. 990 1

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
CHATHAM-KENT HYDRO INC.	89429 0014 RC0001	2008-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
	Assets				
	Total current assets	1599	+	19,970,809	19,098,434
	Total tangible capital assets	2008	+	71,493,548	44,934,423
	Total accumulated amortization of tangible capital assets	2009	–	25,062,852	
	Total intangible capital assets	2178	+		
	Total accumulated amortization of intangible capital assets	2179	–		
	Total long-term assets	2589	+	2,565,256	3,681,778
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	68,966,761	67,714,635
	Liabilities				
	Total current liabilities	3139	+	12,401,010	12,952,336
	Total long-term liabilities	3450	+	27,860,367	27,322,128
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	40,261,377	40,274,464
	Shareholder equity				
	Total shareholder equity (mandatory field)	3620	+	28,705,384	27,440,171
	Total liabilities and shareholder equity	3640	=	68,966,761	67,714,635
	Retained earnings				
	Retained earnings/deficit – end (mandatory field)	3849	=	5,181,959	3,916,746

***** Generic item

Current Assets

Form identifier 1599

Account	Description	GIFI		Current year	Prior year
Cash and deposits					
	* Cash and deposits	1000		6,340,035	4,091,078
	Cash and deposits		+	6,340,035	4,091,078
Accounts receivable					
	* Accounts receivable	1060		12,370,782	12,744,449
	Taxes receivable	1066		109,388	838,981
	Accounts receivable		+	12,480,170	13,583,430
Inventories					
	* Inventories	1120		676,263	780,574
	Inventories		+	676,263	780,574
Due from/investment in related parties					
	* Due from/investment in related parties	1400		383,262	574,993
	Due from/investment in related parties		+	383,262	574,993
Other current assets					
	Prepaid expenses	1484		91,079	68,359
	Other current assets		+	91,079	68,359
	Total current assets	1599	=	19,970,809	19,098,434

***** Generic item

Tangible Capital Assets and Accumulated Amortization

Form identifier 2008/2009

Account	Description	GIFI		Tangible capital assets		Accumulated amortization	Prior year
	Machinery, equipment, furniture and fixtures						
	Computer equipment/software	1774	+	305,533			198,061
	Total			305,533			
	Other tangible capital assets						
	* Other tangible capital assets	1900	+	71,188,015			44,736,362
	*Accumulated amortization of other tangible capital assets	1901			–	25,062,852	
	Total			71,188,015		25,062,852	
	Total tangible capital assets	2008	=	71,493,548			44,934,423
	Total accumulated amortization of tangible capital assets	2009			=	25,062,852	

***** Generic item

Long-term Assets

Form identifier 2589

Account	Description	GIFI		Current year	Prior year
	Other long-term assets				
	* Other long-term assets	2420		2,565,256	3,681,778
	Other long-term assets		+	2,565,256	3,681,778
	Total long-term assets	2589	=	2,565,256	3,681,778

* Generic item

Current Liabilities

Form identifier 3139

Account	Description	GIFI		Current year	Prior year
Amounts payable and accrued liabilities					
	* Amounts payable and accrued liabilities	2620		9,036,529	9,382,408
	Amounts payable and accrued liabilities		+	9,036,529	9,382,408
Due to related parties					
	* Due to related parties	2860		2,248,214	2,727,229
	Due to related parties		+	2,248,214	2,727,229
Other current liabilities					
	* Other current liabilities	2960		1,116,267	842,699
	Other current liabilities		+	1,116,267	842,699
	Total current liabilities	3139	=	12,401,010	12,952,336

***** Generic item

Long-term Liabilities

Form identifier 3450

Account	Description	GIFI		Current year	Prior year
Long-term debt					
	* Long-term debt	3140		3,463,476	2,982,893
	Long-term debt		+	3,463,476	2,982,893
Due to related parties					
	* Due to related parties	3300		23,523,326	23,523,326
	Due to related parties		+	23,523,326	23,523,326
Other long-term liabilities					
	* Other long-term liabilities	3320		873,565	815,909
	Other long-term liabilities		+	873,565	815,909
	Total long-term liabilities	3450	=	27,860,367	27,322,128

* Generic item

Shareholder Equity

Form identifier 3620

Account	Description	GIFI		Current year	Prior year
	* Common shares	3500	+	23,523,425	23,523,425
	* Retained earnings/deficit	3600	+	5,181,959	3,916,746
	Total shareholder equity	3620	=	28,705,384	27,440,171

***** Generic item

Retained Earnings/Deficit

Form identifier 3849

Account	Description	GIFI		Current year	Prior year
	* Retained earnings/deficit – start	3660	+	3,916,746	2,782,920
	* Net income/loss	3680	+	2,415,213	2,283,826
Dividends declared					
	* Dividends declared	3700		1,150,000	1,150,000
	Dividends declared		–	1,150,000	1,150,000
	Retained earnings/deficit – end	3849	=	5,181,959	3,916,746

* 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
CHATHAM-KENT HYDRO INC.	89429 0014 RC0001	2008-12-31

Income statement information

Description	GIFI	
Operating name	0001	
Description of the operation	0002	
Sequence Number	0003	01

Account	Description	GIFI		Current year	Prior year
	Income statement information				
	Total sales of goods and services	8089	+	74,757,336	77,420,812
	Cost of sales	8518	–	61,185,688	64,186,838
	Gross profit/loss	8519	=	13,571,648	13,233,974
	Cost of sales	8518	+	61,185,688	64,186,838
	Total operating expenses	9367	+	11,591,230	10,956,943
	Total expenses (mandatory field)	9368	=	72,776,918	75,143,781
	Total revenue (mandatory field)	8299	+	76,201,957	79,000,558
	Total expenses (mandatory field)	9368	–	72,776,918	75,143,781
	Net non-farming income	9369	=	3,425,039	3,856,777
	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	=	3,425,039	3,856,777
	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	–	1,009,826	1,572,951
	Deferred income tax provision	9995	–		
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	2,415,213	2,283,826

Revenue

Form identifier 8299

Account	Description	GIFI		Current year	Prior year
	* Trade sales of goods and services	8000	+	74,757,336	77,420,812
	Total sales of goods and services	8089	=	74,757,336	77,420,812
Other revenue					
	* Other revenue	8230		1,444,621	1,579,746
	Other revenue		+	1,444,621	1,579,746
	Total revenue	8299	=	76,201,957	79,000,558

***** Generic item

Cost of Sales

Form identifier 8518

Account	Description	GIFI		Current year	Prior year
	* Purchases/cost of materials	8320	+	61,185,688	64,186,838
	Cost of sales	8518	=	61,185,688	64,186,838

* Generic item

Operating Expenses

Form identifier 9367

Account	Description	GIFI		Current year	Prior year
	* Amortization of tangible assets	8670	+	3,595,770	3,315,639
	Interest and bank charges				
	* Interest and bank charges	8710		1,985,886	2,009,246
	Interest and bank charges		+	1,985,886	2,009,246
	Office expenses				
	* Office expenses	8810		1,416,110	1,281,282
	Office expenses		+	1,416,110	1,281,282
	Other expenses				
	* Other expenses	9270		2,475,778	2,287,642
	General and administrative expenses	9284		2,117,686	2,063,134
	Other expenses		+	4,593,464	4,350,776
	Total operating expenses	9367	=	11,591,230	10,956,943

* Generic item

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 141

NOTES CHECKLIST

Corporation's name	Business Number	Tax year-end Year Month Day
CHATHAM-KENT HYDRO INC.	89429 0014 RC0001	2008-12-31

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the "accountant") who prepared or reported on the financial statements.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI) for Corporations* and Guide T4012, *T2 Corporation – Income Tax Guide*.
- Complete this schedule and include it with your T2 return along with the other GIFI schedules.

If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3 and 4 as applicable.

Part 1 – Information on the accountant preparing or reporting on the financial statements

Does the accountant have a professional designation? . . . . . 095 1 Yes [X] 2 No [ ]

Is the accountant connected* with the corporation? . . . . . 097 1 Yes [ ] 2 No [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 accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you do have to complete Part 4 as applicable.

Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant:

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 with the financial statements** above, answer the following question:

Has the accountant expressed a reservation? . . . . . 099 1 Yes [ ] 2 No [X]

Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options:

110

Prepared the tax return (financial statements prepared by client) . . . . . 1 [ ]

Prepared the tax return and the financial information contained therein (financial statements have not been prepared) . . . . . 2 [ ]

Were notes to the financial statements prepared? . . . . . 101 1 Yes [X] 2 No [ ]

If **yes**, complete lines 102 to 107 below:

Are any values presented at other than cost? . . . . . 102 1 Yes [ ] 2 No [X]

Has there been a change in accounting policies since the last return? . . . . . 103 1 Yes [ ] 2 No [X]

Are subsequent events mentioned in the notes? . . . . . 104 1 Yes [ ] 2 No [X]

Is re-evaluation of asset information mentioned in the notes? . . . . . 105 1 Yes [ ] 2 No [X]

Is contingent liability information mentioned in the notes? . . . . . 106 1 Yes [X] 2 No [ ]

Is information regarding commitments mentioned in the notes? . . . . . 107 1 Yes [X] 2 No [ ]

Does the corporation have investments in joint venture(s) or partnership(s)? . . . . . 108 1 Yes [ ] 2 No [X]

If **yes**, complete line 109 below:

Are you filing financial statements of the joint venture(s) or partnership(s)? . . . . . 109 1 Yes [ ] 2 No [ ]

Canada Revenue Agency / Agence du revenu du Canada

NET INCOME (LOSS) FOR INCOME TAX PURPOSES

SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
CHATHAM-KENT HYDRO INC.	89429 0014 RC0001	2008-12-31

- 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			2,415,213	A
Add:				
Provision for income taxes – current	101	1,009,826		
Amortization of tangible assets	104	3,595,770		
Subtotal of additions		4,605,596 ▶	4,605,596	
Other additions:				
Miscellaneous other additions:				
Subtotal of other additions	199	0 ▶	0	
Total additions	500	4,605,596 ▶	4,605,596	
Deduct:				
Subtotal of deductions		▶		
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			7,020,809	

* For reference purposes only

T2 SCH 1 E (08)

Canada

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
CHATHAM-KENT HYDRO INC.	89429 0014 RC0001	2008-12-31

This schedule is to be completed by a corporation having one or more of the following:
- related corporation(s)
- associated corporations(s)

	Name 100	Country of residence (if other than Canada) 200	Business Number (Canadian corporation only) (see note 1) 300	Relationship code (see note 2) 400	Number of common shares owned 500	% of common shares owned 550	Number of preferred shares owned 600	% of preferred shares owned 650	Book value of capital stock 700
1.	CHATHAM-KENT ENERGY INC.		89428 6012 RC0001	1					
2.	CHATHAM-KENT UTILITY SERVICES		86356 0967 RC0001	3					
3.	THE CORPORATION OF THE MUNIC		86633 7058 RC0001	1					
4.	MIDDLESEX POWER DISTRIBUTION		86570 1635 RC0001	3					

Note 1: Enter "NR" if a corporation is not registered.
Note 2: Enter the code number of the relationship that applies from the following order: 1 – Parent 2 – Subsidiary 3 – Associated 4 – Related, but not associated.

T2 SCH 9(99)

Canada

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 23

AGREEMENT AMONG ASSOCIATED CANADIAN-CONTROLLED PRIVATE CORPORATIONS TO ALLOCATE THE BUSINESS LIMIT

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group. Include non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* (ITA) not to be associated for purposes of the small business deduction.

Column 2: Provide the Business Number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code that applies to each corporation:

1 - Associated for purposes of allocating the business limit (unless code 5 applies)
2 - CCPC that is a "third corporation" that has elected under subsection 256(2) not to be associated for purposes of the small business deduction
3 - Non-CCPC that is a "third corporation" as defined in subsection 256(2)
4 - Associated non-CCPC
5 - Associated CCPC to which code 1 does not apply because of a subsection 256(2) election made by a "third corporation"

Column 4: Enter the business limit for the year of each corporation in the associated group. The business limit is computed at line 4 on page 4 of each respective corporation's T2 return.

Column 5: Assign a percentage to allocate the business limit to each corporation that has an association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A. Ensure that the total at line A falls within the range for the calendar year to which the agreement applies:

Calendar year	Acceptable range
2004	$225,001 to $250,000
2005	$250,001 to $300,000
2006	maximum $300,000
2007	$300,001 to $400,000

If the calendar year to which this agreement applies is after 2007, ensure that the total at line A does not exceed $400,000.

Allocating the business limit

Date filed (do not use this area) . . . . . 025 Year Month Day

Enter the calendar year to which the agreement applies . . . . . 050 Year 2008

Is this an amended agreement for the above-noted calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . . 075 1 Yes [ ] 2 No [X]

	1 Names of associated corporations	2 Business Number of associated corporations	3 Association code	4 Business limit for the year (before the allocation) $	5 Percentage of the business limit %	6 Business limit allocated* $
	100	200	300		350	400
1	CHATHAM-KENT HYDRO INC.	89429 0014 RC0001	1	400,000	100.0000	400,000
2	CHATHAM-KENT ENERGY INC.	89428 6012 RC0001	1			
3	CHATHAM-KENT UTILITY SERVICES INC.	86356 0967 RC0001	1	400,000		
4	THE CORPORATION OF THE MUNICIPALITY OI	86633 7058 RC0001	1	400,000		
5	MIDDLESEX POWER DISTRIBUTION CORPORA	86570 1635 RC0001	1	400,000		
				Total	100.0000	400,000 A

Business limit reduction under subsection 125(5.1) of the ITA

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "Large corporation amount" at line 415 of the T2 return. If the corporation is a member of an associated group** of corporations in the current tax year, the amount at line 415 of the T2 return is equal to 0.225% x (A - $10,000,000) where, "A" is the total of taxable capital employed in Canada*** of each corporation in the associated group for its last tax year ending in the preceding calendar year.

*Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules apply if a CCPC has more than one tax year ending in a calendar year and is associated in more than one of those years with another CCPC that has a tax year ending in the same calendar year. In this case, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit determined for the first tax year ending in the calendar year and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year.

** The associated group includes the corporation filing this schedule and each corporation that has an "association code" of 1 or 4 in column 3.

*** "Taxable capital employed in Canada" has the meaning assigned by subsection 181.2(1) or 181.3(1) or section 181.4 of the ITA.

T2 SCH 23 (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
CHATHAM-KENT HYDRO INC.	89429 0014 RC0001	2008-12-31

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	CHATHAM-KENT ENERGY INC.	89428 6012 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

Canada

APPENDIX H

PILS AND INCOME TAX WORKSHEET

PILs or Income Taxes Work Form

Name of LDC: Chatham-Kent Hydro Inc.

File Number: EB-2009-0261

Rate Year: 2010

Version: 1.0

Table of Content

Notes:

(1) Pale green cells represent inputs

(2) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***

PILs or Income Taxes Work Form
Name of LDC: Chatham-Kent Hydro Inc.
File Number: EB-2009-0261
Rate Year: 2010

Data Input Sheet

Applicants Rate Base	Rate Re-Basing Amount			
Average Net Fixed Assets				
Gross Fixed Assets - Re-Basing Opening	$ 75,893,529	A		
Add: CWIP Re-Basing Opening	$ -	B		
Re-Basing Capital Additions	$ 5,517,531	C		
Re-Basing Capital Disposals	$ -	D		
Re-Basing Capital Retirements		E		
Deduct: CWIP Re-Basing Closing		F		
Gross Fixed Assets - Re-Basing Closing	$ 81,411,060	G		
Average Gross Fixed Assets			$ 78,652,295	H = (A + G) / 2
Accumulated Depreciation - Re-Basing Opening	$ 29,187,227	I		
Re-Basing Depreciation Expense	$ 4,119,278	J		
Re-Basing Disposals	$ -	K		
Re-Basing Retirements		L		
Accumulated Depreciation - Re-Basing Closing	$ 33,306,505	M		
Average Accumulated Depreciation			$ 31,246,866	N = (I + M) / 2
Average Net Fixed Assets			**$ 47,405,429**	O = H - M
Working Capital Allowance				
Working Capital Allowance Base	$ 57,787,594	P		
Working Capital Allowance Rate	15.0%	Q		
Working Capital Allowance			**$ 8,668,139**	R = P * Q
Rate Base			**$ 56,073,568**	S = O + R

Return on Rate Base				
Deemed ShortTerm Debt %	4.00%	T	$ 2,242,943	W = S * T
Deemed Long Term Debt %	56.00%	U	$ 31,401,198	X = S * U
Deemed Equity %	40.00%	V	$ 22,429,427	Y = S * V
Short Term Interest	1.33%	Z	$ 29,831	AC = W * Z
Long Term Interest	7.62%	AA	$ 2,392,771	AD = X * AA
Return on Equity (Regulatory Income)	8.01%	AB	**$ 1,796,597**	AE = Y * AB
Return on Rate Base			**$ 4,219,200**	AF = AC + AD + AE

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

Tax Rates & Exemptions

Tax Rates Federal & Provincial As of March 26, 2009		Effective January 1, 2006	Effective January 1, 2007	Effective January 1, 2008	Effective January 1, 2009	Effective January 1, 2010	Effective January 1, 2011	Effective January 1, 2012	Effective January 1, 2013	Effective January 1, 2014
Federal income tax										
General corporate rate	1	38.00%	38.00%	38.00%	38.00%	38.00%	38.00%	38.00%		
Federal tax abatement	2	-10.00%	-10.00%	-10.00%	-10.00%	-10.00%	-10.00%	-10.00%		
Adjusted federal rate	3	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%		
Surtax (4% of line 3)	4	1.12%	1.12%	0.00%	0.00%	0.00%	0.00%	0.00%		
		29.12%	29.12%	28.00%	28.00%	28.00%	28.00%	28.00%		
Rate reduction		-7.00%	-7.00%	-8.50%	-9.00%	-10.00%	-11.50%	-13.00%		
		22.12%	22.12%	19.50%	19.00%	18.00%	16.50%	15.00%	**15.00%**	**15.00%**
Ontario income tax		14.00%	14.00%	14.00%	14.00%	13.00%	11.75%	11.25%	**10.50%**	10.00%
Combined federal and Ontario		36.12%	36.12%	33.50%	33.00%	31.00%	28.25%	26.25%	**25.50%**	**25.00%**
Federal & Ontario Small Business										
Federal small business threshold		400,000	400,000	400,000	500,000	500,000	500,000	500,000		
Ontario Small Business Threshold		400,000	500,000	500,000	500,000	500,000	500,000	500,000		
Federal small business rate		13.12%	13.12%	11.00%	11.00%	11.00%	11.00%	11.00%		
Ontario small business rate		5.50%	5.50%	5.50%	5.50%	5.00%	4.50%	4.50%		

Ontario surtax claw-back of 4.25% starts at $500,000 and eliminates the SBC at $1,500,000.

Ontario Capital Tax

	2006	2007	2008	2009	2010
Capital deduction	10,000,000	12,500,000	15,000,000	15,000,000	15,000,000
Capital tax rate	0.300%	0.225%	0.225%	0.225%	0.075%

OCT will be eliminated on July 1, 2010 but tax will be prorated for the first 6 months in 2010.

NOTES:

1. Based on the federal government's October 30, 2007 Economic Statement.
Bill C-28 received Royal Assent on December 14, 2007.
2. Ontario Economic Statement of December 13, 2007 became Bill 44 and received Royal Assent on May 14, 2008.
Capital tax rate changes and small business deduction income thresholds made retroactive to January 1, 2007.
3. Federal Budget of January 27, 2009 The federal small business limit was increased from $400,000 to $500,000 on January 1, 2009
3. Federal Budget of March 26, 2009 The provincial corporate tax rate was reduced

PILs or Income Taxes Work Form
Name of LDC: Chatham-Kent Hydro Inc.
File Number: EB-2009-0261
Rate Year: 2010

Schedule 8 and 10 UCC and CEC

Historic				
Class	**Class Description**	**UCC End of Year Historic per tax returns**	**Less: Non-Distribution Portion**	**UCC Test Year Opening Balance**
1	Distribution System - post 1987	37,632,279	0	37,632,279
2	Distribution System - pre 1988	0	0	0
8	General Office/Stores Equip	635,340	0	635,340
10	Computer Hardware/ Vehicles	779,843	0	779,843
10.1	Certain Automobiles	0	0	0
12	Computer Software	124,375	0	124,375
13_1	Lease # 1	0	0	0
13_2	Lease #2	0	0	0
13_3	Lease # 3	0	0	0
13_4	Lease # 4	0	0	0
14	Franchise	0	0	0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	235,037	0	235,037
43.1	Certain Energy-Efficient Electrical Generating Equipment	0	0	0
45	Computers & Systems Software acq'd post Mar 22/04	50,983	0	50,983
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	164,488	0	164,488
47	Distribution System - post February 2005	14,998,239	0	14,998,239
50	Data Network Infrastructure Equipment - post Mar 2007	39,695	0	39,695
		0	0	0
		0	0	0
		0	0	0
		0	0	0
		0	0	0
	SUB-TOTAL - UCC	**54,660,279**	**0**	**54,660,279**
CEC	Goodwill	828,109	0	828,109
CEC	Land Rights	0	0	0
CEC	FMV Bump-up	0	0	0
		0	0	0
		0	0	0
	SUB-TOTAL - CEC	**828,109**	**0**	**828,109**

Schedule 13 Tax Reserves Historical

CONTINUITY OF RESERVES

Description	Historical Balance as per tax returns	Non-Distribution Eliminations	Utility Only
Capital Gains Reserves ss.40(1)			0
Tax Reserves Not Deducted for accounting purposes			
Reserve for doubtful accounts ss. 20(1)(l)	105,444		105,444
Reserve for goods and services not delivered ss. 20(1)(m)	4,579,743		4,579,743
Reserve for unpaid amounts ss. 20(1)(n)			0
Debt & Share Issue Expenses ss. 20(1)(e)			0
Other tax reserves			0
			0
			0
Total	**4,685,187**	**0**	**4,685,187**
Financial Statement Reserves (not deductible for Tax Purposes)			
General Reserve for Inventory Obsolescence (non-specific)			0
General reserve for bad debts			0
Accrued Employee Future Benefits:			0
- Medical and Life Insurance			0
-Short & Long-term Disability			0
-Accmulated Sick Leave			0
- Termination Cost			0
- Other Post-Employment Benefits	858,565		858,565
Provision for Environmental Costs			0
Restructuring Costs			0
Accrued Contingent Litigation Costs			0
Accrued Self-Insurance Costs			0
Other Contingent Liabilities			0
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)			0
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)			0
Other			0
Regulatory Asset Recovery	-134,554		-134,554
Asset Retirement Reserve	15,000		15,000
Total	**739,011**	**0**	**739,011**

PILs or Income Taxes Work Form
Name of LDC: Chatham-Kent Hydro Inc.
File Number: EB-2009-0261
Rate Year: 2010

Sch 7-1 Loss Carry Forword Historic

Corporation Loss Continuity and Application

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

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

Historic Year Adjusted Taxable Income

Historic				
	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	Historic Wires Only
Income before PILs/Taxes	A	3,425,039	0	3,425,039
Additions:				
Interest and penalties on taxes	103	0	0	0
Amortization of tangible assets	104	3,595,770	0	3,595,770
Amortization of intangible assets	106	253,053	0	253,053
Recapture of capital cost allowance from Schedule 8	107	0	0	0
Gain on sale of eligible capital property from Schedule 10	108	0	0	0
Income or loss for tax purposes- joint ventures or partnerships	109	0	0	0
Loss in equity of subsidiaries and affiliates	110	0	0	0
Loss on disposal of assets	111	0	0	0
Charitable donations	112	200,000	0	200,000
Taxable Capital Gains	113	7,218	0	7,218
Political Donations	114	0	0	0
Deferred and prepaid expenses	116	0	0	0
Scientific research expenditures deducted on financial statements	118	69,371	0	69,371
Capitalized interest	119	0	0	0
Non-deductible club dues and fees	120	0	0	0
Non-deductible meals and entertainment expense	121	3,160	0	3,160
Non-deductible automobile expenses	122	0	0	0
Non-deductible life insurance premiums	123	0	0	0
Non-deductible company pension plans	124	0	0	0
Tax reserves deducted in prior year	125	94,854	0	94,854
Reserves from financial statements- balance at end of year	126	5,424,198	0	5,424,198
Soft costs on construction and renovation of buildings	127	0	0	0
Book loss on joint ventures or partnerships	205	0	0	0
Capital items expensed	206	0	0	0
Debt issue expense	208	0	0	0
Development expenses claimed in current year	212	0	0	0
Financing fees deducted in books	216	0	0	0
Gain on settlement of debt	220	0	0	0
Non-deductible advertising	226	0	0	0
Non-deductible interest	227	0	0	0
Non-deductible legal and accounting fees	228	0	0	0
Recapture of SR&ED expenditures	231	0	0	0
Share issue expense	235	0	0	0
Write down of capital property	236	0	0	0
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	0	0	0
Other Additions				
Interest Expensed on Capital Leases	290	0	0	0
Realized Income from Deferred Credit Accounts	291	0	0	0
Pensions	292	0	0	0
Non-deductible penalties	293	0	0	0
CDM reserve reversal & Non-deductible tranisition cost	294	85,451	0	85,451
RSVa cost previously deducted	295	1,331,739	0	1,331,739
Total Additions		**11,064,814**	**0**	**11,064,814**
Deductions:				
Gain on disposal of assets per financial statements	401	35,721	0	35,721
Dividends not taxable under section 83	402	0	0	0
Capital cost allowance from Schedule 8	403	3,562,624	0	3,562,624
Terminal loss from Schedule 8	404	0	0	0
Cumulative eligible capital deduction from Schedule 10	405	62,331	0	62,331
Allowable business investment loss	406	0	0	0
Deferred and prepaid expenses	409	0	0	0
Scientific research expenses claimed in year	411	46,901	0	46,901
Tax reserves claimed in current year	413	4,685,187	0	4,685,187
Reserves from financial statements - balance at beginning of year	414	1,068,890	0	1,068,890
Contributions to deferred income plans	416	0	0	0
Book income of joint venture or partnership	305	0	0	0
Equity in income from subsidiary or affiliates	306	0	0	0
Other deductions: (Please explain in detail the nature of the item)				
Interest capitalized for accounting deducted for tax	390	0	0	0
Capital Lease Payments	391	0	0	0
Non-taxable imputed interest income on deferral and variance accounts	392	4,039	0	4,039
Current years capital taxes	393	106,133	0	106,133
Deductible costs included in regulatory assets	394	1,348,849	0	1,348,849
Total Deductions		**10,920,675**	**0**	**10,920,675**
Net Income for Tax Purposes		**3,569,178**	**0**	**3,569,178**
Charitable donations from Schedule 2	311	0	0	0
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320	0	0	0
Non-capital losses of preceding taxation years from Schedule 4	331	0	0	0
Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)*	332	0	0	0
Limited partnership losses of preceding taxation years from Schedule 4	335	0	0	0
TAXABLE INCOME		**3,569,178**	**0**	**3,569,178**

PILs or Income Taxes Work Form
Name of LDC: Chatham-Kent Hydro Inc.
File Number: EB-2009-0261
Rate Year: 2010

Schedule 8 CCA Bridge Year

Class	Class Description	UCC Test Year Opening Balance	Additions	Disposals	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Test Year CCA	UCC End of Bridge Year
1	Distribution System - post 1987	$ 37,632,279	$ -	$ -	$ 37,632,279	$ -	$ 37,632,279	4%	$ 1,505,291	$ 36,126,988
2	Distribution System - pre 1988	$ -	$ -	$ -	$ -	$ -	$ -	6%	$ -	$ -
8	General Office/Stores Equip	$ 635,340	$ 170,000	$ -	$ 805,340	$ 85,000	$ 720,340	20%	$ 144,068	$ 661,272
10	Computer Hardware/ Vehicles	$ 779,843	$ 362,000	$ -	$ 1,141,843	$ 181,000	$ 960,843	30%	$ 288,253	$ 853,590
10.1	Certain Automobiles	$ -	$ -	$ -	$ -	$ -	$ -	30%	$ -	$ -
12	Computer Software	$ 124,375	$ 130,000	$ -	$ 254,375	$ 65,000	$ 189,375	100%	$ 189,375	$ 65,000
13 1	Lease # 1	$ -	$ -	$ -	$ -	$ -	$ -	5	$ -	$ -
13 2	Lease #2	$ -	$ -	$ -	$ -	$ -	$ -	4	$ -	$ -
13 3	Lease # 3	$ -	$ -	$ -	$ -	$ -	$ -	3	$ -	$ -
13 4	Lease # 4	$ -	$ -	$ -	$ -	$ -	$ -	4	$ -	$ -
14	Franchise	$ -	$ -	$ -	$ -	$ -	$ -	7	$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	$ 235,037	$ -	$ -	$ 235,037	$ -	$ 235,037	8%	$ 18,803	$ 216,234
43.1	Certain Energy-Efficient Electrical Generating Equipment	$ -	$ -	$ -	$ -	$ -	$ -	30%	$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04	$ 50,983	$ -	$ -	$ 50,983	$ -	$ 50,983	45%	$ 22,942	$ 28,041
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ 164,488	$ -	$ -	$ 164,488	$ -	$ 164,488	30%	$ 49,346	$ 115,142
47	Distribution System - post February 2005	$ 14,998,239	$ 3,234,390	$ -	$ 18,232,629	$ 1,617,195	$ 16,615,434	8%	$ 1,329,235	$ 16,903,394
50	Data Network Infrastructure Equipment - post Mar 2007	$ 39,695	$ 63,000	$ -	$ 102,695	$ 31,500	$ 71,195	55%	$ 39,157	$ 63,538
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
	TOTAL	$ 54,660,279	$ 3,959,390	$ -	$ 58,619,669	$ 1,979,695	$ 56,639,974		$ 3,586,471	$ 55,033,198

PILs or Income Taxes Work
Name of LDC: Chatham-Kent Hydro Inc.
File Number: EB-2009-0261
Rate Year: 2010

Schedule 10 CEC Bridge Year

Cumulative Eligible Capital				**828,109**
Additions				
Cost of Eligible Capital Property Acquired during Test Year				
Other Adjustments	0			
Subtotal	0	**x 3/4 =**	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	**x 1/2 =**	0	
			0	**0**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				**828,109**
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year	0			
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	**0**
Cumulative Eligible Capital Balance				**828,109**
Current Year Deduction		**828,109**	**x 7% =**	**57,968**
Cumulative Eligible Capital - Closing Balance				**770,141**

PILs or Income Taxes Work Form

Name of LDC: Chatham-Kent Hydro Inc.
File Number: EB-2009-0261
Rate Year: 2010

Schedule 13 Tax Reserves Bridge

CONTINUITY OF RESERVES

Description	Historic Utility Only	Eliminate Amounts Not Relevant for Bridge Year	Adjusted Utility Balance	Bridge Year Adjustments: Additions	Bridge Year Adjustments: Disposals	Balance for Bridge Year	Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)	0		0			0	0	
Tax Reserves Not Deducted for accounting purposes								
Reserve for doubtful accounts ss. 20(1)(l)	105,444		105,444	95,000		200,444	95,000	
Reserve for goods and services not delivered ss. 20(1)(m)	4,579,743		4,579,743			4,579,743	0	
Reserve for unpaid amounts ss. 20(1)(n)	0		0			0	0	
Debt & Share Issue Expenses ss. 20(1)(e)	0		0			0	0	
Other tax reserves	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	**4,685,187**	**0**	**4,685,187**	**95,000**	**0**	**4,780,187**	**95,000**	**0**
Financial Statement Reserves (not deductible for Tax Purposes)								
General Reserve for Inventory Obsolescence (non-specific)	0		0			0	0	
General reserve for bad debts	0		0			0	0	
Accrued Employee Future Benefits:	0		0			0	0	
- Medical and Life Insurance	0		0			0	0	
-Short & Long-term Disability	0		0			0	0	
-Accmulated Sick Leave	0		0			0	0	
- Termination Cost	0		0			0	0	
- Other Post-Employment Benefits	858,565		858,565			858,565	0	
Provision for Environmental Costs	0		0			0	0	
Restructuring Costs	0		0			0	0	
Accrued Contingent Litigation Costs	0		0			0	0	
Accrued Self-Insurance Costs	0		0			0	0	
Other Contingent Liabilities	0		0			0	0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	0		0			0	0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	0		0			0	0	
Other	0		0			0	0	
Regulatory Asset Recovery	-134,554		-134,554			-134,554	0	
Asset Retirement Reserve	15,000		15,000			15,000	0	
Total	**739,011**	**0**	**739,011**	**0**	**0**	**739,011**	**0**	**0**

PILs or Income Taxes Work Form
Name of LDC: Chatham-Kent Hydro Inc.
File Number: EB-2009-0261
Rate Year: 2010

Sch 7-1 Loss Carry Forward Bridge

Corporation Loss Continuity and Application

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

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

Bridge Year Adjusted Taxable Income

Bridge		
	T2S1 line #	Total for Legal Entity
Income before PILs/Taxes	A	2,299,728
Additions:		
Interest and penalties on taxes	103	0
Amortization of tangible assets	104	3,946,813
Amortization of intangible assets	106	0
Recapture of capital cost allowance from Schedule 8	107	0
Gain on sale of eligible capital property from Schedule 10	108	0
Income or loss for tax purposes- joint ventures or partnerships	109	0
Loss in equity of subsidiaries and affiliates	110	0
Loss on disposal of assets	111	0
Charitable donations	112	0
Taxable Capital Gains	113	0
Political Donations	114	0
Deferred and prepaid expenses	116	0
Scientific research expenditures deducted on financial statements	118	0
Capitalized interest	119	0
Non-deductible club dues and fees	120	0
Non-deductible meals and entertainment expense	121	5,000
Non-deductible automobile expenses	122	0
Non-deductible life insurance premiums	123	0
Non-deductible company pension plans	124	0
Tax reserves deducted in prior year	125	5,424,198
Reserves from financial statements- balance at end of year	126	0
Soft costs on construction and renovation of buildings	127	0
Book loss on joint ventures or partnerships	205	0
Capital items expensed	206	0
Debt issue expense	208	0
Development expenses claimed in current year	212	0
Financing fees deducted in books	216	0
Gain on settlement of debt	220	0
Non-deductible advertising	226	0
Non-deductible interest	227	0
Non-deductible legal and accounting fees	228	0
Recapture of SR&ED expenditures	231	0
Share issue expense	235	0
Write down of capital property	236	0
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	0
Other Additions		
Interest Expensed on Capital Leases	290	0
Realized Income from Deferred Credit Accounts	291	1,348,849
Pensions	292	0
Non-deductible penalties	293	0
	294	0

Bridge

	T2S1 line #	Total for Legal Entity
	295	0
Total Additions		**10,724,860**
Deductions:		
Gain on disposal of assets per financial statements	401	39,996
Dividends not taxable under section 83	402	0
Capital cost allowance from Schedule 8	403	3,586,471
Terminal loss from Schedule 8	404	0
Cumulative eligible capital deduction from Schedule 10	405	57,968
Allowable business investment loss	406	0
Deferred and prepaid expenses	409	0
Scientific research expenses claimed in year	411	0
Tax reserves claimed in current year	413	0
Reserves from financial statements - balance at beginning of year	414	5,424,198
Contributions to deferred income plans	416	0
Book income of joint venture or partnership	305	0
Equity in income from subsidiary or affiliates	306	0
Other deductions: (Please explain in detail the nature of the item)		
Interest capitalized for accounting deducted for tax	390	0
Capital Lease Payments	391	0
Non-taxable imputed interest income on deferral and variance accounts	392	0
	393	0
	394	1,531,258
Total Deductions		**10,639,890**
Net Income for Tax Purposes		**2,384,698**
Charitable donations from Schedule 2	311	0
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320	0
Non-capital losses of preceding taxation years from Schedule 4	331	0
Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)*	332	0
Limited partnership losses of preceding taxation years from Schedule 4	335	0
TAXABLE INCOME		**2,384,698**

PILs or Income Taxes Work Form
Name of LDC: Chatham-Kent Hydro Inc.
File Number: EB-2009-0261
Rate Year: 2010

Schedule 8 CCA Test Year

Class	Class Description	UCC Test Year Opening Balance	Additions	Disposals	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Test Year CCA	UCC End of Test Year
1	Distribution System - post 1987	$ 36,126,988	$ -	$ -	$ 36,126,988	$ -	$ 36,126,988	4%	$ 1,445,080	$ 34,681,908
2	Distribution System - pre 1988	$ -	$ -	$ -	$ -	$ -	$ -	6%	$ -	$ -
8	General Office/Stores Equip	$ 661,272	$ 1,079,000	$ -	$ 1,740,272	$ 539,500	$ 1,200,772	20%	$ 240,154	$ 1,500,118
10	Computer Hardware/ Vehicles	$ 853,590	$ 478,000	$ -	$ 1,331,590	$ 239,000	$ 1,092,590	30%	$ 327,777	$ 1,003,813
10.1	Certain Automobiles	$ -	$ -	$ -	$ -	$ -	$ -	30%	$ -	$ -
12	Computer Software	$ 65,000	$ -	$ -	$ 65,000	$ -	$ 65,000	100%	$ 65,000	$ -
13 1	Lease # 1	$ -	$ -	$ -	$ -	$ -	$ -	0	$ -	$ -
13 2	Lease #2	$ -	$ -	$ -	$ -	$ -	$ -	0	$ -	$ -
13 3	Lease # 3	$ -	$ -	$ -	$ -	$ -	$ -	0	$ -	$ -
13 4	Lease # 4	$ -	$ -	$ -	$ -	$ -	$ -	0	$ -	$ -
14	Franchise	$ -	$ -	$ -	$ -	$ -	$ -	0	$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	$ 216,234	$ -	$ -	$ 216,234	$ -	$ 216,234	8%	$ 17,299	$ 198,935
43.1	Certain Energy-Efficient Electrical Generating Equipment	$ -	$ -	$ -	$ -	$ -	$ -	30%	$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04	$ 28,041	$ -	$ -	$ 28,041	$ -	$ 28,041	45%	$ 12,618	$ 15,422
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ 115,142	$ -	$ -	$ 115,142	$ -	$ 115,142	30%	$ 34,542	$ 80,599
47	Distribution System - post February 2005	$ 16,903,394	$ 3,802,531	$ -	$ 20,705,925	$ 1,901,266	$ 18,804,660	8%	$ 1,504,373	$ 19,201,552
50	Data Network Infrastructure Equipment - post Mar 2007	$ 63,538	$ 56,000	$ -	$ 119,538	$ 28,000	$ 91,538	55%	$ 50,346	$ 69,192
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
	TOTAL	$ 55,033,198	$ 5,415,531	$ -	$ 60,448,729	$ 2,707,766	$ 57,740,964		$ 3,697,189	$ 56,751,540

Schedule 10 CEC Test Year

Cumulative Eligible Capital				**770,141**
Additions				
Cost of Eligible Capital Property Acquired during Test Year	0			
Other Adjustments	0			
Subtotal	0	**x 3/4 =**	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	**x 1/2 =**	0	
			0	**0**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				**770,141**
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year	0			
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	**0**
Cumulative Eligible Capital Balance				**770,141**
Current Year Deduction (Carry Forward to Tab "Test Year Taxable Income")		**770,141**	**x 7% =**	**53,910**
Cumulative Eligible Capital - Closing Balance				**716,231**

PILs or Income Taxes Work Form
Name of LDC: Chatham-Kent Hydro Inc.
File Number: EB-2009-0261
Rate Year: 2010

Sch 7-1 Loss Carry Forward Bridge

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	**Total**	**Non-Distribution Portion**	**Utility Balance**
Actual/Estimated Bridge Year			0
Application of Loss Carry Forward to reduce taxable income in 2005			0
Other Adjustments Add (+) Deduct (-)			0
Balance available for use in Test Year	0	0	0
Amount to be used in Test Year			0
Balance available for use post Test Year	0	0	0

Net Capital Loss Carry Forward Deduction	**Total**	**Non-Distribution Portion**	**Utility Balance**
Actual/Estimated Bridge Year			0
Application of Loss Carry Forward to reduce taxable income in 2005			0
Other Adjustments Add (+) Deduct (-)			0
Balance available for use in Test Year	0	0	0
Amount to be used in Test Year			0
Balance available for use post Test Year	0	0	0

PILs or Income Taxes Work Form

Name of LDC: Chatham-Kent Hydro Inc.
File Number: EB-2009-0261
Rate Year: 2010

Taxable Income Test Year

	T2 S1 line #	Test Year Taxable Income
Net Income Before Taxes		1,796,597
Additions:		
Interest and penalties on taxes	103	
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104	4,119,278
Amortization of intangible assets *2-4 ADJUSTED ACCOUNTING DATA P490*	106	
Recapture of capital cost allowance from Schedule 8	107	
Gain on sale of eligible capital property from Schedule 10	108	
Income or loss for tax purposes- joint ventures or partnerships	109	
Loss in equity of subsidiaries and affiliates	110	
Loss on disposal of assets	111	
Charitable donations	112	0
Taxable Capital Gains	113	
Political Donations	114	
Deferred and prepaid expenses	116	
Scientific research expenditures deducted on financial statements	118	
Capitalized interest	119	
Non-deductible club dues and fees	120	
Non-deductible meals and entertainment expense	121	5,000
Non-deductible automobile expenses	122	
Non-deductible life insurance premiums	123	
Non-deductible company pension plans	124	
Tax reserves beginning of year	125	
Reserves from financial statements- balance at end of year	126	5,424,198
Soft costs on construction and renovation of buildings	127	
Book loss on joint ventures or partnerships	205	
Capital items expensed	206	
Debt issue expense	208	
Development expenses claimed in current year	212	
Financing fees deducted in books	216	
Gain on settlement of debt	220	
Non-deductible advertising	226	
Non-deductible interest	227	
Non-deductible legal and accounting fees	228	
Recapture of SR&ED expenditures	231	
Share issue expense	235	
Write down of capital property	236	
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	
Other Additions: (please explain in detail the nature of the item)		
Interest Expensed on Capital Leases	290	
Realized Income from Deferred Credit Accounts	291	1,531,258
Pensions	292	
Non-deductible penalties	293	
	294	
	295	
	296	
	297	
Total Additions		**11,079,734**

	T2 S1 line #	Test Year Taxable Income
Deductions:		
Gain on disposal of assets per financial statements	401	39,996
Dividends not taxable under section 83	402	
Capital cost allowance from Schedule 8	403	3,697,189
Terminal loss from Schedule 8	404	
Cumulative eligible capital deduction from Schedule 10 CEC	405	53,910
Allowable business investment loss	406	
Deferred and prepaid expenses	409	
Scientific research expenses claimed in year	411	
Tax reserves end of year	413	
Reserves from financial statements - balance at beginning of year	414	5,424,198
Contributions to deferred income plans	416	
Book income of joint venture or partnership	305	
Equity in income from subsidiary or affiliates	306	
Other deductions: (Please explain in detail the nature of the item)		
Interest capitalized for accounting deducted for tax	390	
Capital Lease Payments	391	
Non-taxable imputed interest income on deferral and variance accounts	392	
	393	
	394	1,531,258
	395	
	396	
	397	
Total Deductions		**10,746,551**
NET INCOME FOR TAX PURPOSES		**2,129,780**
Charitable donations	311	
Taxable dividends received under section 112 or 113	320	
Non-capital losses of preceding taxation years from Schedule 7-1	331	
Net-capital losses of preceding taxation years (Please show calculation)	332	
Limited partnership losses of preceding taxation years from Schedule 4	335	
REGULATORY TAXABLE INCOME		**2,129,780**

333,183

PILs or
Name of LDC: Chatham-Kent Hydro Inc.
File Number: EB-2009-0261
Rate Year: 2010

Ontario Capital Tax

Applicant	Rate Base	OCT Exemption
		15,000,000
Chatham-Kent Hydro Inc.	$ 56,073,568	$ 15,000,000
Affiliates (if applicable)		
1		$ -
2		$ -
3		$ -
4		$ -
5		$ -
Total	$ 56,073,568	$ 15,000,000

Section A

Wires Only

ONTARIO CAPITAL TAX

Rate Base	$ 56,073,568
Less: Exemption	$ 15,000,000
Deemed Taxable Capital	$ 41,073,568
Rate in Test Year	0.075%
Net Amount (Taxable Capital x Rate)	$ 30,805

PILs,Tax Provision

						Wires Only	
Regulatory Taxable Income						$ 2,129,780	**A**
Ontario Income Taxes							
Income tax payable	**Ontario income tax**	13.00%	**B**	$ 276,871	**C = A * B**		
Small business credit	Ontario Small Business Threshold	$ 500,000	**D**				
	Rate reduction	-8.50%	**E**	-$ 42,500	**F = D * E**		
Surtax		$ 1,000,000	**G = A - D**				
	Ontario surtax claw-back	4.25%	**H**	$ 42,500	**I = G * H**		
Ontario Income tax						$ 276,871	**J = C + F + I**
Combined Tax Rate and PILs	Effective Ontario Tax Rate			13.00%	**K = J / A**		
	Federal tax rate			18.00%	**L**		
	Combined tax rate					31.00%	**M = L + L**
Total Income Taxes						**$ 660,232**	**N = A * M**
Investment Tax Credits							**O**
Miscellaneous Tax Credits							**P**
Total Tax Credits						$ -	**Q = O + P**
Corporate PILs/Income Tax Provision for Test Year						**$ 660,232**	**R = N - Q**
Corporate PILs/Income Tax Provision Gross Up				69.00%	**S = 1 - M**	**$ 296,626**	**T = R / S - N**
Income Tax (grossed-up)						**$ 956,858**	**U = R + T**
Ontario Capital Tax (not grossed-up)						**$ 30,805**	**V**
Tax Provision for Test Year Rate Recovery						**$ 987,663**	**W = U + V**

OVERVIEW:

The purpose of this evidence is to summarize the method and cost of financing capital requirements for the 2010 Test Year.

Capital Structure:

Chatham-Kent Hydro has a current deemed capital structure of 56.7% debt with a return of 7.04%, and 43.3% equity with a return of 9% as approved in the 2009 IRM rate decision (EB-2008-0855).

Chatham-Kent Hydro has prepared this Application with a deemed capital structure of 56% Long Term Debt, 4% Short Term Debt, and 40% Equity to comply with the Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario Electricity Distributors dated December 20, 2006 (the "Cost of Capital Report").

Chatham-Kent Hydro is aware of and is participating in the OEB's review of the Cost of Capital (EB-2009-0084) and expects the outcome of that proceeding may impact the capital structure and the overall cost of capital.

Return on Equity:

Chatham-Kent Hydro is requesting a return on equity ("ROE") for the 2010 Test Year of 8.01% in accordance with the Cost of Capital Parameter Updates for 2009 Cost of Service Applications issued by the OEB on February 24, 2009.

Chatham-Kent Hydro also understands that the OEB will be finalizing the ROE for 2010 rates based on January 2010 market interest rate information.

Chatham-Kent Hydro's use of an ROE of 8.01% is without prejudice to the outcome of the regulatory proceeding (EB-2009-0084) and any revised ROE that may be adopted by the OEB in early 2010.

Cost of Debt: Long Term

Chatham-Kent Hydro is requesting a return on Long Term Debt for the 2010 Test Year of 7.62% in accordance with the Cost of Capital Parameter Updates for 2009 Cost of Service Applications issued by the OEB on February 24, 2009. The current rate of 7.04% is being paid on the existing Long Term Debt ($23,523,326) with the Municipality of Chatham-Kent, the major shareholder of Chatham-Kent Energy. In the Cost of Capital Report the OEB 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". Chatham-Kent Hydro has not renegotiated the interest rate on the current Long Term Debt and it is callable at the discretion of the Municipality of Chatham-Kent.

Chatham-Kent Hydro also understands that the OEB will be finalizing the Long Term Debt rate for 2010 rates based on January 2010 market interest rate information.

Chatham-Kent Hydro's use of a Long Term Debt rate of 7.62% is without prejudice to the outcome of the regulatory proceeding (EB-2009-0084) and any revised Long Term Debt rate that may be adopted by the OEB in early 2010.

Cost of Debt: Short Term

Chatham-Kent Hydro is requesting a return on Short Term Debt for the 2010 Test year of 1.33% in accordance with the Cost of Capital Parameter Updates for 2009 Cost of Service Applications issued by the OEB on February 24, 2009.

Chatham-Kent Hydro understands that the OEB will be finalizing the return on short term debt for 2010 rates based on January 2010 market interest rate information.

Chatham-Kent Hydro's use of a Return on Short Term Debt of 1.33% is without prejudice to the outcome of the regulatory proceeding (EB-2009-0084) and any revised Short Term Debt rate that may be adopted by the OEB in early 2010.

Rate Base and Rate of Return

Exhibit 5, Tab 1, Schedule 2 details Chatham-Kent Hydro's rate base, deemed debt/equity ratios, deemed rate of return, actual debt/equity ratios and actual rates of return for 2006 Board Approved, 2006 Actual, 2008 Actual, 2009 Bridge Year Forecast, and 2010 Test Year Forecast.

Capital Structure and Cost of Capital:

Chatham-Kent Hydro has used the Capital Structure that complies with the Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario Electricity Distributors dated December 20, 2006 (the "Cost of Capital Report").

The calculation of the Capital components in the Cost of Capital is illustrated in Table 5-1 for 2006 to 2010. The information on the Debt Arrangement with the Municipality of Chatham-Kent and other Companies is attached as Appendix A.

Table 5-1

Capitalization and Cost of Capital

Deemed Capital Structure for Board Approved 2006

Description	%	$	Cost Rate	Return
	Capitalization Ratio			
Debt				
Long Term Debt	50.00%	22,165,200	7.04%	1,560,430
Short Term Debt				
Total Debt	50.00%	22,165,200		1,560,430
Equity				
Common Share Equity	50.00%	28,144,322	9.00%	2,532,989
Preferred Shares				
Total Equity	50.00%	28,144,322		2,532,989
Total Rate Base	100.00%	50,309,522	8.14%	4,093,419

Deemed Capital Structure for 2006

Description	%	$	Cost Rate	Return
	Capitalization Ratio			
Debt				
Long Term Debt	50.00%	25,906,779	7.04%	1,823,837
Short Term Debt				
Total Debt	50.00%	25,906,779		1,823,837
Equity				
Common Share Equity	50.00%	25,906,779	9.00%	2,331,610
Preferred Shares				
Total Equity	50.00%	25,906,779		2,331,610
Total Rate Base	100.00%	51,813,558	8.02%	4,155,447

Deemed Capital Structure for 2007

Description	Capitalization Ratio %	$	Cost Rate	Return
Debt				
Long Term Debt	50.00%	27,001,734	7.04%	1,900,922
Short Term Debt				
Total Debt	50.00%	27,001,734		1,900,922
Equity				
Common Share Equity	50.00%	27,001,734	9.00%	2,430,156
Preferred Shares				
Total Equity	50.00%	27,001,734		2,430,156
Total Rate Base	100.00%	54,003,469	8.02%	4,331,078

Deemed Capital Structure for 2008

Description	Capitalization Ratio %	$	Cost Rate	Return
Debt				
Long Term Debt	53.33%	29,669,930	7.04%	2,088,763
Short Term Debt				
Total Debt	53.33%	29,669,930		2,088,763
Equity				
Common Share Equity	46.67%	25,964,666	9.00%	2,336,820
Preferred Shares				
Total Equity	46.67%	25,964,666		2,336,820
Total Rate Base	100.00%	55,634,596	7.95%	4,425,583

Deemed Capital Structure for 2009

Description	Capitalization Ratio %	$	Cost Rate	Return
Debt				
Long Term Debt	56.67%	31,446,572	7.04%	2,213,839
Short Term Debt				
Total Debt	56.67%	31,446,572		2,213,839
Equity				
Common Share Equity	43.33%	24,044,114	9.00%	2,163,970
Preferred Shares				
Total Equity	43.33%	24,044,114		2,163,970
Total Rate Base	100.00%	55,490,686	7.89%	4,377,809

Deemed Capital Structure for 2010

Description	Capitalization Ratio %	$	Cost Rate	Return
Debt				
Long Term Debt	56.00%	31,401,198	7.62%	2,392,771
Short Term Debt	4.00%	2,242,943	1.33%	29,831
Total Debt	60.00%	33,644,141		2,422,602
Equity				
Common Share Equity	40.00%	22,429,427	8.01%	1,796,597
Preferred Shares				
Total Equity	40.00%	22,429,427		1,796,597
Total Rate Base	100.00%	56,073,568	7.52%	4,219,200

APPENDIX A

LONG TERM DEBT ARRANGEMENT

Long Term Debt Arrangements

Current Long Term Debt

Chatham-Kent Hydro has a Long Term Note with the Municipality of Chatham-Kent which is the major shareholder of Chatham-Kent Energy. This debt was put into place based on the Transfer Bylaw upon the incorporation of Chatham-Kent Hydro on September 20, 2000.

The terms of the long term debt are;

- Interest rate paid will be the interest rate allowed in distribution rates and approved by the OEB
- There are no set repayment terms
- Callable at the discretion of the Municipality of Chatham-Kent

New Long Term Debt

Chatham-Kent Hydro plans on incurring new Long Term Debt in the amount of $1,000,000 and $2,000,000 in 2009 and 2010 respectively. The Long Term Debt will be provided from the shareholder, Chatham-Kent Energy and the terms will be;

- Interest rate paid will be the interest rate allowed in distribution rates and approved by the OEB
- There will be no set repayment terms
- Callable at the discretion of Chatham-Kent Energy.

REVENUE DEFICIENCY:

OVERVIEW

Chatham-Kent Hydro has provided detailed calculations supporting its 2010 revenue deficiency. Chatham-Kent Hydro’s net revenue deficiency is $1,241,796 and when grossed up for PILs Chatham-Kent Hydro’s revenue deficiency is $1,799,705. Table 6-1 on the following page provides the revenue deficiency calculations for the 2009 Bridge Year, 2010 Test Year at Existing 2009 OEB-approved rates and the 2010 Test Year Revenue Requirement.

Table 6-1
Revenue Sufficiency/Deficiency

Description	2009 Bridge	2010 Test Existing Rates	2010 Test - Required Revenue
Revenue			
Revenue Deficiency			**1,799,705**
Distribution Revenue	12,800,555	12,838,181	12,838,181
Other Operating Revenue (Net)	1,181,584	1,187,450	1,187,450
Smart Meter Deferral Account Adjustment			
Total Revenue	**13,982,139**	**14,025,631**	**15,825,336**
Costs and Expenses			
Administrative & General, Billing & Collecting	4,064,299	4,574,078	4,574,078
Operation & Maintenance	1,761,886	2,229,034	2,229,034
Depreciation & Amortization	3,701,765	3,815,361	3,815,361
Property Taxes	0	0	0
Capital Taxes	91,104	30,805	30,805
Deemed Interest	2,088,763	2,422,602	2,422,602
Total Costs and Expenses	**11,707,817**	**13,071,881**	**13,071,881**
Less OCT Included Above			
Total Costs and Expenses Net of OCT	**11,707,817**	**13,071,881**	**13,071,881**
Utility Income Before Income Taxes	**2,274,322**	**953,750**	**2,753,455**
Income Taxes:			
Corporate Income Taxes	876,644	398,949	956,858
Total Income Taxes	**876,644**	**398,949**	**956,858**
Utility Net Income	**1,397,678**	**554,801**	**1,796,597**
Capital Tax Expense Calculation:			
Total Rate Base	55,490,686	56,073,568	56,073,568
Exemption	15,000,000	15,000,000	15,000,000
Deemed Taxable Capital	**40,490,686**	**41,073,568**	**41,073,568**
Ontario Capital Tax	91,104	30,805	30,805
Income Tax Expense Calculation:			
Accounting Income	2,274,322	953,750	2,753,455
Tax Adjustments to Accounting Income	382,175	333,183	333,183
Taxable Income	**2,656,497**	**1,286,933**	**3,086,638**
Income Tax Expense	876,644	398,949	956,858
	33.00%	31.00%	31.00%
Actual Return on Rate Base:			
Rate Base	55,490,686	56,073,568	56,073,568
Interest Expense	2,088,763	2,422,602	2,422,602
Net Income	1,397,678	554,801	1,796,597
Total Actual Return on Rate Base	**3,486,441**	**2,977,403**	**4,219,200**
Actual Return on Rate Base	6.28%	5.31%	7.52%
Required Return on Rate Base:			
Rate Base	55,490,686	56,073,568	56,073,568
Return Rates:			
Return on Debt (Weighted)	7.04%	7.20%	7.20%
Return on Equity	9.00%	8.01%	8.01%
Deemed Interest Expense	2,083,360	2,422,602	2,422,602
Return On Equity	2,330,775	1,796,597	1,796,597
Total Return	**4,414,135**	**4,219,200**	**4,219,200**
Expected Return on Rate Base	7.95%	7.52%	7.52%
Revenue Deficiency After Tax	**927,694**	**1,241,796**	**-0**
Revenue Deficiency Before Tax	**1,384,618**	**1,799,705**	**-0**

Cost Drivers on Sufficiency/Deficiency

Chatham-Kent Hydro has encountered a number of situations that will affect revenue and operation expenditures. Current economic conditions have caused a reduction in revenue; and incorporating the mandated changes from the OEB such as the requirements for LEAP which is one the drivers for the increase in the Administrative Expenditures, and the addition of staff in apprenticeship programs to prepare for upcoming retirements have affected costs.

Distribution Revenue

Chatham-Kent Hydro's service area is currently encountering numerous shut down and slow downs from businesses in the GS greater than 50kW and the Large User class. The slowdown of the businesses is causing a significant reduction in demand and consumption. This directly relates to a reduction in revenue ($625,000).

There also continues to be significant reduction in consumption by the Residential class as a result of the many conservation programs that Chatham-Kent Hydro offers and supports ($139,000).

Lower volumes directly produce a reduction in revenue which contributes to the revenue deficiency.

Operation and Maintenance Expense

Chatham-Kent Hydro has recently experienced the retirement of two linepersons and will have another two linepersons retire in the next few years. There will also be a retirement of a meter technician. The time required to fully train and have an employee work through the apprenticeship programs is four years, and requires Chatham-Kent Hydro to hire five new staff members in 2010. Therefore there are additional staff members in the 2010 Test Year to ensure that Chatham-Kent Hydro has enough qualified linepersons and meter technicians to ensure service quality and safety standards are met. Chatham-Kent Hydro also requires additional staff to meet the new regulations and again ensure Chatham-Kent Hydro meets service quality and safety standards ($380,000).

Administration and Billing

Chatham-Kent Hydro is incorporating a number of changes for LEAP, which entails going to monthly billing for the residential customers ($172,000). Chatham-Kent Hydro will also receive additional services on information technology infrastructure to meet the new accounting standards (IFRS) which includes regulatory support and reporting ($185,000). An upgrade of customer information system and additional network security is also required. The increased network security is required due to the investments in smart meters and the introduction of time-of-use billing which is interfaced with the Meter Data Management and Repository ("MDMR") of the IESO ($40,000).

COST ALLOCATION:

Overview

On September 15, 2006, the OEB issued its directions on Cost Allocation Methodology for Electricity Distributors (the "Directions"). On November 15, 2006, the Board issued the Cost Allocation Information Filing Guidelines for Electricity Distributors ("the Guidelines"), the Cost Allocation Model (the "Model") and User Instructions (the "Instructions") for the Model. Chatham-Kent Hydro prepared a cost allocation filing based on a 2010 forecast consistent with Chatham-Kent Hydro's understanding of the Directions, the Guidelines, the Model and the Instructions.

Chatham-Kent Hydro had originally submitted a cost allocation informational filing to the OEB on February 28, 2007 based on 2006 Board Approved data.

The information filing on February 28, 2007 provided information on cross subsidization among rate classes. The information also provided an indication as to what potential changes will occur in the service charge for each rate class.

Chatham-Kent Hydro has taken the cost allocation model and updated the information to reflect the 2010 Test Year information. The outcome of the updated cost allocation model has been used to assist in allocating costs to reduce cross subsidization and to propose the fixed service charge.

SUMMARY OF RESULTS AND PROPOSED CHANGES:

Cost Allocation Study:

The data used in the Cost Allocation Model has been updated using the 2010 load forecast volume, rate classes and number of customers. The load forecast for 2010 is much lower than the cost allocation information filing that Chatham-Kent Hydro provided to the OEB previously. One of the more significant changes is in the large user rate class where one of the customers has idled the plant causing a 32,416,430 kWh decline in volume and the other customer has begun to reduce its consumption. There are also a number of General Service greater than 50 kWcustomers that have closed or slowed down production. Additional information regarding load reductions is found in Exhibit 3.

Chatham-Kent Hydro is proposing to no longer have a large user class as the two customers in this class are not expected to meet the criteria of being a Large User customer. As a result the historical load for these customers has been moved to their new Intermediate rate class.

Chatham-Kent Hydro is proposing to have a new rate class, Intermediate, which is to replace the Time of Use class. The Intermediate rate class is defined as customers with 1,000 to 4,999 kW demand. Therefore some customers in the > 50 kW General Service class, Time of Use class and Large User class will be moved into the Intermediate class. For consistency purposes customers in this class have had all their historical and forecasted loads moved to the new rate class.

Chatham-Kent Hydro is also proposing another new class, the Standby class. While Chatham-Kent Hydro has had a stand-by rate, there has not been a separate rate class for this type of customer. The customer was previously in the Time of Use class and has a generator on site. Due to the size of the customer, the significant load of the generator on site and the unique customer profile Chatham-Kent Hydro is proposing to have a separate class for this customer.

The Unmetered Scattered Load customers are now classified in a separate rate class. They were previously included in the General Service < 50 kW rate class.

The methodology of the updated Cost Allocation model is consistent with the methodology used in the 2006 Cost Allocation Model. Consistent with the Guidelines, Chatham-Kent Hydro's assets were broken out into primary and secondary distribution functions. The breakout of assets, capital contributions, depreciation, accumulated depreciation, customer data and load data by primary, line transformer and secondary categories was developed from the best data available to Chatham-Kent Hydro, its engineering records, and its customer and financial information systems.

The results of a cost allocation study are typically presented in the form of revenue to cost ratios. The ratio is shown by rate classification and is the percentage of distribution revenue collected by rate classification compared to the costs allocated to the classification. The percentage identifies the rate classifications that are being subsidized and those that are over-contributing. A percentage of less than 100% means the rate classification is under-contributing and is being subsidized by other classes of customers. A percentage of greater than 100% indicates the rate classification is over-contributing and is subsidizing other classes of customers.

Initial Cost Allocation Filing:

The following Table 7-1 outlines the revenue to cost ratios from the Cost Allocation Informational Filing submitted by Chatham-Kent Hydro on February 28, 2007. The calculations are based on Chatham-Kent Hydro's OEB-approved 2006 electricity distribution rates.

Table 7-1
Revenue to Cost Ratios as Filed in Chatham-Kent Hydro Inc.'s Initial Cost Allocation Informational Filing

Rate Classification	Revenue	Allocated Cost	Revenue to Cost Percentage
Residential	8,192,905	8,280,031	98.9%
General Service < 50	2,353,516	2,287,360	102.9%
General Service 50 to 999	2,150,693	2,123,250	101.3%
Intermediate 1,000 to 4,999	545,867	589,123	92.7%
Large user	646,498	199,150	324.6%
Streetlight	144,972	329,450	44.0%
Sentinel Light	22,763	47,936	47.5%
Unmetered Scattered	80,415	27,445	293.0%
Standby	112,559	366,441	30.7%
Total	14,250,188	14,250,186	

The following Table 7-2 outlines the revenue to cost ratios with the transformer allowance excluded from the Cost Allocation Informational Filing submitted by Chatham-Kent Hydro on February 28, 2007. The calculations are based on Chatham-Kent Hydro's OEB-approved 2006 electricity distribution rates.

Table 7-2
Initial Cost Allocation Informational Filing excluding Transformer Allowance

Rate Classification	Revenue	Allocated Cost	Revenue to Cost Percentage
Residential	8,192,868	7,963,863	102.9%
General Service < 50	2,353,491	2,192,120	107.4%
General Service 50 to 999	1,840,630	2,090,263	88.1%
Intermediate 1,000 to 4,999	447,730	599,082	74.7%
Large user	573,349	202,390	283.3%
Streetlight	144,949	309,379	46.9%
Sentinel Light	22,760	45,246	50.3%
Unmetered Scattered	80,413	25,860	311.0%
Standby	112,526	340,513	33.0%
Total	13,768,717	13,768,716	

Updated Cost Allocation:

In preparing for this rate Application a number of customers have been reclassified based on the level of consumption. As noted above the Large User rate class has been eliminated, and the customer has been transferred to the Intermediate rate class. The revenue to cost ratios for the updated study based on 2010 forecast information is provided in Table 7-3 below:

Table 7-3
Revenue to Cost Ratios from Chatham-Kent Hydro Inc.'s
2010 Cost Allocation Information

Rate Classification	Revenue	Allocated Cost	Revenue to Cost Percentage
Residential	9,083,307	9,057,735	100.3%
General Service < 50	2,459,892	2,282,774	107.8%
General Service 50 to 999	1,692,959	2,709,615	62.5%
Intermediate 1,000 to 4,999	2,556,894	1,002,962	254.9%
Streetlight	146,611	337,632	43.4%
Sentinel Light	23,325	46,626	50.0%
Unmetered Scattered	17,161	32,100	53.5%
Standby	237,068	747,772	31.7%
Total	16,217,217	16,217,217	

The following Table 7-4 outlines the revenue to cost ratios with the transformer allowance excluded from the Cost Allocation based on 2010 forecast.

Table 7-4
Revenue to Cost Ratios from Chatham-Kent Hydro Inc.'s
2010 Cost Allocation Information excluding Transformer Allowance

Rate Classification	Revenue	Allocated Cost	Revenue to Cost Percentage
Residential	8,866,877	8,861,291	100.1%
General Service < 50	2,400,936	2,235,926	107.4%
General Service 50 to 999	1,652,809	2,610,399	63.3%
Intermediate 1,000 to 4,999	2,491,371	1,015,234	245.4%
Streetlight	143,090	322,705	44.3%
Sentinel Light	22,759	44,658	51.0%
Unmetered Scattered	15,983	30,678	52.1%
Standby	231,511	704,443	32.9%
Total	15,825,336	15,825,336	

In the table 7-5 is a summary of the revenue to cost ratios comparing the Initial Cost Allocation Model to the updated Cost Allocation based on 2010 Test Year Revenue.

Table 7-5
Summary of Revenue to Cost Ratio

Rate Classification	Initial Cost Model	Initial Cost Alloc. Model without Transformer Allow	2010 Cost Allocation Model	2010 Cost Alloc. Model without Transformer Allow.
Residential	98.9%	102.9%	100.3%	100.1%
General Service < 50	102.9%	107.4%	107.8%	107.4%
General Service 50 to 999	101.3%	88.1%	62.5%	63.3%
Intermediate 1,000 to 4,999	92.7%	74.7%	254.9%	245.4%
Large User	324.6%	283.3%		
Streetlight	44.0%	46.9%	43.4%	44.3%
Sentinel Light	47.5%	50.3%	50.0%	51.0%
Unmetered Scattered	293.0%	311.0%	53.5%	52.1%
Standby	30.7%	33.0%	31.7%	32.9%

Proposed Adjustment to Cost Allocation:

On November 28, 2007, the OEB issued its "Report on Application of Cost Allocation for Electricity Distributors" (the "Cost Allocation Report"). In the Cost Allocation Report, the OEB established what it considered to be the appropriate ranges of revenue to cost ratios.

Chatham-Kent Hydro is proposing in this Application to re-align its revenue to cost ratios by adjusting the allocations of revenue among rate classes in order to reduce some of the cross-subsidization that is occurring.

The following table outlines the revenue splits required to achieve the proposed revenue to cost ratios

Table 7-6
Revenue Split by Rate Class to Achieve Proposed Revenue to Cost Ratios

Rate Classification	Revenue split to achieve Revenue cost Ratio
Residential	54.2%
General Service < 50	14.8%
General Service 50 to 999	17.2%
Intermediate 1,000 to 4,999	9.0%
Streetlight	2.0%
Sentinel Light	0.3%
Unmetered Scattered	0.2%

Cost Allocation Summary

The discussion and tables above support Chatham-Kent Hydro's proposed reallocation of distribution revenues across customer classes, in order to begin moving toward revenue to cost ratios of 100% and reduce cross-subsidization. Chatham-Kent Hydro submits that the proposed reallocation of distribution revenue is fair and reasonable for the following reasons:

- Customer class revenues will more closely reflect the actual costs of providing distribution service to that class; and
- The allocations take into account customer impacts and any possible rate mitigation.

Table 7-7
Revenue to Cost Ratio (%)

Rate Classification	From cost Allocation Model	Column 1 Revised Transformer Ownership Allowance	Proposed for Test Year	Board Target Range
Residential	100.28%	100.06%	98.12%	85-115%
General Service < 50	107.76%	107.38%	105.26%	80-120%
General Service 50 to 999	62.48%	63.32%	101.92%	80-180%
Intermediate 1,000 to 4,999	254.93%	245.40%	133.60%	80-180%
Streetlight	43.42%	44.34%	94.22%	70-120%
Sentinel Light	50.03%	50.96%	85.46%	70-120%
Unmetered Scattered	53.46%	52.10%	94.16%	80-120%
Standby	31.70%	32.86%	55.29%	80-180%

Table 7-8
Test Year Revenue Impacts

Rate Classification	Current Revenue	Test Year Revenue Assuming Current Revenue to Cost Ratio	Test Year Revenue Assuming Proposed Revenue to Cost Ratio
Residential	6,887,599	8,100,391	7,927,879
General Service < 50	1,876,182	2,206,546	2,159,088
General Service 50 to 999	1,277,736	1,502,724	2,510,397
Intermediate 1,000 to 4,999	2,085,182	2,452,348	1,317,410
Streetlight	112,056	131,787	292,758
Sentinel Light	18,016	21,188	36,595
Unmetered Scattered	12,675	14,907	27,812
Standby	176,853	207,994	365,947
Total	12,446,299	14,637,886	14,637,886

APPENDIX A

COST ALLOCATION MODEL – INITIAL FILING

2006 Cost Allocation Information Filing
Chatham Kent Hydro Inc.
EB-2005-0350 EB-2006-0247
Monday, January 15, 2007

Sheet I2 Class Selection - Second Run

Instructions:
Step 1: Pleae input your existing classes
Step 2: If this is your first run, select "First Run" in the drop-down menu below
Step 3: After all classes have been entered, Click the "Update" button in row E41

Click for Drop-Down Menu → Second Run

If desired, provide a summary of this run (40 characters max.)

		Utility's Class Definition	Current
1	Residential		YES
2	GS <50		YES
3	GS>50-Regular		YES
4	GS> 50-TOU		YES
5	GS >50-Intermediate		YES
6	Large Use >5MW		YES
7	Street Light		YES
8	Sentinel		YES
9	Unmetered Scattered Load		YES
10	Embedded Distributor		NO
11	Back-up/Standby Power		YES
12	Rate Class 1		NO
13	Rate class 2		NO
14	Rate class 3		NO
15	Rate class 4		NO
16	Rate class 5		NO
17	Rate class 6		NO
18	Rate class 7		NO
19	Rate class 8		NO
20	Rate class 9		NO

Update

** **Space available for additional information about this run**

2006 Cost Allocation Information Filing
Chatham Kent Hydro Inc.
EB-2005-0350 EB-2006-0247
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	Differences?
Approved Target Net Income ($)	$2,263,928		
Approved PILs ($)	$1,572,932		
Approved Interest ($)	$1,770,895		
Approved Specific Service Charges ($)	$348,917		
Approved Transformer Ownership Allowance ($)	$481,469		
Approved Low Voltage Wheeling Adjustment ($)	$562,500		
Approved Revenue Requirement ($)	$14,331,218		
Revenue Requirement to be Used in this model ($)	$14,250,187	**$14,250,186**	**Rev Req Matches**
Approved Rate Base ($)	$50,309,522		
Rate Base to be Used in this model ($)	$50,297,367	**$50,297,367**	**Rate Base Matches**

Uniform System of Accounts - Detail Accounts

USoA Account #	Accounts	Financial Statement (EDR Sheet 2.4, Column P)	Model Adjustments	Reclassify accounts	Direct Allocation	Reclassified Balance
1005	Cash	$0				$0
1010	Cash Advances and Working Funds	$0				$0
1020	Interest Special Deposits	$0				$0
1030	Dividend Special Deposits	$0				$0
1040	Other Special Deposits	$0				$0
1060	Term Deposits	$0				$0
1070	Current Investments	$0				$0
1100	Customer Accounts Receivable	$0				$0
1102	Accounts Receivable - Services	$0				$0
1104	Accounts Receivable - Recoverable Work	$0				$0
1105	Accounts Receivable - Merchandise, Jobbing, etc.	$0				$0
1110	Other Accounts Receivable	$0				$0
1120	Accrued Utility Revenues	$0				$0
1130	Accumulated Provision for Uncollectible Accounts--Credit	$0				$0
1140	Interest and Dividends Receivable	$0				$0
1150	Rents Receivable	$0				$0
1170	Notes Receivable	$0				$0
1180	Prepayments	$0				$0
1190	Miscellaneous Current and Accrued Assets	$0				$0
1200	Accounts Receivable from Associated Companies	$0				$0
1210	Notes Receivable from Associated Companies	$0				$0
1305	Fuel Stock	$0				$0
1330	Plant Materials and Operating Supplies	$0				$0
1340	Merchandise	$0				$0
1350	Other Materials and Supplies	$0				$0
1405	Long Term Investments in Non-Associated Companies	$0				$0
1408	Long Term Receivable - Street Lighting Transfer	$0				$0
1410	Other Special or Collateral Funds	$0				$0

1415	Sinking Funds	$0				$0
1425	Unamortized Debt Expense	$0				$0
1445	Unamortized Discount on Long-Term Debt--Debit	$0				$0
1455	Unamortized Deferred Foreign Currency Translation Gains and Losses	$0				$0
1460	Other Non-Current Assets	$0				$0
1465	O.M.E.R.S. Past Service Costs	$0				$0
1470	Past Service Costs - Employee Future Benefits	$0				$0
1475	Past Service Costs - Other Pension Plans	$0				$0
1480	Portfolio Investments - Associated Companies	$0				$0
1485	Investment in Associated Companies - Significant Influence	$0				$0
1490	Investment in Subsidiary Companies	$0				$0
1505	Unrecovered Plant and Regulatory Study Costs	$0				$0
1508	Other Regulatory Assets	$0				$0
1510	Preliminary Survey and Investigation Charges	$0				$0
1515	Emission Allowance Inventory	$0				$0
1516	Emission Allowances Withheld	$0				$0
1518	RCVARetail	$0				$0
1520	Power Purchase Variance Account	$0				$0
1525	Miscellaneous Deferred Debits	$0				$0
1530	Deferred Losses from Disposition of Utility Plant	$0				$0
1540	Unamortized Loss on Reacquired Debt	$0				$0
1545	Development Charge Deposits/ Receivables	$0				$0
1548	RCVASTR	$0				$0
1560	Deferred Development Costs	$0				$0
1562	Deferred Payments in Lieu of Taxes	$0				$0
1563	Account 1563 - Deferred PILs Contra Account	$0				$0
1565	Conservation and Demand Management Expenditures and Recoveries	$524,558				$524,558
1570	Qualifying Transition Costs	$0				$0
1571	Pre-market Opening Energy Variance	$0				$0
1572	Extraordinary Event Costs	$0				$0
1574	Deferred Rate Impact Amounts	$0				$0
1580	RSVAWMS	$0				$0
1582	RSVAONE-TIME	$0				$0
1584	RSVANW	$0				$0
1586	RSVACN	$0				$0
1588	RSVAPOWER	$0				$0
1590	Recovery of Regulatory Asset Balances	$0				$0
1605	Electric Plant in Service - Control Account	$0				$0
1606	Organization	$0				$0
1608	Franchises and Consents	$0				$0
1610	Miscellaneous Intangible Plant	$0				$0
1615	Land	$0				$0
1616	Land Rights	$0				$0
1620	Buildings and Fixtures	$0				$0
1630	Leasehold Improvements	$0				$0
1635	Boiler Plant Equipment	$0				$0
1640	Engines and Engine-Driven Generators	$0				$0
1645	Turbogenerator Units	$0				$0
1650	Reservoirs, Dams and Waterways	$0				$0
1655	Water Wheels, Turbines and Generators	$0				$0
1660	Roads, Railroads and Bridges	$0				$0
1665	Fuel Holders, Producers and Accessories	$0				$0
1670	Prime Movers	$0				$0
1675	Generators	$0				$0
1680	Accessory Electric Equipment	$0				$0
1685	Miscellaneous Power Plant Equipment	$0				$0
1705	Land	$0				$0
1706	Land Rights	$0				$0
1708	Buildings and Fixtures	$0				$0
1710	Leasehold Improvements	$0				$0
1715	Station Equipment	$0				$0
1720	Towers and Fixtures	$0				$0
1725	Poles and Fixtures	$0				$0
1730	Overhead Conductors and Devices	$0				$0
1735	Underground Conduit	$0				$0
1740	Underground Conductors and Devices	$0				$0
1745	Roads and Trails	$0				$0
1805	Land	$189,212				$189,212
1806	Land Rights	$0				$0
1808	Buildings and Fixtures	$435,610				$435,610
1810	Leasehold Improvements	$0				$0
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0				$0
1820	Distribution Station Equipment - Normally Primary below 50 kV	$210,827		$463,230		$674,056
1825	Storage Battery Equipment	$0				$0
1830	Poles, Towers and Fixtures	$1,879,967		($44,957)	$218,922	$1,616,088
1835	Overhead Conductors and Devices	$15,069,503		($103,123)	$726,018	$14,240,362
1840	Underground Conduit	$616,722				$616,722
1845	Underground Conductors and Devices	$12,195,195		($80)		$12,195,115
1850	Line Transformers	$10,834,508		($10,483)	$4,487	$10,819,538
1855	Services	$1,713,773		($4,967)	$12,577	$1,696,229
1860	Meters	$2,803,649		($299,620)	$22,512	$2,481,518
1865	Other Installations on Customer's Premises	$0				$0
1870	Leased Property on Customer Premises	$0				$0
1875	Street Lighting and Signal Systems	$0				$0
1905	Land	$205,766				$205,766
1906	Land Rights	$0				$0
1908	Buildings and Fixtures	$2,644,076				$2,644,076
1910	Leasehold Improvements	$0				$0

1915	Office Furniture and Equipment		$76,027			$76,027
1920	Computer Equipment - Hardware		$308,327			$308,327
1925	Computer Software		$9,144			$9,144
1930	Transportation Equipment		$1,426,340			$1,426,340
1935	Stores Equipment		$0			$0
1940	Tools, Shop and Garage Equipment		$487,765			$487,765
1945	Measurement and Testing Equipment		$0			$0
1950	Power Operated Equipment		$0			$0
1955	Communication Equipment		$0			$0
1960	Miscellaneous Equipment		$0			$0
1965	Water Heater Rental Units		$0			$0
1970	Load Management Controls - Customer Premises		$0			$0
1975	Load Management Controls - Utility Premises		$0			$0
1980	System Supervisory Equipment		$597,956			$597,956
1985	Sentinel Lighting Rental Units		$0			$0
1990	Other Tangible Property		$1,311,799			$1,311,799
1995	Contributions and Grants - Credit		($2,488,420)		($2,488,420)	$0
2005	Property Under Capital Leases		$0			$0
2010	Electric Plant Purchased or Sold		$0			$0
2020	Experimental Electric Plant Unclassified		$0			$0
2030	Electric Plant and Equipment Leased to Others		$0			$0
2040	Electric Plant Held for Future Use		$0			$0
2050	Completed Construction Not Classified--Electric		$0			$0
2055	Construction Work in Progress--Electric		$0			$0
2060	Electric Plant Acquisition Adjustment		$0			$0
2065	Other Electric Plant Adjustment		$0			$0
2070	Other Utility Plant		$0			$0
2075	Non-Utility Property Owned or Under Capital Leases		$0			$0
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment		($10,575,078)		$156,852	($10,731,930)
2120	Accumulated Amortization of Electric Utility Plant - Intangibles		$0			$0
2140	Accumulated Amortization of Electric Plant Acquisition Adjustment		$0			$0
2160	Accumulated Amortization of Other Utility Plant		$0			$0
2180	Accumulated Amortization of Non-Utility Property		$0			$0
2205	Accounts Payable		$0			$0
2208	Customer Credit Balances		$0			$0
2210	Current Portion of Customer Deposits		$0			$0
2215	Dividends Declared		$0			$0
2220	Miscellaneous Current and Accrued Liabilities		$0			$0
2225	Notes and Loans Payable		$0			$0
2240	Accounts Payable to Associated Companies		$0			$0
2242	Notes Payable to Associated Companies		$0			$0
2250	Debt Retirement Charges(DRC) Payable		$0			$0
2252	Transmission Charges Payable		$0			$0
2254	Electrical Safety Authority Fees Payable		$0			$0
2256	Independent Market Operator Fees and Penalties Payable		$0			$0
2260	Current Portion of Long Term Debt		$0			$0
2262	Ontario Hydro Debt - Current Portion		$0			$0
2264	Pensions and Employee Benefits - Current Portion		$0			$0
2268	Accrued Interest on Long Term Debt		$0			$0
2270	Matured Long Term Debt		$0			$0
2272	Matured Interest on Long Term Debt		$0			$0
2285	Obligations Under Capital Leases--Current		$0			$0
2290	Commodity Taxes		$0			$0
2292	Payroll Deductions / Expenses Payable		$0			$0
2294	Accrual for Taxes, Payments in Lieu of Taxes, Etc.		$0			$0
2296	Future Income Taxes - Current		$0			$0
2305	Accumulated Provision for Injuries and Damages		$0			$0
2306	Employee Future Benefits		$0			$0
2308	Other Pensions - Past Service Liability		$0			$0
2310	Vested Sick Leave Liability		$0			$0
2315	Accumulated Provision for Rate Refunds		$0			$0
2320	Other Miscellaneous Non-Current Liabilities		$0			$0
2325	Obligations Under Capital Lease--Non-Current		$0			$0
2330	Development Charge Fund		$0			$0
2335	Long Term Customer Deposits		$0			$0
2340	Collateral Funds Liability		$0			$0
2345	Unamortized Premium on Long Term Debt		$0			$0
2348	O.M.E.R.S. - Past Service Liability - Long Term Portion		$0			$0
2350	Future Income Tax - Non-Current		$0			$0
2405	Other Regulatory Liabilities		$0			$0
2410	Deferred Gains from Disposition of Utility Plant		$0			$0
2415	Unamortized Gain on Reacquired Debt		$0			$0
2425	Other Deferred Credits		$0			$0
2435	Accrued Rate-Payer Benefit		$0			$0
2505	Debentures Outstanding - Long Term Portion		$0			$0
2510	Debenture Advances		$0			$0
2515	Reacquired Bonds		$0			$0
2520	Other Long Term Debt		$0			$0
2525	Term Bank Loans - Long Term Portion		$0			$0
2530	Ontario Hydro Debt Outstanding - Long Term Portion		$0			$0
2550	Advances from Associated Companies		$0			$0
3005	Common Shares Issued		$0			$0
3008	Preference Shares Issued		$0			$0
3010	Contributed Surplus		$0			$0
3020	Donations Received		$0			$0
3022	Development Charges Transferred to Equity		$0			$0
3026	Capital Stock Held in Treasury		$0			$0
3030	Miscellaneous Paid-In Capital		$0			$0

3035	Installments Received on Capital Stock	$0			$0
3040	Appropriated Retained Earnings	$0			$0
3045	Unappropriated Retained Earnings	$0			$0
3046	Balance Transferred From Income	$0	$0	($67,041)	($2,330,969)
3047	Appropriations of Retained Earnings - Current Period	$0			$0
3048	Dividends Payable-Preference Shares	$0			$0
3049	Dividends Payable-Common Shares	$0			$0
3055	Adjustment to Retained Earnings	$0			$0
3065	Unappropriated Undistributed Subsidiary Earnings	$0			$0
4006	Residential Energy Sales	($8,762,889)			($8,762,889)
4010	Commercial Energy Sales	$0			$0
4015	Industrial Energy Sales	$0			$0
4020	Energy Sales to Large Users	($3,154,744)			($3,154,744)
4025	Street Lighting Energy Sales	($401,766)			($401,766)
4030	Sentinel Lighting Energy Sales	($17,955)			($17,955)
4035	General Energy Sales	($23,366,901)			($23,366,901)
4040	Other Energy Sales to Public Authorities	$0			$0
4045	Energy Sales to Railroads and Railways	$0			$0
4050	Revenue Adjustment	($515,257)			($515,257)
4055	Energy Sales for Resale	($9,166,112)			($9,166,112)
4060	Interdepartmental Energy Sales	$0			$0
4062	Billed WMS	($5,605,772)			($5,605,772)
4064	Billed-One-Time	$0			$0
4066	Billed NW	($4,919,290)			($4,919,290)
4068	Billed CN	($4,295,601)			($4,295,601)
4080	Distribution Services Revenue	($11,001,393)	$1,798,568		($12,799,961)
4082	Retail Services Revenues	($63,840)			($63,840)
4084	Service Transaction Requests (STR) Revenues	($404)			($404)
4090	Electric Services Incidental to Energy Sales	($108,607)			($108,607)
4105	Transmission Charges Revenue	$0			$0
4110	Transmission Services Revenue	$0			$0
4205	Interdepartmental Rents	$0			$0
4210	Rent from Electric Property	($208,492)			($208,492)
4215	Other Utility Operating Income	($73,282)			($73,282)
4220	Other Electric Revenues	($11,622)			($11,622)
4225	Late Payment Charges	($195,525)			($195,525)
4230	Sales of Water and Water Power	$0			$0
4235	Miscellaneous Service Revenues	($140,963)	$140,963		($348,917)
4240	Provision for Rate Refunds	$0			$0
4245	Government Assistance Directly Credited to Income	$0			$0
4305	Regulatory Debits	$0			$0
4310	Regulatory Credits	$0			$0
4315	Revenues from Electric Plant Leased to Others	$0			$0
4320	Expenses of Electric Plant Leased to Others	$0			$0
4325	Revenues from Merchandise, Jobbing, Etc.	$0			$0
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	$0			$0
4335	Profits and Losses from Financial Instrument Hedges	$0			$0
4340	Profits and Losses from Financial Instrument Investments	$0			$0
4345	Gains from Disposition of Future Use Utility Plant	$0			$0
4350	Losses from Disposition of Future Use Utility Plant	$0			$0
4355	Gain on Disposition of Utility and Other Property	($103,666)			($103,666)
4360	Loss on Disposition of Utility and Other Property	$0			$0
4365	Gains from Disposition of Allowances for Emission	$0			$0
4370	Losses from Disposition of Allowances for Emission	$0			$0
4375	Revenues from Non-Utility Operations	$0			$0
4380	Expenses of Non-Utility Operations	$0			$0
4385	Non-Utility Rental Income	$0			$0
4390	Miscellaneous Non-Operating Income	($58,383)			($58,383)
4395	Rate-Payer Benefit Including Interest	$0			$0
4398	Foreign Exchange Gains and Losses, Including Amortization	$0			$0
4405	Interest and Dividend Income	($277,488)			($277,488)
4415	Equity in Earnings of Subsidiary Companies	$0			$0
4505	Operation Supervision and Engineering	$0			$0
4510	Fuel	$0			$0
4515	Steam Expense	$0			$0
4520	Steam From Other Sources	$0			$0
4525	Steam Transferred--Credit	$0			$0
4530	Electric Expense	$0			$0
4535	Water For Power	$0			$0
4540	Water Power Taxes	$0			$0
4545	Hydraulic Expenses	$0			$0
4550	Generation Expense	$0			$0
4555	Miscellaneous Power Generation Expenses	$0			$0
4560	Rents	$0			$0
4565	Allowances for Emissions	$0			$0
4605	Maintenance Supervision and Engineering	$0			$0
4610	Maintenance of Structures	$0			$0
4615	Maintenance of Boiler Plant	$0			$0
4620	Maintenance of Electric Plant	$0			$0
4625	Maintenance of Reservoirs, Dams and Waterways	$0			$0
4630	Maintenance of Water Wheels, Turbines and Generators	$0			$0
4635	Maintenance of Generating and Electric Plant	$0			$0
4640	Maintenance of Miscellaneous Power Generation Plant	$0			$0
4705	Power Purchased	$45,425,848			$45,425,848
4708	Charges-WMS	$5,605,773			$5,605,773
4710	Cost of Power Adjustments	($601,798)			($601,798)
4712	Charges-One-Time	$0			$0
4714	Charges-NW	$4,919,290			$4,919,290
4715	System Control and Load Dispatching	$0			$0

4716	Charges-CN		$4,293,420			$4,293,420
4720	Other Expenses		$0			$0
4725	Competition Transition Expense		$0			$0
4730	Rural Rate Assistance Expense		$0			$0
4805	Operation Supervision and Engineering		$0			$0
4810	Load Dispatching		$0			$0
4815	Station Buildings and Fixtures Expenses		$0			$0
4820	Transformer Station Equipment - Operating Labour		$0			$0
4825	Transformer Station Equipment - Operating Supplies and Expense		$0			$0
4830	Overhead Line Expenses		$0			$0
4835	Underground Line Expenses		$0			$0
4840	Transmission of Electricity by Others		$0			$0
4845	Miscellaneous Transmission Expense		$0			$0
4850	Rents		$0			$0
4905	Maintenance Supervision and Engineering		$0			$0
4910	Maintenance of Transformer Station Buildings and Fixtures		$0			$0
4916	Maintenance of Transformer Station Equipment		$0			$0
4930	Maintenance of Towers, Poles and Fixtures		$0			$0
4935	Maintenance of Overhead Conductors and Devices		$0			$0
4940	Maintenance of Overhead Lines - Right of Way		$0			$0
4945	Maintenance of Overhead Lines - Roads and Trails Repairs		$0			$0
4950	Maintenance of Overhead Lines - Snow Removal from Roads and Trails		$0			$0
4960	Maintenance of Underground Lines		$0			$0
4965	Maintenance of Miscellaneous Transmission Plant		$0			$0
5005	Operation Supervision and Engineering		$143,807			$143,807
5010	Load Dispatching		$0			$0
5012	Station Buildings and Fixtures Expense		$0			$0
5014	Transformer Station Equipment - Operation Labour		$0			$0
5015	Transformer Station Equipment - Operation Supplies and Expenses		$0			$0
5016	Distribution Station Equipment - Operation Labour		$2,068			$2,068
5017	Distribution Station Equipment - Operation Supplies and Expenses		$5,890			$5,890
5020	Overhead Distribution Lines and Feeders - Operation Labour		$112,180			$112,180
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses		$36,883			$36,883
5030	Overhead Subtransmission Feeders - Operation		$0			$0
5035	Overhead Distribution Transformers- Operation		$68,840	$268,819		$337,659
5040	Underground Distribution Lines and Feeders - Operation Labour		$155,038			$155,038
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses		$63,632			$63,632
5050	Underground Subtransmission Feeders - Operation		$0			$0
5055	Underground Distribution Transformers - Operation		$804	$3,140		$3,944
5060	Street Lighting and Signal System Expense		$0			$0
5065	Meter Expense		$193,124			$193,124
5070	Customer Premises - Operation Labour		$13,570			$13,570
5075	Customer Premises - Materials and Expenses		$3,690			$3,690
5085	Miscellaneous Distribution Expense		$0			$0
5090	Underground Distribution Lines and Feeders - Rental Paid		$0			$0
5095	Overhead Distribution Lines and Feeders - Rental Paid		$0			$0
5096	Other Rent		$0			$0
5105	Maintenance Supervision and Engineering		$147,804			$147,804
5110	Maintenance of Buildings and Fixtures - Distribution Stations		$0			$0
5112	Maintenance of Transformer Station Equipment		$0			$0
5114	Maintenance of Distribution Station Equipment		$161,821			$161,821
5120	Maintenance of Poles, Towers and Fixtures		$44,352			$44,352
5125	Maintenance of Overhead Conductors and Devices		$101,344			$101,344
5130	Maintenance of Overhead Services		$121,515			$121,515
5135	Overhead Distribution Lines and Feeders - Right of Way		$168,586			$168,586
5145	Maintenance of Underground Conduit		$3,992			$3,992
5150	Maintenance of Underground Conductors and Devices		$13,466			$13,466
5155	Maintenance of Underground Services		$28,209			$28,209
5160	Maintenance of Line Transformers		$53,652	$209,510		$263,162
5165	Maintenance of Street Lighting and Signal Systems		$0			$0
5170	Sentinel Lights - Labour		$0			$0
5172	Sentinel Lights - Materials and Expenses		$0			$0
5175	Maintenance of Meters		$16,662			$16,662
5178	Customer Installations Expenses- Leased Property		$0			$0
5185	Water Heater Rentals - Labour		$0			$0
5186	Water Heater Rentals - Materials and Expenses		$0			$0
5190	Water Heater Controls - Labour		$0			$0
5192	Water Heater Controls - Materials and Expenses		$0			$0
5195	Maintenance of Other Installations on Customer Premises		$0			$0
5205	Purchase of Transmission and System Services		$0			$0
5210	Transmission Charges		$0			$0
5215	Transmission Charges Recovered		$0			$0
5305	Supervision		$54,562			$54,562
5310	Meter Reading Expense		$98,403			$98,403
5315	Customer Billing		$865,907			$865,907
5320	Collecting		$322,189			$322,189
5325	Collecting- Cash Over and Short		$188			$188

5330	Collection Charges	$0			$0
5335	Bad Debt Expense	$137,396			$137,396
5340	Miscellaneous Customer Accounts Expenses	$0			$0
5405	Supervision	$0			$0
5410	Community Relations - Sundry	$20,696			$20,696
5415	Energy Conservation	$0			$0
5420	Community Safety Program	$142			$142
5425	Miscellaneous Customer Service and Informational Expenses	$0			$0
5505	Supervision	$0			$0
5510	Demonstrating and Selling Expense	$0			$0
5515	Advertising Expense	$2,173			$2,173
5520	Miscellaneous Sales Expense	$0			$0
5605	Executive Salaries and Expenses	$0			$0
5610	Management Salaries and Expenses	$377,394			$377,394
5615	General Administrative Salaries and Expenses	$175,436			$175,436
5620	Office Supplies and Expenses	$43,391			$43,391
5625	Administrative Expense Transferred Credit	$0			$0
5630	Outside Services Employed	$268,397			$268,397
5635	Property Insurance	$83,600			$83,600
5640	Injuries and Damages	$88,070			$88,070
5645	Employee Pensions and Benefits	$290,415			$290,415
5650	Franchise Requirements	$0			$0
5655	Regulatory Expenses	$300,000			$300,000
5660	General Advertising Expenses	$0			$0
5665	Miscellaneous General Expenses	$615,576	($562,500)		$53,076
5670	Rent	$0			$0
5675	Maintenance of General Plant	$501,235			$501,235
5680	Electrical Safety Authority Fees	$0			$0
5685	Independent Market Operator Fees and Penalties	$0			$0
5705	Amortization Expense - Property, Plant, and Equipment	$2,817,363		($71,974)	$2,889,337
5710	Amortization of Limited Term Electric Plant	$0			$0
5715	Amortization of Intangibles and Other Electric Plant	$0			$0
5720	Amortization of Electric Plant Acquisition Adjustments	$0			$0
5725	Miscellaneous Amortization	$0			$0
5730	Amortization of Unrecovered Plant and Regulatory Study Costs	$0			$0
5735	Amortization of Deferred Development Costs	$0			$0
5740	Amortization of Deferred Charges	$0			$0
6005	Interest on Long Term Debt	$0	$0	($52,441)	$1,823,336
6010	Amortization of Debt Discount and Expense	$0			$0
6015	Amortization of Premium on Debt Credit	$0			$0
6020	Amortization of Loss on Reacquired Debt	$0			$0
6025	Amortization of Gain on Reacquired Debt--Credit	$0			$0
6030	Interest on Debt to Associated Companies	$0			$0
6035	Other Interest Expense	$0			$0
6040	Allowance for Borrowed Funds Used During Construction--Credit	$0			$0
6042	Allowance For Other Funds Used During Construction	$0			$0
6045	Interest Expense on Capital Lease Obligations	$0			$0
6105	Taxes Other Than Income Taxes	$0			$0
6110	Income Taxes	$0	$0	($46,579)	$1,619,511
6115	Provision for Future Income Taxes	$0			$0
6205	Donations	$0			$0
6210	Life Insurance	$0			$0
6215	Penalties	$0			$0
6225	Other Deductions	$0			$0
6305	Extraordinary Income	$0			$0
6310	Extraordinary Deductions	$0			$0
6315	Income Taxes, Extraordinary Items	$0			$0
6405	Discontinues Operations - Income/ Gains	$0			$0
6410	Discontinued Operations - Deductions/ Losses	$0			$0
6415	Income Taxes, Discontinued Operations	$0			$0

$0

Reclassification Equals to Zero. O.K. to Proceed.

Asset Accounts Directly Allocated	($1,347,052)

2006 Cost Allocation Information Filing
Chatham Kent Hydro Inc.
EB-2005-0350 EB-2006-0247
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	$40,477,227

RATE BASE AND DISTRIBUTION ASSETS

		BALANCE SHEET ITEMS									EXPENSE ITEMS			
											5705	5710	5715	5720
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	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	$524,558		-	524,558			$ (30,000)		494,558	$30,000			
1805	Land	$189,212		($189,212)	-									
1805-1	Land Station >50 kV			$0	-					-				
1805-2	Land Station <50 kV		100.00%	$189,212	189,212					189,212				
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	$435,610		($435,610)	-									
1808-1	Buildings and Fixtures > 50 kV			$0	-					-				
1808-2	Buildings and Fixtures < 50 KV		100.00%	$435,610	435,610			$ (86,515)		349,095	$26,226			
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	$674,056		($674,056)	-					-				
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)			$0	-					-				
1820-2	Distribution Station Equipment - Normally Primary below 50 kV Primary)		31.28%	$210,845	210,845			$ (25,412)		185,433	$10,551			
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)		68.72%	$463,212	463,212			$ (55,828)		407,384	$23,181			
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	$1,616,088		($1,616,088)	-									
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery			$0	-					-				
1830-4	Poles, Towers and Fixtures - Primary		76.46%	$1,235,661	1,235,661			$ (132,076)		1,103,585	$ 56,506			

2006 Cost Allocation Information Filing

Chatham Kent Hydro Inc.

EB-2005-0350 EB-2006-0247

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	$40,477,227

RATE BASE AND DISTRIBUTION ASSETS		BALANCE SHEET ITEMS									EXPENSE ITEMS			
											5705	5710	5715	5720
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	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		23.54%	$380,427	380,427			$ (40,663)		339,764	$ 17,397			
1835	Overhead Conductors and Devices	$14,240,362		($14,240,362)	-									
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery			$0	-					-				
1835-4	Overhead Conductors and Devices - Primary		87.63%	$12,478,830	12,478,830			$ (2,440,451)		10,038,378	$ 705,175			
1835-5	Overhead Conductors and Devices - Secondary		12.37%	$1,761,533	1,761,533			$ (344,498)		1,417,035	$ 99,544			
1840	Underground Conduit	$616,722		($616,722)	-									
1840-3	Underground Conduit - Bulk Delivery			$0	-					-				
1840-4	Underground Conduit - Primary		100.00%	$616,722	616,722			$ (64,700)		552,022	$27,477			
1840-5	Underground Conduit - Secondary		0.00%	$0	-					-				
1845	Underground Conductors and Devices	$12,195,115		($12,195,115)	-									
1845-3	Underground Conductors and Devices - Bulk Delivery			$0	-					-				
1845-4	Underground Conductors and Devices - Primary		53.49%	$6,523,167	6,523,167			$ (1,357,827)		5,165,340	$ 379,298			
1845-5	Underground Conductors and Devices - Secondary		46.51%	$5,671,948	5,671,948			$ (1,180,642)		4,491,306	$ 329,802			
1850	Line Transformers	$10,819,538		$0	10,819,538			$ (2,082,583)		8,736,956	$564,768			
1855	Services	$1,696,229		$0	1,696,229			$ (181,933)		1,514,296	$76,464			
1860	Meters	$2,481,518		$0	2,481,518			$ (510,749)		1,970,769	$166,174			
	Total	**$45,489,008**		**$0**	**$45,489,008**	**$0**	**$0**	**($8,533,875)**	**$0**	**36,955,133**	**$2,512,562**	**$0**	**$0**	**$0**
	SUB TOTAL from I3	**$45,489,008**												

2006 Cost Allocation Information Filing
Chatham Kent Hydro Inc.
EB-2005-0350 EB-2006-0247
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	$40,477,227

RATE BASE AND DISTRIBUTION ASSETS		BALANCE SHEET ITEMS									EXPENSE ITEMS			
											5705	5710	5715	5720
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	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
											5705	5710	5715	5720
General Plant		Break out Functions				Contributed Capital - 1995	Accumulated Depreciation - 2105 Capital Contribution	Accumulated Depreciation - 2105 Fixed Assets Only	Accumulated Depreciation - 2120	Net Asset	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	$205,766			205,766					$ 205,766				
1906	Land Rights	$0			-					$ -				
1908	Buildings and Fixtures	$2,644,076			2,644,076			$ (265,581)		$ 2,378,495	$70,997			
1910	Leasehold Improvements	$0			-					$ -				
1915	Office Furniture and Equipment	$76,027			76,027			$ (35,383)		$ 40,644	9,354			
1920	Computer Equipment - Hardware	$308,327			308,327			$ (203,528)		$ 104,799	52,688			
1925	Computer Software	$9,144			9,144					$ 9,144				
1930	Transportation Equipment	$1,426,340			1,426,340			$ (812,881)		$ 613,459				
1935	Stores Equipment	$0			-					$ -				
1940	Tools, Shop and Garage Equipment	$487,765			487,765			$ (286,198)		$ 201,567	69,830			
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	$597,956			597,956			$ (261,494)		$ 336,461	80,719			
1990	Other Tangible Property	$1,311,799			1,311,799			$ (332,989)		$ 978,810	93,187			
2005	Property Under Capital Leases	$0			-					$ -				
2010	Electric Plant Purchased or Sold	$0			-					$ -				
	Total	$7,067,201		$0	$7,067,201	$0	$0	($2,198,055)	$0	$4,869,146	$376,775	$0	$0	$0
	SUB TOTAL from I3	$7,067,201												
	I3 Directly Allocated	($1,347,052)												
	Grand Total	$51,209,157		$0	$52,556,209	$0	$0	($10,731,930)	$0	$41,824,279	$2,889,337	$0	$0	$0

2006 Cost Allocation Information Filing
Chatham Kent Hydro Inc.
EB-2005-0350 EB-2006-0247
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	$40,477,227

RATE BASE AND DISTRIBUTION ASSETS		BALANCE SHEET ITEMS									EXPENSE ITEMS				
											5705	5710	5715	5720	
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**	**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	$0				$0	Balanced								
2105	Accumulated Depreciation - 2105	($10,731,930)						$10,731,930	Balanced						
2120	Accumulated Depreciation - 2120	$0							$0	Balanced					
	Total	**($10,731,930)**													
	Net Assets	**$40,477,227**	**Net Fixed Assets Match EDR**												
Amortization Expenses															
5705	Amortization Expense - Property, Plant, and Equipment	$2,889,337									($2,889,337)	Balanced			
5710	Amortization of Limited Term Electric Plant	$0										$0	Balanced		
5715	Amortization of Intangibles and Other Electric Plant	$0											$0	Balanced	
5720	Amortization of Electric Plant Acquisition Adjustments	$0												$0	Balanced
	Total Amortization Expense	**$2,889,337**													

2006 Cost Allocation Information Filing
Chatham Kent Hydro Inc.
EB-2005-0350 EB-2006-0247
Monday, January 15, 2007

Ontario

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	4 GS> 50-TOU	5 GS >50-Intermediate	6 Large Use >5MW	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	11 Back-up/Standby Power
crev	Distribution Revenue (sale)	$12,799,961	$7,305,082	$2,114,873	$1,928,553	$0	$506,336	$630,552	$124,784	$19,817	$78,727	$91,237
mi	Miscellaneous Revenue (mi)	$1,450,226	$887,823	$238,643	$222,140	$0	$39,531	$15,946	$20,188	$2,946	$1,688	$21,323
	Total Revenue	**$14,250,187**	**$8,192,905**	**$2,353,516**	**$2,150,693**	**$0**	**$545,867**	**$646,498**	**$144,972**	**$22,763**	**$80,415**	**$112,559**
	Expenses											
di	Distribution Costs (di)	$1,915,352	$1,071,206	$297,795	$300,002	$0	$88,250	$31,430	$55,485	$7,994	$4,576	$58,615
cu	Customer Related Costs (cu)	$1,705,691	$1,156,978	$316,338	$210,305	$0	$17,022	$2,814	$1,037	$181	$97	$919
ad	General and Administration (ad)	$2,204,025	$1,352,019	$372,367	$311,770	$0	$65,683	$21,439	$35,403	$5,123	$2,929	$37,293
dep	Depreciation and Amortization (dep)	$2,889,337	$1,633,146	$441,304	$447,147	$0	$139,541	$47,806	$78,494	$11,429	$6,545	$83,924
INPUT	PILs (INPUT)	$1,619,511	$915,080	$246,866	$250,672	$0	$78,153	$26,832	$44,607	$6,510	$3,730	$47,061
INT	Interest	$1,823,336	$1,030,248	$277,936	$282,221	$0	$87,989	$30,209	$50,221	$7,329	$4,199	$52,983
	Total Expenses	**$12,157,252**	**$7,158,677**	**$1,952,606**	**$1,802,117**	**$0**	**$476,637**	**$160,531**	**$265,247**	**$38,566**	**$22,076**	**$280,794**
	Direct Allocation	**($238,035)**	**($195,725)**	**($20,561)**	**($39,661)**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$17,912**
NI	Allocated Net Income (NI)	$2,330,969	$1,317,079	$355,316	$360,794	$0	$112,486	$38,620	$64,203	$9,370	$5,368	$67,734
	Revenue Requirement (includes NI)	$14,250,185	$8,280,031	$2,287,360	$2,123,250	$0	$589,123	$199,150	$329,450	$47,936	$27,445	$366,441
		Revenue Requirement Input equals Output										
	Rate Base Calculation											
	Net Assets											
dp	Distribution Plant - Gross	$45,489,008	$25,710,560	$6,939,439	$7,032,720	$0	$2,188,263	$751,624	$1,251,123	$182,359	$104,485	$1,328,435
gp	General Plant - Gross	$7,067,201	$3,993,215	$1,077,272	$1,093,881	$0	$341,043	$117,090	$194,656	$28,408	$16,276	$205,362
accum dep	Accumulated Depreciation	($10,731,930)	($6,071,600)	($1,641,328)	($1,652,925)	$0	($510,988)	($175,768)	($293,790)	($42,646)	($24,439)	($318,446)
co	Capital Contribution	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total Net Plant	**$41,824,279**	**$23,632,174**	**$6,375,383**	**$6,473,676**	**$0**	**$2,018,318**	**$692,945**	**$1,151,988**	**$168,121**	**$96,321**	**$1,215,351**
	Directly Allocated Net Fixed Assets	**($1,347,052)**	**($1,129,264)**	**($118,645)**	**($199,306)**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$100,163**
COP	Cost of Power (COP)	$59,642,533	$16,429,902	$7,376,958	$24,527,668	$0	$5,655,523	$2,868,859	$538,630	$27,846	$58,195	$2,158,951
	OM&A Expenses	$5,825,068	$3,580,202	$986,500	$822,077	$0	$170,955	$55,683	$91,924	$13,298	$7,602	$96,826
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Subtotal	***$65,467,601***	***$20,010,104***	***$8,363,458***	***$25,349,745***	***$0***	***$5,826,478***	***$2,924,543***	***$630,554***	***$41,144***	***$65,797***	***$2,255,778***
	Working Capital	**$9,820,140**	**$3,001,516**	**$1,254,519**	**$3,802,462**	**$0**	**$873,972**	**$438,681**	**$94,583**	**$6,172**	**$9,869**	**$338,367**
	Total Rate Base	**$50,297,367**	**$25,504,426**	**$7,511,257**	**$10,076,832**	**$0**	**$2,892,290**	**$1,131,627**	**$1,246,572**	**$174,293**	**$106,191**	**$1,653,881**
		Rate Base Input equals Output										
	Equity Component of Rate Base	**$25,148,684**	**$12,752,213**	**$3,755,628**	**$5,038,416**	**$0**	**$1,446,145**	**$565,813**	**$623,286**	**$87,146**	**$53,095**	**$826,940**
	Net Income on Allocated Assets	**$2,330,971**	**$1,229,953**	**$421,471**	**$388,237**	**$0**	**$69,230**	**$485,967**	**($120,275)**	**($15,803)**	**$58,339**	**($186,147)**
	Net Income on Direct Allocation Assets	**($67,041)**	**($56,202)**	**($5,905)**	**($9,919)**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$4,985**
	Net Income	**$2,263,930**	**$1,173,751**	**$415,566**	**$378,318**	**$0**	**$69,230**	**$485,967**	**($120,275)**	**($15,803)**	**$58,339**	**($181,162)**
	RATIOS ANALYSIS											
	REVENUE TO EXPENSES %	100.00%	98.95%	102.89%	101.29%	0.00%	92.66%	324.63%	44.00%	47.49%	293.01%	30.72%
	EXISTING REVENUE MINUS ALLOCATED COSTS	$2	($87,126)	$66,156	$27,443	$0	($43,256)	$447,347	($184,478)	($25,173)	$52,971	($253,882)
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.00%	9.20%	11.07%	7.51%	0.00%	4.79%	85.89%	-19.30%	-18.13%	109.88%	-21.91%

2006 Cost Allocation Information Filing
Chatham Kent Hydro Inc.
EB-2005-0350 EB-2006-0247
Monday, January 15, 2007

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - Second Run

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary	1 Residential	2 GS <50	3 GS>50-Regular	4 GS> 50-TOU	5 GS >50-Intermediate	6 Large Use >5MW	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	11 Back-up/Standby Power
Customer Unit Cost per month - Avoided Cost	$3.42	$8.61	$45.17	$0.00	$124.21	$26.15	$0.03	$0.03	$0.03	$163.17
Customer Unit Cost per month - Directly Related	$5.31	$13.48	$75.04	$0.00	$179.95	$104.91	$0.06	$0.06	$0.06	$225.71
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$14.78	$23.79	$89.21	$0.00	$207.62	$177.01	$9.09	$11.05	$8.33	$444.42
Fixed Charge per approved 2006 EDR	$11.75	$30.31	$158.39	$0.00	$4,208.90	$12,877.94	$0.47	$3.86	$3.28	$158.39

Information to be Used to Allocate PILs, ROD, ROE and A&G	Total	1 Residential	2 GS <50	3 GS>50-Regular	4 GS> 50-TOU	5 GS >50-Intermediate	6 Large Use >5MW	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	11 Back-up/Standby Power
General Plant - Gross Assets	$7,067,201	$3,993,215	$1,077,272	$1,093,881	$0	$341,043	$117,090	$194,656	$28,408	$16,276	$205,362
General Plant - Accumulated Depreciation	($2,198,055)	($1,241,977)	($335,055)	($340,221)	$0	($106,072)	($36,417)	($60,542)	($8,836)	($5,062)	($63,872)
General Plant - Net Fixed Assets	$4,869,146	$2,751,237	$742,217	$753,660	$0	$234,971	$80,672	$134,113	$19,573	$11,214	$141,490
General Plant - Depreciation	$376,775	$212,891	$57,433	$58,318	$0	$18,182	$6,242	$10,378	$1,515	$868	$10,949
Total Net Fixed Assets Excluding General Plant	$36,955,133	$20,880,937	$5,633,166	$5,720,016	$0	$1,783,347	$612,273	$1,017,875	$148,549	$85,108	$1,073,861
Total Administration and General Expense	$2,204,025	$1,352,019	$372,367	$311,770	$0	$65,683	$21,439	$35,403	$5,123	$2,929	$37,293
Total O&M	$3,621,043	$2,228,184	$614,133	$510,307	$0	$105,272	$34,244	$56,522	$8,175	$4,673	$59,533

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

USoA Account #	Accounts	Total	1 Residential	2 GS <50	3 GS>50-Regular	4 GS> 50-TOU	5 GS >50-Intermediate	6 Large Use >5MW	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	11 Back-up/Standby Power
	Distribution Plant											
1860	Meters	$2,481,518	$1,577,511	$504,352	$312,068	$0	$71,923	$7,832	$0	$0	$0	$7,832
	Accumulated Amortization											
	Accum. Amortization of Electric Utility Plant - Meters only	($510,749)	($324,685)	($103,806)	($64,230)	$0	($14,803)	($1,612)	$0	$0	$0	($1,612)
	Meter Net Fixed Assets	**$1,970,769**	**$1,252,826**	**$400,546**	**$247,838**	**$0**	**$57,119**	**$6,220**	**$0**	**$0**	**$0**	**$6,220**
	Misc Revenue											
4082	Retail Services Revenues	($63,840)	($42,396)	($12,027)	($8,945)	$0	($379)	($90)	$0	$0	$0	($3)
4084	Service Transaction Requests (STR) Revenues	($404)	($268)	($76)	($57)	$0	($2)	($1)	$0	$0	$0	($0)
4090	Electric Services Incidental to Energy Sales	($108,607)	($72,125)	($20,461)	($15,218)	$0	($645)	($153)	$0	$0	$0	($5)
4220	Other Electric Revenues	($11,622)	($6,567)	($1,772)	($1,799)	$0	($561)	($193)	($320)	($47)	($27)	($338)
4225	Late Payment Charges	($195,525)	($127,188)	($28,622)	($35,585)	$0	($1,065)	($3,065)	$0	$0	$0	$0
	Sub-total	*($379,998)*	*($248,544)*	*($62,957)*	*($61,603)*	*$0*	*($2,652)*	*($3,502)*	*($320)*	*($47)*	*($27)*	*($346)*
	Operation											
5065	Meter Expense	$193,124	$122,770	$39,251	$24,287	$0	$5,597	$610	$0	$0	$0	$610
5070	Customer Premises - Operation Labour	$13,570	$11,113	$1,271	$144	$0	$7	$1	$815	$142	$76	$0
5075	Customer Premises - Materials and Expenses	$3,690	$3,022	$346	$39	$0	$2	$0	$222	$39	$21	$0
	Sub-total	*$210,384*	*$136,905*	*$40,868*	*$24,470*	*$0*	*$5,606*	*$611*	*$1,037*	*$181*	*$97*	*$610*
	Maintenance											
5175	Maintenance of Meters	$16,662	$10,592	$3,386	$2,095	$0	$483	$53	$0	$0	$0	$53
	Billing and Collection											
5310	Meter Reading Expense	$98,403	$60,461	$24,198	$9,594	$0	$3,557	$395	$0	$0	$0	$198
5315	Customer Billing	$865,907	$575,042	$163,132	$121,330	$0	$5,139	$1,223	$0	$0	$0	$41
5320	Collecting	$322,189	$213,963	$60,699	$45,145	$0	$1,912	$455	$0	$0	$0	$15
5325	Collecting- Cash Over and Short	$188	$125	$35	$26	$0	$1	$0	$0	$0	$0	$0
5330	Collection Charges	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub-total	$1,286,687	$849,590	$248,065	$176,095	$0	$10,609	$2,074	$0	$0	$0	$254
	Total Operation, Maintenance and Billing	$1,513,733	$997,087	$292,319	$202,660	$0	$16,698	$2,737	$1,037	$181	$97	$916
	Amortization Expense - Meters	$166,174	$105,637	$33,774	$20,897	$0	$4,816	$524	$0	$0	$0	$524
	Allocated PILs	$76,312	$48,512	$15,510	$9,597	$0	$2,212	$241	$0	$0	$0	$241
	Allocated Debt Return	$85,916	$54,617	$17,462	$10,805	$0	$2,490	$271	$0	$0	$0	$271
	Allocated Equity Return	$109,836	$69,823	$22,323	$13,813	$0	$3,183	$347	$0	$0	$0	$347
	Total	**$1,571,972**	**$1,027,132**	**$318,431**	**$196,168**	**$0**	**$26,748**	**$618**	**$717**	**$134**	**$70**	**$1,953**

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

USoA Account #	Accounts	Total	1 Residential	2 GS <50	3 GS>50-Regular	4 GS> 50-TOU	5 GS >50-Intermediate	6 Large Use >5MW	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	11 Back-up/Standby Power
	Distribution Plant											
1860	Meters	$2,481,518	$1,577,511	$504,352	$312,068	$0	$71,923	$7,832	$0	$0	$0	$7,832
	Accumulated Amortization											
	Accum. Amortization of Electric Utility Plant - Meters only	($510,749)	($324,685)	($103,806)	($64,230)	$0	($14,803)	($1,612)	$0	$0	$0	($1,612)
	Meter Net Fixed Assets	$1,970,769	$1,252,826	$400,546	$247,838	$0	$57,119	$6,220	$0	$0	$0	$6,220
	Allocated General Plant Net Fixed Assets	$259,665	$165,070	$52,775	$32,655	$0	$7,526	$820	$0	$0	$0	$820
	Meter Net Fixed Assets Including General Plant	$2,230,434	$1,417,896	$453,321	$280,492	$0	$64,645	$7,039	$0	$0	$0	$7,039
	Misc Revenue											
4082	Retail Services Revenues	($63,840)	($42,396)	($12,027)	($8,945)	$0	($379)	($90)	$0	$0	$0	($3)
4084	Service Transaction Requests (STR) Revenues	($404)	($268)	($76)	($57)	$0	($2)	($1)	$0	$0	$0	($0)
4090	Electric Services Incidental to Energy Sales	($108,607)	($72,125)	($20,461)	($15,218)	$0	($645)	($153)	$0	$0	$0	($5)
4220	Other Electric Revenues	($11,622)	($6,567)	($1,772)	($1,799)	$0	($561)	($193)	($320)	($47)	($27)	($338)
4225	Late Payment Charges	($195,525)	($127,188)	($28,622)	($35,585)	$0	($1,065)	($3,065)	$0	$0	$0	$0
	Sub-total	*($379,998)*	*($248,544)*	*($62,957)*	*($61,603)*	*$0*	*($2,652)*	*($3,502)*	*($320)*	*($47)*	*($27)*	*($346)*
	Operation											
5065	Meter Expense	$193,124	$122,770	$39,251	$24,287	$0	$5,597	$610	$0	$0	$0	$610
5070	Customer Premises - Operation Labour	$13,570	$11,113	$1,271	$144	$0	$7	$1	$815	$142	$76	$0
5075	Customer Premises - Materials and Expenses	$3,690	$3,022	$346	$39	$0	$2	$0	$222	$39	$21	$0
	Sub-total	*$210,384*	*$136,905*	*$40,868*	*$24,470*	*$0*	*$5,606*	*$611*	*$1,037*	*$181*	*$97*	*$610*
	Maintenance											
5175	Maintenance of Meters	$16,662	$10,592	$3,386	$2,095	$0	$483	$53	$0	$0	$0	$53
	Billing and Collection											
5310	Meter Reading Expense	$98,403	$60,461	$24,198	$9,594	$0	$3,557	$395	$0	$0	$0	$198
5315	Customer Billing	$865,907	$575,042	$163,132	$121,330	$0	$5,139	$1,223	$0	$0	$0	$41
5320	Collecting	$322,189	$213,963	$60,699	$45,145	$0	$1,912	$455	$0	$0	$0	$15
5325	Collecting- Cash Over and Short	$188	$125	$35	$26	$0	$1	$0	$0	$0	$0	$0
5330	Collection Charges	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub-total	*$1,286,687*	*$849,590*	*$248,065*	*$176,095*	*$0*	*$10,609*	*$2,074*	*$0*	*$0*	*$0*	*$254*
	Total Operation, Maintenance and Billing	$1,513,733	$997,087	$292,319	$202,660	$0	$16,698	$2,737	$1,037	$181	$97	$916
	Amortization Expense - Meters	$166,174	$105,637	$33,774	$20,897	$0	$4,816	$524	$0	$0	$0	$524
	Amortization Expense - General Plant assigned to Meters	*$20,093*	*$12,773*	*$4,084*	*$2,527*	*$0*	*$582*	*$63*	*$0*	*$0*	*$0*	*$63*
	Admin and General	$919,599	$605,013	$177,242	$123,814	$0	$10,419	$1,714	$650	$113	$61	$574
	Allocated PILs	$86,366	$54,903	$17,553	$10,861	$0	$2,503	$273	$0	$0	$0	$273
	Allocated Debt Return	$97,236	$61,813	$19,763	$12,228	$0	$2,818	$307	$0	$0	$0	$307
	Allocated Equity Return	$124,308	$79,023	$25,265	$15,633	$0	$3,603	$392	$0	$0	$0	$392
	Total	**$2,547,511**	**$1,667,706**	**$507,042**	**$327,017**	**$0**	**$38,788**	**$2,509**	**$1,367**	**$248**	**$131**	**$2,704**

Scenario 3

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

USoA Account #	Accounts	Total	1 Residential	2 GS <50	3 GS>50-Regular	4 GS> 50-TOU	5 GS >50-Intermediate	6 Large Use >5MW	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	11 Back-up/Standby Power
	Distribution Plant											
1565	Conservation and Demand Management Expenditures and Recoveries	$524,558	$322,783	$88,966	$73,925	$0	$15,250	$4,961	$8,188	$1,184	$677	$8,624
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-4	Poles, Towers and Fixtures - Primary	$494,264	$404,770	$46,305	$5,239	$0	$258	$29	$29,697	$5,182	$2,770	$14
1830-5	Poles, Towers and Fixtures - Secondary	$152,171	$124,908	$14,289	$1,355	$0	$0	$0	$9,164	$1,599	$855	$0
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-4	Overhead Conductors and Devices - Primary	$4,991,532	$4,087,736	$467,625	$52,909	$0	$2,609	$290	$299,912	$52,329	$27,976	$145
1835-5	Overhead Conductors and Devices - Secondary	$704,613	$578,375	$66,165	$6,276	$0	$0	$0	$42,435	$7,404	$3,958	$0
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary	$246,689	$202,022	$23,111	$2,615	$0	$129	$14	$14,822	$2,586	$1,383	$7
1840-5	Underground Conduit - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary	$2,609,267	$2,136,818	$244,446	$27,657	$0	$1,364	$152	$156,776	$27,354	$14,624	$76
1845-5	Underground Conductors and Devices - Secondary	$2,268,779	$1,862,308	$213,043	$20,208	$0	$0	$0	$136,635	$23,840	$12,746	$0
1850	Line Transformers	$4,327,815	$3,552,449	$406,390	$38,548	$0	$0	$0	$260,639	$45,476	$24,313	$0
1855	Services	$1,696,229	$1,185,909	$271,329	$128,684	$0	$0	$0	$87,009	$15,181	$8,116	$0
1860	Meters	$2,481,518	$1,577,511	$504,352	$312,068	$0	$71,923	$7,832	$0	$0	$0	$7,832
	Sub-total	*$20,497,434*	*$16,035,590*	*$2,346,020*	*$669,484*	*$0*	*$91,533*	*$13,277*	*$1,045,278*	*$182,136*	*$97,419*	*$16,698*
	Accumulated Amortization											
	Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	($3,835,885)	($2,992,785)	($431,748)	($129,686)	$0	($26,391)	($4,760)	($194,225)	($33,811)	($18,120)	($4,360)
	Customer Related Net Fixed Assets	$16,661,549	$13,042,805	$1,914,272	$539,798	$0	$65,142	$8,518	$851,052	$148,325	$79,298	$12,338
	Allocated General Plant Net Fixed Assets	$2,195,298	$1,718,498	$252,221	$71,123	$0	$8,583	$1,122	$112,133	$19,543	$10,448	$1,626
	Customer Related NFA Including General Plant	$18,856,847	$14,761,303	$2,166,494	$610,921	$0	$73,725	$9,640	$963,186	$167,869	$89,746	$13,964
	Misc Revenue											
4082	Retail Services Revenues	($63,840)	($42,396)	($12,027)	($8,945)	$0	($379)	($90)	$0	$0	$0	($3)
4084	Service Transaction Requests (STR) Revenues	($404)	($268)	($76)	($57)	$0	($2)	($1)	$0	$0	$0	($0)
4090	Electric Services Incidental to Energy Sales	($108,607)	($72,125)	($20,461)	($15,218)	$0	($645)	($153)	$0	$0	$0	($5)
4220	Other Electric Revenues	($11,622)	($6,567)	($1,772)	($1,799)	$0	($561)	($193)	($320)	($47)	($27)	($338)
4225	Late Payment Charges	($195,525)	($127,188)	($28,622)	($35,585)	$0	($1,065)	($3,065)	$0	$0	$0	$0
4235	Miscellaneous Service Revenues	($348,917)	($231,713)	($65,734)	($48,890)	$0	($2,071)	($493)	$0	$0	$0	($16)
	Sub-total	*($728,915)*	*($480,257)*	*($128,692)*	*($110,493)*	*$0*	*($4,722)*	*($3,995)*	*($320)*	*($47)*	*($27)*	*($362)*
	Operating and Maintenance											
5005	Operation Supervision and Engineering	$57,523	$45,708	$5,802	$1,373	$0	$277	$75	$3,336	$580	$311	$59
5010	Load Dispatching	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5020	Overhead Distribution Lines and Feeders - Operation Labour	$44,872	$36,759	$4,205	$465	$0	$20	$2	$2,697	$471	$252	$1
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$14,753	$12,086	$1,383	$153	$0	$7	$1	$887	$155	$83	$0
5035	Overhead Distribution Transformers- Operation	$135,064	$110,866	$12,683	$1,203	$0	$0	$0	$8,134	$1,419	$759	$0
5040	Underground Distribution Lines and Feeders - Operation Labour	$62,015	$50,839	$5,816	$611	$0	$18	$2	$3,730	$651	$348	$1
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$25,453	$20,866	$2,387	$251	$0	$7	$1	$1,531	$267	$143	$0
5055	Underground Distribution Transformers - Operation	$1,577	$1,295	$148	$14	$0	$0	$0	$95	$17	$9	$0
5065	Meter Expense	$193,124	$122,770	$39,251	$24,287	$0	$5,597	$610	$0	$0	$0	$610
5070	Customer Premises - Operation Labour	$13,570	$11,113	$1,271	$144	$0	$7	$1	$815	$142	$76	$0
5075	Customer Premises - Materials and Expenses	$3,690	$3,022	$346	$39	$0	$2	$0	$222	$39	$21	$0
5085	Miscellaneous Distribution Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5090	Underground Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5095	Overhead Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5096	Other Rent	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5105	Maintenance Supervision and Engineering	$59,122	$46,979	$5,963	$1,411	$0	$284	$77	$3,429	$597	$320	$61
5120	Maintenance of Poles, Towers and Fixtures	$17,741	$14,537	$1,663	$181	$0	$7	$1	$1,067	$186	$99	$0
5125	Maintenance of Overhead Conductors and Devices	$40,538	$33,207	$3,799	$421	$0	$19	$2	$2,436	$425	$227	$1
5130	Maintenance of Overhead Services	$121,515	$84,957	$19,438	$9,219	$0	$0	$0	$6,233	$1,088	$581	$0
5135	Overhead Distribution Lines and Feeders - Right of Way	$67,434	$55,242	$6,319	$699	$0	$30	$3	$4,053	$707	$378	$2
5145	Maintenance of Underground Conduit	$1,597	$1,308	$150	$17	$0	$1	$0	$96	$17	$9	$0
5150	Maintenance of Underground Conductors and Devices	$5,386	$4,416	$505	$53	$0	$2	$0	$324	$57	$30	$0
5155	Maintenance of Underground Services	$28,209	$19,722	$4,512	$2,140	$0	$0	$0	$1,447	$252	$135	$0
5160	Maintenance of Line Transformers	$105,265	$86,406	$9,885	$938	$0	$0	$0	$6,339	$1,106	$591	$0
5175	Maintenance of Meters	$16,662	$10,592	$3,386	$2,095	$0	$483	$53	$0	$0	$0	$53
	Sub-total	*$1,015,110*	*$772,687*	*$128,911*	*$45,714*	*$0*	*$6,761*	*$828*	*$46,872*	*$8,175*	*$4,373*	*$789*

	Billing and Collection											
5305	Supervision	$54,562	$36,234	$10,279	$7,645	$0	$324	$77	$0	$0	$0	$3
5310	Meter Reading Expense	$98,403	$60,461	$24,198	$9,594	$0	$3,557	$395	$0	$0	$0	$198
5315	Customer Billing	$865,907	$575,042	$163,132	$121,330	$0	$5,139	$1,223	$0	$0	$0	$41
5320	Collecting	$322,189	$213,963	$60,699	$45,145	$0	$1,912	$455	$0	$0	$0	$15
5325	Collecting- Cash Over and Short	$188	$125	$35	$26	$0	$1	$0	$0	$0	$0	$0
5330	Collection Charges	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5335	Bad Debt Expense	$137,396	$123,656	$13,740	$0	$0	$0	$0	$0	$0	$0	$0
5340	Miscellaneous Customer Accounts Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub-total	*$1,478,645*	*$1,009,481*	*$272,083*	*$183,740*	*$0*	*$10,933*	*$2,151*	*$0*	*$0*	*$0*	*$256*
	Sub Total Operating, Maintenance and Biling	*$2,493,755*	*$1,782,168*	*$400,994*	*$229,455*	*$0*	*$17,694*	*$2,979*	*$46,872*	*$8,175*	*$4,373*	*$1,046*
	Amortization Expense - Customer Related	$1,167,805	$899,017	$135,781	$46,746	$0	$10,035	$1,986	$57,056	$9,915	$5,320	$1,948
	Amortization Expense - General Plant assigned to Meters	$169,872	$132,978	$19,517	$5,503	$0	$664	$87	$8,677	$1,512	$808	$126
	Admin and General	$1,515,486	$1,081,385	$243,135	$140,184	$0	$11,040	$1,865	$29,358	$5,123	$2,741	$655
	Allocated PILs	$730,171	$571,584	$83,890	$23,656	$0	$2,855	$373	$37,296	$6,500	$3,475	$541
	Allocated Debt Return	$822,067	$643,521	$94,449	$26,633	$0	$3,214	$420	$41,990	$7,318	$3,913	$609
	Allocated Equity Return	$1,050,938	$822,683	$120,744	$34,048	$0	$4,109	$537	$53,681	$9,356	$5,002	$778
	PLCC Adjustment for Line Transformer	$264,273	$219,174	$25,071	$2,380	$0	$0	$0	$16,143	$0	$1,506	$0
	PLCC Adjustment for Primary Costs	$232,651	$192,503	$22,020	$2,509	$0	$124	$14	$14,154	$0	$1,321	$7
	PLCC Adjustment for Secondary Costs	$208,646	$168,544	$16,311	$1,769	$0	$0	$0	$18,530	$0	$3,487	$5
	Total	$6,515,609	**$4,872,859**	**$906,417**	**$389,074**	**$0**	**$44,764**	**$4,239**	**$225,784**	**$47,852**	**$19,292**	**$5,328**

Below: Grouping to avoid disclosure

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

Accounts	Total	Residential	GS <50	GS>50-Regular	GS> 50-TOU	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load	Back-up/Standby Power
Distribution Plant											
CWMC	$ 2,481,518	$ 1,577,511	$ 504,352	$ 312,068	$ -	$ 71,923	$ 7,832	$ -	$ -	$ -	$ 7,832
Accumulated Amortization											
Accum. Amortization of Electric Utility Plant - Meters only	$ (510,749)	$ (324,685)	$ (103,806)	$ (64,230)	$ -	$ (14,803)	$ (1,612)	$ -	$ -	$ -	$ (1,612)
Meter Net Fixed Assets	$ 1,970,769	$ 1,252,826	$ 400,546	$ 247,838	$ -	$ 57,119	$ 6,220	$ -	$ -	$ -	$ 6,220
Misc Revenue											
CWNB	$ (172,851)	$ (114,789)	$ (32,564)	$ (24,220)	$ -	$ (1,026)	$ (244)	$ -	$ -	$ -	$ (8)
NFA	$ (11,622)	$ (6,567)	$ (1,772)	$ (1,799)	$ -	$ (561)	$ (193)	$ (320)	$ (47)	$ (27)	$ (338)
LPHA	$ (195,525)	$ (127,188)	$ (28,622)	$ (35,585)	$ -	$ (1,065)	$ (3,065)	$ -	$ -	$ -	$ -
Sub-total	$ (379,998)	$ (248,544)	$ (62,957)	$ (61,603)	$ -	$ (2,652)	$ (3,502)	$ (320)	$ (47)	$ (27)	$ (346)
Operation											
CWMC	$ 193,124	$ 122,770	$ 39,251	$ 24,287	$ -	$ 5,597	$ 610	$ -	$ -	$ -	$ 610
CCA	$ 17,260	$ 14,135	$ 1,617	$ 183	$ -	$ 9	$ 1	$ 1,037	$ 181	$ 97	$ 1
Sub-total	$ 210,384	$ 136,905	$ 40,868	$ 24,470	$ -	$ 5,606	$ 611	$ 1,037	$ 181	$ 97	$ 610
Maintenance											
1860	$ 16,662	$ 10,592	$ 3,386	$ 2,095	$ -	$ 483	$ 53	$ -	$ -	$ -	$ 53
Billing and Collection											
CWMR	$ 98,403	$ 60,461	$ 24,198	$ 9,594	$ -	$ 3,557	$ 395	$ -	$ -	$ -	$ 198
CWNB	$ 1,188,284	$ 789,130	$ 223,867	$ 166,501	$ -	$ 7,052	$ 1,679	$ -	$ -	$ -	$ 56
Sub-total	$ 1,286,687	$ 849,590	$ 248,065	$ 176,095	$ -	$ 10,609	$ 2,074	$ -	$ -	$ -	$ 254
Total Operation, Maintenance and Billing	$ 1,513,733	$ 997,087	$ 292,319	$ 202,660	$ -	$ 16,698	$ 2,737	$ 1,037	$ 181	$ 97	$ 916
Amortization Expense - Meters	$ 166,174	$ 105,637	$ 33,774	$ 20,897	$ -	$ 4,816	$ 524	$ -	$ -	$ -	$ 524
Allocated PILs	$ 76,312	$ 48,512	$ 15,510	$ 9,597	$ -	$ 2,212	$ 241	$ -	$ -	$ -	$ 241
Allocated Debt Return	$ 85,916	$ 54,617	$ 17,462	$ 10,805	$ -	$ 2,490	$ 271	$ -	$ -	$ -	$ 271
Allocated Equity Return	$ 109,836	$ 69,823	$ 22,323	$ 13,813	$ -	$ 3,183	$ 347	$ -	$ -	$ -	$ 347
Total	**$ 1,571,972**	**$ 1,027,132**	**$ 318,431**	**$ 196,168**	**$ -**	**$ 26,748**	**$ 618**	**$ 717**	**$ 134**	**$ 70**	**$ 1,953**

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

Accounts	Total	Residential	GS <50	GS>50-Regular	GS> 50-TOU	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load	Back-up/Standby Power
Distribution Plant											
CWMC	$ 2,481,518	$ 1,577,511	$ 504,352	$ 312,068	$ -	$ 71,923	$ 7,832	$ -	$ -	$ -	$ 7,832
Accumulated Amortization											
Accum. Amortization of Electric Utility Plant - Meters only	$ (510,749)	$ (324,685)	$ (103,806)	$ (64,230)	$ -	$ (14,803)	$ (1,612)	$ -	$ -	$ -	$ (1,612)
Meter Net Fixed Assets	$ 1,970,769	$ 1,252,826	$ 400,546	$ 247,838	$ -	$ 57,119	$ 6,220	$ -	$ -	$ -	$ 6,220
Allocated General Plant Net Fixed Assets	$ 259,665	$ 165,070	$ 52,775	$ 32,655	$ -	$ 7,526	$ 820	$ -	$ -	$ -	$ 820
Meter Net Fixed Assets Including General Plant	$ 2,230,434	$ 1,417,896	$ 453,321	$ 280,492	$ -	$ 64,645	$ 7,039	$ -	$ -	$ -	$ 7,039
Misc Revenue											
CWNB	$ (172,851)	$ (114,789)	$ (32,564)	$ (24,220)	$ -	$ (1,026)	$ (244)	$ -	$ -	$ -	$ (8)
NFA	$ (11,622)	$ (6,567)	$ (1,772)	$ (1,799)	$ -	$ (561)	$ (193)	$ (320)	$ (47)	$ (27)	$ (338)
LPHA	$ (195,525)	$ (127,188)	$ (28,622)	$ (35,585)	$ -	$ (1,065)	$ (3,065)	$ -	$ -	$ -	$ -
Sub-total	*$ (379,998)*	*$ (248,544)*	*$ (62,957)*	*$ (61,603)*	*$ -*	*$ (2,652)*	*$ (3,502)*	*$ (320)*	*$ (47)*	*$ (27)*	*$ (346)*
Operation											
CWMC	$ 193,124	$ 122,770	$ 39,251	$ 24,287	$ -	$ 5,597	$ 610	$ -	$ -	$ -	$ 610
CCA	$ 17,260	$ 14,135	$ 1,617	$ 183	$ -	$ 9	$ 1	$ 1,037	$ 181	$ 97	$ 1
Sub-total	*$ 210,384*	*$ 136,905*	*$ 40,868*	*$ 24,470*	*$ -*	*$ 5,606*	*$ 611*	*$ 1,037*	*$ 181*	*$ 97*	*$ 610*
Maintenance											
1860	$ 16,662	$ 10,592	$ 3,386	$ 2,095	$ -	$ 483	$ 53	$ -	$ -	$ -	$ 53
Billing and Collection											
CWMR	$ 98,403	$ 60,461	$ 24,198	$ 9,594	$ -	$ 3,557	$ 395	$ -	$ -	$ -	$ 198
CWNB	$ 1,188,284	$ 789,130	$ 223,867	$ 166,501	$ -	$ 7,052	$ 1,679	$ -	$ -	$ -	$ 56
Sub-total	*$ 1,286,687*	*$ 849,590*	*$ 248,065*	*$ 176,095*	*$ -*	*$ 10,609*	*$ 2,074*	*$ -*	*$ -*	*$ -*	*$ 254*
Total Operation, Maintenance and Billing	$ 1,513,733	$ 997,087	$ 292,319	$ 202,660	$ -	$ 16,698	$ 2,737	$ 1,037	$ 181	$ 97	$ 916
Amortization Expense - Meters	$ 166,174	$ 105,637	$ 33,774	$ 20,897	$ -	$ 4,816	$ 524	$ -	$ -	$ -	$ 524
Amortization Expense - General Plant assigned to Meters	$ 20,093	$ 12,773	$ 4,084	$ 2,527	$ -	$ 582	$ 63	$ -	$ -	$ -	$ 63
Admin and General	$ 919,599	$ 605,013	$ 177,242	$ 123,814	$ -	$ 10,419	$ 1,714	$ 650	$ 113	$ 61	$ 574
Allocated PILs	$ 86,366	$ 54,903	$ 17,553	$ 10,861	$ -	$ 2,503	$ 273	$ -	$ -	$ -	$ 273
Allocated Debt Return	$ 97,236	$ 61,813	$ 19,763	$ 12,228	$ -	$ 2,818	$ 307	$ -	$ -	$ -	$ 307
Allocated Equity Return	$ 124,308	$ 79,023	$ 25,265	$ 15,633	$ -	$ 3,603	$ 392	$ -	$ -	$ -	$ 392
Total	**$ 2,547,511**	**$ 1,667,706**	**$ 507,042**	**$ 327,017**	**$ -**	**$ 38,788**	**$ 2,509**	**$ 1,367**	**$ 248**	**$ 131**	**$ 2,704**

Scenario 3

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

USoA Account #	Accounts	Total	Residential	GS <50	GS>50-Regular	GS> 50-TOU	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load	Back-up/Standby Power
	Distribution Plant											
	CDMPP	$ 524,558	$ 322,783	$ 88,966	$ 73,925	$ -	$ 15,250	$ 4,961	$ 8,188	$ 1,184	$ 677	$ 8,624
	Poles, Towers and Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	PNCP	$ 8,341,752	$ 6,831,346	$ 781,487	$ 88,420	$ -	$ 4,360	$ 484	$ 501,208	$ 87,451	$ 46,754	$ 242
	SNCP	$ 3,125,563	$ 2,565,591	$ 293,496	$ 27,839	$ -	$ -	$ -	$ 188,234	$ 32,843	$ 17,559	$ -
	Overhead Conductors and Devices	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	LTNCP	$ 4,327,815	$ 3,552,449	$ 406,390	$ 38,548	$ -	$ -	$ -	$ 260,639	$ 45,476	$ 24,313	$ -
	CWCS	$ 1,696,229	$ 1,185,909	$ 271,329	$ 128,684	$ -	$ -	$ -	$ 87,009	$ 15,181	$ 8,116	$ -
	CWMC	$ 2,481,518	$ 1,577,511	$ 504,352	$ 312,068	$ -	$ 71,923	$ 7,832	$ -	$ -	$ -	$ 7,832
	Sub-total	*$ 20,497,434*	*$ 16,035,590*	*$ 2,346,020*	*$ 669,484*	*$ -*	*$ 91,533*	*$ 13,277*	*$ 1,045,278*	*$ 182,136*	*$ 97,419*	*$ 16,698*
	Accumulated Amortization											
	Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	$ (3,835,885)	$ (2,992,785)	$ (431,748)	$ (129,686)	$ -	$ (26,391)	$ (4,760)	$ (194,225)	$ (33,811)	$ (18,120)	$ (4,360)
	Customer Related Net Fixed Assets	$ 16,661,549	$ 13,042,805	$ 1,914,272	$ 539,798	$ -	$ 65,142	$ 8,518	$ 851,052	$ 148,325	$ 79,298	$ 12,338
	Allocated General Plant Net Fixed Assets	$ 2,195,298	$ 1,718,498	$ 252,221	$ 71,123	$ -	$ 8,583	$ 1,122	$ 112,133	$ 19,543	$ 10,448	$ 1,626
	Customer Related NFA Including General Plant	$ 18,856,847	$ 14,761,303	$ 2,166,494	$ 610,921	$ -	$ 73,725	$ 9,640	$ 963,186	$ 167,869	$ 89,746	$ 13,964
	Misc Revenue											
	CWNB	$ (521,768)	$ (346,502)	$ (98,298)	$ (73,109)	$ -	$ (3,096)	$ (737)	$ -	$ -	$ -	$ (25)
	NFA	$ (11,622)	$ (6,567)	$ (1,772)	$ (1,799)	$ -	$ (561)	$ (193)	$ (320)	$ (47)	$ (27)	$ (338)
	LPHA	$ (195,525)	$ (127,188)	$ (28,622)	$ (35,585)	$ -	$ (1,065)	$ (3,065)	$ -	$ -	$ -	$ -
	Sub-total	*$ (728,915)*	*$ (480,257)*	*$ (128,692)*	*$ (110,493)*	*$ -*	*$ (4,722)*	*$ (3,995)*	*$ (320)*	*$ (47)*	*$ (27)*	*$ (362)*
	Operating and Maintenance											
	1815-1855	$ 116,644	$ 92,687	$ 11,764	$ 2,784	$ -	$ 561	$ 153	$ 6,766	$ 1,177	$ 632	$ 121
	1830 & 1835	$ 127,060	$ 104,086	$ 11,907	$ 1,318	$ -	$ 57	$ 6	$ 7,637	$ 1,332	$ 712	$ 3
	1850	$ 241,906	$ 198,566	$ 22,715	$ 2,155	$ -	$ -	$ -	$ 14,569	$ 2,542	$ 1,359	$ -
	1840 & 1845	$ 87,468	$ 71,704	$ 8,203	$ 862	$ -	$ 25	$ 3	$ 5,261	$ 918	$ 491	$ 1
	CWMC	$ 193,124	$ 122,770	$ 39,251	$ 24,287	$ -	$ 5,597	$ 610	$ -	$ -	$ -	$ 610
	CCA	$ 17,260	$ 14,135	$ 1,617	$ 183	$ -	$ 9	$ 1	$ 1,037	$ 181	$ 97	$ 1
	O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1830	$ 17,741	$ 14,537	$ 1,663	$ 181	$ -	$ 7	$ 1	$ 1,067	$ 186	$ 99	$ 0
	1835	$ 40,538	$ 33,207	$ 3,799	$ 421	$ -	$ 19	$ 2	$ 2,436	$ 425	$ 227	$ 1
	1855	$ 149,724	$ 104,679	$ 23,950	$ 11,359	$ -	$ -	$ -	$ 7,680	$ 1,340	$ 716	$ -
	1840	$ 1,597	$ 1,308	$ 150	$ 17	$ -	$ 1	$ 0	$ 96	$ 17	$ 9	$ 0
	1845	$ 5,386	$ 4,416	$ 505	$ 53	$ -	$ 2	$ 0	$ 324	$ 57	$ 30	$ 0
	1860	$ 16,662	$ 10,592	$ 3,386	$ 2,095	$ -	$ 483	$ 53	$ -	$ -	$ -	$ 53
	Sub-total	*$ 1,015,110*	*$ 772,687*	*$ 128,911*	*$ 45,714*	*$ -*	*$ 6,761*	*$ 828*	*$ 46,872*	*$ 8,175*	*$ 4,373*	*$ 789*
	Billing and Collection											
	CWNB	$ 1,242,846	$ 825,364	$ 234,146	$ 174,146	$ -	$ 7,376	$ 1,756	$ -	$ -	$ -	$ 59
	CWMR	$ 98,403	$ 60,461	$ 24,198	$ 9,594	$ -	$ 3,557	$ 395	$ -	$ -	$ -	$ 198
	BDHA	$ 137,396	$ 123,656	$ 13,740	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Sub-total	*$ 1,478,645*	*$ 1,009,481*	*$ 272,083*	*$ 183,740*	*$ -*	*$ 10,933*	*$ 2,151*	*$ -*	*$ -*	*$ -*	*$ 256*
	Sub Total Operating, Maintenance and Biling	*$ 2,493,755*	*$ 1,782,168*	*$ 400,994*	*$ 229,455*	*$ -*	*$ 17,694*	*$ 2,979*	*$ 46,872*	*$ 8,175*	*$ 4,373*	*$ 1,046*
	Amortization Expense - Customer Related	$ 1,167,805	$ 899,017	$ 135,781	$ 46,746	$ -	$ 10,035	$ 1,986	$ 57,056	$ 9,915	$ 5,320	$ 1,948
	Amortization Expense - General Plant assigned to Meters	$ 169,872	$ 132,978	$ 19,517	$ 5,503	$ -	$ 664	$ 87	$ 8,677	$ 1,512	$ 808	$ 126
	Admin and General	$ 1,515,486	$ 1,081,385	$ 243,135	$ 140,184	$ -	$ 11,040	$ 1,865	$ 29,358	$ 5,123	$ 2,741	$ 655
	Allocated PILs	$ 730,171	$ 571,584	$ 83,890	$ 23,656	$ -	$ 2,855	$ 373	$ 37,296	$ 6,500	$ 3,475	$ 541
	Allocated Debt Return	$ 822,067	$ 643,521	$ 94,449	$ 26,633	$ -	$ 3,214	$ 420	$ 41,990	$ 7,318	$ 3,913	$ 609
	Allocated Equity Return	$ 1,050,938	$ 822,683	$ 120,744	$ 34,048	$ -	$ 4,109	$ 537	$ 53,681	$ 9,356	$ 5,002	$ 778
	PLCC Adjustment for Line Transformer	$ 264,273	$ 219,174	$ 25,071	$ 2,380	$ -	$ -	$ -	$ 16,143	$ -	$ 1,506	$ -
	PLCC Adjustment for Primary Costs	$ 232,651	$ 192,503	$ 22,020	$ 2,509	$ -	$ 124	$ 14	$ 14,154	$ -	$ 1,321	$ 7
	PLCC Adjustment for Secondary Costs	$ 208,646	$ 168,544	$ 16,311	$ 1,769	$ -	$ -	$ -	$ 18,530	$ -	$ 3,487	$ 5
	Total	**$ 6,515,609**	**$ 4,872,859**	**$ 906,417**	**$ 389,074**	**$ -**	**$ 44,764**	**$ 4,239**	**$ 225,784**	**$ 47,852**	**$ 19,292**	**$ 5,328**

APPENDIX B

COST ALLOCATION MODEL – INITIAL WITHOUT TRANSFORMER ALLOWANCE

2006 Cost Allocation Information Filing
Chatham Kent Hydro Inc.
EB-2005-0350 EB-2006-0247
Monday, January 15, 2007

Sheet I2 Class Selection - Second Run

Instructions:
Step 1: Pleae input your existing classes
Step 2: If this is your first run, select "First Run" in the drop-down menu below
Step 3: After all classes have been entered, Click the "Update" button in row E41

Click for Drop-Down Menu → Second Run

If desired, provide a summary of this run (40 characters max.)

		Utility's Class Definition	Current
1	Residential		YES
2	GS <50		YES
3	GS>50-Regular		YES
4	GS> 50-TOU		YES
5	GS >50-Intermediate		YES
6	Large Use >5MW		YES
7	Street Light		YES
8	Sentinel		YES
9	Unmetered Scattered Load		YES
10	Embedded Distributor		NO
11	Back-up/Standby Power		YES
12	Rate Class 1		NO
13	Rate class 2		NO
14	Rate class 3		NO
15	Rate class 4		NO
16	Rate class 5		NO
17	Rate class 6		NO
18	Rate class 7		NO
19	Rate class 8		NO
20	Rate class 9		NO

Update

** Space available for additional information about this run

2006 Cost Allocation Information Filing

Chatham Kent Hydro Inc.

EB-2005-0350 EB-2006-0247

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	Differences?
Approved Target Net Income ($)	$2,263,928		
Approved PILs ($)	$1,572,932		
Approved Interest ($)	$1,770,895		
Approved Specific Service Charges ($)	$348,917		
Approved Transformer Ownership Allowance ($)			
Approved Low Voltage Wheeling Adjustment ($)	$562,500		
Approved Revenue Requirement ($)	$14,331,218		
Revenue Requirement to be Used in this model ($)	$13,768,718	**$13,768,717**	**Rev Req Matches**
Approved Rate Base ($)	$50,309,522		
Rate Base to be Used in this model ($)	$50,225,147	**$50,225,147**	**Rate Base Matches**

Uniform System of Accounts - Detail Accounts

USoA Account #	Accounts	Financial Statement (EDR Sheet 2.4, Column P)	Model Adjustments	Reclassify accounts	Direct Allocation	Reclassified Balance
1005	Cash	$0				$0
1010	Cash Advances and Working Funds	$0				$0
1020	Interest Special Deposits	$0				$0
1030	Dividend Special Deposits	$0				$0
1040	Other Special Deposits	$0				$0
1060	Term Deposits	$0				$0
1070	Current Investments	$0				$0
1100	Customer Accounts Receivable	$0				$0
1102	Accounts Receivable - Services	$0				$0
1104	Accounts Receivable - Recoverable Work	$0				$0
1105	Accounts Receivable - Merchandise, Jobbing, etc.	$0				$0
1110	Other Accounts Receivable	$0				$0
1120	Accrued Utility Revenues	$0				$0
1130	Accumulated Provision for Uncollectible Accounts--Credit	$0				$0
1140	Interest and Dividends Receivable	$0				$0
1150	Rents Receivable	$0				$0
1170	Notes Receivable	$0				$0
1180	Prepayments	$0				$0
1190	Miscellaneous Current and Accrued Assets	$0				$0
1200	Accounts Receivable from Associated Companies	$0				$0
1210	Notes Receivable from Associated Companies	$0				$0
1305	Fuel Stock	$0				$0
1330	Plant Materials and Operating Supplies	$0				$0
1340	Merchandise	$0				$0
1350	Other Materials and Supplies	$0				$0
1405	Long Term Investments in Non-Associated Companies	$0				$0
1408	Long Term Receivable - Street Lighting Transfer	$0				$0
1410	Other Special or Collateral Funds	$0				$0

1415	Sinking Funds	$0				$0
1425	Unamortized Debt Expense	$0				$0
1445	Unamortized Discount on Long-Term Debt--Debit	$0				$0
1455	Unamortized Deferred Foreign Currency Translation Gains and Losses	$0				$0
1460	Other Non-Current Assets	$0				$0
1465	O.M.E.R.S. Past Service Costs	$0				$0
1470	Past Service Costs - Employee Future Benefits	$0				$0
1475	Past Service Costs - Other Pension Plans	$0				$0
1480	Portfolio Investments - Associated Companies	$0				$0
1485	Investment in Associated Companies - Significant Influence	$0				$0
1490	Investment in Subsidiary Companies	$0				$0
1505	Unrecovered Plant and Regulatory Study Costs	$0				$0
1508	Other Regulatory Assets	$0				$0
1510	Preliminary Survey and Investigation Charges	$0				$0
1515	Emission Allowance Inventory	$0				$0
1516	Emission Allowances Withheld	$0				$0
1518	RCVARetail	$0				$0
1520	Power Purchase Variance Account	$0				$0
1525	Miscellaneous Deferred Debits	$0				$0
1530	Deferred Losses from Disposition of Utility Plant	$0				$0
1540	Unamortized Loss on Reacquired Debt	$0				$0
1545	Development Charge Deposits/ Receivables	$0				$0
1548	RCVASTR	$0				$0
1560	Deferred Development Costs	$0				$0
1562	Deferred Payments in Lieu of Taxes	$0				$0
1563	Account 1563 - Deferred PILs Contra Account	$0				$0
1565	Conservation and Demand Management Expenditures and Recoveries	$524,558				$524,558
1570	Qualifying Transition Costs	$0				$0
1571	Pre-market Opening Energy Variance	$0				$0
1572	Extraordinary Event Costs	$0				$0
1574	Deferred Rate Impact Amounts	$0				$0
1580	RSVAWMS	$0				$0
1582	RSVAONE-TIME	$0				$0
1584	RSVANW	$0				$0
1586	RSVACN	$0				$0
1588	RSVAPOWER	$0				$0
1590	Recovery of Regulatory Asset Balances	$0				$0
1605	Electric Plant in Service - Control Account	$0				$0
1606	Organization	$0				$0
1608	Franchises and Consents	$0				$0
1610	Miscellaneous Intangible Plant	$0				$0
1615	Land	$0				$0
1616	Land Rights	$0				$0
1620	Buildings and Fixtures	$0				$0
1630	Leasehold Improvements	$0				$0
1635	Boiler Plant Equipment	$0				$0
1640	Engines and Engine-Driven Generators	$0				$0
1645	Turbogenerator Units	$0				$0
1650	Reservoirs, Dams and Waterways	$0				$0
1655	Water Wheels, Turbines and Generators	$0				$0
1660	Roads, Railroads and Bridges	$0				$0
1665	Fuel Holders, Producers and Accessories	$0				$0
1670	Prime Movers	$0				$0
1675	Generators	$0				$0
1680	Accessory Electric Equipment	$0				$0
1685	Miscellaneous Power Plant Equipment	$0				$0
1705	Land	$0				$0
1706	Land Rights	$0				$0
1708	Buildings and Fixtures	$0				$0
1710	Leasehold Improvements	$0				$0
1715	Station Equipment	$0				$0
1720	Towers and Fixtures	$0				$0
1725	Poles and Fixtures	$0				$0
1730	Overhead Conductors and Devices	$0				$0
1735	Underground Conduit	$0				$0
1740	Underground Conductors and Devices	$0				$0
1745	Roads and Trails	$0				$0
1805	Land	$189,212				$189,212
1806	Land Rights	$0				$0
1808	Buildings and Fixtures	$435,610				$435,610
1810	Leasehold Improvements	$0				$0
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0				$0
1820	Distribution Station Equipment - Normally Primary below 50 kV	$210,827		$463,230		$674,056
1825	Storage Battery Equipment	$0				$0
1830	Poles, Towers and Fixtures	$1,879,967		($44,957)	$218,922	$1,616,088
1835	Overhead Conductors and Devices	$15,069,503		($103,123)	$726,018	$14,240,362
1840	Underground Conduit	$616,722				$616,722
1845	Underground Conductors and Devices	$12,195,195		($80)		$12,195,115
1850	Line Transformers	$10,834,508		($10,483)	$4,487	$10,819,538
1855	Services	$1,713,773		($4,967)	$12,577	$1,696,229
1860	Meters	$2,803,649		($299,620)	$22,512	$2,481,518
1865	Other Installations on Customer's Premises	$0				$0
1870	Leased Property on Customer Premises	$0				$0
1875	Street Lighting and Signal Systems	$0				$0
1905	Land	$205,766				$205,766
1906	Land Rights	$0				$0
1908	Buildings and Fixtures	$2,644,076				$2,644,076
1910	Leasehold Improvements	$0				$0

1915	Office Furniture and Equipment	$76,027			$76,027
1920	Computer Equipment - Hardware	$308,327			$308,327
1925	Computer Software	$9,144			$9,144
1930	Transportation Equipment	$1,426,340			$1,426,340
1935	Stores Equipment	$0			$0
1940	Tools, Shop and Garage Equipment	$487,765			$487,765
1945	Measurement and Testing Equipment	$0			$0
1950	Power Operated Equipment	$0			$0
1955	Communication Equipment	$0			$0
1960	Miscellaneous Equipment	$0			$0
1965	Water Heater Rental Units	$0			$0
1970	Load Management Controls - Customer Premises	$0			$0
1975	Load Management Controls - Utility Premises	$0			$0
1980	System Supervisory Equipment	$597,956			$597,956
1985	Sentinel Lighting Rental Units	$0			$0
1990	Other Tangible Property	$1,311,799			$1,311,799
1995	Contributions and Grants - Credit	($2,488,420)		($2,488,420)	$0
2005	Property Under Capital Leases	$0			$0
2010	Electric Plant Purchased or Sold	$0			$0
2020	Experimental Electric Plant Unclassified	$0			$0
2030	Electric Plant and Equipment Leased to Others	$0			$0
2040	Electric Plant Held for Future Use	$0			$0
2050	Completed Construction Not Classified--Electric	$0			$0
2055	Construction Work in Progress--Electric	$0			$0
2060	Electric Plant Acquisition Adjustment	$0			$0
2065	Other Electric Plant Adjustment	$0			$0
2070	Other Utility Plant	$0			$0
2075	Non-Utility Property Owned or Under Capital Leases	$0			$0
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	($10,575,078)		$156,852	($10,731,930)
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	$0			$0
2140	Accumulated Amortization of Electric Plant Acquisition Adjustment	$0			$0
2160	Accumulated Amortization of Other Utility Plant	$0			$0
2180	Accumulated Amortization of Non-Utility Property	$0			$0
2205	Accounts Payable	$0			$0
2208	Customer Credit Balances	$0			$0
2210	Current Portion of Customer Deposits	$0			$0
2215	Dividends Declared	$0			$0
2220	Miscellaneous Current and Accrued Liabilities	$0			$0
2225	Notes and Loans Payable	$0			$0
2240	Accounts Payable to Associated Companies	$0			$0
2242	Notes Payable to Associated Companies	$0			$0
2250	Debt Retirement Charges(DRC) Payable	$0			$0
2252	Transmission Charges Payable	$0			$0
2254	Electrical Safety Authority Fees Payable	$0			$0
2256	Independent Market Operator Fees and Penalties Payable	$0			$0
2260	Current Portion of Long Term Debt	$0			$0
2262	Ontario Hydro Debt - Current Portion	$0			$0
2264	Pensions and Employee Benefits - Current Portion	$0			$0
2268	Accrued Interest on Long Term Debt	$0			$0
2270	Matured Long Term Debt	$0			$0
2272	Matured Interest on Long Term Debt	$0			$0
2285	Obligations Under Capital Leases--Current	$0			$0
2290	Commodity Taxes	$0			$0
2292	Payroll Deductions / Expenses Payable	$0			$0
2294	Accrual for Taxes, Payments in Lieu of Taxes, Etc.	$0			$0
2296	Future Income Taxes - Current	$0			$0
2305	Accumulated Provision for Injuries and Damages	$0			$0
2306	Employee Future Benefits	$0			$0
2308	Other Pensions - Past Service Liability	$0			$0
2310	Vested Sick Leave Liability	$0			$0
2315	Accumulated Provision for Rate Refunds	$0			$0
2320	Other Miscellaneous Non-Current Liabilities	$0			$0
2325	Obligations Under Capital Lease--Non-Current	$0			$0
2330	Development Charge Fund	$0			$0
2335	Long Term Customer Deposits	$0			$0
2340	Collateral Funds Liability	$0			$0
2345	Unamortized Premium on Long Term Debt	$0			$0
2348	O.M.E.R.S. - Past Service Liability - Long Term Portion	$0			$0
2350	Future Income Tax - Non-Current	$0			$0
2405	Other Regulatory Liabilities	$0			$0
2410	Deferred Gains from Disposition of Utility Plant	$0			$0
2415	Unamortized Gain on Reacquired Debt	$0			$0
2425	Other Deferred Credits	$0			$0
2435	Accrued Rate-Payer Benefit	$0			$0
2505	Debentures Outstanding - Long Term Portion	$0			$0
2510	Debenture Advances	$0			$0
2515	Reacquired Bonds	$0			$0
2520	Other Long Term Debt	$0			$0
2525	Term Bank Loans - Long Term Portion	$0			$0
2530	Ontario Hydro Debt Outstanding - Long Term Portion	$0			$0
2550	Advances from Associated Companies	$0			$0
3005	Common Shares Issued	$0			$0
3008	Preference Shares Issued	$0			$0
3010	Contributed Surplus	$0			$0
3020	Donations Received	$0			$0
3022	Development Charges Transferred to Equity	$0			$0
3026	Capital Stock Held in Treasury	$0			$0
3030	Miscellaneous Paid-In Capital	$0			$0

3035	Installments Received on Capital Stock		$0			$0
3040	Appropriated Retained Earnings		$0			$0
3045	Unappropriated Retained Earnings		$0			$0
3046	Balance Transferred From Income		$0	$0	($67,041)	($2,330,969)
3047	Appropriations of Retained Earnings - Current Period		$0			$0
3048	Dividends Payable-Preference Shares		$0			$0
3049	Dividends Payable-Common Shares		$0			$0
3055	Adjustment to Retained Earnings		$0			$0
3065	Unappropriated Undistributed Subsidiary Earnings		$0			$0
4006	Residential Energy Sales		($8,762,889)			($8,762,889)
4010	Commercial Energy Sales		$0			$0
4015	Industrial Energy Sales		$0			$0
4020	Energy Sales to Large Users		($3,154,744)			($3,154,744)
4025	Street Lighting Energy Sales		($401,766)			($401,766)
4030	Sentinel Lighting Energy Sales		($17,955)			($17,955)
4035	General Energy Sales		($23,366,901)			($23,366,901)
4040	Other Energy Sales to Public Authorities		$0			$0
4045	Energy Sales to Railroads and Railways		$0			$0
4050	Revenue Adjustment		($515,257)			($515,257)
4055	Energy Sales for Resale		($9,166,112)			($9,166,112)
4060	Interdepartmental Energy Sales		$0			$0
4062	Billed WMS		($5,605,772)			($5,605,772)
4064	Billed-One-Time		$0			$0
4066	Billed NW		($4,919,290)			($4,919,290)
4068	Billed CN		($4,295,601)			($4,295,601)
4080	Distribution Services Revenue		($11,001,393)	$1,317,098		($12,318,491)
4082	Retail Services Revenues		($63,840)			($63,840)
4084	Service Transaction Requests (STR) Revenues		($404)			($404)
4090	Electric Services Incidental to Energy Sales		($108,607)			($108,607)
4105	Transmission Charges Revenue		$0			$0
4110	Transmission Services Revenue		$0			$0
4205	Interdepartmental Rents		$0			$0
4210	Rent from Electric Property		($208,492)			($208,492)
4215	Other Utility Operating Income		($73,282)			($73,282)
4220	Other Electric Revenues		($11,622)			($11,622)
4225	Late Payment Charges		($195,525)			($195,525)
4230	Sales of Water and Water Power		$0			$0
4235	Miscellaneous Service Revenues		($140,963)	$140,963		($348,917)
4240	Provision for Rate Refunds		$0			$0
4245	Government Assistance Directly Credited to Income		$0			$0
4305	Regulatory Debits		$0			$0
4310	Regulatory Credits		$0			$0
4315	Revenues from Electric Plant Leased to Others		$0			$0
4320	Expenses of Electric Plant Leased to Others		$0			$0
4325	Revenues from Merchandise, Jobbing, Etc.		$0			$0
4330	Costs and Expenses of Merchandising, Jobbing, Etc.		$0			$0
4335	Profits and Losses from Financial Instrument Hedges		$0			$0
4340	Profits and Losses from Financial Instrument Investments		$0			$0
4345	Gains from Disposition of Future Use Utility Plant		$0			$0
4350	Losses from Disposition of Future Use Utility Plant		$0			$0
4355	Gain on Disposition of Utility and Other Property		($103,666)			($103,666)
4360	Loss on Disposition of Utility and Other Property		$0			$0
4365	Gains from Disposition of Allowances for Emission		$0			$0
4370	Losses from Disposition of Allowances for Emission		$0			$0
4375	Revenues from Non-Utility Operations		$0			$0
4380	Expenses of Non-Utility Operations		$0			$0
4385	Non-Utility Rental Income		$0			$0
4390	Miscellaneous Non-Operating Income		($58,383)			($58,383)
4395	Rate-Payer Benefit Including Interest		$0			$0
4398	Foreign Exchange Gains and Losses, Including Amortization		$0			$0
4405	Interest and Dividend Income		($277,488)			($277,488)
4415	Equity in Earnings of Subsidiary Companies		$0			$0
4505	Operation Supervision and Engineering		$0			$0
4510	Fuel		$0			$0
4515	Steam Expense		$0			$0
4520	Steam From Other Sources		$0			$0
4525	Steam Transferred--Credit		$0			$0
4530	Electric Expense		$0			$0
4535	Water For Power		$0			$0
4540	Water Power Taxes		$0			$0
4545	Hydraulic Expenses		$0			$0
4550	Generation Expense		$0			$0
4555	Miscellaneous Power Generation Expenses		$0			$0
4560	Rents		$0			$0
4565	Allowances for Emissions		$0			$0
4605	Maintenance Supervision and Engineering		$0			$0
4610	Maintenance of Structures		$0			$0
4615	Maintenance of Boiler Plant		$0			$0
4620	Maintenance of Electric Plant		$0			$0
4625	Maintenance of Reservoirs, Dams and Waterways		$0			$0
4630	Maintenance of Water Wheels, Turbines and Generators		$0			$0
4635	Maintenance of Generating and Electric Plant		$0			$0
4640	Maintenance of Miscellaneous Power Generation Plant		$0			$0
4705	Power Purchased		$45,425,848			$45,425,848
4708	Charges-WMS		$5,605,773			$5,605,773
4710	Cost of Power Adjustments		($601,798)			($601,798)
4712	Charges-One-Time		$0			$0
4714	Charges-NW		$4,919,290			$4,919,290
4715	System Control and Load Dispatching		$0			$0

4716	Charges-CN	$4,293,420		$4,293,420
4720	Other Expenses	$0		$0
4725	Competition Transition Expense	$0		$0
4730	Rural Rate Assistance Expense	$0		$0
4805	Operation Supervision and Engineering	$0		$0
4810	Load Dispatching	$0		$0
4815	Station Buildings and Fixtures Expenses	$0		$0
4820	Transformer Station Equipment - Operating Labour	$0		$0
4825	Transformer Station Equipment - Operating Supplies and Expense	$0		$0
4830	Overhead Line Expenses	$0		$0
4835	Underground Line Expenses	$0		$0
4840	Transmission of Electricity by Others	$0		$0
4845	Miscellaneous Transmission Expense	$0		$0
4850	Rents	$0		$0
4905	Maintenance Supervision and Engineering	$0		$0
4910	Maintenance of Transformer Station Buildings and Fixtures	$0		$0
4916	Maintenance of Transformer Station Equipment	$0		$0
4930	Maintenance of Towers, Poles and Fixtures	$0		$0
4935	Maintenance of Overhead Conductors and Devices	$0		$0
4940	Maintenance of Overhead Lines - Right of Way	$0		$0
4945	Maintenance of Overhead Lines - Roads and Trails Repairs	$0		$0
4950	Maintenance of Overhead Lines - Snow Removal from Roads and Trails	$0		$0
4960	Maintenance of Underground Lines	$0		$0
4965	Maintenance of Miscellaneous Transmission Plant	$0		$0
5005	Operation Supervision and Engineering	$143,807		$143,807
5010	Load Dispatching	$0		$0
5012	Station Buildings and Fixtures Expense	$0		$0
5014	Transformer Station Equipment - Operation Labour	$0		$0
5015	Transformer Station Equipment - Operation Supplies and Expenses	$0		$0
5016	Distribution Station Equipment - Operation Labour	$2,068		$2,068
5017	Distribution Station Equipment - Operation Supplies and Expenses	$5,890		$5,890
5020	Overhead Distribution Lines and Feeders - Operation Labour	$112,180		$112,180
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$36,883		$36,883
5030	Overhead Subtransmission Feeders - Operation	$0		$0
5035	Overhead Distribution Transformers- Operation	$68,840	$0	$68,840
5040	Underground Distribution Lines and Feeders - Operation Labour	$155,038		$155,038
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$63,632		$63,632
5050	Underground Subtransmission Feeders - Operation	$0		$0
5055	Underground Distribution Transformers - Operation	$804	$0	$804
5060	Street Lighting and Signal System Expense	$0		$0
5065	Meter Expense	$193,124		$193,124
5070	Customer Premises - Operation Labour	$13,570		$13,570
5075	Customer Premises - Materials and Expenses	$3,690		$3,690
5085	Miscellaneous Distribution Expense	$0		$0
5090	Underground Distribution Lines and Feeders - Rental Paid	$0		$0
5095	Overhead Distribution Lines and Feeders - Rental Paid	$0		$0
5096	Other Rent	$0		$0
5105	Maintenance Supervision and Engineering	$147,804		$147,804
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$0		$0
5112	Maintenance of Transformer Station Equipment	$0		$0
5114	Maintenance of Distribution Station Equipment	$161,821		$161,821
5120	Maintenance of Poles, Towers and Fixtures	$44,352		$44,352
5125	Maintenance of Overhead Conductors and Devices	$101,344		$101,344
5130	Maintenance of Overhead Services	$121,515		$121,515
5135	Overhead Distribution Lines and Feeders - Right of Way	$168,586		$168,586
5145	Maintenance of Underground Conduit	$3,992		$3,992
5150	Maintenance of Underground Conductors and Devices	$13,466		$13,466
5155	Maintenance of Underground Services	$28,209		$28,209
5160	Maintenance of Line Transformers	$53,652	$0	$53,652
5165	Maintenance of Street Lighting and Signal Systems	$0		$0
5170	Sentinel Lights - Labour	$0		$0
5172	Sentinel Lights - Materials and Expenses	$0		$0
5175	Maintenance of Meters	$16,662		$16,662
5178	Customer Installations Expenses- Leased Property	$0		$0
5185	Water Heater Rentals - Labour	$0		$0
5186	Water Heater Rentals - Materials and Expenses	$0		$0
5190	Water Heater Controls - Labour	$0		$0
5192	Water Heater Controls - Materials and Expenses	$0		$0
5195	Maintenance of Other Installations on Customer Premises	$0		$0
5205	Purchase of Transmission and System Services	$0		$0
5210	Transmission Charges	$0		$0
5215	Transmission Charges Recovered	$0		$0
5305	Supervision	$54,562		$54,562
5310	Meter Reading Expense	$98,403		$98,403
5315	Customer Billing	$865,907		$865,907
5320	Collecting	$322,189		$322,189
5325	Collecting- Cash Over and Short	$188		$188

5330	Collection Charges		$0			$0
5335	Bad Debt Expense		$137,396			$137,396
5340	Miscellaneous Customer Accounts Expenses		$0			$0
5405	Supervision		$0			$0
5410	Community Relations - Sundry		$20,696			$20,696
5415	Energy Conservation		$0			$0
5420	Community Safety Program		$142			$142
5425	Miscellaneous Customer Service and Informational Expenses		$0			$0
5505	Supervision		$0			$0
5510	Demonstrating and Selling Expense		$0			$0
5515	Advertising Expense		$2,173			$2,173
5520	Miscellaneous Sales Expense		$0			$0
5605	Executive Salaries and Expenses		$0			$0
5610	Management Salaries and Expenses		$377,394			$377,394
5615	General Administrative Salaries and Expenses		$175,436			$175,436
5620	Office Supplies and Expenses		$43,391			$43,391
5625	Administrative Expense Transferred Credit		$0			$0
5630	Outside Services Employed		$268,397			$268,397
5635	Property Insurance		$83,600			$83,600
5640	Injuries and Damages		$88,070			$88,070
5645	Employee Pensions and Benefits		$290,415			$290,415
5650	Franchise Requirements		$0			$0
5655	Regulatory Expenses		$300,000			$300,000
5660	General Advertising Expenses		$0			$0
5665	Miscellaneous General Expenses		$615,576	($562,500)		$53,076
5670	Rent		$0			$0
5675	Maintenance of General Plant		$501,235			$501,235
5680	Electrical Safety Authority Fees		$0			$0
5685	Independent Market Operator Fees and Penalties		$0			$0
5705	Amortization Expense - Property, Plant, and Equipment		$2,817,363		($71,974)	$2,889,337
5710	Amortization of Limited Term Electric Plant		$0			$0
5715	Amortization of Intangibles and Other Electric Plant		$0			$0
5720	Amortization of Electric Plant Acquisition Adjustments		$0			$0
5725	Miscellaneous Amortization		$0			$0
5730	Amortization of Unrecovered Plant and Regulatory Study Costs		$0			$0
5735	Amortization of Deferred Development Costs		$0			$0
5740	Amortization of Deferred Charges		$0			$0
6005	Interest on Long Term Debt		$0	$0	($52,441)	$1,823,336
6010	Amortization of Debt Discount and Expense		$0			$0
6015	Amortization of Premium on Debt Credit		$0			$0
6020	Amortization of Loss on Reacquired Debt		$0			$0
6025	Amortization of Gain on Reacquired Debt--Credit		$0			$0
6030	Interest on Debt to Associated Companies		$0			$0
6035	Other Interest Expense		$0			$0
6040	Allowance for Borrowed Funds Used During Construction--Credit		$0			$0
6042	Allowance For Other Funds Used During Construction		$0			$0
6045	Interest Expense on Capital Lease Obligations		$0			$0
6105	Taxes Other Than Income Taxes		$0			$0
6110	Income Taxes		$0	$0	($46,579)	$1,619,511
6115	Provision for Future Income Taxes		$0			$0
6205	Donations		$0			$0
6210	Life Insurance		$0			$0
6215	Penalties		$0			$0
6225	Other Deductions		$0			$0
6305	Extraordinary Income		$0			$0
6310	Extraordinary Deductions		$0			$0
6315	Income Taxes, Extraordinary Items		$0			$0
6405	Discontinues Operations - Income/ Gains		$0			$0
6410	Discontinued Operations - Deductions/ Losses		$0			$0
6415	Income Taxes, Discontinued Operations		$0			$0

$0

Reclassification Equals to Zero. O.K. to Proceed.

Asset Accounts Directly Allocated	($1,347,052)

2006 Cost Allocation Information Filing
Chatham Kent Hydro Inc.
EB-2005-0350 EB-2006-0247
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	$40,477,227

RATE BASE AND DISTRIBUTION ASSETS

		BALANCE SHEET ITEMS									EXPENSE ITEMS			
											5705	5710	5715	5720
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	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	$524,558		-	524,558			$ (30,000)		494,558	$30,000			
1805	Land	$189,212		($189,212)	-									
1805-1	Land Station >50 kV			$0	-					-				
1805-2	Land Station <50 kV		100.00%	$189,212	189,212					189,212				
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	$435,610		($435,610)	-									
1808-1	Buildings and Fixtures > 50 kV			$0	-					-				
1808-2	Buildings and Fixtures < 50 KV		100.00%	$435,610	435,610			$ (86,515)		349,095	$26,226			
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	$674,056		($674,056)	-					-				
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)			$0	-					-				
1820-2	Distribution Station Equipment - Normally Primary below 50 kV Primary)		31.28%	$210,845	210,845			$ (25,412)		185,433	$10,551			
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)		68.72%	$463,212	463,212			$ (55,828)		407,384	$23,181			
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	$1,616,088		($1,616,088)	-									
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery			$0	-					-				
1830-4	Poles, Towers and Fixtures - Primary		76.46%	$1,235,661	1,235,661			$ (132,076)		1,103,585	$ 56,506			

2006 Cost Allocation Information Filing
Chatham Kent Hydro Inc.
EB-2005-0350 EB-2006-0247
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	$40,477,227

RATE BASE AND DISTRIBUTION ASSETS		BALANCE SHEET ITEMS									EXPENSE ITEMS			
											5705	5710	5715	5720
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	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		23.54%	$380,427	380,427			$ (40,663)		339,764	$ 17,397			
1835	Overhead Conductors and Devices	$14,240,362		($14,240,362)	-									
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery			$0	-					-				
1835-4	Overhead Conductors and Devices - Primary		87.63%	$12,478,830	12,478,830			$ (2,440,451)		10,038,378	$ 705,175			
1835-5	Overhead Conductors and Devices - Secondary		12.37%	$1,761,533	1,761,533			$ (344,498)		1,417,035	$ 99,544			
1840	Underground Conduit	$616,722		($616,722)	-									
1840-3	Underground Conduit - Bulk Delivery			$0	-					-				
1840-4	Underground Conduit - Primary		100.00%	$616,722	616,722			$ (64,700)		552,022	$27,477			
1840-5	Underground Conduit - Secondary		0.00%	$0	-					-				
1845	Underground Conductors and Devices	$12,195,115		($12,195,115)	-									
1845-3	Underground Conductors and Devices - Bulk Delivery			$0	-					-				
1845-4	Underground Conductors and Devices - Primary		53.49%	$6,523,167	6,523,167			$ (1,357,827)		5,165,340	$ 379,298			
1845-5	Underground Conductors and Devices - Secondary		46.51%	$5,671,948	5,671,948			$ (1,180,642)		4,491,306	$ 329,802			
1850	Line Transformers	$10,819,538		$0	10,819,538			$ (2,082,583)		8,736,956	$564,768			
1855	Services	$1,696,229		$0	1,696,229			$ (181,933)		1,514,296	$76,464			
1860	Meters	$2,481,518		$0	2,481,518			$ (510,749)		1,970,769	$166,174			
	Total	**$45,489,008**		**$0**	**$45,489,008**	**$0**	**$0**	**($8,533,875)**	**$0**	**36,955,133**	**$2,512,562**	**$0**	**$0**	**$0**
	SUB TOTAL from I3	**$45,489,008**												

2006 Cost Allocation Information Filing

Chatham Kent Hydro Inc.

EB-2005-0350 EB-2006-0247

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	**$40,477,227**

RATE BASE AND DISTRIBUTION ASSETS		BALANCE SHEET ITEMS									EXPENSE ITEMS			
											5705	5710	5715	5720
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**	**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**
											5705	5710	5715	5720
General Plant		**Break out Functions**				**Contributed Capital - 1995**	**Accumulated Depreciation - 2105 Capital Contribution**	**Accumulated Depreciation - 2105 Fixed Assets Only**	**Accumulated Depreciation - 2120**	**Net Asset**	**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	$205,766			205,766					$ 205,766				
1906	Land Rights	$0			-					$ -				
1908	Buildings and Fixtures	$2,644,076			2,644,076			$ (265,581)		$ 2,378,495	$70,997			
1910	Leasehold Improvements	$0			-					$ -				
1915	Office Furniture and Equipment	$76,027			76,027			$ (35,383)		$ 40,644	9,354			
1920	Computer Equipment - Hardware	$308,327			308,327			$ (203,528)		$ 104,799	52,688			
1925	Computer Software	$9,144			9,144					$ 9,144				
1930	Transportation Equipment	$1,426,340			1,426,340			$ (812,881)		$ 613,459				
1935	Stores Equipment	$0			-					$ -				
1940	Tools, Shop and Garage Equipment	$487,765			487,765			$ (286,198)		$ 201,567	69,830			
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	$597,956			597,956			$ (261,494)		$ 336,461	80,719			
1990	Other Tangible Property	$1,311,799			1,311,799			$ (332,989)		$ 978,810	93,187			
2005	Property Under Capital Leases	$0			-					$ -				
2010	Electric Plant Purchased or Sold	$0			-					$ -				
	Total	$7,067,201		$0	$7,067,201	$0	$0	($2,198,055)	$0	$4,869,146	$376,775	$0	$0	$0
	SUB TOTAL from I3	$7,067,201												
	I3 Directly Allocated	($1,347,052)												
	Grand Total	$51,209,157		$0	$52,556,209	$0	$0	($10,731,930)	$0	$41,824,279	$2,889,337	$0	$0	$0

2006 Cost Allocation Information Filing

Chatham Kent Hydro Inc.

EB-2005-0350 EB-2006-0247

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	**$40,477,227**

RATE BASE AND DISTRIBUTION ASSETS

		BALANCE SHEET ITEMS									**EXPENSE ITEMS**				
											5705	**5710**	**5715**	**5720**	
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**	**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	$0				$0	**Balanced**								
2105	Accumulated Depreciation - 2105	($10,731,930)						$10,731,930	**Balanced**						
2120	Accumulated Depreciation - 2120	$0							$0	**Balanced**					
	Total	**($10,731,930)**													
	Net Assets	**$40,477,227**	**Net Fixed Assets Match EDR**												
Amortization Expenses															
5705	Amortization Expense - Property, Plant, and Equipment	$2,889,337									($2,889,337)	**Balanced**			
5710	Amortization of Limited Term Electric Plant	$0										$0	**Balanced**		
5715	Amortization of Intangibles and Other Electric Plant	$0											$0	**Balanced**	
5720	Amortization of Electric Plant Acquisition Adjustments	$0												$0	**Balanced**
	Total Amortization Expense	**$2,889,337**													

2006 Cost Allocation Information Filing
Chatham Kent Hydro Inc.
EB-2005-0350 EB-2006-0247
Monday, January 15, 2007

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	4 GS> 50-TOU	5 GS >50-Intermediate	6 Large Use >5MW	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	11 Back-up/Standby Power
crev	Distribution Revenue (sale)	$12,318,491	$7,305,082	$2,114,873	$1,618,426	$0	$408,156	$557,389	$124,784	$19,817	$78,727	$91,237
mi	Miscellaneous Revenue (mi)	$1,450,226	$887,786	$238,618	$222,203	$0	$39,574	$15,960	$20,165	$2,943	$1,686	$21,290
	Total Revenue	$13,768,717	$8,192,868	$2,353,491	$1,840,630	$0	$447,730	$573,349	$144,949	$22,760	$80,413	$112,526
	Expenses											
di	Distribution Costs (di)	$1,433,883	$763,311	$208,201	$252,521	$0	$88,250	$31,430	$40,633	$5,970	$3,392	$40,175
cu	Customer Related Costs (cu)	$1,705,691	$1,156,978	$316,338	$210,305	$0	$17,022	$2,814	$1,037	$181	$97	$919
ad	General and Administration (ad)	$2,204,025	$1,344,162	$367,005	$325,535	$0	$75,141	$24,516	$30,446	$4,490	$2,549	$30,182
dep	Depreciation and Amortization (dep)	$2,889,337	$1,633,017	$441,215	$447,374	$0	$139,697	$47,857	$78,413	$11,419	$6,539	$83,807
INPUT	PILs (INPUT)	$1,619,511	$915,000	$246,811	$250,813	$0	$78,250	$26,864	$44,556	$6,503	$3,726	$46,988
INT	Interest	$1,823,336	$1,030,158	$277,874	$282,379	$0	$88,098	$30,244	$50,164	$7,322	$4,195	$52,902
	Total Expenses	$11,675,783	$6,842,625	$1,857,445	$1,768,928	$0	$486,457	$163,725	$245,249	$35,886	$20,497	$254,971
	Direct Allocation	($238,035)	($195,725)	($20,561)	($39,661)	$0	$0	$0	$0	$0	$0	$17,912
NI	Allocated Net Income (NI)	$2,330,969	$1,316,963	$355,237	$360,996	$0	$112,625	$38,665	$64,130	$9,360	$5,363	$67,630
	Revenue Requirement (includes NI)	$13,768,716	$7,963,863	$2,192,120	$2,090,263	$0	$599,082	$202,390	$309,379	$45,246	$25,860	$340,513
		Revenue Requirement Input equals Output										
	Rate Base Calculation											
	Net Assets											
dp	Distribution Plant - Gross	$45,489,008	$25,708,617	$6,938,113	$7,036,124	$0	$2,190,602	$752,385	$1,249,897	$182,203	$104,391	$1,326,677
gp	General Plant - Gross	$7,067,201	$3,992,864	$1,077,033	$1,094,494	$0	$341,464	$117,227	$194,435	$28,380	$16,259	$205,045
accum dep	Accumulated Depreciation	($10,731,930)	($6,071,380)	($1,641,177)	($1,653,311)	$0	($511,252)	($175,854)	($293,651)	($42,628)	($24,429)	($318,247)
co	Capital Contribution	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total Net Plant	$41,824,279	$23,630,102	$6,373,968	$6,477,308	$0	$2,020,813	$693,757	$1,150,681	$167,954	$96,221	$1,213,475
	Directly Allocated Net Fixed Assets	($1,347,052)	($1,129,264)	($118,645)	($199,306)	$0	$0	$0	$0	$0	$0	$100,163
COP	Cost of Power (COP)	$59,642,533	$16,429,902	$7,376,958	$24,527,668	$0	$5,655,523	$2,868,859	$538,630	$27,846	$58,195	$2,158,951
	OM&A Expenses	$5,343,599	$3,264,451	$891,544	$788,361	$0	$180,413	$58,760	$72,116	$10,641	$6,038	$71,275
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Subtotal	*$64,986,132*	*$19,694,352*	*$8,268,502*	*$25,316,030*	*$0*	*$5,835,936*	*$2,927,619*	*$610,746*	*$38,488*	*$64,232*	*$2,230,226*
	Working Capital	$9,747,920	$2,954,153	$1,240,275	$3,797,404	$0	$875,390	$439,143	$91,612	$5,773	$9,635	$334,534
	Total Rate Base	$50,225,147	$25,454,991	$7,495,599	$10,075,407	$0	$2,896,204	$1,132,900	$1,242,293	$173,727	$105,856	$1,648,172
		Rate Base Input equals Output										
	Equity Component of Rate Base	$25,112,573	$12,727,495	$3,747,799	$5,037,703	$0	$1,448,102	$566,450	$621,146	$86,864	$52,928	$824,086
	Net Income on Allocated Assets	$2,330,970	$1,545,968	$516,607	$111,363	$0	($38,726)	$409,624	($100,301)	($13,125)	$59,916	($160,357)
	Net Income on Direct Allocation Assets	($67,041)	($56,202)	($5,905)	($9,919)	$0	$0	$0	$0	$0	$0	$4,985
	Net Income	$2,263,929	$1,489,766	$510,703	$101,444	$0	($38,726)	$409,624	($100,301)	($13,125)	$59,916	($155,372)
	RATIOS ANALYSIS											
	REVENUE TO EXPENSES %	100.00%	102.88%	107.36%	88.06%	0.00%	74.74%	283.29%	46.85%	50.30%	310.96%	33.05%
	EXISTING REVENUE MINUS ALLOCATED COSTS	$1	$229,005	$161,371	($249,633)	$0	($151,351)	$370,959	($164,431)	($22,486)	$54,553	($227,987)
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.02%	11.71%	13.63%	2.01%	0.00%	-2.67%	72.31%	-16.15%	-15.11%	113.20%	-18.85%

2006 Cost Allocation Information Filing
Chatham Kent Hydro Inc.
EB-2005-0350 EB-2006-0247
Monday, January 15, 2007

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	4	5	6	7	8	9	11
	Residential	GS <50	GS>50-Regular	GS> 50-TOU	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load	Back-up/Standby Power
Customer Unit Cost per month - Avoided Cost	$3.42	$8.61	$45.17	$0.00	$124.21	$26.14	$0.03	$0.03	$0.03	$163.21
Customer Unit Cost per month - Directly Related	$5.58	$14.18	$79.32	$0.00	$186.90	$115.15	$0.06	$0.06	$0.06	$234.00
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$14.63	$24.11	$93.68	$0.00	$217.29	$194.94	$8.62	$10.43	$7.86	$422.49
Fixed Charge per approved 2006 EDR	$11.75	$30.31	$158.39	$0.00	$4,208.90	$12,877.94	$0.47	$3.86	$3.28	$158.39

Information to be Used to Allocate PILs, ROD, ROE and A&G

		1	2	3	4	5	6	7	8	9	11
	Total	Residential	GS <50	GS>50-Regular	GS> 50-TOU	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load	Back-up/Standby Power
General Plant - Gross Assets	$7,067,201	$3,992,864	$1,077,033	$1,094,494	$0	$341,464	$117,227	$194,435	$28,380	$16,259	$205,045
General Plant - Accumulated Depreciation	($2,198,055)	($1,241,868)	($334,981)	($340,412)	$0	($106,203)	($36,460)	($60,473)	($8,827)	($5,057)	($63,774)
General Plant - Net Fixed Assets	$4,869,146	$2,750,996	$742,052	$754,083	$0	$235,261	$80,767	$133,961	$19,553	$11,202	$141,272
General Plant - Depreciation	$376,775	$212,872	$57,420	$58,351	$0	$18,205	$6,250	$10,366	$1,513	$867	$10,932
Total Net Fixed Assets Excluding General Plant	$36,955,133	$20,879,106	$5,631,916	$5,723,225	$0	$1,785,552	$612,991	$1,016,719	$148,401	$85,019	$1,072,203
Total Administration and General Expense	$2,204,025	$1,344,162	$367,005	$325,535	$0	$75,141	$24,516	$30,446	$4,490	$2,549	$30,182
Total O&M	$3,139,574	$1,920,288	$524,539	$462,827	$0	$105,272	$34,244	$41,670	$6,151	$3,489	$41,093

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

			1	2	3	4	5	6	7	8	9	11
USoA Account #	Accounts	Total	Residential	GS <50	GS>50-Regular	GS> 50-TOU	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load	Back-up/Standby Power
	Distribution Plant											
1860	Meters	$2,481,518	$1,577,511	$504,352	$312,068	$0	$71,923	$7,832	$0	$0	$0	$7,832
	Accumulated Amortization											
	Accum. Amortization of Electric Utility Plant - Meters only	($510,749)	($324,685)	($103,806)	($64,230)	$0	($14,803)	($1,612)	$0	$0	$0	($1,612)
	Meter Net Fixed Assets	**$1,970,769**	**$1,252,826**	**$400,546**	**$247,838**	**$0**	**$57,119**	**$6,220**	**$0**	**$0**	**$0**	**$6,220**
	Misc Revenue											
4082	Retail Services Revenues	($63,840)	($42,396)	($12,027)	($8,945)	$0	($379)	($90)	$0	$0	$0	($3)
4084	Service Transaction Requests (STR) Revenues	($404)	($268)	($76)	($57)	$0	($2)	($1)	$0	$0	$0	($0)
4090	Electric Services Incidental to Energy Sales	($108,607)	($72,125)	($20,461)	($15,218)	$0	($645)	($153)	$0	$0	$0	($5)
4220	Other Electric Revenues	($11,622)	($6,566)	($1,771)	($1,800)	$0	($562)	($193)	($320)	($47)	($27)	($337)
4225	Late Payment Charges	($195,525)	($127,188)	($28,622)	($35,585)	$0	($1,065)	($3,065)	$0	$0	$0	$0
	Sub-total	*($379,998)*	*($248,543)*	*($62,957)*	*($61,604)*	*$0*	*($2,652)*	*($3,502)*	*($320)*	*($47)*	*($27)*	*($345)*
	Operation											
5065	Meter Expense	$193,124	$122,770	$39,251	$24,287	$0	$5,597	$610	$0	$0	$0	$610
5070	Customer Premises - Operation Labour	$13,570	$11,113	$1,271	$144	$0	$7	$1	$815	$142	$76	$0
5075	Customer Premises - Materials and Expenses	$3,690	$3,022	$346	$39	$0	$2	$0	$222	$39	$21	$0

	Sub-total	*$210,384*	*$136,905*	*$40,868*	*$24,470*	*$0*	*$5,606*	*$611*	*$1,037*	*$181*	*$97*	*$610*
	Maintenance											
5175	Maintenance of Meters	$16,662	$10,592	$3,386	$2,095	$0	$483	$53	$0	$0	$0	$53
	Billing and Collection											
5310	Meter Reading Expense	$98,403	$60,461	$24,198	$9,594	$0	$3,557	$395	$0	$0	$0	$198
5315	Customer Billing	$865,907	$575,042	$163,132	$121,330	$0	$5,139	$1,223	$0	$0	$0	$41
5320	Collecting	$322,189	$213,963	$60,699	$45,145	$0	$1,912	$455	$0	$0	$0	$15
5325	Collecting- Cash Over and Short	$188	$125	$35	$26	$0	$1	$0	$0	$0	$0	$0
5330	Collection Charges	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub-total	$1,286,687	$849,590	$248,065	$176,095	$0	$10,609	$2,074	$0	$0	$0	$254
	Total Operation, Maintenance and Billing	$1,513,733	$997,087	$292,319	$202,660	$0	$16,698	$2,737	$1,037	$181	$97	$916
	Amortization Expense - Meters	$166,174	$105,637	$33,774	$20,897	$0	$4,816	$524	$0	$0	$0	$524
	Allocated PILs	$76,312	$48,512	$15,510	$9,597	$0	$2,212	$241	$0	$0	$0	$241
	Allocated Debt Return	$85,916	$54,617	$17,462	$10,805	$0	$2,490	$271	$0	$0	$0	$271
	Allocated Equity Return	$109,836	$69,823	$22,323	$13,813	$0	$3,183	$347	$0	$0	$0	$347
	Total	**$1,571,972**	**$1,027,133**	**$318,431**	**$196,167**	**$0**	**$26,747**	**$618**	**$717**	**$134**	**$70**	**$1,954**

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

			1	2	3	4	5	6	7	8	9	11
USoA Account #	**Accounts**	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**GS> 50-TOU**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Back-up/Standby Power**
	Distribution Plant											
1860	Meters	$2,481,518	$1,577,511	$504,352	$312,068	$0	$71,923	$7,832	$0	$0	$0	$7,832
	Accumulated Amortization											
	Accum. Amortization of Electric Utility Plant - Meters only	($510,749)	($324,685)	($103,806)	($64,230)	$0	($14,803)	($1,612)	$0	$0	$0	($1,612)
	Meter Net Fixed Assets	$1,970,769	$1,252,826	$400,546	$247,838	$0	$57,119	$6,220	$0	$0	$0	$6,220
	Allocated General Plant Net Fixed Assets	$259,665	$165,070	$52,775	$32,655	$0	$7,526	$820	$0	$0	$0	$820
	Meter Net Fixed Assets Including General Plant	$2,230,434	$1,417,896	$453,321	$280,492	$0	$64,645	$7,039	$0	$0	$0	$7,039
	Misc Revenue											
4082	Retail Services Revenues	($63,840)	($42,396)	($12,027)	($8,945)	$0	($379)	($90)	$0	$0	$0	($3)
4084	Service Transaction Requests (STR) Revenues	($404)	($268)	($76)	($57)	$0	($2)	($1)	$0	$0	$0	($0)
4090	Electric Services Incidental to Energy Sales	($108,607)	($72,125)	($20,461)	($15,218)	$0	($645)	($153)	$0	$0	$0	($5)
4220	Other Electric Revenues	($11,622)	($6,566)	($1,771)	($1,800)	$0	($562)	($193)	($320)	($47)	($27)	($337)
4225	Late Payment Charges	($195,525)	($127,188)	($28,622)	($35,585)	$0	($1,065)	($3,065)	$0	$0	$0	$0
	Sub-total	*($379,998)*	*($248,543)*	*($62,957)*	*($61,604)*	*$0*	*($2,652)*	*($3,502)*	*($320)*	*($47)*	*($27)*	*($345)*
	Operation											
5065	Meter Expense	$193,124	$122,770	$39,251	$24,287	$0	$5,597	$610	$0	$0	$0	$610
5070	Customer Premises - Operation Labour	$13,570	$11,113	$1,271	$144	$0	$7	$1	$815	$142	$76	$0
5075	Customer Premises - Materials and Expenses	$3,690	$3,022	$346	$39	$0	$2	$0	$222	$39	$21	$0
	Sub-total	*$210,384*	*$136,905*	*$40,868*	*$24,470*	*$0*	*$5,606*	*$611*	*$1,037*	*$181*	*$97*	*$610*
	Maintenance											
5175	Maintenance of Meters	$16,662	$10,592	$3,386	$2,095	$0	$483	$53	$0	$0	$0	$53
	Billing and Collection											
5310	Meter Reading Expense	$98,403	$60,461	$24,198	$9,594	$0	$3,557	$395	$0	$0	$0	$198
5315	Customer Billing	$865,907	$575,042	$163,132	$121,330	$0	$5,139	$1,223	$0	$0	$0	$41
5320	Collecting	$322,189	$213,963	$60,699	$45,145	$0	$1,912	$455	$0	$0	$0	$15
5325	Collecting- Cash Over and Short	$188	$125	$35	$26	$0	$1	$0	$0	$0	$0	$0
5330	Collection Charges	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub-total	*$1,286,687*	*$849,590*	*$248,065*	*$176,095*	*$0*	*$10,609*	*$2,074*	*$0*	*$0*	*$0*	*$254*
	Total Operation, Maintenance and Billing	$1,513,733	$997,087	$292,319	$202,660	$0	$16,698	$2,737	$1,037	$181	$97	$916
	Amortization Expense - Meters	$166,174	$105,637	$33,774	$20,897	$0	$4,816	$524	$0	$0	$0	$524
	Amortization Expense - General Plant assigned to Meters	*$20,093*	*$12,773*	*$4,084*	*$2,527*	*$0*	*$582*	*$63*	*$0*	*$0*	*$0*	*$63*
	Admin and General	$1,060,523	$697,940	$204,527	$142,544	$0	$11,919	$1,960	$758	$132	$71	$673
	Allocated PILs	$86,366	$54,903	$17,553	$10,861	$0	$2,503	$273	$0	$0	$0	$273
	Allocated Debt Return	$97,236	$61,813	$19,763	$12,228	$0	$2,818	$307	$0	$0	$0	$307
	Allocated Equity Return	$124,308	$79,023	$25,265	$15,633	$0	$3,603	$392	$0	$0	$0	$392
	Total	**$2,688,435**	**$1,760,634**	**$534,328**	**$345,745**	**$0**	**$40,287**	**$2,754**	**$1,475**	**$266**	**$141**	**$2,803**

Scenario 3

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

			1	2	3	4	5	6	7	8	9	11
USoA Account #	**Accounts**	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**GS> 50-TOU**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Back-up/Standby Power**
	Distribution Plant											
1565	Conservation and Demand Management Expenditures and Recoveries	$524,558	$320,840	$87,640	$77,329	$0	$17,589	$5,721	$6,962	$1,028	$583	$6,866
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-4	Poles, Towers and Fixtures - Primary	$494,264	$404,770	$46,305	$5,239	$0	$258	$29	$29,697	$5,182	$2,770	$14
1830-5	Poles, Towers and Fixtures - Secondary	$152,171	$124,908	$14,289	$1,355	$0	$0	$0	$9,164	$1,599	$855	$0
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-4	Overhead Conductors and Devices - Primary	$4,991,532	$4,087,736	$467,625	$52,909	$0	$2,609	$290	$299,912	$52,329	$27,976	$145
1835-5	Overhead Conductors and Devices - Secondary	$704,613	$578,375	$66,165	$6,276	$0	$0	$0	$42,435	$7,404	$3,958	$0
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary	$246,689	$202,022	$23,111	$2,615	$0	$129	$14	$14,822	$2,586	$1,383	$7
1840-5	Underground Conduit - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary	$2,609,267	$2,136,818	$244,446	$27,657	$0	$1,364	$152	$156,776	$27,354	$14,624	$76
1845-5	Underground Conductors and Devices - Secondary	$2,268,779	$1,862,308	$213,043	$20,208	$0	$0	$0	$136,635	$23,840	$12,746	$0
1850	Line Transformers	$4,327,815	$3,552,449	$406,390	$38,548	$0	$0	$0	$260,639	$45,476	$24,313	$0
1855	Services	$1,696,229	$1,185,909	$271,329	$128,684	$0	$0	$0	$87,009	$15,181	$8,116	$0
1860	Meters	$2,481,518	$1,577,511	$504,352	$312,068	$0	$71,923	$7,832	$0	$0	$0	$7,832
	Sub-total	*$20,497,434*	*$16,033,647*	*$2,344,694*	*$672,887*	*$0*	*$93,872*	*$14,038*	*$1,044,052*	*$181,980*	*$97,324*	*$14,940*
	Accumulated Amortization											
	Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	($3,835,885)	($2,992,674)	($431,672)	($129,880)	$0	($26,525)	($4,803)	($194,155)	($33,802)	($18,115)	($4,260)
	Customer Related Net Fixed Assets	$16,661,549	$13,040,973	$1,913,022	$543,007	$0	$67,347	$9,235	$849,897	$148,178	$79,209	$10,680
	Allocated General Plant Net Fixed Assets	$2,195,298	$1,718,257	$252,057	$71,546	$0	$8,874	$1,217	$111,981	$19,524	$10,437	$1,407
	Customer Related NFA Including General Plant	$18,856,847	$14,759,230	$2,165,079	$614,553	$0	$76,221	$10,452	$961,878	$167,702	$89,646	$12,088
	Misc Revenue											
4082	Retail Services Revenues	($63,840)	($42,396)	($12,027)	($8,945)	$0	($379)	($90)	$0	$0	$0	($3)
4084	Service Transaction Requests (STR) Revenues	($404)	($268)	($76)	($57)	$0	($2)	($1)	$0	$0	$0	($0)
4090	Electric Services Incidental to Energy Sales	($108,607)	($72,125)	($20,461)	($15,218)	$0	($645)	($153)	$0	$0	$0	($5)
4220	Other Electric Revenues	($11,622)	($6,566)	($1,771)	($1,800)	$0	($562)	($193)	($320)	($47)	($27)	($337)
4225	Late Payment Charges	($195,525)	($127,188)	($28,622)	($35,585)	$0	($1,065)	($3,065)	$0	$0	$0	$0
4235	Miscellaneous Service Revenues	($348,917)	($231,713)	($65,734)	($48,890)	$0	($2,071)	($493)	$0	$0	$0	($16)
	Sub-total	*($728,915)*	*($480,256)*	*($128,691)*	*($110,494)*	*$0*	*($4,723)*	*($3,995)*	*($320)*	*($47)*	*($27)*	*($362)*
	Operating and Maintenance											
5005	Operation Supervision and Engineering	$57,523	$45,708	$5,802	$1,373	$0	$277	$75	$3,336	$580	$311	$59
5010	Load Dispatching	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5020	Overhead Distribution Lines and Feeders - Operation Labour	$44,872	$36,759	$4,205	$465	$0	$20	$2	$2,697	$471	$252	$1
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$14,753	$12,086	$1,383	$153	$0	$7	$1	$887	$155	$83	$0
5035	Overhead Distribution Transformers- Operation	$27,536	$22,603	$2,586	$245	$0	$0	$0	$1,658	$289	$155	$0
5040	Underground Distribution Lines and Feeders - Operation Labour	$62,015	$50,839	$5,816	$611	$0	$18	$2	$3,730	$651	$348	$1
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$25,453	$20,866	$2,387	$251	$0	$7	$1	$1,531	$267	$143	$0
5055	Underground Distribution Transformers - Operation	$322	$264	$30	$3	$0	$0	$0	$19	$3	$2	$0
5065	Meter Expense	$193,124	$122,770	$39,251	$24,287	$0	$5,597	$610	$0	$0	$0	$610
5070	Customer Premises - Operation Labour	$13,570	$11,113	$1,271	$144	$0	$7	$1	$815	$142	$76	$0
5075	Customer Premises - Materials and Expenses	$3,690	$3,022	$346	$39	$0	$2	$0	$222	$39	$21	$0
5085	Miscellaneous Distribution Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5090	Underground Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

5095	Overhead Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5096	Other Rent	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5105	Maintenance Supervision and Engineering	$59,122	$46,979	$5,963	$1,411	$0	$284	$77	$3,429	$597	$320	$61
5120	Maintenance of Poles, Towers and Fixtures	$17,741	$14,537	$1,663	$181	$0	$7	$1	$1,067	$186	$99	$0
5125	Maintenance of Overhead Conductors and Devices	$40,538	$33,207	$3,799	$421	$0	$19	$2	$2,436	$425	$227	$1
5130	Maintenance of Overhead Services	$121,515	$84,957	$19,438	$9,219	$0	$0	$0	$6,233	$1,088	$581	$0
5135	Overhead Distribution Lines and Feeders - Right of Way	$67,434	$55,242	$6,319	$699	$0	$30	$3	$4,053	$707	$378	$2
5145	Maintenance of Underground Conduit	$1,597	$1,308	$150	$17	$0	$1	$0	$96	$17	$9	$0
5150	Maintenance of Underground Conductors and Devices	$5,386	$4,416	$505	$53	$0	$2	$0	$324	$57	$30	$0
5155	Maintenance of Underground Services	$28,209	$19,722	$4,512	$2,140	$0	$0	$0	$1,447	$252	$135	$0
5160	Maintenance of Line Transformers	$21,461	$17,616	$2,015	$191	$0	$0	$0	$1,292	$226	$121	$0
5175	Maintenance of Meters	$16,662	$10,592	$3,386	$2,095	$0	$483	$53	$0	$0	$0	$53
	Sub-total	*$822,522*	*$614,603*	*$110,826*	*$43,999*	*$0*	*$6,761*	*$828*	*$35,273*	*$6,151*	*$3,291*	*$789*
	Billing and Collection											
5305	Supervision	$54,562	$36,234	$10,279	$7,645	$0	$324	$77	$0	$0	$0	$3
5310	Meter Reading Expense	$98,403	$60,461	$24,198	$9,594	$0	$3,557	$395	$0	$0	$0	$198
5315	Customer Billing	$865,907	$575,042	$163,132	$121,330	$0	$5,139	$1,223	$0	$0	$0	$41
5320	Collecting	$322,189	$213,963	$60,699	$45,145	$0	$1,912	$455	$0	$0	$0	$15
5325	Collecting- Cash Over and Short	$188	$125	$35	$26	$0	$1	$0	$0	$0	$0	$0
5330	Collection Charges	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5335	Bad Debt Expense	$137,396	$123,656	$13,740	$0	$0	$0	$0	$0	$0	$0	$0
5340	Miscellaneous Customer Accounts Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub-total	*$1,478,645*	*$1,009,481*	*$272,083*	*$183,740*	*$0*	*$10,933*	*$2,151*	*$0*	*$0*	*$0*	*$256*
	Sub Total Operating, Maintenance and Biling	*$2,301,167*	*$1,624,084*	*$382,910*	*$227,739*	*$0*	*$17,694*	*$2,979*	*$35,273*	*$6,151*	*$3,291*	*$1,046*
	Amortization Expense - Customer Related	$1,167,805	$898,906	$135,706	$46,940	$0	$10,169	$2,029	$56,986	$9,906	$5,315	$1,848
	Amortization Expense - General Plant assigned to Meters	$169,872	$132,959	$19,504	$5,536	$0	$687	$94	$8,665	$1,511	$808	$109
	Admin and General	$1,613,116	$1,136,826	$267,911	$160,183	$0	$12,629	$2,133	$25,772	$4,490	$2,404	$768
	Allocated PILs	$730,171	$571,504	$83,836	$23,797	$0	$2,951	$405	$37,246	$6,494	$3,471	$468
	Allocated Debt Return	$822,067	$643,431	$94,387	$26,792	$0	$3,323	$456	$41,933	$7,311	$3,908	$527
	Allocated Equity Return	$1,050,938	$822,568	$120,665	$34,251	$0	$4,248	$582	$53,608	$9,346	$4,996	$674
	PLCC Adjustment for Line Transformer	$198,635	$164,761	$18,848	$1,788	$0	$0	$0	$12,108	$0	$1,129	$0
	PLCC Adjustment for Primary Costs	$234,863	$194,318	$22,228	$2,533	$0	$126	$14	$14,303	$0	$1,335	$7
	PLCC Adjustment for Secondary Costs	$210,192	$169,815	$16,457	$1,785	$0	$0	$0	$18,634	$0	$3,497	$5
	Total	$6,482,531	**$4,821,127**	**$918,695**	**$408,636**	**$0**	**$46,852**	**$4,669**	**$214,118**	**$45,162**	**$18,206**	**$5,065**

Below: Grouping to avoid disclosure

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

Accounts	Total	Residential	GS <50	GS>50-Regular	GS> 50-TOU	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load	Back-up/Standby Power
Distribution Plant											
CWMC	$ 2,481,518	$ 1,577,511	$ 504,352	$ 312,068	$ -	$ 71,923	$ 7,832	$ -	$ -	$ -	$ 7,832
Accumulated Amortization											
Accum. Amortization of Electric Utility Plant - Meters only	$ (510,749)	$ (324,685)	$ (103,806)	$ (64,230)	$ -	$ (14,803)	$ (1,612)	$ -	$ -	$ -	$ (1,612)
Meter Net Fixed Assets	$ 1,970,769	$ 1,252,826	$ 400,546	$ 247,838	$ -	$ 57,119	$ 6,220	$ -	$ -	$ -	$ 6,220
Misc Revenue											
CWNB	$ (172,851)	$ (114,789)	$ (32,564)	$ (24,220)	$ -	$ (1,026)	$ (244)	$ -	$ -	$ -	$ (8)
NFA	$ (11,622)	$ (6,566)	$ (1,771)	$ (1,800)	$ -	$ (562)	$ (193)	$ (320)	$ (47)	$ (27)	$ (337)
LPHA	$ (195,525)	$ (127,188)	$ (28,622)	$ (35,585)	$ -	$ (1,065)	$ (3,065)	$ -	$ -	$ -	$ -
Sub-total	*$ (379,998)*	*$ (248,543)*	*$ (62,957)*	*$ (61,604)*	*$ -*	*$ (2,652)*	*$ (3,502)*	*$ (320)*	*$ (47)*	*$ (27)*	*$ (345)*
Operation											
CWMC	$ 193,124	$ 122,770	$ 39,251	$ 24,287	$ -	$ 5,597	$ 610	$ -	$ -	$ -	$ 610
CCA	$ 17,260	$ 14,135	$ 1,617	$ 183	$ -	$ 9	$ 1	$ 1,037	$ 181	$ 97	$ 1
Sub-total	$ 210,384	$ 136,905	$ 40,868	$ 24,470	$ -	$ 5,606	$ 611	$ 1,037	$ 181	$ 97	$ 610
Maintenance											
1860	$ 16,662	$ 10,592	$ 3,386	$ 2,095	$ -	$ 483	$ 53	$ -	$ -	$ -	$ 53
Billing and Collection											
CWMR	$ 98,403	$ 60,461	$ 24,198	$ 9,594	$ -	$ 3,557	$ 395	$ -	$ -	$ -	$ 198
CWNB	$ 1,188,284	$ 789,130	$ 223,867	$ 166,501	$ -	$ 7,052	$ 1,679	$ -	$ -	$ -	$ 56
Sub-total	$ 1,286,687	$ 849,590	$ 248,065	$ 176,095	$ -	$ 10,609	$ 2,074	$ -	$ -	$ -	$ 254
Total Operation, Maintenance and Billing	$ 1,513,733	$ 997,087	$ 292,319	$ 202,660	$ -	$ 16,698	$ 2,737	$ 1,037	$ 181	$ 97	$ 916
Amortization Expense - Meters	$ 166,174	$ 105,637	$ 33,774	$ 20,897	$ -	$ 4,816	$ 524	$ -	$ -	$ -	$ 524
Allocated PILs	$ 76,312	$ 48,512	$ 15,510	$ 9,597	$ -	$ 2,212	$ 241	$ -	$ -	$ -	$ 241
Allocated Debt Return	$ 85,916	$ 54,617	$ 17,462	$ 10,805	$ -	$ 2,490	$ 271	$ -	$ -	$ -	$ 271
Allocated Equity Return	$ 109,836	$ 69,823	$ 22,323	$ 13,813	$ -	$ 3,183	$ 347	$ -	$ -	$ -	$ 347
Total	**$ 1,571,972**	**$ 1,027,133**	**$ 318,431**	**$ 196,167**	**$ -**	**$ 26,747**	**$ 618**	**$ 717**	**$ 134**	**$ 70**	**$ 1,954**

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

Accounts	Total	Residential	GS <50	GS>50-Regular	GS> 50-TOU	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load	Back-up/Standby Power
Distribution Plant											
CWMC	$ 2,481,518	$ 1,577,511	$ 504,352	$ 312,068	$ -	$ 71,923	$ 7,832	$ -	$ -	$ -	$ 7,832
Accumulated Amortization											
Accum. Amortization of Electric Utility Plant - Meters only	$ (510,749)	$ (324,685)	$ (103,806)	$ (64,230)	$ -	$ (14,803)	$ (1,612)	$ -	$ -	$ -	$ (1,612)
Meter Net Fixed Assets	$ 1,970,769	$ 1,252,826	$ 400,546	$ 247,838	$ -	$ 57,119	$ 6,220	$ -	$ -	$ -	$ 6,220
Allocated General Plant Net Fixed Assets	$ 259,665	$ 165,070	$ 52,775	$ 32,655	$ -	$ 7,526	$ 820	$ -	$ -	$ -	$ 820
Meter Net Fixed Assets Including General Plant	$ 2,230,434	$ 1,417,896	$ 453,321	$ 280,492	$ -	$ 64,645	$ 7,039	$ -	$ -	$ -	$ 7,039
Misc Revenue											
CWNB	$ (172,851)	$ (114,789)	$ (32,564)	$ (24,220)	$ -	$ (1,026)	$ (244)	$ -	$ -	$ -	$ (8)
NFA	$ (11,622)	$ (6,566)	$ (1,771)	$ (1,800)	$ -	$ (562)	$ (193)	$ (320)	$ (47)	$ (27)	$ (337)
LPHA	$ (195,525)	$ (127,188)	$ (28,622)	$ (35,585)	$ -	$ (1,065)	$ (3,065)	$ -	$ -	$ -	$ -
Sub-total	*$ (379,998)*	*$ (248,543)*	*$ (62,957)*	*$ (61,604)*	*$ -*	*$ (2,652)*	*$ (3,502)*	*$ (320)*	*$ (47)*	*$ (27)*	*$ (345)*

Operation										
CWMC	$ 193,124	$ 122,770	$ 39,251	$ 24,287	$ -	$ 5,597	$ 610	$ -	$ -	$ -	$ 610
CCA	$ 17,260	$ 14,135	$ 1,617	$ 183	$ -	$ 9	$ 1	$ 1,037	$ 181	$ 97	$ 1
Sub-total	*$ 210,384*	*$ 136,905*	*$ 40,868*	*$ 24,470*	*$ -*	*$ 5,606*	*$ 611*	*$ 1,037*	*$ 181*	*$ 97*	*$ 610*
Maintenance											
1860	$ 16,662	$ 10,592	$ 3,386	$ 2,095	$ -	$ 483	$ 53	$ -	$ -	$ -	$ 53
Billing and Collection											
CWMR	$ 98,403	$ 60,461	$ 24,198	$ 9,594	$ -	$ 3,557	$ 395	$ -	$ -	$ -	$ 198
CWNB	$ 1,188,284	$ 789,130	$ 223,867	$ 166,501	$ -	$ 7,052	$ 1,679	$ -	$ -	$ -	$ 56
Sub-total	*$ 1,286,687*	*$ 849,590*	*$ 248,065*	*$ 176,095*	*$ -*	*$ 10,609*	*$ 2,074*	*$ -*	*$ -*	*$ -*	*$ 254*
Total Operation, Maintenance and Billing	$ 1,513,733	$ 997,087	$ 292,319	$ 202,660	$ -	$ 16,698	$ 2,737	$ 1,037	$ 181	$ 97	$ 916
Amortization Expense - Meters	$ 166,174	$ 105,637	$ 33,774	$ 20,897	$ -	$ 4,816	$ 524	$ -	$ -	$ -	$ 524
Amortization Expense - General Plant assigned to Meters	$ 20,093	$ 12,773	$ 4,084	$ 2,527	$ -	$ 582	$ 63	$ -	$ -	$ -	$ 63
Admin and General	$ 1,060,523	$ 697,940	$ 204,527	$ 142,544	$ -	$ 11,919	$ 1,960	$ 758	$ 132	$ 71	$ 673
Allocated PILs	$ 86,366	$ 54,903	$ 17,553	$ 10,861	$ -	$ 2,503	$ 273	$ -	$ -	$ -	$ 273
Allocated Debt Return	$ 97,236	$ 61,813	$ 19,763	$ 12,228	$ -	$ 2,818	$ 307	$ -	$ -	$ -	$ 307
Allocated Equity Return	$ 124,308	$ 79,023	$ 25,265	$ 15,633	$ -	$ 3,603	$ 392	$ -	$ -	$ -	$ 392
Total	**$ 2,688,435**	**$ 1,760,634**	**$ 534,328**	**$ 345,745**	**$ -**	**$ 40,287**	**$ 2,754**	**$ 1,475**	**$ 266**	**$ 141**	**$ 2,803**

Scenario 3

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

USoA Account #	Accounts	Total	Residential	GS <50	GS>50-Regular	GS> 50-TOU	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load	Back-up/Standby Power
	Distribution Plant											
	CDMPP	$ 524,558	$ 320,840	$ 87,640	$ 77,329	$ -	$ 17,589	$ 5,721	$ 6,962	$ 1,028	$ 583	$ 6,866
	Poles, Towers and Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	PNCP	$ 8,341,752	$ 6,831,346	$ 781,487	$ 88,420	$ -	$ 4,360	$ 484	$ 501,208	$ 87,451	$ 46,754	$ 242
	SNCP	$ 3,125,563	$ 2,565,591	$ 293,496	$ 27,839	$ -	$ -	$ -	$ 188,234	$ 32,843	$ 17,559	$ -
	Overhead Conductors and Devices	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	LTNCP	$ 4,327,815	$ 3,552,449	$ 406,390	$ 38,548	$ -	$ -	$ -	$ 260,639	$ 45,476	$ 24,313	$ -
	CWCS	$ 1,696,229	$ 1,185,909	$ 271,329	$ 128,684	$ -	$ -	$ -	$ 87,009	$ 15,181	$ 8,116	$ -
	CWMC	$ 2,481,518	$ 1,577,511	$ 504,352	$ 312,068	$ -	$ 71,923	$ 7,832	$ -	$ -	$ -	$ 7,832
	Sub-total	*$ 20,497,434*	*$ 16,033,647*	*$ 2,344,694*	*$ 672,887*	*$ -*	*$ 93,872*	*$ 14,038*	*$ 1,044,052*	*$ 181,980*	*$ 97,324*	*$ 14,940*
	Accumulated Amortization											
	Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	$ (3,835,885)	$ (2,992,674)	$ (431,672)	$ (129,880)	$ -	$ (26,525)	$ (4,803)	$ (194,155)	$ (33,802)	$ (18,115)	$ (4,260)
	Customer Related Net Fixed Assets	$ 16,661,549	$ 13,040,973	$ 1,913,022	$ 543,007	$ -	$ 67,347	$ 9,235	$ 849,897	$ 148,178	$ 79,209	$ 10,680
	Allocated General Plant Net Fixed Assets	$ 2,195,298	$ 1,718,257	$ 252,057	$ 71,546	$ -	$ 8,874	$ 1,217	$ 111,981	$ 19,524	$ 10,437	$ 1,407
	Customer Related NFA Including General Plant	$ 18,856,847	$ 14,759,230	$ 2,165,079	$ 614,553	$ -	$ 76,221	$ 10,452	$ 961,878	$ 167,702	$ 89,646	$ 12,088
	Misc Revenue											
	CWNB	$ (521,768)	$ (346,502)	$ (98,298)	$ (73,109)	$ -	$ (3,096)	$ (737)	$ -	$ -	$ -	$ (25)
	NFA	$ (11,622)	$ (6,566)	$ (1,771)	$ (1,800)	$ -	$ (562)	$ (193)	$ (320)	$ (47)	$ (27)	$ (337)
	LPHA	$ (195,525)	$ (127,188)	$ (28,622)	$ (35,585)	$ -	$ (1,065)	$ (3,065)	$ -	$ -	$ -	$ -
	Sub-total	*$ (728,915)*	*$ (480,256)*	*$ (128,691)*	*$ (110,494)*	*$ -*	*$ (4,723)*	*$ (3,995)*	*$ (320)*	*$ (47)*	*$ (27)*	*$ (362)*
	Operating and Maintenance											
	1815-1855	$ 116,644	$ 92,687	$ 11,764	$ 2,784	$ -	$ 561	$ 153	$ 6,766	$ 1,177	$ 632	$ 121
	1830 & 1835	$ 127,060	$ 104,086	$ 11,907	$ 1,318	$ -	$ 57	$ 6	$ 7,637	$ 1,332	$ 712	$ 3
	1850	$ 49,318	$ 40,483	$ 4,631	$ 439	$ -	$ -	$ -	$ 2,970	$ 518	$ 277	$ -
	1840 & 1845	$ 87,468	$ 71,704	$ 8,203	$ 862	$ -	$ 25	$ 3	$ 5,261	$ 918	$ 491	$ 1
	CWMC	$ 193,124	$ 122,770	$ 39,251	$ 24,287	$ -	$ 5,597	$ 610	$ -	$ -	$ -	$ 610
	CCA	$ 17,260	$ 14,135	$ 1,617	$ 183	$ -	$ 9	$ 1	$ 1,037	$ 181	$ 97	$ 1
	O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1830	$ 17,741	$ 14,537	$ 1,663	$ 181	$ -	$ 7	$ 1	$ 1,067	$ 186	$ 99	$ 0
	1835	$ 40,538	$ 33,207	$ 3,799	$ 421	$ -	$ 19	$ 2	$ 2,436	$ 425	$ 227	$ 1
	1855	$ 149,724	$ 104,679	$ 23,950	$ 11,359	$ -	$ -	$ -	$ 7,680	$ 1,340	$ 716	$ -
	1840	$ 1,597	$ 1,308	$ 150	$ 17	$ -	$ 1	$ 0	$ 96	$ 17	$ 9	$ 0
	1845	$ 5,386	$ 4,416	$ 505	$ 53	$ -	$ 2	$ 0	$ 324	$ 57	$ 30	$ 0
	1860	$ 16,662	$ 10,592	$ 3,386	$ 2,095	$ -	$ 483	$ 53	$ -	$ -	$ -	$ 53
	Sub-total	*$ 822,522*	*$ 614,603*	*$ 110,826*	*$ 43,999*	*$ -*	*$ 6,761*	*$ 828*	*$ 35,273*	*$ 6,151*	*$ 3,291*	*$ 789*
	Billing and Collection											
	CWNB	$ 1,242,846	$ 825,364	$ 234,146	$ 174,146	$ -	$ 7,376	$ 1,756	$ -	$ -	$ -	$ 59
	CWMR	$ 98,403	$ 60,461	$ 24,198	$ 9,594	$ -	$ 3,557	$ 395	$ -	$ -	$ -	$ 198
	BDHA	$ 137,396	$ 123,656	$ 13,740	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Sub-total	*$ 1,478,645*	*$ 1,009,481*	*$ 272,083*	*$ 183,740*	*$ -*	*$ 10,933*	*$ 2,151*	*$ -*	*$ -*	*$ -*	*$ 256*
	Sub Total Operating, Maintenance and Biling	*$ 2,301,167*	*$ 1,624,084*	*$ 382,910*	*$ 227,739*	*$ -*	*$ 17,694*	*$ 2,979*	*$ 35,273*	*$ 6,151*	*$ 3,291*	*$ 1,046*
	Amortization Expense - Customer Related	$ 1,167,805	$ 898,906	$ 135,706	$ 46,940	$ -	$ 10,169	$ 2,029	$ 56,986	$ 9,906	$ 5,315	$ 1,848
	Amortization Expense - General Plant assigned to Meters	$ 169,872	$ 132,959	$ 19,504	$ 5,536	$ -	$ 687	$ 94	$ 8,665	$ 1,511	$ 808	$ 109
	Admin and General	$ 1,613,116	$ 1,136,826	$ 267,911	$ 160,183	$ -	$ 12,629	$ 2,133	$ 25,772	$ 4,490	$ 2,404	$ 768
	Allocated PILs	$ 730,171	$ 571,504	$ 83,836	$ 23,797	$ -	$ 2,951	$ 405	$ 37,246	$ 6,494	$ 3,471	$ 468
	Allocated Debt Return	$ 822,067	$ 643,431	$ 94,387	$ 26,792	$ -	$ 3,323	$ 456	$ 41,933	$ 7,311	$ 3,908	$ 527
	Allocated Equity Return	$ 1,050,938	$ 822,568	$ 120,665	$ 34,251	$ -	$ 4,248	$ 582	$ 53,608	$ 9,346	$ 4,996	$ 674
	PLCC Adjustment for Line Transformer	$ 198,635	$ 164,761	$ 18,848	$ 1,788	$ -	$ -	$ -	$ 12,108	$ -	$ 1,129	$ -
	PLCC Adjustment for Primary Costs	$ 234,863	$ 194,318	$ 22,228	$ 2,533	$ -	$ 126	$ 14	$ 14,303	$ -	$ 1,335	$ 7
	PLCC Adjustment for Secondary Costs	$ 210,192	$ 169,815	$ 16,457	$ 1,785	$ -	$ -	$ -	$ 18,634	$ -	$ 3,497	$ 5
	Total	**$ 6,482,531**	**$ 4,821,127**	**$ 918,695**	**$ 408,636**	**$ -**	**$ 46,852**	**$ 4,669**	**$ 214,118**	**$ 45,162**	**$ 18,206**	**$ 5,065**

APPENDIX C

COST ALLOCATION MODEL – CURRENT WITHOUT TRANSFORMER ALLOWANCE

2010 Cost Allocation Information Filing
Chatham Kent Hydro Inc.
EB-2005-0350 EB-2006-0247
Tuesday, September 28, 2010

Sheet I2 Class Selection - Second Run

Instructions:
Step 1: Pleae input your existing classes
Step 2: If this is your first run, select "First Run" in the drop-down menu below
Step 3: After all classes have been entered, Click the "Update" button in row E41

If desired, provide a summary of this run (40 characters max.)

Click for Drop-Down Menu → Second Run

		Utility's Class Definition	Current
1	Residential		YES
2	GS <50		YES
3	GS>50-Regular		YES
4	GS> 50-TOU		NO
5	GS >50-Intermediate		YES
6	Large Use >5MW		NO
7	Street Light		YES
8	Sentinel		YES
9	Unmetered Scattered Load		YES
10	Embedded Distributor		NO
11	Back-up/Standby Power		YES
12	Rate Class 1		NO
13	Rate class 2		NO
14	Rate class 3		NO
15	Rate class 4		NO
16	Rate class 5		NO
17	Rate class 6		NO
18	Rate class 7		NO
19	Rate class 8		NO
20	Rate class 9		NO

Update

** Space available for additional information about this run

2010 Cost Allocation Information Filing
Chatham Kent Hydro Inc.
EB-2005-0350 EB-2006-0247
Tuesday, September 28, 2010

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	Differences?
Approved Target Net Income ($)	$1,796,597		
Approved PILs ($)	$987,663		
Approved Interest ($)	$2,422,602		
Approved Specific Service Charges ($)	$494,368		
Approved Transformer Ownership Allowance ($)			
Approved Low Voltage Wheeling Adjustment ($)			
Approved Revenue Requirement ($)	$15,825,336		
Revenue Requirement to be Used in this model ($)	$15,825,336	**$15,825,336**	**Rev Req Matches**
Approved Rate Base ($)	$56,073,568		
Rate Base to be Used in this model ($)	$56,073,568	**$56,073,568**	**Rate Base Matches**

Uniform System of Accounts - Detail Accounts

USoA Account #	Accounts	Financial Statement (EDR Sheet 2.4, Column P)	Model Adjustments	Reclassify accounts	Direct Allocation	Reclassified Balance
1005	Cash	$2,714,222				$2,714,222
1010	Cash Advances and Working Funds	$2,200				$2,200
1020	Interest Special Deposits	$0				$0
1030	Dividend Special Deposits	$0				$0
1040	Other Special Deposits	$0				$0
1060	Term Deposits	$0				$0
1070	Current Investments	$0				$0
1100	Customer Accounts Receivable	$2,356,500				$2,356,500
1102	Accounts Receivable - Services	$0				$0
1104	Accounts Receivable - Recoverable Work	$100,000				$100,000
1105	Accounts Receivable - Merchandise, Jobbing, etc.	$0				$0
1110	Other Accounts Receivable	$0				$0
1120	Accrued Utility Revenues	$5,891,300				$5,891,300
1130	Accumulated Provision for Uncollectible Accounts--Credit	($100,000)				($100,000)
1140	Interest and Dividends Receivable	$0				$0
1150	Rents Receivable	$0				$0
1170	Notes Receivable	$0				$0
1180	Prepayments	$210,000				$210,000
1190	Miscellaneous Current and Accrued Assets	$0				$0
1200	Accounts Receivable from Associated Companies	$0				$0
1210	Notes Receivable from Associated Companies	$0				$0
1305	Fuel Stock	$0				$0
1330	Plant Materials and Operating Supplies	$800,000				$800,000
1340	Merchandise	$0				$0
1350	Other Materials and Supplies	$0				$0
1405	Long Term Investments in Non-Associated Companies	$0				$0
1408	Long Term Receivable - Street Lighting Transfer	$0				$0
1410	Other Special or Collateral Funds	$0				$0

1415	Sinking Funds	$0		$0
1425	Unamortized Debt Expense	$0		$0
1445	Unamortized Discount on Long-Term Debt--Debit	$0		$0
1455	Unamortized Deferred Foreign Currency Translation Gains and Losses	$0		$0
1460	Other Non-Current Assets	$0		$0
1465	O.M.E.R.S. Past Service Costs	$0		$0
1470	Past Service Costs - Employee Future Benefits	$0		$0
1475	Past Service Costs - Other Pension Plans	$0		$0
1480	Portfolio Investments - Associated Companies	$0		$0
1485	Investment in Associated Companies - Significant Influence	$0		$0
1490	Investment in Subsidiary Companies	$0		$0
1505	Unrecovered Plant and Regulatory Study Costs	$0		$0
1508	Other Regulatory Assets	$941,474		$941,474
1510	Preliminary Survey and Investigation Charges	$0		$0
1515	Emission Allowance Inventory	$0		$0
1516	Emission Allowances Withheld	$0		$0
1518	RCVARetail	($164,436)		($164,436)
1520	Power Purchase Variance Account	$0		$0
1525	Miscellaneous Deferred Debits	$156,120		$156,120
1530	Deferred Losses from Disposition of Utility Plant	$0		$0
1540	Unamortized Loss on Reacquired Debt	$0		$0
1545	Development Charge Deposits/ Receivables	$0		$0
1548	RCVASTR	$111,990		$111,990
1550	LV Charges - Variance	($189,896)		($189,896)
1555	Smart Meters Recovery	$2,911,643		$2,911,643
1556	Smart Meters OM & A	$504,545		$504,545
1560	Deferred Development Costs	$0		$0
1562	Deferred Payments in Lieu of Taxes	($4,225,539)		($4,225,539)
1563	Account 1563 - Deferred PILs Contra Account	$4,496,953		$4,496,953
1565	Conservation and Demand Management Expenditures and Recoveries	$0		$0
1566	C & DM Costs Contra	$0		
1570	Qualifying Transition Costs	$14,466		$14,466
1571	Pre-market Opening Energy Variance	$0		$0
1572	Extraordinary Event Costs	$103,209		$103,209
1574	Deferred Rate Impact Amounts	$80,000		$80,000
1580	RSVAWMS	($1,934,285)		($1,934,285)
1582	RSVAONE-TIME	$59,310		$59,310
1584	RSVANW	$515,926		$515,926
1586	RSVACN	($1,243,022)		($1,243,022)
1588	RSVAPOWER	$1,319,968		$1,319,968
1590	Recovery of Regulatory Asset Balances	$135,942		$135,942
1592	PILs and Tax Variance for 2006 & Subsequent Years	($60,127)		($60,127)
1605	Electric Plant in Service - Control Account	$0		$0
1606	Organization	$0		$0
1608	Franchises and Consents	$0		$0
1610	Miscellaneous Intangible Plant	$0		$0
1615	Land	$0		$0
1616	Land Rights	$0		$0
1620	Buildings and Fixtures	$0		$0
1630	Leasehold Improvements	$0		$0
1635	Boiler Plant Equipment	$0		$0
1640	Engines and Engine-Driven Generators	$0		$0
1645	Turbogenerator Units	$0		$0
1650	Reservoirs, Dams and Waterways	$0		$0
1655	Water Wheels, Turbines and Generators	$0		$0
1660	Roads, Railroads and Bridges	$0		$0
1665	Fuel Holders, Producers and Accessories	$0		$0
1670	Prime Movers	$0		$0
1675	Generators	$0		$0
1680	Accessory Electric Equipment	$0		$0
1685	Miscellaneous Power Plant Equipment	$0		$0
1705	Land	$0		$0
1706	Land Rights	$0		$0
1708	Buildings and Fixtures	$0		$0
1710	Leasehold Improvements	$0		$0
1715	Station Equipment	$0		$0
1720	Towers and Fixtures	$0		$0
1725	Poles and Fixtures	$0		$0
1730	Overhead Conductors and Devices	$0		$0
1735	Underground Conduit	$0		$0
1740	Underground Conductors and Devices	$0		$0
1745	Roads and Trails	$0		$0
1805	Land	$117,846		$117,846
1806	Land Rights	$0		$0
1808	Buildings and Fixtures	$372,472		$372,472
1810	Leasehold Improvements	$0		$0
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0		$0
1820	Distribution Station Equipment - Normally Primary below 50 kV	$845,093		$845,093
1825	Storage Battery Equipment	$0		$0
1830	Poles, Towers and Fixtures	$5,039,154	$218,922	$4,820,232
1835	Overhead Conductors and Devices	$19,967,803	$726,018	$19,241,785
1840	Underground Conduit	$1,399,174		$1,399,174
1845	Underground Conductors and Devices	$15,601,251		$15,601,251
1850	Line Transformers	$15,877,537	$4,487	$15,873,050
1855	Services	$3,967,343	$12,577	$3,954,766
1860	Meters	$7,083,804	$22,512	$7,061,292
1865	Other Installations on Customer's Premises	$0		$0
1870	Leased Property on Customer Premises	$0		$0

1875	Street Lighting and Signal Systems	$0		$0
1905	Land	$781,011		$781,011
1906	Land Rights	$0		$0
1908	Buildings and Fixtures	$3,712,081		$3,712,081
1910	Leasehold Improvements	$0		$0
1915	Office Furniture and Equipment	$137,926		$137,926
1920	Computer Equipment - Hardware	$614,217		$614,217
1925	Computer Software	$613,096		$613,096
1930	Transportation Equipment	$3,271,106		$3,271,106
1935	Stores Equipment	$0		$0
1940	Tools, Shop and Garage Equipment	$835,113		$835,113
1945	Measurement and Testing Equipment	$0		$0
1950	Power Operated Equipment	$0		$0
1955	Communication Equipment	$0		$0
1960	Miscellaneous Equipment	$0		$0
1965	Water Heater Rental Units	$0		$0
1970	Load Management Controls - Customer Premises	$0		$0
1975	Load Management Controls - Utility Premises	$0		$0
1980	System Supervisory Equipment	$847,728		$847,728
1985	Sentinel Lighting Rental Units	$0		$0
1990	Other Tangible Property	$1,867,796		$1,867,796
1995	Contributions and Grants - Credit	($4,299,253)	($4,299,253)	($0)
2005	Property Under Capital Leases	$0		$0
2010	Electric Plant Purchased or Sold	$0		$0
2020	Experimental Electric Plant Unclassified	$0		$0
2030	Electric Plant and Equipment Leased to Others	$0		$0
2040	Electric Plant Held for Future Use	$0		$0
2050	Completed Construction Not Classified--Electric	$0		$0
2055	Construction Work in Progress--Electric	$0		$0
2060	Electric Plant Acquisition Adjustment	$0		$0
2065	Other Electric Plant Adjustment	$0		$0
2070	Other Utility Plant	$0		$0
2075	Non-Utility Property Owned or Under Capital Leases	$0		$0
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	($31,246,866)	$781,374	($32,028,240)
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	$0		$0
2140	Accumulated Amortization of Electric Plant Acquisition Adjustment	$0		$0
2160	Accumulated Amortization of Other Utility Plant	$0		$0
2180	Accumulated Amortization of Non-Utility Property	$0		$0
2205	Accounts Payable	($6,723,224)		($6,723,224)
2208	Customer Credit Balances	$0		$0
2210	Current Portion of Customer Deposits	($1,116,267)		($1,116,267)
2215	Dividends Declared	$0		$0
2220	Miscellaneous Current and Accrued Liabilities	$0		$0
2225	Notes and Loans Payable	$0		$0
2240	Accounts Payable to Associated Companies	($2,083,620)		($2,083,620)
2242	Notes Payable to Associated Companies	$0		$0
2250	Debt Retirement Charges(DRC) Payable	$0		$0
2252	Transmission Charges Payable	$0		$0
2254	Electrical Safety Authority Fees Payable	$0		$0
2256	Independent Market Operator Fees and Penalties Payable	$0		$0
2260	Current Portion of Long Term Debt	$0		$0
2262	Ontario Hydro Debt - Current Portion	$0		$0
2264	Pensions and Employee Benefits - Current Portion	$0		$0
2268	Accrued Interest on Long Term Debt	$0		$0
2270	Matured Long Term Debt	$0		$0
2272	Matured Interest on Long Term Debt	$0		$0
2285	Obligations Under Capital Leases--Current	$0		$0
2290	Commodity Taxes	$0		$0
2292	Payroll Deductions / Expenses Payable	$0		$0
2294	Accrual for Taxes, Payments in Lieu of Taxes, Etc.	$109,388		$109,388
2296	Future Income Taxes - Current	$0		$0
2305	Accumulated Provision for Injuries and Damages	$0		$0
2306	Employee Future Benefits	($858,565)		($858,565)
2308	Other Pensions - Past Service Liability	$0		$0
2310	Vested Sick Leave Liability	$0		$0
2315	Accumulated Provision for Rate Refunds	$0		$0
2320	Other Miscellaneous Non-Current Liabilities	($15,000)		($15,000)
2325	Obligations Under Capital Lease--Non-Current	$0		$0
2330	Development Charge Fund	$0		$0
2335	Long Term Customer Deposits	($3,463,476)		($3,463,476)
2340	Collateral Funds Liability	$0		$0
2345	Unamortized Premium on Long Term Debt	$0		$0
2348	O.M.E.R.S. - Past Service Liability - Long Term Portion	$0		$0
2350	Future Income Tax - Non-Current	$0		$0
2405	Other Regulatory Liabilities	$0		$0
2410	Deferred Gains from Disposition of Utility Plant	$0		$0
2415	Unamortized Gain on Reacquired Debt	$0		$0
2425	Other Deferred Credits	$0		$0
2435	Accrued Rate-Payer Benefit	$0		$0
2505	Debentures Outstanding - Long Term Portion	$0		$0
2510	Debenture Advances	$0		$0
2515	Reacquired Bonds	$0		$0
2520	Other Long Term Debt	($3,000,000)		($3,000,000)
2525	Term Bank Loans - Long Term Portion	$0		$0
2530	Ontario Hydro Debt Outstanding - Long Term Portion	$0		$0
2550	Advances from Associated Companies	($23,523,326)		($23,523,326)
3005	Common Shares Issued	($23,523,425)		($23,523,425)
3008	Preference Shares Issued	$0		$0

3010	Contributed Surplus	$0			$0
3020	Donations Received	$0			$0
3022	Development Charges Transferred to Equity	$0			$0
3026	Capital Stock Held in Treasury	$0			$0
3030	Miscellaneous Paid-In Capital	$0			$0
3035	Installments Received on Capital Stock	$0			$0
3040	Appropriated Retained Earnings	$0			$0
3045	Unappropriated Retained Earnings	$35,386			$35,386
3046	Balance Transferred From Income	$0	$0	($65,690)	($1,862,287)
3047	Appropriations of Retained Earnings - Current Period	$0			$0
3048	Dividends Payable-Preference Shares	$0			$0
3049	Dividends Payable-Common Shares	$1,500,000			$1,500,000
3055	Adjustment to Retained Earnings	$0			$0
3065	Unappropriated Undistributed Subsidiary Earnings	$0			$0
4006	Residential Energy Sales	($10,883,765)			($10,883,765)
4010	Commercial Energy Sales	$0			$0
4015	Industrial Energy Sales	$0			$0
4020	Energy Sales to Large Users	$0			$0
4025	Street Lighting Energy Sales	($455,313)			($455,313)
4030	Sentinel Lighting Energy Sales	($24,183)			($24,183)
4035	General Energy Sales	($25,136,740)			($25,136,740)
4040	Other Energy Sales to Public Authorities	$0			$0
4045	Energy Sales to Railroads and Railways	$0			$0
4050	Revenue Adjustment	$0			$0
4055	Energy Sales for Resale	($4,222,896)			($4,222,896)
4060	Interdepartmental Energy Sales	$0			$0
4062	Billed WMS	($4,359,335)			($4,359,335)
4064	Billed-One-Time	$0			$0
4066	Billed NW	($3,078,724)			($3,078,724)
4068	Billed CN	($2,595,180)			($2,595,180)
4075	Billed LV	($228,345)			($228,345)
4080	Distribution Services Revenue	($12,502,681)	$2,135,205		($14,637,886)
4082	Retail Services Revenues	($65,004)			($65,004)
4084	Service Transaction Requests (STR) Revenues	($1,996)			($1,996)
4090	Electric Services Incidental to Energy Sales	$0			$0
4105	Transmission Charges Revenue	$0			$0
4110	Transmission Services Revenue	$0			$0
4205	Interdepartmental Rents	($156,996)			($156,996)
4210	Rent from Electric Property	($126,996)			($126,996)
4215	Other Utility Operating Income	$0			$0
4220	Other Electric Revenues	($9,996)			($9,996)
4225	Late Payment Charges	($188,861)			($188,861)
4230	Sales of Water and Water Power	$0			$0
4235	Miscellaneous Service Revenues	($494,368)	$494,368		($494,368)
4240	Provision for Rate Refunds	$0			$0
4245	Government Assistance Directly Credited to Income	$0			$0
4305	Regulatory Debits	$0			$0
4310	Regulatory Credits	$0			$0
4315	Revenues from Electric Plant Leased to Others	$0			$0
4320	Expenses of Electric Plant Leased to Others	$0			$0
4325	Revenues from Merchandise, Jobbing, Etc.	$0			$0
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	$0			$0
4335	Profits and Losses from Financial Instrument Hedges	$0			$0
4340	Profits and Losses from Financial Instrument Investments	$0			$0
4345	Gains from Disposition of Future Use Utility Plant	$0			$0
4350	Losses from Disposition of Future Use Utility Plant	$0			$0
4355	Gain on Disposition of Utility and Other Property	$0			$0
4360	Loss on Disposition of Utility and Other Property	($40,000)			($40,000)
4365	Gains from Disposition of Allowances for Emission	$0			$0
4370	Losses from Disposition of Allowances for Emission	$0			$0
4375	Revenues from Non-Utility Operations	($396,329)			($396,329)
4380	Expenses of Non-Utility Operations	$166,642			$166,642
4385	Non-Utility Rental Income	$0			$0
4390	Miscellaneous Non-Operating Income	($30,996)			($30,996)
4395	Rate-Payer Benefit Including Interest	$0			$0
4398	Foreign Exchange Gains and Losses, Including Amortization	$0			$0
4405	Interest and Dividend Income	($122,237)		$50,000	($72,237)
4415	Equity in Earnings of Subsidiary Companies	$0			$0
4505	Operation Supervision and Engineering	$0			$0
4510	Fuel	$0			$0
4515	Steam Expense	$0			$0
4520	Steam From Other Sources	$0			$0
4525	Steam Transferred--Credit	$0			$0
4530	Electric Expense	$0			$0
4535	Water For Power	$0			$0
4540	Water Power Taxes	$0			$0
4545	Hydraulic Expenses	$0			$0
4550	Generation Expense	$0			$0
4555	Miscellaneous Power Generation Expenses	$0			$0
4560	Rents	$0			$0
4565	Allowances for Emissions	$0			$0
4605	Maintenance Supervision and Engineering	$0			$0
4610	Maintenance of Structures	$0			$0
4615	Maintenance of Boiler Plant	$0			$0
4620	Maintenance of Electric Plant	$0			$0
4625	Maintenance of Reservoirs, Dams and Waterways	$0			$0
4630	Maintenance of Water Wheels, Turbines and Generators	$0			$0
4635	Maintenance of Generating and Electric Plant	$0			$0
4640	Maintenance of Miscellaneous Power Generation Plant	$0			$0

4705	Power Purchased		$40,722,897			$40,722,897
4708	Charges-WMS		$4,359,335			$4,359,335
4710	Cost of Power Adjustments		$0			$0
4712	Charges-One-Time		$0			$0
4714	Charges-NW		$3,078,724			$3,078,724
4715	System Control and Load Dispatching		$40,151			$40,151
4716	Charges-CN		$2,595,180			$2,595,180
4720	Other Expenses		$0			$0
4725	Competition Transition Expense		$0			$0
4730	Rural Rate Assistance Expense		$0			$0
4750	LV Charges		$228,345			$228,345
4805	Operation Supervision and Engineering		$0			$0
4810	Load Dispatching		$0			$0
4815	Station Buildings and Fixtures Expenses		$0			$0
4820	Transformer Station Equipment - Operating Labour		$0			$0
4825	Transformer Station Equipment - Operating Supplies and Expense		$0			$0
4830	Overhead Line Expenses		$0			$0
4835	Underground Line Expenses		$0			$0
4840	Transmission of Electricity by Others		$0			$0
4845	Miscellaneous Transmission Expense		$0			$0
4850	Rents		$0			$0
4905	Maintenance Supervision and Engineering		$0			$0
4910	Maintenance of Transformer Station Buildings and Fixtures		$0			$0
4916	Maintenance of Transformer Station Equipment		$0			$0
4930	Maintenance of Towers, Poles and Fixtures		$0			$0
4935	Maintenance of Overhead Conductors and Devices		$0			$0
4940	Maintenance of Overhead Lines - Right of Way		$0			$0
4945	Maintenance of Overhead Lines - Roads and Trails Repairs		$0			$0
4950	Maintenance of Overhead Lines - Snow Removal from Roads and Trails		$0			$0
4960	Maintenance of Underground Lines		$0			$0
4965	Maintenance of Miscellaneous Transmission Plant		$0			$0
5005	Operation Supervision and Engineering		$164,224			$164,224
5010	Load Dispatching		$0			$0
5012	Station Buildings and Fixtures Expense		$0			$0
5014	Transformer Station Equipment - Operation Labour		$0			$0
5015	Transformer Station Equipment - Operation Supplies and Expenses		$0			$0
5016	Distribution Station Equipment - Operation Labour		$107,180			$107,180
5017	Distribution Station Equipment - Operation Supplies and Expenses		$6,471			$6,471
5020	Overhead Distribution Lines and Feeders - Operation Labour		$110,535			$110,535
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses		$36,711			$36,711
5030	Overhead Subtransmission Feeders - Operation		$0			$0
5035	Overhead Distribution Transformers- Operation		$50,252	$0		$50,252
5040	Underground Distribution Lines and Feeders - Operation Labour		$163,707			$163,707
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses		$26,656			$26,656
5050	Underground Subtransmission Feeders - Operation		$0			$0
5055	Underground Distribution Transformers - Operation		$47	$0		$47
5060	Street Lighting and Signal System Expense		$0			$0
5065	Meter Expense		$345,446			$345,446
5070	Customer Premises - Operation Labour		$27,909			$27,909
5075	Customer Premises - Materials and Expenses		$2,098			$2,098
5085	Miscellaneous Distribution Expense		$0			$0
5090	Underground Distribution Lines and Feeders - Rental Paid		$0			$0
5095	Overhead Distribution Lines and Feeders - Rental Paid		$0			$0
5096	Other Rent		$0			$0
5105	Maintenance Supervision and Engineering		$315,211			$315,211
5110	Maintenance of Buildings and Fixtures - Distribution Stations		$0			$0
5112	Maintenance of Transformer Station Equipment		$0			$0
5114	Maintenance of Distribution Station Equipment		$151,068			$151,068
5120	Maintenance of Poles, Towers and Fixtures		$53,155			$53,155
5125	Maintenance of Overhead Conductors and Devices		$190,050			$190,050
5130	Maintenance of Overhead Services		$120,532			$120,532
5135	Overhead Distribution Lines and Feeders - Right of Way		$180,000			$180,000
5145	Maintenance of Underground Conduit		$3,706			$3,706
5150	Maintenance of Underground Conductors and Devices		$5,863			$5,863
5155	Maintenance of Underground Services		$54,106			$54,106
5160	Maintenance of Line Transformers		$91,936	$0		$91,936
5165	Maintenance of Street Lighting and Signal Systems		$0			$0
5170	Sentinel Lights - Labour		$0			$0
5172	Sentinel Lights - Materials and Expenses		$0			$0
5175	Maintenance of Meters		$22,170			$22,170
5178	Customer Installations Expenses- Leased Property		$0			$0
5185	Water Heater Rentals - Labour		$0			$0
5186	Water Heater Rentals - Materials and Expenses		$0			$0
5190	Water Heater Controls - Labour		$0			$0
5192	Water Heater Controls - Materials and Expenses		$0			$0
5195	Maintenance of Other Installations on Customer Premises		$0			$0
5205	Purchase of Transmission and System Services		$0			$0

5210	Transmission Charges		$0			$0
5215	Transmission Charges Recovered		$0			$0
5305	Supervision		$137,237			$137,237
5310	Meter Reading Expense		$34,853			$34,853
5315	Customer Billing		$1,025,552			$1,025,552
5320	Collecting		$416,389			$416,389
5325	Collecting- Cash Over and Short		$0			$0
5330	Collection Charges		$0			$0
5335	Bad Debt Expense		$212,766			$212,766
5340	Miscellaneous Customer Accounts Expenses		$0			$0
5405	Supervision		$0			$0
5410	Community Relations - Sundry		$44,929			$44,929
5415	Energy Conservation		$0			$0
5420	Community Safety Program		$9,557			$9,557
5425	Miscellaneous Customer Service and Informational Expenses		$0			$0
5505	Supervision		$0			$0
5510	Demonstrating and Selling Expense		$0			$0
5515	Advertising Expense		$2,043			$2,043
5520	Miscellaneous Sales Expense		$0			$0
5605	Executive Salaries and Expenses		$73,847			$73,847
5610	Management Salaries and Expenses		$875,544			$875,544
5615	General Administrative Salaries and Expenses		$245,314			$245,314
5620	Office Supplies and Expenses		$59,699			$59,699
5625	Administrative Expense Transferred Credit		$0			$0
5630	Outside Services Employed		$233,633			$233,633
5635	Property Insurance		$84,175			$84,175
5640	Injuries and Damages		$0			$0
5645	Employee Pensions and Benefits		$250,137			$250,137
5650	Franchise Requirements		$0			$0
5655	Regulatory Expenses		$339,852			$339,852
5660	General Advertising Expenses		$0			$0
5665	Miscellaneous General Expenses		$0	$0		$0
5670	Rent		$0			$0
5675	Maintenance of General Plant		$528,550			$528,550
5680	Electrical Safety Authority Fees		$0			$0
5685	Independent Market Operator Fees and Penalties		$0			$0
5705	Amortization Expense - Property, Plant, and Equipment		$3,815,361		($138,585)	$3,953,947
5710	Amortization of Limited Term Electric Plant		$0			$0
5715	Amortization of Intangibles and Other Electric Plant		$0			$0
5720	Amortization of Electric Plant Acquisition Adjustments		$0			$0
5725	Miscellaneous Amortization		$0			$0
5730	Amortization of Unrecovered Plant and Regulatory Study Costs		$0			$0
5735	Amortization of Deferred Development Costs		$0			$0
5740	Amortization of Deferred Charges		$0			$0
6005	Interest on Long Term Debt		$0	$0	($88,578)	$2,511,181
6010	Amortization of Debt Discount and Expense		$0			$0
6015	Amortization of Premium on Debt Credit		$0			$0
6020	Amortization of Loss on Reacquired Debt		$0			$0
6025	Amortization of Gain on Reacquired Debt--Credit		$0			$0
6030	Interest on Debt to Associated Companies		$0			$0
6035	Other Interest Expense		$1,800,831			$1,800,831
6040	Allowance for Borrowed Funds Used During Construction--Credit		$0			$0
6042	Allowance For Other Funds Used During Construction		$0			$0
6045	Interest Expense on Capital Lease Obligations		$0			$0
6105	Taxes Other Than Income Taxes		$0			$0
6110	Income Taxes		$359,438	($359,438)	($36,112)	$1,023,775
6115	Provision for Future Income Taxes		$0			$0
6205	Donations		$0			$0
6210	Life Insurance		$0			$0
6215	Penalties		$0			$0
6225	Other Deductions		$0			$0
6305	Extraordinary Income		$0			$0
6310	Extraordinary Deductions		$0			$0
6315	Income Taxes, Extraordinary Items		$0			$0
6405	Discontinues Operations - Income/ Gains		$0			$0
6410	Discontinued Operations - Deductions/ Losses		$0			$0
6415	Income Taxes, Discontinued Operations		$0			$0

$50,000

Reclassification has not been done correctly as the total does not add to zero

Asset Accounts Directly Allocated	($2,533,363)

2010 Cost Allocation Information Filing

Chatham Kent Hydro Inc.

EB-2005-0350 EB-2006-0247

Tuesday, September 28, 2010

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	$47,405,429

RATE BASE AND DISTRIBUTION ASSETS

		BALANCE SHEET ITEMS									EXPENSE ITEMS			
											5705	5710	5715	5720
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	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	$0		-	-					-				
1805	Land	$117,846		($117,846)	-									
1805-1	Land Station >50 kV			$0	-					-				
1805-2	Land Station <50 kV		100.00%	$117,846	117,846					117,846				
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	$372,472		($372,472)	-									
1808-1	Buildings and Fixtures > 50 kV			$0	-					-				
1808-2	Buildings and Fixtures < 50 KV		100.00%	$372,472	372,472			$ (147,011)		225,461	$16,191			
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	$845,093		($845,093)	-					-				
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)			$0	-					-				
1820-2	Distribution Station Equipment - Normally Primary below 50 kV Primary)		31.28%	$264,345	264,345			$ (77,604)		186,741	$12,060			
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)		68.72%	$580,748	580,748			$ (170,490)		410,258	$26,495			
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	$4,820,232		($4,820,232)	-									
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery			$0	-					-				
1830-4	Poles, Towers and Fixtures - Primary		76.46%	$3,685,550	3,685,550			$ (762,563)		2,922,987	$ 156,359			

2010 Cost Allocation Information Filing

Chatham Kent Hydro Inc.

EB-2005-0350 EB-2006-0247

Tuesday, September 28, 2010

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	$47,405,429

RATE BASE AND DISTRIBUTION ASSETS

						BALANCE SHEET ITEMS					EXPENSE ITEMS			
											5705	5710	5715	5720
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	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		23.54%	$1,134,683	1,134,683			$ (234,773)		899,910	$ 48,139			
1835	Overhead Conductors and Devices	$19,241,785		($19,241,785)	-									
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery			$0	-					-				
1835-4	Overhead Conductors and Devices - Primary		87.63%	$16,861,576	16,861,576			$ (6,925,086)		9,936,489	$ 786,998			
1835-5	Overhead Conductors and Devices - Secondary		12.37%	$2,380,209	2,380,209			$ (977,557)		1,402,652	$ 111,094			
1840	Underground Conduit	$1,399,174		($1,399,174)	-									
1840-3	Underground Conduit - Bulk Delivery			$0	-					-				
1840-4	Underground Conduit - Primary		100.00%	$1,399,174	1,399,174			$ (327,789)		1,071,385	$60,796			
1840-5	Underground Conduit - Secondary		0.00%	$0	-					-				
1845	Underground Conductors and Devices	$15,601,251		($15,601,251)	-									
1845-3	Underground Conductors and Devices - Bulk Delivery			$0	-					-				
1845-4	Underground Conductors and Devices - Primary		53.49%	$8,345,109	8,345,109			$ (3,841,918)		4,503,191	$ 455,886			
1845-5	Underground Conductors and Devices - Secondary		46.51%	$7,256,142	7,256,142			$ (3,340,579)		3,915,562	$ 396,396			
1850	Line Transformers	$15,873,050		$0	15,873,050			$ (6,056,944)		9,816,105	$768,803			
1855	Services	$3,954,766		$0	3,954,766			$ (891,601)		3,063,165	$166,665			
1860	Meters	$7,061,292		$0	7,061,292			$ (2,370,229)		4,691,064	$472,966			
	Total	**$69,286,960**		**$0**	**$69,286,960**	**$0**	**$0**	**($26,124,144)**	**$0**	**43,162,816**	**$3,478,849**	**$0**	**$0**	**$0**
	SUB TOTAL from I3	**$69,286,960**												

2010 Cost Allocation Information Filing
Chatham Kent Hydro Inc.
EB-2005-0350 EB-2006-0247
Tuesday, September 28, 2010

Ontario

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	$47,405,429

RATE BASE AND DISTRIBUTION ASSETS		BALANCE SHEET ITEMS									EXPENSE ITEMS			
											5705	5710	5715	5720
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	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
											5705	5710	5715	5720
General Plant		Break out Functions				Contributed Capital - 1995	Accumulated Depreciation - 2105 Capital Contribution	Accumulated Depreciation - 2105 Fixed Assets Only	Accumulated Depreciation - 2120	Net Asset	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	$781,011			781,011					$ 781,011				
1906	Land Rights	$0			-					$ -				
1908	Buildings and Fixtures	$3,712,081			3,712,081			$ (843,534)		$ 2,868,547	$121,529			
1910	Leasehold Improvements	$0			-					$ -				
1915	Office Furniture and Equipment	$137,926			137,926			$ (92,057)		$ 45,868	9,472			
1920	Computer Equipment - Hardware	$614,217			614,217			$ (423,895)		$ 190,321	30,672			
1925	Computer Software	$613,096			613,096			$ (283,994)		$ 329,102	79,287			
1930	Transportation Equipment	$3,271,106			3,271,106			$ (1,957,966)		$ 1,313,139				
1935	Stores Equipment	$0			-					$ -				
1940	Tools, Shop and Garage Equipment	$835,113			835,113			$ (546,827)		$ 288,286	41,085			
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	$847,728			847,728			$ (626,094)		$ 221,634	47,330			
1990	Other Tangible Property	$1,867,796			1,867,796			$ (1,129,728)		$ 738,068	145,722			
2005	Property Under Capital Leases	$0			-					$ -				
2010	Electric Plant Purchased or Sold	$0			-					$ -				
	Total	$12,680,072		$0	$12,680,072	$0	$0	($5,904,096)	$0	$6,775,976	$475,098	$0	$0	$0
	SUB TOTAL from I3	$12,680,072												
	I3 Directly Allocated	($2,533,363)												
	Grand Total	$79,433,669		$0	$81,967,032	$0	$0	($32,028,240)	$0	$49,938,792	$3,953,947	$0	$0	$0

2010 Cost Allocation Information Filing
Chatham Kent Hydro Inc.
EB-2005-0350 EB-2006-0247
Tuesday, September 28, 2010

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	**$47,405,429**

RATE BASE AND DISTRIBUTION ASSETS		BALANCE SHEET ITEMS									EXPENSE ITEMS				
											5705	5710	5715	5720	
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**	**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	$0				$0	Balanced								
2105	Accumulated Depreciation - 2105	($32,028,240)						$32,028,240	Balanced						
2120	Accumulated Depreciation - 2120	$0							$0	Balanced					
	Total	**($32,028,240)**													
	Net Assets	**$47,405,429**	**Net Fixed Assets Match EDR**												
Amortization Expenses															
5705	Amortization Expense - Property, Plant, and Equipment	$3,953,947									($3,953,947)	Balanced			
5710	Amortization of Limited Term Electric Plant	$0									$0	$0	Balanced		
5715	Amortization of Intangibles and Other Electric Plant	$0											$0	Balanced	
5720	Amortization of Electric Plant Acquisition Adjustments	$0												$0	Balanced
	Total Amortization Expense	**$3,953,947**													

Sheet O1 Revenue to Cost Summary Worksheet - Second Run

Class Revenue, Cost Analysis, and Return on Rate Base

			1	2	3	5	7	8	9	11
Rate Base Assets		Total	Residential	GS <50	GS>50-Regular	GS >50-Intermediate	Street Light	Sentinel	Unmetered Scattered Load	Back-up/Standby Power
crev	Distribution Revenue (sale)	$14,637,886	$8,100,391	$2,206,546	$1,502,724	$2,452,348	$131,787	$21,188	$14,907	$207,994
mi	Miscellaneous Revenue (mi)	$1,187,450	$766,486	$194,390	$150,085	$39,023	$11,303	$1,571	$1,075	$23,517
	Total Revenue	$15,825,336	$8,866,877	$2,400,936	$1,652,809	$2,491,371	$143,090	$22,759	$15,983	$231,511
	Expenses									
di	Distribution Costs (di)	$1,831,411	$873,046	$212,941	$378,845	$196,083	$48,053	$6,585	$4,568	$111,290
cu	Customer Related Costs (cu)	$2,224,420	$1,604,252	$412,465	$187,959	$16,801	$1,856	$282	$168	$637
ad	General and Administration (ad)	$2,747,280	$1,670,302	$421,265	$388,281	$145,930	$35,076	$4,830	$3,329	$78,267
dep	Depreciation and Amortization (dep)	$3,953,947	$2,091,162	$518,257	$737,549	$273,521	$98,191	$13,572	$9,338	$212,356
INPUT	PILs (INPUT)	$1,023,775	$540,848	$132,051	$190,553	$72,630	$26,467	$3,678	$2,518	$55,032
INT	Interest	$2,511,181	$1,326,625	$323,902	$467,400	$178,152	$64,919	$9,021	$6,177	$134,985
	Total Expenses	$14,292,014	$8,106,235	$2,020,882	$2,350,586	$883,117	$274,561	$37,968	$26,098	$592,567
	Direct Allocation	($328,965)	($228,767)	($25,160)	($86,810)	$0	$0	$0	$0	$11,772
NI	Allocated Net Income (NI)	$1,862,287	$983,823	$240,205	$346,623	$132,117	$48,144	$6,690	$4,581	$100,104
	Revenue Requirement (includes NI)	$15,825,336	$8,861,291	$2,235,926	$2,610,399	$1,015,234	$322,705	$44,658	$30,678	$704,443
		Revenue Requirement Input equals Output								
	Rate Base Calculation									
	Net Assets									
dp	Distribution Plant - Gross	$69,286,960	$36,389,423	$8,857,939	$13,043,226	$4,973,376	$1,785,057	$247,107	$169,829	$3,821,003
gp	General Plant - Gross	$12,680,072	$6,698,723	$1,635,526	$2,360,110	$899,567	$327,807	$45,551	$31,189	$681,599
accum dep	Accumulated Depreciation	($32,028,240)	($16,706,109)	($4,052,162)	($6,108,354)	($2,330,117)	($821,840)	($113,262)	($78,183)	($1,818,215)
co	Capital Contribution	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total Net Plant	$49,938,792	$26,382,037	$6,441,304	$9,294,983	$3,542,825	$1,291,025	$179,396	$122,836	$2,684,386
	Directly Allocated Net Fixed Assets	($2,533,363)	($1,809,276)	($193,443)	($610,958)	$0	$0	$0	$0	$80,314
COP	Cost of Power (COP)	$50,984,482	$15,838,738	$6,900,966	$14,530,137	$10,701,304	$440,418	$26,554	$82,709	$2,463,656
	OM&A Expenses	$6,803,112	$4,147,600	$1,046,672	$955,085	$358,815	$84,984	$11,697	$8,064	$190,194
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Subtotal	*$57,787,594*	*$19,986,338*	*$7,947,638*	*$15,485,221*	*$11,060,119*	*$525,403*	*$38,251*	*$90,773*	*$2,653,850*
	Working Capital	$8,668,139	$2,997,951	$1,192,146	$2,322,783	$1,659,018	$78,810	$5,738	$13,616	$398,078
	Total Rate Base	$56,073,568	$27,570,712	$7,440,006	$11,006,808	$5,201,843	$1,369,835	$185,134	$136,452	$3,162,778
		Rate Base Input equals Output								
	Equity Component of Rate Base	$22,429,427	$11,028,285	$2,976,002	$4,402,723	$2,080,737	$547,934	$74,054	$54,581	$1,265,111
	Net Income on Allocated Assets	$1,862,287	$989,409	$405,215	($610,967)	$1,608,253	($131,471)	($15,209)	($10,115)	($372,828)
	Net Income on Direct Allocation Assets	($65,690)	($46,914)	($5,016)	($15,842)	$0	$0	$0	$0	$2,083
	Net Income	$1,796,597	$942,495	$400,199	($626,809)	$1,608,253	($131,471)	($15,209)	($10,115)	($370,746)
	RATIOS ANALYSIS									
	REVENUE TO EXPENSES %	100.00%	100.06%	107.38%	63.32%	245.40%	44.34%	50.96%	52.10%	32.86%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($0)	$5,586	$165,010	($957,590)	$1,476,136	($179,615)	($21,899)	($14,696)	($472,933)
	RETURN ON EQUITY COMPONENT OF RATE BASE	8.01%	8.55%	13.45%	-14.24%	77.29%	-23.99%	-20.54%	-18.53%	-29.31%

2010 Cost Allocation Information Filing
Chatham Kent Hydro Inc.
EB-2005-0350 EB-2006-0247
Tuesday, September 28, 2010

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	5	7	8	9	11
	Residential	GS <50	GS>50-Regular	GS >50-Intermediate	Street Light	Sentinel	Unmetered Scattered Load	Back-up/Standby Power
Customer Unit Cost per month - Avoided Cost	$5.84	$13.91	$50.17	$81.69	$0.07	$0.06	$0.06	$120.52
Customer Unit Cost per month - Directly Related	$8.75	$20.82	$75.34	$121.88	$0.13	$0.11	$0.11	$172.43
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$18.12	$33.74	$97.46	$128.62	$9.02	$11.37	$9.06	$216.99
Fixed Charge per approved 2006 EDR	$12.33	$31.01	$159.37	$4,705.58	$0.47	$3.88	$3.30	$159.37

Information to be Used to Allocate PILs, ROD, ROE and A&G

		1	2	3	5	7	8	9	11
	Total	Residential	GS <50	GS>50-Regular	GS >50-Intermediate	Street Light	Sentinel	Unmetered Scattered Load	Back-up/Standby Power
General Plant - Gross Assets	$12,680,072	$6,698,723	$1,635,526	$2,360,110	$899,567	$327,807	$45,551	$31,189	$681,599
General Plant - Accumulated Depreciation	($5,904,096)	($3,119,060)	($761,534)	($1,098,915)	($418,856)	($152,634)	($21,209)	($14,522)	($317,366)
General Plant - Net Fixed Assets	$6,775,976	$3,579,663	$873,992	$1,261,196	$480,710	$175,173	$24,341	$16,667	$364,233
General Plant - Depreciation	$475,098	$250,988	$61,280	$88,429	$33,705	$12,282	$1,707	$1,169	$25,538
Total Net Fixed Assets Excluding General Plant	$43,162,816	$22,802,374	$5,567,311	$8,033,787	$3,062,115	$1,115,851	$155,055	$106,169	$2,320,154
Total Administration and General Expense	$2,747,280	$1,670,302	$421,265	$388,281	$145,930	$35,076	$4,830	$3,329	$78,267
Total O&M	$4,055,831	$2,477,298	$625,406	$566,804	$212,884	$49,908	$6,868	$4,735	$111,927

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

			1	2	3	5	7	8	9	11
USoA Account #	Accounts	Total	Residential	GS <50	GS>50-Regular	GS >50-Intermediate	Street Light	Sentinel	Unmetered Scattered Load	Back-up/Standby Power
	<u>**Distribution Plant**</u>									
1860	Meters	$7,061,292	$4,497,839	$1,560,128	$870,148	$122,182	$1,298	$0	$0	$9,697
	<u>**Accumulated Amortization**</u>									
	Accum. Amortization of Electric Utility Plant - Meters only	($2,370,229)	($1,509,767)	($523,681)	($292,078)	($41,012)	($436)	$0	$0	($3,255)
	Meter Net Fixed Assets	**$4,691,064**	**$2,988,072**	**$1,036,448**	**$578,070**	**$81,170**	**$862**	**$0**	**$0**	**$6,442**
	<u>**Misc Revenue**</u>									
4082	Retail Services Revenues	($65,004)	($49,183)	($10,432)	($5,056)	($332)	$0	$0	$0	($2)
4084	Service Transaction Requests (STR) Revenues	($1,996)	($1,510)	($320)	($155)	($10)	$0	$0	$0	($0)
4090	Electric Services Incidental to Energy Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0
4220	Other Electric Revenues	($9,996)	($5,281)	($1,289)	($1,861)	($709)	($258)	($36)	($25)	($537)
4225	Late Payment Charges	($188,861)	($110,765)	($47,909)	($25,046)	($5,141)	$0	$0	$0	$0
	Sub-total	*($265,857)*	*($166,739)*	*($59,951)*	*($32,117)*	*($6,192)*	*($258)*	*($36)*	*($25)*	*($539)*
	<u>**Operation**</u>									
5065	Meter Expense	$345,446	$220,039	$76,323	$42,569	$5,977	$63	$0	$0	$474
5070	Customer Premises - Operation Labour	$27,909	$23,024	$2,442	$338	$22	$1,663	$263	$156	$1
5075	Customer Premises - Materials and Expenses	$2,098	$1,731	$184	$25	$2	$125	$20	$12	$0

	Sub-total	*$375,452*	*$244,794*	*$78,948*	*$42,932*	*$6,001*	*$1,852*	*$282*	*$168*	*$475*
	Maintenance									
5175	Maintenance of Meters	$22,170	$14,121	$4,898	$2,732	$384	$4	$0	$0	$30
	Billing and Collection									
5310	Meter Reading Expense	$34,853	$12,688	$15,663	$4,051	$2,360	$0	$0	$0	$89
5315	Customer Billing	$1,025,552	$775,954	$164,577	$79,762	$5,232	$0	$0	$0	$27
5320	Collecting	$416,389	$315,049	$66,821	$32,385	$2,124	$0	$0	$0	$11
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	$0	$0
5330	Collection Charges	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub-total	$1,476,795	$1,103,692	$247,061	$116,198	$9,716	$0	$0	$0	$127
	Total Operation, Maintenance and Billing	$1,874,417	$1,362,607	$330,908	$161,862	$16,101	$1,856	$282	$168	$633
	Amortization Expense - Meters	$472,966	$301,266	$104,498	$58,283	$8,184	$87	$0	$0	$650
	Allocated PILs	$96,170	$61,257	$21,248	$11,851	$1,664	$18	$0	$0	$132
	Allocated Debt Return	$235,891	$150,256	$52,118	$29,068	$4,082	$43	$0	$0	$324
	Allocated Equity Return	$174,936	$111,429	$38,651	$21,557	$3,027	$32	$0	$0	$240
	Total	**$2,588,523**	**$1,820,076**	**$487,471**	**$250,503**	**$26,865**	**$1,777**	**$246**	**$143**	**$1,440**

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

			1	2	3	5	7	8	9	11
USoA Account #	**Accounts**	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**GS >50-Intermediate**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Back-up/Standby Power**
	Distribution Plant									
1860	Meters	$7,061,292	$4,497,839	$1,560,128	$870,148	$122,182	$1,298	$0	$0	$9,697
	Accumulated Amortization									
	Accum. Amortization of Electric Utility Plant - Meters only	($2,370,229)	($1,509,767)	($523,681)	($292,078)	($41,012)	($436)	$0	$0	($3,255)
	Meter Net Fixed Assets	$4,691,064	$2,988,072	$1,036,448	$578,070	$81,170	$862	$0	$0	$6,442
	Allocated General Plant Net Fixed Assets	$736,433	$469,087	$162,708	$90,749	$12,743	$135	$0	$0	$1,011
	Meter Net Fixed Assets Including General Plant	$5,427,497	$3,457,159	$1,199,156	$668,819	$93,912	$998	$0	$0	$7,453
	Misc Revenue									
4082	Retail Services Revenues	($65,004)	($49,183)	($10,432)	($5,056)	($332)	$0	$0	$0	($2)
4084	Service Transaction Requests (STR) Revenues	($1,996)	($1,510)	($320)	($155)	($10)	$0	$0	$0	($0)
4090	Electric Services Incidental to Energy Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0
4220	Other Electric Revenues	($9,996)	($5,281)	($1,289)	($1,861)	($709)	($258)	($36)	($25)	($537)
4225	Late Payment Charges	($188,861)	($110,765)	($47,909)	($25,046)	($5,141)	$0	$0	$0	$0
	Sub-total	*($265,857)*	*($166,739)*	*($59,951)*	*($32,117)*	*($6,192)*	*($258)*	*($36)*	*($25)*	*($539)*
	Operation									
5065	Meter Expense	$345,446	$220,039	$76,323	$42,569	$5,977	$63	$0	$0	$474
5070	Customer Premises - Operation Labour	$27,909	$23,024	$2,442	$338	$22	$1,663	$263	$156	$1
5075	Customer Premises - Materials and Expenses	$2,098	$1,731	$184	$25	$2	$125	$20	$12	$0
	Sub-total	*$375,452*	*$244,794*	*$78,948*	*$42,932*	*$6,001*	*$1,852*	*$282*	*$168*	*$475*
	Maintenance									
5175	Maintenance of Meters	$22,170	$14,121	$4,898	$2,732	$384	$4	$0	$0	$30
	Billing and Collection									
5310	Meter Reading Expense	$34,853	$12,688	$15,663	$4,051	$2,360	$0	$0	$0	$89
5315	Customer Billing	$1,025,552	$775,954	$164,577	$79,762	$5,232	$0	$0	$0	$27
5320	Collecting	$416,389	$315,049	$66,821	$32,385	$2,124	$0	$0	$0	$11
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	$0	$0
5330	Collection Charges	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub-total	*$1,476,795*	*$1,103,692*	*$247,061*	*$116,198*	*$9,716*	*$0*	*$0*	*$0*	*$127*
	Total Operation, Maintenance and Billing	$1,874,417	$1,362,607	$330,908	$161,862	$16,101	$1,856	$282	$168	$633
	Amortization Expense - Meters	$472,966	$301,266	$104,498	$58,283	$8,184	$87	$0	$0	$650
	Amortization Expense - General Plant assigned to Meters	*$51,635*	*$32,890*	*$11,408*	*$6,363*	*$893*	*$9*	*$0*	*$0*	*$71*
	Admin and General	$1,265,606	$918,729	$222,895	$110,881	$11,037	$1,304	$198	$118	$443
	Allocated PILs	$111,267	$70,874	$24,583	$13,711	$1,925	$20	$0	$0	$153
	Allocated Debt Return	$272,923	$173,844	$60,300	$33,632	$4,722	$50	$0	$0	$375
	Allocated Equity Return	$202,399	$128,922	$44,718	$24,941	$3,502	$37	$0	$0	$278
	Total	**$3,985,355**	**$2,822,393**	**$739,359**	**$377,555**	**$40,173**	**$3,106**	**$445**	**$261**	**$2,063**

Scenario 3

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

			1	2	3	5	7	8	9	11
USoA Account #	**Accounts**	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**GS >50-Intermediate**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Back-up/Standby Power**
	Distribution Plant									
1565	Conservation and Demand Management Expenditures and Recoveries	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-4	Poles, Towers and Fixtures - Primary	$1,474,220	$1,216,205	$128,976	$17,860	$1,171	$87,847	$13,867	$8,251	$42
1830-5	Poles, Towers and Fixtures - Secondary	$453,873	$375,988	$39,873	$4,017	$0	$27,158	$4,287	$2,551	$0
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-4	Overhead Conductors and Devices - Primary	$6,744,630	$5,564,200	$590,073	$81,708	$5,359	$401,905	$63,440	$37,750	$194
1835-5	Overhead Conductors and Devices - Secondary	$952,083	$788,705	$83,641	$8,426	$0	$56,969	$8,992	$5,351	$0
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary	$559,670	$461,717	$48,964	$6,780	$445	$33,350	$5,264	$3,132	$16
1840-5	Underground Conduit - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary	$3,338,044	$2,753,827	$292,038	$40,439	$2,652	$198,911	$31,398	$18,683	$96
1845-5	Underground Conductors and Devices - Secondary	$2,902,457	$2,404,393	$254,981	$25,685	$0	$173,671	$27,414	$16,312	$0
1850	Line Transformers	$6,349,220	$5,259,689	$557,780	$56,188	$0	$379,910	$59,969	$35,684	$0
1855	Services	$3,954,766	$2,806,112	$595,166	$299,769	$0	$202,687	$31,994	$19,038	$0
1860	Meters	$7,061,292	$4,497,839	$1,560,128	$870,148	$122,182	$1,298	$0	$0	$9,697
	Sub-total	*$33,790,255*	*$26,128,677*	*$4,151,620*	*$1,411,019*	*$131,810*	*$1,563,706*	*$246,625*	*$146,752*	*$10,046*
	Accumulated Amortization									
	Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	($12,419,204)	($9,623,890)	($1,468,717)	($503,265)	($80,566)	($584,171)	($91,998)	($54,967)	($11,630)
	Customer Related Net Fixed Assets	$21,371,051	$16,504,787	$2,682,903	$907,754	$51,244	$979,535	$154,626	$91,785	($1,584)
	Allocated General Plant Net Fixed Assets	$3,354,965	$2,591,028	$421,179	$142,505	$8,045	$153,774	$24,274	$14,409	($249)
	Customer Related NFA Including General Plant	$24,726,016	$19,095,814	$3,104,082	$1,050,260	$59,289	$1,133,309	$178,901	$106,194	($1,833)
	Misc Revenue									
4082	Retail Services Revenues	($65,004)	($49,183)	($10,432)	($5,056)	($332)	$0	$0	$0	($2)
4084	Service Transaction Requests (STR) Revenues	($1,996)	($1,510)	($320)	($155)	($10)	$0	$0	$0	($0)
4090	Electric Services Incidental to Energy Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0
4220	Other Electric Revenues	($9,996)	($5,281)	($1,289)	($1,861)	($709)	($258)	($36)	($25)	($537)
4225	Late Payment Charges	($188,861)	($110,765)	($47,909)	($25,046)	($5,141)	$0	$0	$0	$0
4235	Miscellaneous Service Revenues	($494,368)	($374,049)	($79,334)	($38,449)	($2,522)	$0	$0	$0	($13)
	Sub-total	*($760,225)*	*($540,788)*	*($139,285)*	*($70,567)*	*($8,714)*	*($258)*	*($36)*	*($25)*	*($552)*
	Operating and Maintenance									
5005	Operation Supervision and Engineering	$65,690	$52,464	$6,423	$1,699	$316	$3,770	$594	$355	$68
5010	Load Dispatching	$0	$0	$0	$0	$0	$0	$0	$0	$0
5020	Overhead Distribution Lines and Feeders - Operation Labour	$44,214	$36,498	$3,871	$515	$30	$2,636	$416	$248	$1
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$14,684	$12,122	$1,285	$171	$10	$876	$138	$82	$0
5035	Overhead Distribution Transformers- Operation	$20,101	$16,651	$1,766	$178	$0	$1,203	$190	$113	$0
5040	Underground Distribution Lines and Feeders - Operation Labour	$65,483	$54,118	$5,739	$702	$30	$3,909	$617	$367	$1
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$10,662	$8,812	$934	$114	$5	$636	$100	$60	$0
5055	Underground Distribution Transformers - Operation	$19	$16	$2	$0	$0	$1	$0	$0	$0
5065	Meter Expense	$345,446	$220,039	$76,323	$42,569	$5,977	$63	$0	$0	$474
5070	Customer Premises - Operation Labour	$27,909	$23,024	$2,442	$338	$22	$1,663	$263	$156	$1
5075	Customer Premises - Materials and Expenses	$2,098	$1,731	$184	$25	$2	$125	$20	$12	$0
5085	Miscellaneous Distribution Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0
5090	Underground Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0

5095	Overhead Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0
5096	Other Rent	$0	$0	$0	$0	$0	$0	$0	$0	$0
5105	Maintenance Supervision and Engineering	$126,084	$100,699	$12,327	$3,261	$607	$7,237	$1,140	$682	$131
5120	Maintenance of Poles, Towers and Fixtures	$21,262	$17,558	$1,862	$241	$13	$1,268	$200	$119	$0
5125	Maintenance of Overhead Conductors and Devices	$76,020	$62,747	$6,654	$890	$53	$4,532	$715	$426	$2
5130	Maintenance of Overhead Services	$120,532	$85,524	$18,139	$9,136	$0	$6,177	$975	$580	$0
5135	Overhead Distribution Lines and Feeders - Right of Way	$72,000	$59,435	$6,303	$838	$49	$4,293	$678	$403	$2
5145	Maintenance of Underground Conduit	$1,483	$1,223	$130	$18	$1	$88	$14	$8	$0
5150	Maintenance of Underground Conductors and Devices	$2,345	$1,938	$206	$25	$1	$140	$22	$13	$0
5155	Maintenance of Underground Services	$54,106	$38,391	$8,143	$4,101	$0	$2,773	$438	$260	$0
5160	Maintenance of Line Transformers	$36,774	$30,464	$3,231	$325	$0	$2,200	$347	$207	$0
5175	Maintenance of Meters	$22,170	$14,121	$4,898	$2,732	$384	$4	$0	$0	$30
	Sub-total	*$1,129,082*	*$837,575*	*$160,861*	*$67,879*	*$7,500*	*$43,596*	*$6,868*	*$4,092*	*$712*
	Billing and Collection									
5305	Supervision	$137,237	$103,836	$22,023	$10,674	$700	$0	$0	$0	$4
5310	Meter Reading Expense	$34,853	$12,688	$15,663	$4,051	$2,360	$0	$0	$0	$89
5315	Customer Billing	$1,025,552	$775,954	$164,577	$79,762	$5,232	$0	$0	$0	$27
5320	Collecting	$416,389	$315,049	$66,821	$32,385	$2,124	$0	$0	$0	$11
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	$0	$0
5330	Collection Charges	$0	$0	$0	$0	$0	$0	$0	$0	$0
5335	Bad Debt Expense	$212,766	$137,809	$59,534	$15,423	$0	$0	$0	$0	$0
5340	Miscellaneous Customer Accounts Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub-total	*$1,826,798*	*$1,345,337*	*$328,619*	*$142,295*	*$10,416*	*$0*	*$0*	*$0*	*$131*
	Sub Total Operating, Maintenance and Biling	*$2,955,880*	*$2,182,911*	*$489,479*	*$210,174*	*$17,916*	*$43,596*	*$6,868*	*$4,092*	*$843*
	Amortization Expense - Customer Related	$1,779,915	$1,348,420	$230,801	$90,230	$14,209	$75,358	$11,859	$7,091	$1,947
	Amortization Expense - General Plant assigned to Meters	$235,234	$181,670	$29,531	$9,992	$564	$10,782	$1,702	$1,010	($17)
	Admin and General	$1,996,714	$1,471,814	$329,707	$143,976	$12,281	$30,640	$4,830	$2,876	$590
	Allocated PILs	$506,898	$391,476	$63,636	$21,531	$1,215	$23,234	$3,668	$2,177	($38)
	Allocated Debt Return	$1,243,352	$960,236	$156,089	$52,812	$2,981	$56,989	$8,996	$5,340	($92)
	Allocated Equity Return	$922,067	$712,109	$115,756	$39,166	$2,211	$42,263	$6,671	$3,960	($68)
	PLCC Adjustment for Line Transformer	$230,700	$192,912	$20,457	$2,062	$0	$13,957	$0	$1,311	$0
	PLCC Adjustment for Primary Costs	$320,331	$266,707	$28,282	$3,933	$261	$19,324	$0	$1,815	$9
	PLCC Adjustment for Secondary Costs	$250,660	$204,269	$16,583	$2,105	$0	$25,422	$0	$2,276	$5
	Total	$8,078,145	**$6,043,961**	**$1,210,391**	**$489,214**	**$42,404**	**$223,899**	**$44,558**	**$21,121**	**$2,597**

Below: Grouping to avoid disclosure

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

Accounts	Total	Residential	GS <50	GS>50-Regular	GS >50-Intermediate	Street Light	Sentinel	Unmetered Scattered Load	Back-up/Standby Power
Distribution Plant									
CWMC	$ 7,061,292	$ 4,497,839	$ 1,560,128	$ 870,148	$ 122,182	$ 1,298	$ -	$ -	$ 9,697
Accumulated Amortization									
Accum. Amortization of Electric Utility Plant - Meters only	$ (2,370,229)	$ (1,509,767)	$ (523,681)	$ (292,078)	$ (41,012)	$ (436)	$ -	$ -	$ (3,255)
Meter Net Fixed Assets	$ 4,691,064	$ 2,988,072	$ 1,036,448	$ 578,070	$ 81,170	$ 862	$ -	$ -	$ 6,442
Misc Revenue									
CWNB	$ (67,000)	$ (50,694)	$ (10,752)	$ (5,211)	$ (342)	$ -	$ -	$ -	$ (2)
NFA	$ (9,996)	$ (5,281)	$ (1,289)	$ (1,861)	$ (709)	$ (258)	$ (36)	$ (25)	$ (537)
LPHA	$ (188,861)	$ (110,765)	$ (47,909)	$ (25,046)	$ (5,141)	$ -	$ -	$ -	$ -
Sub-total	*$ (265,857)*	*$ (166,739)*	*$ (59,951)*	*$ (32,117)*	*$ (6,192)*	*$ (258)*	*$ (36)*	*$ (25)*	*$ (539)*
Operation									
CWMC	$ 345,446	$ 220,039	$ 76,323	$ 42,569	$ 5,977	$ 63	$ -	$ -	$ 474
CCA	$ 30,007	$ 24,755	$ 2,625	$ 364	$ 24	$ 1,788	$ 282	$ 168	$ 1
Sub-total	$ 375,452	$ 244,794	$ 78,948	$ 42,932	$ 6,001	$ 1,852	$ 282	$ 168	$ 475
Maintenance									
1860	$ 22,170	$ 14,121	$ 4,898	$ 2,732	$ 384	$ 4	$ -	$ -	$ 30
Billing and Collection									
CWMR	$ 34,853	$ 12,688	$ 15,663	$ 4,051	$ 2,360	$ -	$ -	$ -	$ 89
CWNB	$ 1,441,941	$ 1,091,003	$ 231,398	$ 112,147	$ 7,356	$ -	$ -	$ -	$ 38
Sub-total	$ 1,476,795	$ 1,103,692	$ 247,061	$ 116,198	$ 9,716	$ -	$ -	$ -	$ 127
Total Operation, Maintenance and Billing	$ 1,874,417	$ 1,362,607	$ 330,908	$ 161,862	$ 16,101	$ 1,856	$ 282	$ 168	$ 633
Amortization Expense - Meters	$ 472,966	$ 301,266	$ 104,498	$ 58,283	$ 8,184	$ 87	$ -	$ -	$ 650
Allocated PILs	$ 96,170	$ 61,257	$ 21,248	$ 11,851	$ 1,664	$ 18	$ -	$ -	$ 132
Allocated Debt Return	$ 235,891	$ 150,256	$ 52,118	$ 29,068	$ 4,082	$ 43	$ -	$ -	$ 324
Allocated Equity Return	$ 174,936	$ 111,429	$ 38,651	$ 21,557	$ 3,027	$ 32	$ -	$ -	$ 240
Total	**$ 2,588,523**	**$ 1,820,076**	**$ 487,471**	**$ 250,503**	**$ 26,865**	**$ 1,777**	**$ 246**	**$ 143**	**$ 1,440**

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

Accounts	Total	Residential	GS <50	GS>50-Regular	GS >50-Intermediate	Street Light	Sentinel	Unmetered Scattered Load	Back-up/Standby Power
Distribution Plant									
CWMC	$ 7,061,292	$ 4,497,839	$ 1,560,128	$ 870,148	$ 122,182	$ 1,298	$ -	$ -	$ 9,697
Accumulated Amortization									
Accum. Amortization of Electric Utility Plant - Meters only	$ (2,370,229)	$ (1,509,767)	$ (523,681)	$ (292,078)	$ (41,012)	$ (436)	$ -	$ -	$ (3,255)
Meter Net Fixed Assets	$ 4,691,064	$ 2,988,072	$ 1,036,448	$ 578,070	$ 81,170	$ 862	$ -	$ -	$ 6,442
Allocated General Plant Net Fixed Assets	$ 736,433	$ 469,087	$ 162,708	$ 90,749	$ 12,743	$ 135	$ -	$ -	$ 1,011
Meter Net Fixed Assets Including General Plant	$ 5,427,497	$ 3,457,159	$ 1,199,156	$ 668,819	$ 93,912	$ 998	$ -	$ -	$ 7,453
Misc Revenue									
CWNB	$ (67,000)	$ (50,694)	$ (10,752)	$ (5,211)	$ (342)	$ -	$ -	$ -	$ (2)
NFA	$ (9,996)	$ (5,281)	$ (1,289)	$ (1,861)	$ (709)	$ (258)	$ (36)	$ (25)	$ (537)
LPHA	$ (188,861)	$ (110,765)	$ (47,909)	$ (25,046)	$ (5,141)	$ -	$ -	$ -	$ -
Sub-total	*$ (265,857)*	*$ (166,739)*	*$ (59,951)*	*$ (32,117)*	*$ (6,192)*	*$ (258)*	*$ (36)*	*$ (25)*	*$ (539)*

<u>Operation</u>									
CWMC	$ 345,446	$ 220,039	$ 76,323	$ 42,569	$ 5,977	$ 63	$ -	$ -	$ 474
CCA	$ 30,007	$ 24,755	$ 2,625	$ 364	$ 24	$ 1,788	$ 282	$ 168	$ 1
Sub-total	*$ 375,452*	*$ 244,794*	*$ 78,948*	*$ 42,932*	*$ 6,001*	*$ 1,852*	*$ 282*	*$ 168*	*$ 475*
<u>Maintenance</u>									
1860	$ 22,170	$ 14,121	$ 4,898	$ 2,732	$ 384	$ 4	$ -	$ -	$ 30
<u>Billing and Collection</u>									
CWMR	$ 34,853	$ 12,688	$ 15,663	$ 4,051	$ 2,360	$ -	$ -	$ -	$ 89
CWNB	$ 1,441,941	$ 1,091,003	$ 231,398	$ 112,147	$ 7,356	$ -	$ -	$ -	$ 38
Sub-total	*$ 1,476,795*	*$ 1,103,692*	*$ 247,061*	*$ 116,198*	*$ 9,716*	*$ -*	*$ -*	*$ -*	*$ 127*
Total Operation, Maintenance and Billing	$ 1,874,417	$ 1,362,607	$ 330,908	$ 161,862	$ 16,101	$ 1,856	$ 282	$ 168	$ 633
Amortization Expense - Meters	$ 472,966	$ 301,266	$ 104,498	$ 58,283	$ 8,184	$ 87	$ -	$ -	$ 650
Amortization Expense - General Plant assigned to Meters	$ 51,635	$ 32,890	$ 11,408	$ 6,363	$ 893	$ 9	$ -	$ -	$ 71
Admin and General	$ 1,265,606	$ 918,729	$ 222,895	$ 110,881	$ 11,037	$ 1,304	$ 198	$ 118	$ 443
Allocated PILs	$ 111,267	$ 70,874	$ 24,583	$ 13,711	$ 1,925	$ 20	$ -	$ -	$ 153
Allocated Debt Return	$ 272,923	$ 173,844	$ 60,300	$ 33,632	$ 4,722	$ 50	$ -	$ -	$ 375
Allocated Equity Return	$ 202,399	$ 128,922	$ 44,718	$ 24,941	$ 3,502	$ 37	$ -	$ -	$ 278
Total	**$ 3,985,355**	**$ 2,822,393**	**$ 739,359**	**$ 377,555**	**$ 40,173**	**$ 3,106**	**$ 445**	**$ 261**	**$ 2,063**

Scenario 3

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

USoA Account #	Accounts	Total	Residential	GS <50	GS>50-Regular	GS >50-Intermediate	Street Light	Sentinel	Unmetered Scattered Load	Back-up/Standby Power
	Distribution Plant									
	CDMPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Poles, Towers and Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	PNCP	$ 12,116,563	$ 9,995,950	$ 1,060,051	$ 146,787	$ 9,628	$ 722,013	$ 113,969	$ 67,816	$ 349
	SNCP	$ 4,308,413	$ 3,569,087	$ 378,495	$ 38,128	$ -	$ 257,797	$ 40,693	$ 24,214	$ -
	Overhead Conductors and Devices	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	LTNCP	$ 6,349,220	$ 5,259,689	$ 557,780	$ 56,188	$ -	$ 379,910	$ 59,969	$ 35,684	$ -
	CWCS	$ 3,954,766	$ 2,806,112	$ 595,166	$ 299,769	$ -	$ 202,687	$ 31,994	$ 19,038	$ -
	CWMC	$ 7,061,292	$ 4,497,839	$ 1,560,128	$ 870,148	$ 122,182	$ 1,298	$ -	$ -	$ 9,697
	Sub-total	*$ 33,790,255*	*$ 26,128,677*	*$ 4,151,620*	*$ 1,411,019*	*$ 131,810*	*$ 1,563,706*	*$ 246,625*	*$ 146,752*	*$ 10,046*
	Accumulated Amortization									
	Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	$ (12,419,204)	$ (9,623,890)	$ (1,468,717)	$ (503,265)	$ (80,566)	$ (584,171)	$ (91,998)	$ (54,967)	$ (11,630)
	Customer Related Net Fixed Assets	$ 21,371,051	$ 16,504,787	$ 2,682,903	$ 907,754	$ 51,244	$ 979,535	$ 154,626	$ 91,785	$ (1,584)
	Allocated General Plant Net Fixed Assets	$ 3,354,965	$ 2,591,028	$ 421,179	$ 142,505	$ 8,045	$ 153,774	$ 24,274	$ 14,409	$ (249)
	Customer Related NFA Including General Plant	$ 24,726,016	$ 19,095,814	$ 3,104,082	$ 1,050,260	$ 59,289	$ 1,133,309	$ 178,901	$ 106,194	$ (1,833)
	Misc Revenue									
	CWNB	$ (561,368)	$ (424,743)	$ (90,086)	$ (43,660)	$ (2,864)	$ -	$ -	$ -	$ (15)
	NFA	$ (9,996)	$ (5,281)	$ (1,289)	$ (1,861)	$ (709)	$ (258)	$ (36)	$ (25)	$ (537)
	LPHA	$ (188,861)	$ (110,765)	$ (47,909)	$ (25,046)	$ (5,141)	$ -	$ -	$ -	$ -
	Sub-total	*$ (760,225)*	*$ (540,788)*	*$ (139,285)*	*$ (70,567)*	*$ (8,714)*	*$ (258)*	*$ (36)*	*$ (25)*	*$ (552)*
	Operating and Maintenance									
	1815-1855	$ 191,774	$ 153,163	$ 18,750	$ 4,960	$ 924	$ 11,007	$ 1,734	$ 1,037	$ 200
	1830 & 1835	$ 130,899	$ 108,054	$ 11,459	$ 1,523	$ 89	$ 7,805	$ 1,232	$ 733	$ 3
	1850	$ 56,894	$ 47,131	$ 4,998	$ 503	$ -	$ 3,404	$ 537	$ 320	$ -
	1840 & 1845	$ 76,145	$ 62,929	$ 6,674	$ 816	$ 35	$ 4,545	$ 717	$ 427	$ 1
	CWMC	$ 345,446	$ 220,039	$ 76,323	$ 42,569	$ 5,977	$ 63	$ -	$ -	$ 474
	CCA	$ 30,007	$ 24,755	$ 2,625	$ 364	$ 24	$ 1,788	$ 282	$ 168	$ 1
	O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1830	$ 21,262	$ 17,558	$ 1,862	$ 241	$ 13	$ 1,268	$ 200	$ 119	$ 0
	1835	$ 76,020	$ 62,747	$ 6,654	$ 890	$ 53	$ 4,532	$ 715	$ 426	$ 2
	1855	$ 174,639	$ 123,915	$ 26,282	$ 13,238	$ -	$ 8,950	$ 1,413	$ 841	$ -
	1840	$ 1,483	$ 1,223	$ 130	$ 18	$ 1	$ 88	$ 14	$ 8	$ 0
	1845	$ 2,345	$ 1,938	$ 206	$ 25	$ 1	$ 140	$ 22	$ 13	$ 0
	1860	$ 22,170	$ 14,121	$ 4,898	$ 2,732	$ 384	$ 4	$ -	$ -	$ 30
	Sub-total	*$ 1,129,082*	*$ 837,575*	*$ 160,861*	*$ 67,879*	*$ 7,500*	*$ 43,596*	*$ 6,868*	*$ 4,092*	*$ 712*
	Billing and Collection									
	CWNB	$ 1,579,178	$ 1,194,840	$ 253,421	$ 122,820	$ 8,056	$ -	$ -	$ -	$ 42
	CWMR	$ 34,853	$ 12,688	$ 15,663	$ 4,051	$ 2,360	$ -	$ -	$ -	$ 89
	BDHA	$ 212,766	$ 137,809	$ 59,534	$ 15,423	$ -	$ -	$ -	$ -	$ -
	Sub-total	*$ 1,826,798*	*$ 1,345,337*	*$ 328,619*	*$ 142,295*	*$ 10,416*	*$ -*	*$ -*	*$ -*	*$ 131*
	Sub Total Operating, Maintenance and Biling	*$ 2,955,880*	*$ 2,182,911*	*$ 489,479*	*$ 210,174*	*$ 17,916*	*$ 43,596*	*$ 6,868*	*$ 4,092*	*$ 843*
	Amortization Expense - Customer Related	$ 1,779,915	$ 1,348,420	$ 230,801	$ 90,230	$ 14,209	$ 75,358	$ 11,859	$ 7,091	$ 1,947
	Amortization Expense - General Plant assigned to Meters	$ 235,234	$ 181,670	$ 29,531	$ 9,992	$ 564	$ 10,782	$ 1,702	$ 1,010	$ (17)
	Admin and General	$ 1,996,714	$ 1,471,814	$ 329,707	$ 143,976	$ 12,281	$ 30,640	$ 4,830	$ 2,876	$ 590
	Allocated PILs	$ 506,898	$ 391,476	$ 63,636	$ 21,531	$ 1,215	$ 23,234	$ 3,668	$ 2,177	$ (38)
	Allocated Debt Return	$ 1,243,352	$ 960,236	$ 156,089	$ 52,812	$ 2,981	$ 56,989	$ 8,996	$ 5,340	$ (92)
	Allocated Equity Return	$ 922,067	$ 712,109	$ 115,756	$ 39,166	$ 2,211	$ 42,263	$ 6,671	$ 3,960	$ (68)
	PLCC Adjustment for Line Transformer	$ 230,700	$ 192,912	$ 20,457	$ 2,062	$ -	$ 13,957	$ -	$ 1,311	$ -
	PLCC Adjustment for Primary Costs	$ 320,331	$ 266,707	$ 28,282	$ 3,933	$ 261	$ 19,324	$ -	$ 1,815	$ 9
	PLCC Adjustment for Secondary Costs	$ 250,660	$ 204,269	$ 16,583	$ 2,105	$ -	$ 25,422	$ -	$ 2,276	$ 5
	Total	**$ 8,078,145**	**$ 6,043,961**	**$ 1,210,391**	**$ 489,214**	**$ 42,404**	**$ 223,899**	**$ 44,558**	**$ 21,121**	**$ 2,597**

OVERVIEW:

This Exhibit documents the calculation of Chatham-Kent Hydro's proposed distribution rates by rate class for the 2010 Test Year, based on rate design as proposed in this Exhibit.

Chatham-Kent Hydro has determined its total 2010 service revenue requirement to be $15,825,336. The total revenue offsets in the amount of $1,187,450 reduce Chatham-Kent Hydro's total service revenue requirement to a base revenue requirement to $14,637,886 which is used to determine the proposed distribution rates. The base revenue requirement is derived from Chatham-Kent Hydro's 2010 capital and operating forecasts, weather normalized usage, forecasted customer counts, and Chatham-Kent Hydro's regulated return on rate base. The revenue requirements are summarized below in Table 8-1.

Table 8-1
Calculation of Base Revenue Requirement

OM&A Expenses	6,803,112
Amortization Expenses	3,815,361
Total Distribution Expenses	**10,618,473**
Regulated Return On Capital	4,219,200
PILs	987,663
Service Revenue Requirement	**15,825,336**
Less: Revenue Offsets	1,187,450
Base Revenue Requirement	14,637,886

The outstanding base revenue requirement is allocated to the various rate classes using the following proposed apportionment of revenue as outlined in Exhibit 7 – Cost Allocation.

Table 8-2
Proposed Apportionment of Revenue to Rate Classes

Rate Classification	Proposed Proportion of
Residential	54.2%
General Service Less Than 50 kW	14.8%
General Service Greater Than 50 kW	17.2%
Intermediate	9.0%
Street Lights	2.0%
Sentinel Lights	0.3%
Unmetered Scattered Load	0.2%
Standby	2.5%
Total	100.00%

The following Table 8-3 outlines the results of this allocation.

Table 8-3
Allocation of Outstanding Base Revenue Requirement

Rate Classification	Proposed Proportion of
Residential	7,927,879
General Service Less Than 50 kW	2,159,088
General Service Greater Than 50 kW	2,510,397
Intermediate	1,317,410
Street Lights	292,758
Sentinel Lights	36,595
Unmetered Scattered Load	27,812
Standby	365,947
Total	14,637,886

Determination of Monthly Fixed/Volumetric Charges:

Table 8-4 illustrates Chatham-Kent Hydro's current OEB-approved (2009 IRM) monthly fixed charges, the 2010 updated cost allocation Ceiling and Floor Fixed Month Rates for all rate classes. Table 8-5 contains the 2009 IRM approved volumetric rates.

Table 8-4
Current Monthly Fixed Charges

Rate Classification	Currently Monthly Charge	Cost Allocation Fixed Ceiling	Cost Allocation Fixed Floor
Residential	$12.33	$18.12	$5.84
General Service Less Than 50 kW	$31.01	$33.74	$13.91
General Service Greater Than 50 kW	$159.37	$97.46	$50.17
Intermediate	$4,705.58	$128.62	$81.69
Street Lights	$0.47	$9.02	$0.07
Sentinel Lights	$3.88	$11.37	$0.06
Unmetered Scattered Load	$3.30	$9.06	$0.06
Standby	$4,705.58	$216.99	$120.52

Table 8-5
Current Monthly Volumetric Charges

Rate Classification	Volumetric Charge	
Residential	0.0139	$/kWh
General Service Less Than 50 kW	0.0092	$/kWh
General Service Greater Than 50 kW	1.5717	$/kW
Intermediate	2.3623	$/kW
Street Lights	3.1115	$/kW
Sentinel Lights	2.9955	$/kW
Unmetered Scattered Load	0.0054	$/kWh
Standby	2.3623	$/kW

Using the existing approved fixed charges applied to the forecasted number of customers for 2010 and the approved volumetric charge applied to the forecasted volumetric billing determinants, the following Table 8-6 outlines the current split between fixed and variable distribution revenue.

Table 8-6
Current Fixed and Variable Proportion

Rate Classification	Fixed Revenue Proportion	Variable Revenue Proportion
Residential	61.5%	38.5%
General Service Less Than 50 kW	60.2%	39.8%
General Service Greater Than 50 kW	57.1%	42.9%
Intermediate	67.8%	32.2%
Street Lights	54.1%	45.9%
Sentinel Lights	84.4%	15.6%
Unmetered Scattered Load	60.7%	39.3%
Standby	25.1%	74.9%

Chatham-Kent Hydro submits that it is appropriate for 2010 to change the previous fixed/variable proportions in the current rates for all customer classifications.

In its November 28, 2007 Report on Application of Cost Allocation for Electricity Distributors, referred to in Exhibit 8 above, the OEB addressed a number of “Other Rate Matters”, including the treatment of the fixed rate component (the Monthly Service Charge, or “MSC”) of the bill. On page 12 of the Report, the OEB determined that the floor amount for the MSC should be the avoided costs, as that term is defined in the September 29, 2006 report of the OEB entitled “Cost Allocation: Board Directions on Cost Allocation Methodology for Electricity Distributors”. Chatham-Kent Hydro’s MSCs exceed that floor amount. With respect to the upper bound for the MSC, the OEB considered it to be inappropriate to make changes to the MSC ceiling at this time, given the number of issues that remain to be examined within the scope of the OEB’s Rate Review proceeding (EB-2009-0031). The OEB indicated that for the time being, it does not expect distributors to make changes to the MSC that result in a charge that is greater than the ceiling as defined in the Methodology for the MSC; and that distributors that are currently above that value are not required to make changes to their current MSC to bring it to or below that level at this time.

Chatham-Kent Hydro is recommending that the fixed charge be equal to the ceiling amount allowed in the Cost Allocation model with the same exceptions. The rate classes where Chatham-Kent Hydro is proposing a fixed charge that is not the ceiling from the 2010 cost allocation model, are the intermediate, standby, street light and sentinel light classes. The reason for the exception is by using the ceiling for fixed charge the rate impact on these customers is too high. Therefore for rate mitigation purposes Chatham-Kent Hydro is proposing a lower fixed charge.

The variable portion of the electricity revenue is the result of moving the fixed charge to the amount proposed using the cost allocation model as well as minimizing rate impacts. The following Table 8-7 provides Chatham-Kent Hydro's calculations of its proposed monthly fixed distribution charges for the 2010 Test Year assuming the fixed/variable split supporting the current approved rates.

Table 8-7
Proposed Fixed Distribution Charge

Customer Class	Total Base Revenue Requirement	Fixed Revenue Proportion	2010 Test Year Annualized Customers	Proposed Fixed Distribution Charge
Residential	$7,927,879	78.6%	343,732	$18.12
General Service Less Than 50 kW	$2,159,088	57.0%	36,452	$33.74
General Service Greater Than 50 kW	$2,510,397	19.6%	5,048	$97.46
Intermediate	$1,317,410	20.0%	331	$795.83
Street Lights	$292,758	54.1%	129,016	$1.23
Sentinel Lights	$36,595	84.4%	3,919	$7.88
Unmetered Scatter Load	$27,812	75.9%	2,332	$9.06
Standby	$365,947	20.0%	12	$6,099.12
Total	$14,637,886			

Proposed Volumetric Charges:

The variable distribution charge is calculated by dividing the variable distribution portion of the base revenue requirement by the appropriate 2010 Test Year usage, kWh or kW, as the class charge determinant.

The following Table 8-8 provides Chatham-Kent Hydro's calculations of its proposed variable distribution charges for the 2010 Test Year.

Table 8-8
Variable Distribution Charge Calculation

Customer Class	Total Base Revenue Requirement	Variable Revenue Proportion	Variable Revenue	Transformer Allowance	Standby Charge	Net Volumetric Revenue	2010 Test Year Volumetric	Proposed Volumetric Distribution Charge
Residential	$7,927,879	21.4%	$1,698,302	$0	$0	$1,698,302	199,501,364	$0.0085
General Service Less Than 50 kW	$2,159,088	43.0%	$929,013	$0	$0	$929,013	86,923,094	$0.0107
General Service Greater Than 50 kW	$2,510,397	80.4%	$2,018,457	$131,486	$0	$2,149,943	456,548	$4.71
Intermediate	$1,317,410	80.0%	$1,053,928	$211,993	$0	$1,265,921	353,322	$3.58
Street Lights	$292,758	45.9%	$134,336	$0	$0	$134,336	16,969	$7.92
Sentinel Lights	$36,595	15.6%	$5,708	$0	$0	$5,708	997	$5.73
Unmetered Scatter Load	$27,812	24.1%	$6,691	$0	$0	$6,691	1,041,782	$0.0064
Standby	$365,947	80.0%	$292,758	$48,403	($30,942)	$310,219	80,671	$3.85
Total	$14,637,886		$6,139,194	$391,882	($30,942)	$6,500,133		

Adjustment to Transformer Allowance:

Currently, Chatham-Kent Hydro provides a Transformer Allowance to those customers that own their transformation facilities. Chatham-Kent Hydro proposes to maintain the current approved transformer ownership allowance of $0.60 per kW. The Transformer Allowance is intended to reflect the costs to a distributor of providing step down transformation facilities to the customer's utilization voltage level. Since the distributor provides electricity at utilization voltage, the cost of this transformation is captured in and recovered through the distribution rates. Therefore, when a customer provides its own step down transformation from primary to secondary, it should receive a credit of these costs already included in the distribution rates.

Table 8-9 summarizes the percentage of transformer allowance expected to be credited to the customers in 2010, as a number of customers do not own their own transformer.

Table 8-9
Percentage of Transformer Allowance

Description	Billed Demand	Transformer Allowance	% Transformer Owned by Customers	Amount
General Service > 50 to 999 kW	456,548	219,143	48%	131,486
Intermediate	353,322	353,322	100%	211,993
Standby	80,671	80,671	100%	48,403
Total	890,541	653,136	73%	391,882

RATE MITIGATION:

Chatham-Kent Hydro is proposing two rate mitigation plans as follows;

- Smart meter Disposition Rider will be recovered over two years
- LRAM/SSM recovery will begin in 2011 and be recovered over a 3 year period

Chatham-Kent Hydro submits that after the two rate mitigation proposals the remaining amount for recovery is reasonable and no further mitigation is required.

OTHER ELECTRICITY CHARGES:

Other charges excluding transmission charges;

Chatham-Kent Hydro is proposing to leave the Wholesale Market Service, Rural Rate Protection Charge and Standard Supply Service – Administrative charges at the rates approved by the OEB in EB-2008-0166.

Retail transmission service rates (RTSR);

Chatham-Kent Hydro is proposing to change the rates for Retail Transmission – Network Service and Retail Transmission Line and Transformation Connection Service. The reasons for proposing a rate change are to reduce the expected variance and to reflect the updated charges from Hydro One for these services.

Table 8-10 is a summary of the revenue and costs along with the variance for 2007 and 2008. The variances in each year were about the same, as in 2007 the variance for both services provided a debit variance of $58,158 ($391,220 debit plus $333,062 credit) and in 2008 the debit variance was $54,177 ($95,579 credit plus $149,756 debit).

Table 8-10
Summary Network Service and Line Transformation Connection

2007

	IESO		Hydro One Charges						Revenue		Variance	
	Network	Connection	Network	Connection	Specific LV	Shared LVDS	HVDS - High	Total Connection	Network	Connection	Network	Connection
January	238,682	202,093	106,480	68,386	4,674	9,065	24,238	106,363	(345,355)	(367,605)	(193)	(59,149)
Feburuary	255,574	216,268	112,571	72,790	4,674	9,944	25,065	112,473	(349,400)	(412,294)	18,745	(83,553)
March	236,619	197,077	107,473	69,520	4,674	8,552	24,041	106,788	(348,608)	(332,121)	(4,516)	(28,256)
April	212,624	188,440	101,370	64,670	4,674	7,639	23,605	100,587	(331,239)	(361,659)	(17,246)	(72,632)
May	286,730	235,932	100,198	63,891	4,692	7,564	24,205	100,353	(312,364)	(338,992)	74,564	(2,707)
June	347,037	285,819	123,795	79,933	3,640	11,018	27,945	122,536	(351,913)	(372,722)	118,919	35,634
July	336,391	281,165	124,259	81,202	3,640	11,986	28,561	125,389	(385,696)	(405,721)	74,953	834
August	347,286	289,058	131,947	85,799	3,640	12,113	29,384	130,936	(394,555)	(420,142)	84,679	(147)
September	290,808	267,064	126,398	82,364	3,640	10,326	27,571	123,900	(351,010)	(381,033)	66,197	9,932
October	259,655	226,223	102,388	66,626	3,640	9,742	25,006	105,014	(316,353)	(345,587)	45,690	(14,350)
November	192,035	197,681	99,714	64,187	3,640	11,958	23,248	103,033	(328,886)	(355,158)	(37,137)	(54,444)
December	200,369	195,050	104,036	67,285	3,640	9,744	32,179	112,847	(337,839)	(372,121)	(33,434)	(64,223)
	3,203,811	2,781,871	1,340,627	866,654	48,868	119,652	315,048	1,350,221	(4,153,219)	(4,465,155)	391,220	(333,062)

2008

	IESO		Hydro One Charges						Revenue		Variance	
	Network	Connection	Network	Connection	Specific LV	Shared LVDS	HVDS - High	Total Connection	Network	Connection	Network	Connection
January	199,339	196,423	104,212	67,017	3,640	9,342	23,698	103,697	(348,260)	(370,920)	(44,709)	(70,801)
Feburuary	197,771	194,139	106,546	69,009	3,640	9,372	23,713	105,733	(342,470)	(377,988)	(38,153)	(78,116)
March	181,231	188,905	99,016	63,828	3,640	8,361	22,491	98,320	(334,631)	(356,887)	(54,384)	(69,662)
April	178,958	182,904	93,552	59,984	3,640	6,847	21,922	92,392	(304,727)	(332,425)	(32,216)	(57,129)
May	186,680	183,291	70,077	48,036	3,640	6,444	21,082	79,202	(256,034)	(217,780)	723	44,713
June	277,154	267,454	91,395	63,307	3,640	10,368	26,898	104,212	(312,605)	(279,268)	55,943	92,398
July	268,025	263,219	93,535	64,966	3,640	11,175	27,279	107,060	(342,086)	(305,736)	19,474	64,543
August	241,023	263,278	90,868	63,333	3,640	10,861	26,489	104,323	(317,463)	(284,853)	14,428	82,748
September	259,783	247,412	92,092	63,948	3,640	9,768	26,876	104,233	(287,725)	(260,899)	64,149	90,746
October	167,701	169,919	71,035	48,347	2,320	7,228	22,605	80,500	(266,236)	(237,500)	(27,499)	12,919
November	185,595	183,388	77,266	53,609	3,640	12,346	22,885	92,479	(279,680)	(249,372)	(16,819)	26,495
December	188,323	186,281	77,652	54,000	3,640	10,134	27,326	95,099	(302,492)	(270,479)	(36,517)	10,901
	2,531,582	2,526,612	1,067,247	719,383	42,359	112,246	293,263	1,167,251	(3,694,409)	(3,544,107)	(95,579)	149,756

The changes in Hydro One's charges for these services is expected to create a larger debit variance of $133,782 ($41,175 credit plus $174,957 debit), and as a result Chatham-Kent Hydro is proposing to change the rates. Chatham-Kent Hydro's proposal is to decrease the Retail Transmission – Network Service rate by 1.3% and an increase to the Retail Transmission – Line and Transformation Connection Service rate by 6.1%. The details of the estimated 2010 variance and the calculation of the rate change is provided in Table 8-11.

Table 8-11
Proposed Retail Transmission Service Rates

	IESO		Hydro One		Total		Rate Change		Revenue		Difference	
	Network	Connection	Network	Connection	Network	Connection	Network	Connection	Network	Connection	Network	Connection
Forecast 2010	2,265,550	2,269,587	827,982	724,957	3,093,532	2,994,544	3,201,866	3,059,081	(3,243,041)	(2,884,124)	(41,175)	174,957

	Network	Connection
Hydro One		
New	2.66	2.37
Pervious	2.57	2.32
	0.09	0.05
	3.50%	2.16%
IESO Rates		
New	2.66	2.37
Pervious	2.57	2.32
	0.09	0.05
	3.50%	2.16%
CK H Rate Change		
Estimated Revenue	(3,243,041)	(2,884,124)
Estimated Varaince	(41,175)	174,957
Difference %	-1.3%	6.1%

Rates for 2010		2010	
CK H Rate - Network	**Current**	**Proposed**	**Difference**
Residential	0.0048	0.0047	(0.0001)
GS < 50 kW	0.0043	0.0042	(0.0001)
GS kW 50 to 4,999	1.7720	1.7495	(0.0225)
GS kW 50 to 4,999 TOU	1.8882	1.8642	(0.0240)
Standby	1.8882	1.8642	(0.0240)
Unmetered Scattered	0.0043	0.0042	(0.0001)
Streetlight	1.3363	1.3193	(0.0170)
Sentinel Light	1.3460	1.3289	(0.0171)

CK H Rate - Connection	**Current**	**Proposed**	**Difference**
Residential	0.0041	0.0043	0.0002
GS < 50 kW	0.0037	0.0039	0.0002
GS kW 50 to 4,999	1.4556	1.5439	0.0883
GS kW 50 to 4,999 TOU	1.5942	1.6909	0.0967
Standby	1.5942	1.6909	0.0967
Unmetered Scattered	0.0037	0.0039	0.0002
Streetlight	1.1244	1.1926	0.0682
Sentinel Light	1.1475	1.2171	0.0696

Low Voltage Charges:

Chatham-Kent Hydro has forecasted a Low Voltage ongoing cost of $228,345 based on the assumed volume and charges for the Common ST lines and shared LV distribution stations. The table below illustrates the related volumes and rates for the Low voltage charges.

Table 8-12
Estimated Low Voltage Costs

	Annual Units	Rate	Months	Total
Monthly Fixed Charge (Number of Meters)	17	116.08	12	$23,680
Common ST Lines (Based on average annual usage)	604,185	0.35		$211,465
2008 Regulatory (Based on May 2009)		-566.68	12	-$6,800
Total				$228,345

The calculation of the Low voltage usage is based on the February to May 2009 actual usage charged from Hydro One, the forecast is based upon the average of those four months. The estimated volume is provided in Table 8-13.

Table 8-13
Allocation of Low Voltage Costs

2010	**Feb**	**Mar**	**Apr**	**May**	**Sum**	**Average**	**Annual**
1745046003	16,350	16,167	14,248	12,891	59,656	14,914	178,968
3107654001	24,647	11,016	21,515	18,277	75,455	18,864	226,365
1619612002	11,396	24,593	10,822	9,437	56,248	14,062	168,744
2195598006	1,802	1,731	1,517	1,392	6,442	1,611	19,326
5249756004	1,356	1,132	683	423	3,594	899	10,782
	55,551	54,639	48,785	42,420	201,395	50,349	604,185

The estimated low voltage charge is $228,345 and is being allocated to the various rate classes based upon the low voltage revenue at the current rates, as shown in Table 8-14.

Table 8-14
Allocation of Low Voltage Costs

Customer Class	Current Low Voltage Rates		Basis for Allocation ($)	Allocation Percentages	Allocated $
	per KWh	per kW			
Residential	0.0006		123,691	30.19%	68,933
General Service < 50 kW	0.0006		53,892	13.15%	30,034
General Service > 50 to 999 kW		0.2470	112,767	27.52%	62,846
Intermediate		0.2700	95,397	23.28%	53,165
Large Use		0.3003	0	0.00%	0
Streetlights		0.0815	1,382	0.34%	770
Sentinel Lights		0.1762	176	0.04%	98
Unmetered Scattered Loads	0.0006		646	0.16%	360
Standby		0.2700	21,781	5.32%	12,139
TOTALS			**409,732**	**100.00%**	**228,345**

The following Table 8-15 provides Chatham-Kent Hydro's calculations of its proposed low voltage rate adder for the 2010 Test Year.

Table 8-15
Low Voltage Rate Adder

Customer Class	LV Adj. Allocated	Calculated kWh	Calculated kW	Volumetric Rate Type	LV/ Adj. Rates/kWh	LV Adj. Rates/ kW
Residential	68,933	199,501,364	0	kWh	0.0003	
General Service < 50 kW	30,034	86,923,094	0	kWh	0.0003	
General Service > 50 to 999 kW	62,846	183,018,503	456,548	kW		0.14
Intermediate	53,165	134,791,341	353,322	kW		0.15
Large Use	0	0	0	kW		0.00
Streetlights	770	5,547,412	16,969	kW		0.05
Sentinel Lights	98	334,470	997	kW		0.10
Unmetered Scattered Loads	360	1,041,782	0	kWh	0.0003	
Standby	12,139	31,031,687	80,671	kW		0.15
TOTALS	**228,345**	**642,189,652**	**908,507**			

PROPOSED RATES:

Chatham-Kent Hydro's proposed rates are summarized in Table 8-16

Table 8-16
Proposed Rates

2010 TEST YEAR - BASE REVENUE DISTRIBUTION RATES

Customer Class	Connection	Customer	kW	kWh
Residential	28,644	18.12	0.0000	0.0085
General Service < 50 kW	3,038	33.74	0.0000	0.0107
General Service > 50 to 999 kW	421	97.46	4.7091	0.0000
Intermediate	28	795.83	3.5829	0.0000
Large Use	-	0.00	0.0000	0.0000
Streetlights	10,751	1.23	7.9163	0.0000
Sentinel Lights	327	7.88	5.7266	0.0000
Unmetered Scattered Loads	194	9.06	0.0000	0.0064
Standby	1	6,099.12	3.8455	0.0000
Standby Charge			1.3500	

2010 TEST YEAR - Low Voltage Distribution Rates

Customer Class	Connection	Customer	kW	kWh
Residential				0.0003
General Service < 50 kW				0.0003
General Service > 50 to 999 kW			0.1377	
Intermediate			0.1505	
Large Use			0.0000	
Streetlights			0.0454	
Sentinel Lights			0.0982	
Unmetered Scattered Loads				0.0003
Standby			0.1505	

2010 TEST YEAR SMART METER PERMANENT RATE

Customer Class	Connection	Customer	kW	kWh
Residential		0.18		
General Service < 50 kW		0.18		
General Service > 50 to 999 kW		0.18		
Intermediate		0.18		
Large Use		0.00		
Streetlights		0.00		
Sentinel Lights		0.00		
Unmetered Scattered Loads		0.00		
Standby		0.18		

2010 TEST YEAR SMART METER DISPOSITION RIDER

Customer Class	Connection	Customer	kW	kWh
Residential		0.45		
General Service < 50 kW		0.45		
General Service > 50 to 999 kW		0.45		
Intermediate		0.45		
Large Use				
Streetlights				
Sentinel Lights				
Unmetered Scattered Loads				
Standby		0.45		

2010 TEST YEAR SMART METER ADDER

Customer Class	Connection	Customer	kW	kWh
Residential		0.51		
General Service < 50 kW		0.51		
General Service > 50 to 999 kW		0.51		
Intermediate		0.51		
Large Use		0.00		
Streetlights		0.00		
Sentinel Lights		0.00		
Unmetered Scattered Loads		0.00		
Standby		0.51		

2010 TEST YEAR - Distribution Rates

Customer Class	Connection	Customer	kW	kWh
Residential	28,644	18.81	0.0000	0.0088
General Service < 50 kW	3,038	34.43	0.0000	0.0110
General Service > 50 to 999 kW	421	98.15	4.8468	0.0000
Intermediate	28	796.52	3.7334	0.0000
Large Use	0	0.00	0.0000	0.0000
Streetlights	10,751	1.23	7.9617	0.0000
Sentinel Lights	327	7.88	5.8248	0.0000
Unmetered Scattered Loads	194	9.06	0.0000	0.0067
Standby	1	6,099.81	3.9960	0.0000

The customer connection charge is the base distribution revenue rate plus the permanent smart meter rate plus the smart meter adder.

The smart meter disposition rider of $0.45 per customer is a separate rate on the rate schedule, which is the same presentation as the current rate schedule.

The volumetric rate is the distribution rate plus the low voltage charge.

Loss Adjustment Factor:

Chatham-Kent Hydro has calculated the total loss factor to be applied to customers' consumption based on the average wholesale and retail kWh for the years 2002 to 2008. The calculations are summarized in Table 8-17 below.

Table 8-17
Loss Adjustment Factor

Description	2002	2003	2004	2005	2006	2007	2008	Total
"Wholesale" kWh IESO plus Embedded Generation	646,090,049	888,154,703	895,309,958	929,673,073	881,982,466	865,212,451	838,305,749	5,944,728,449
"Wholesale" kWh for Large Use customer(s)	50,554,946	69,758,005	60,082,549	54,147,448	55,278,859	50,721,953	45,640,226	386,183,987
Net "Wholesale" kWh (A)-(B)	595,535,103	818,396,698	835,227,409	875,525,625	826,703,607	814,490,498	792,665,522	5,558,544,462
"Retail" kWh (Distributor)	619,528,378	858,175,736	868,090,356	908,820,594	862,524,429	844,556,150	818,165,740	5,779,861,383
"Retail" kWh for Large Use Customer(s)	50,049,397	69,060,425	59,481,724	53,605,974	54,726,070	50,214,733	45,183,824	382,322,147
Net "Retail" kWh (D)-(E)	569,478,981	789,115,311	808,608,632	855,214,620	807,798,359	794,341,417	772,981,916	5,397,539,236
Loss Factor [(C)/(F)]	104.58%	103.71%	103.29%	102.37%	102.34%	102.54%	102.55%	102.98%
Distribution Loss Adjustment Factor (6 year avg.)								**102.98%**
Supply Facility Loss Factor	100.60%	100.64%	100.99%	101.85%	101.94%	101.92%	101.41%	101.41%
Supply Facility Loss Adjustment Factor (6 year avg.)								**101.41%**
Total Loss Factor								**1.0443**

Supply Facility Loss Factor

The supply facility loss factor (the "SFLF") calculation is shown in Table 8-18 and represents the losses of supply to Chatham-Kent Hydro. The SFLF is calculated on the measured quantities between the transformer stations and the wholesale meter points. The SFLF is used in the calculations of the total loss factor above.

Table 8-18
Supply Facility Loss Factor

Description	May 1, to Dec 31 2002	Full Year 2003	Full Year 2004	Full Year 2005	Full Year 2006	Full Year 2007	Full Year 2008	Total
"Wholesale" kWh IESO With Losses	649,973,252	893,794,600	904,175,458	946,838,236	899,106,310	881,809,112	852,818,080	6,028,515,048
"Wholesale" kWh IESO No Losses	646,090,049	888,154,703	895,309,958	929,673,073	881,982,466	865,212,451	838,305,749	5,944,728,449
Supply Facility Loss Factor	0.00601	0.00635	0.00990	0.01846	0.01942	0.01918	0.01731	0.01409

Total Loss Factor by Class

Table 8-19 sets out the class-specific Loss Factors used by Chatham-Kent Hydro in the calculation of commodity and other non-distribution charges.

Table 8-19
Total Loss Factor

Total Utility Loss Adjustment Factor	LAF
Supply Facility Loss Factor	1.0141
Distribution Loss Factor	
Distribution Loss Factor - Secondary Metered Customer < 5,000kW	1.0298
Distribution Loss Factor - Primary Metered Customer < 5,000kW	1.0195
Distribution Loss Factor - Secondary Metered Customer > 5,000kW	1.0285
Distribution Loss Factor - Primary Metered Customer > 5,000kW	1.0182
Total Loss Factor	
Total Loss Factor - Secondary Metered Customer < 5,000kW	1.0443
Total Loss Factor - Primary Metered Customer < 5,000kW	1.0339
Total Loss Factor - Secondary Metered Customer > 5,000kW	1.0430
Total Loss Factor - Primary Metered Customer > 5,000kW	1.0326

EXISTING RATE CLASSES:

Chatham-Kent Hydro has changed two rate classes to better reflect the customer consumption. Chatham-Kent Hydro is proposing to have a new rate class, Intermediate, which will be for customers with a demand between 1,000 kW and 4,999 kW. The other rate class being proposed is the Standby class.

Chatham-Kent Hydro is proposing not to continue to have a Large User class as it is expected that no customer will meet the criteria of a demand of 5,000 kW or higher in 2010; and to discontinue the Time of Use class as it is better defined in the Intermediate class.

EXISTING RATE SCHEDULE:

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	12.33
Smart Meter Disposition Rider	$	2.11
Distribution Volumetric Rate	$/kWh	0.0.0139
Regulatory Asset Recovery	$/kWh	0.0000
Retail Transmission Rate – Network Service Rate	$/kWh	0.0048
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0041
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	$	31.01
Smart Meter Disposition Rider	$	2.11
Distribution Volumetric Rate	$/kWh	0.0092
Regulatory Asset Recovery	$/kWh	0.0000
Retail Transmission Rate – Network Service Rate	$/kWh	0.0043
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0037
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	$	159.37
Smart Meter Disposition Rider	$	2.11
Distribution Volumetric Rate	$/kW	1.5717
Regulatory Asset Recovery	$/kW	0.0000
Retail Transmission Rate – Network Service Rate	$/kW	1.7720
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.4556
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	1.8882
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	1.5942
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Intermediate 1,000 to 4,999 kw- TOU

Service Charge	$	4,705.58
Smart Meter Disposition Rider	$	2.11
Distribution Volumetric Rate	$/kW	2.3623
Regulatory Asset Recovery	$/kW	0.0000
Retail Transmission Rate – Network Service Rate	$/kW	1.8882
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.5942
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Large Use

Service Charge	$	12,945.69
Smart Meter Disposition Rider	$	2.11
Distribution Volumetric Rate	$/kW	3.0357
Regulatory Asset Recovery	$/kW	0.0000
Retail Transmission Rate – Network Service Rate	$/kW	2.0819

Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.8253
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)	$	3.30
Distribution Volumetric Rate	$/kWh	0.0054
Regulatory Asset Recovery	$/kWh	0.0000
Retail Transmission Rate – Network Service Rate	$/kWh	0.0043
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0037
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)	$	3.88
Distribution Volumetric Rate	$/kW	2.9955
Regulatory Asset Recovery	$/kW	0.0000
Retail Transmission Rate – Network Service Rate	$/kW	1.3460
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.1475
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Street Lighting

Service Charge (per connection)	$	0.47
Distribution Volumetric Rate	$/kW	3.1115
Regulatory Asset Recovery	$/kW	0.0000
Retail Transmission Rate – Network Service Rate	$/kW	1.3363
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.1244
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
Statement of Account	$	15.00
Request for other billing information	$	15.00
Easement Letter	$	15.00
Account history	$	15.00
Returned Cheque (plus bank charges)	$	15.00
Charge to certify cheque	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special metered 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
Disconnect/Reconnect at meter - during Regular Hours	$	65.00
Install / Remove load control device – during regular hours	$	65.00
Disconnect/Reconnect at meter - after regular hours	$	185.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35
Meter upgrade requested by customer plus installation – per month	$	10.00

		plus installation on a time and materials basis.
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)

Retail Service Charges (if applicable)

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Request (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, peer request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year		no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

Loss Factor

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0470
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0369
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0365
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0266

SCHEDULE OF PROPOSED RATES AND CHARGES:

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	18.81
Smart Meter Disposition Rider - effective until April 30, 2012	$	0.45
Distribution Volumetric Rate	$/kWh	0.0085
Low Voltage Distribution Rate	$/kWh	0.0003
Deferral and Variance Account Rider	$/kWh	0.0002
LRAM/SSM Rider	$/kWh	0.0000
Retail Transmission Rate – Network Service Rate	$/kWh	0.0047
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0043
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.2500

General Service Less Than 50 kW

Service Charge	$	33.74
Smart Meter Disposition Rider - effective until April 30, 2012	$	0.45
Distribution Volumetric Rate	$/kWh	0.0107
Low Voltage Distribution Rate	$/kWh	0.0003
Deferral and Variance Account Rider	$/kWh	(0.0007)
LRAM/SSM Rider	$/kWh	0.0000
Retail Transmission Rate – Network Service Rate	$/kWh	0.0042
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0039
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.2500

General Service 50 to 999 kW

Service Charge	$	97.46
Smart Meter Disposition Rider - effective until April 30, 2012	$	0.45
Distribution Volumetric Rate	$/kW	4.7091
Low Voltage Distribution Rate	$/kW	0.1377
Deferral and Variance Account Rider	$/kWh	(0.6859)
LRAM/SSM Rider	$/kWh	0.0000
Retail Transmission Rate – Network Service Rate	$/kW	1.7495
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.5439
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	1.8642
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	1.6909
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.2500

General Service Intermediate - 1,000 to 4,999 kW

Service Charge	$	795.83
Smart Meter Disposition Rider - effective until April 30, 2012	$	0.45
Distribution Volumetric Rate	$/kW	3.5829
Low Voltage Distribution Rate	$/kW	0.1505
Deferral and Variance Account Rider	$/kWh	(0.3825)
LRAM/SSM Rider	$/kWh	0.0000
Retail Transmission Rate – Network Service Rate	$/kW	1.8642
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.6909
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.2500

Standby Power		
Service Charge	$	6,099.12
Smart Meter Disposition Rider - effective until April 30, 2012	$	0.45
Distribution Volumetric Rate	$/kW	3.8455
Low Voltage Distribution Rate	$/kW	0.1505
Deferral and Variance Account Rider	$/kWh	(0.6702)
LRAM/SSM Rider	$/kWh	0.0000
Retail Transmission Rate – Network Service Rate	$/kW	1.8642
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.6909
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.2500
Standby Charge – for a month where standby power is not provided. The charge is applied to the contracted amount (e.g. nameplate rating of generation facility).	$/kW	1.3500

Unmetered Scattered Load		
Service Charge (per connection)	**$**	9.06
Distribution Volumetric Rate	$/kWh	0.0064
Low Voltage Distribution Rate	$/kWh	0.0003
Deferral and Variance Account Rider	$/kWh	(0.0015)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0042
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0039
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.2500

Sentinel Lighting		
Service Charge (per connection)	**$**	7.88
Distribution Volumetric Rate	$/kW	5.7266
Low Voltage Distribution Rate	$/kW	0.0982
Deferral and Variance Account Rider	$/kW	0.3111
Retail Transmission Rate – Network Service Rate	$/kW	1.3289
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2171
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.2500

Street Lighting		
Service Charge (per connection)	**$**	1.23
Distribution Volumetric Rate	$/kW	7.9163
Low Voltage Distribution Rate	$/kW	0.0454
Deferral and Variance Account Rider	$/kW	(0.8041)
Retail Transmission Rate – Network Service Rate	$/kW	1.3193
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.1926
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.2500

Specific Service Charges		
Customer Administration		
Arrears certificate	$	15.00
Statement of Account	$	15.00
Easement letter	$	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	$	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
Disconnect/Reconnect Charge – At Meter During Regular Hours	$	65.00
Temporary service install & remove – overhead – no transformer	$	500.00
Temporary service install & remove – overhead – with transformer	$	1,000.00
Specific charge for access to the power poles – per pole/year	$	22.35
Switching for company maintenance – Charge based on Time and Materials	$	
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)

Retail Service Charges (if applicable)	**Metric**	**Current**
Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity		
One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variance Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing credit, per customer, per retailer		0.30
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party		0.25
Processing fee, per request, applied to the requesting party		0.30
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year		no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0443
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0430
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0339
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0141

RECONCILIATION OF RATE CLASS REVENUE:

The expected revenue includes the recovery of distribution costs and the low voltage charges. A summary is provided in Table 8-20.

Table 8-20
Expected Revenue Including Low Voltage Charges

Customer Class	Total Net Rev. Requirement	LV & Wheeling Charges	Expected Revenue
Residential	7,927,879	68,933	7,996,812
General Service < 50 kW	2,159,088	30,034	2,189,122
General Service > 50 to 999 kW	2,510,397	62,846	2,573,243
Intermediate	1,317,410	53,165	1,370,575
Large Use	0	0	0
Streetlights	292,758	770	293,528
Sentinel Lights	36,595	98	36,693
Unmetered Scattered Loads	27,812	360	28,172
Standby	365,947	12,139	378,086
TOTAL	14,637,886	228,345	14,866,230

The revenue reconciliation is provided in Table 8-21. The distribution revenue includes the revenue for the smart meter permanent rate and the smart meter adder. After taking these two items into account the variance is only $15,216, which is minimal and proves that the rates and revenue are reconciled.

Table 8-21
Revenue Reconciliation

Customer Class	Fixed Distribution Revenue	Variable Distribution Revenue	Transformer Allowance Credit	Total Distribution Revenue	Expected
Residential	$ 6,465,607	$ 1,755,612		$ 8,221,219	$ 7,996,812
General Service < 50 kW	$ 1,255,048	$ 956,154		$ 2,211,202	$ 2,189,122
General Service > 50 to 999 kW	$ 495,420	$ 2,212,796	($131,486)	$ 2,576,730	$ 2,573,243
Intermediate	$ 263,711	$ 1,319,091	($211,993)	$ 1,370,809	$ 1,370,575
Large Use	$ -	$ -		$ -	$ -
Streetlights	$ 158,689	$ 135,106		$ 293,795	$ 293,528
Sentinel Lights	$ 30,882	$ 5,806		$ 36,688	$ 36,693
Unmetered Scattered Loads	$ 21,128	$ 6,980		$ 28,108	$ 28,172
Back-up/Standby Power	$ 73,198	$ 353,305	($48,403)	$ 378,100	$ 378,086
Total	**$ 8,763,684**	**$ 6,744,850**	**($391,882)**	**$ 15,116,652**	**$ 14,866,230**
Difference				- 250,422	
Smart Meter Permanenet Rate		$ 0.18	32,082	69,297	
Smart Meter Adder		$ 0.51	32,082	196,341	
Difference Due to Rounding				15,216	

RATE AND BILL IMPACTS:

Appendix A to this Schedule presents the results of the assessment of customer total bill impacts by customer rate class.

The total bill impacts are calculated for each rate class at various levels of consumption. The rate impacts are assessed on the basis of moving to the proposed distribution rates.

APPENDIX A

BILL IMPACTS

License Number EB-2002-0563, File Number
August 31, 2009

BILL IMPACTS *(Monthly Consumptions)*

RESIDENTIAL

Consumption 100

	2009 BILL			2010 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			12.33			18.81	6.48	52.55%	64.60%
Distribution (kWh)	100	0.0139	1.39	100	0.0088	0.88	(0.51)	(36.69%)	3.02%
Smart Meter Disposition Rider (per month)			2.11			0.45	(1.66)	(78.67%)	1.55%
LRAM & SSM Rider (kWh)	100			100	0.0000	0.00	0.00	0.00%	0.00%
Regulatory Assets (kWh)	100	0.0000	0.00	100	0.0002	0.02	0.02	100.00%	0.07%
Sub-Total			**15.83**			**20.16**	**4.33**	**27.35%**	**69.23%**
RTSR - Network	105	0.0048	0.50	104	0.0047	0.49	(0.01)	(2.33%)	1.69%
RTSR - Connection	105	0.0041	0.43	104	0.0043	0.45	0.02	4.61%	1.54%
Sub- Total			**16.76**			**21.10**	**4.34**	**25.88%**	**72.46%**
Wholesale Market Rate	105	0.0052	0.54	104	0.0052	0.54	(0.00)	(0.25%)	1.87%
RRRP	105	0.0013	0.14	104	0.0013	0.14	(0.00)	(0.25%)	0.47%
DRC	105	0.0070	0.73	104	0.0070	0.73	(0.00)	(0.25%)	2.51%
Cost of Power Commodity	105	0.0500	5.24	104	0.0500	5.22	(0.01)	(0.25%)	17.93%
Cost of Power Commodity		0.0590	0.00		0.0590	0.00	0.00	0.00%	0.00%
Total Bill Before Taxes			**23.41**			**27.73**	**4.32**	**18.46%**	**95.24%**
GST		5.00%	1.17		5.00%	1.39	0.22	18.46%	4.76%
Total Bill			**24.58**			**29.12**	**4.54**	**18.46%**	**100.00%**

RESIDENTIAL

Consumption 250

	2009 BILL			2010 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			12.33			18.81	6.48	52.55%	44.30%
Distribution (kWh)	250	0.0139	3.48	250	0.0088	2.20	(1.28)	(36.69%)	5.18%
Smart Meter Disposition Rider (per month)			2.11			0.45	(1.66)	(78.67%)	1.06%
LRAM & SSM Rider (kWh)	250			250	0.0000	0.00	0.00	0.00%	0.00%
Regulatory Assets (kWh)	250	0.0000	0.00	250	0.0002	0.05	0.05	100.00%	0.11%
Sub-Total			**17.92**			**21.51**	**3.59**	**20.06%**	**50.66%**
RTSR - Network	262	0.0048	1.26	261	0.0047	1.23	(0.03)	(2.33%)	2.89%
RTSR - Connection	262	0.0041	1.07	261	0.0043	1.12	0.05	4.61%	2.64%
Sub- Total			**20.24**			**23.86**	**3.61**	**17.85%**	**56.19%**
Wholesale Market Rate	262	0.0052	1.36	261	0.0052	1.36	(0.00)	(0.25%)	3.20%
RRRP	262	0.0013	0.34	261	0.0013	0.34	(0.00)	(0.25%)	0.80%
DRC	262	0.007	1.83	261	0.007	1.83	(0.00)	(0.25%)	4.30%
Cost of Power Commodity	262	0.0500	13.09	261	0.0500	13.05	(0.03)	(0.25%)	30.75%
Cost of Power Commodity		0.0590	0.00		0.0590	0.00	0.00	0.00%	0.00%
Total Bill Before Taxes			**36.87**			**40.44**	**3.57**	**9.69%**	**81.40%**
GST		5.00%	1.84		5.00%	2.02	0.18	9.69%	4.76%
Total Bill			**38.71**			**42.46**	**3.75**	**9.69%**	**86.16%**

RESIDENTIAL

Consumption 500

	2009 BILL			2010 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			12.33			18.81	6.48	52.55%	19.38%
Distribution (kWh)	500	0.0139	6.95	500	0.0088	4.40	(2.55)	(36.69%)	4.53%
Smart Meter Disposition Rider (per month)			2.11			0.45	(1.66)	(78.67%)	0.46%
LRAM & SSM Rider (kWh)	500			500	0.0000	0.00	0.00	0.00%	0.00%
Regulatory Assets (kWh)	500	0.0000	0.00	500	0.0002	0.10	0.10	100.00%	0.10%
Sub-Total			**21.39**			**23.76**	**2.37**	**11.06%**	**24.48%**
RTSR - Network	524	0.0048	2.51	522	0.0047	2.45	(0.06)	(2.33%)	2.53%
RTSR - Connection	524	0.0041	2.15	522	0.0043	2.25	0.10	4.61%	2.31%
Sub- Total			**26.05**			**28.46**	**2.41**	**9.24%**	**29.32%**
Wholesale Market Rate	524	0.0052	2.72	522	0.0052	2.72	(0.01)	(0.25%)	2.80%
RRRP	524	0.0013	0.68	522	0.0013	0.68	(0.00)	(0.25%)	0.70%
DRC	524	0.007	3.66	522	0.007	3.66	(0.01)	(0.25%)	3.77%
Cost of Power Commodity	524	0.0500	26.18	522	0.0500	26.11	(0.07)	(0.25%)	26.90%
Cost of Power Commodity (kWh)	524	0.0590	30.89	522	0.0590	30.81	(0.08)	(0.25%)	31.75%
Total Bill Before Taxes			**90.18**			**92.42**	**2.24**	**2.49%**	**83.13%**
GST		5.00%	4.51		5.00%	4.62	0.11	2.49%	4.76%
Total Bill			**94.69**			**97.04**	**2.36**	**2.49%**	**87.89%**

RESIDENTIAL

		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge			12.33			18.81	6.48	52.55%	20.10%
800	Distribution (kWh)	800	0.0139	11.12	800	0.0088	7.04	(4.08)	(36.69%)	7.52%
	Smart Meter Disposition Rider (per month)			2.11			0.45	(1.66)	(78.67%)	0.48%
	LRAM & SSM Rider (kWh)	800			800	0.0000	0.00	0.00	0.00%	0.00%
	Regulatory Assets (kWh)	800	0.0000	0.00	800	0.0002	0.15	0.15	100.00%	0.17%
	Sub-Total			**25.56**			**26.45**	**0.89**	**3.50%**	**28.26%**
	RTSR - Network	838	0.0048	4.02	835	0.0047	3.93	(0.09)	(2.33%)	4.20%
	RTSR - Connection	838	0.0041	3.43	835	0.0043	3.59	0.16	4.61%	3.84%
	Sub- Total			**33.01**			**33.97**	**0.96**	**2.91%**	**36.30%**
	Wholesale Market Rate	838	0.0052	4.36	835	0.0052	4.34	(0.01)	(0.25%)	4.64%
	RRRP	838	0.0013	1.09	835	0.0013	1.09	(0.00)	(0.25%)	1.16%
	DRC	838	0.007	5.86	835	0.007	5.85	(0.01)	(0.25%)	6.25%
	Cost of Power Commodity	600	0.0500	30.00	600	0.0500	30.00	0.00	0.00%	32.05%
	Cost of Power Commodity (kWh)	238	0.0590	14.02	235	0.0590	13.89	(0.13)	(0.89%)	14.84%
	Total Bill Before Taxes			**88.34**			**89.15**	**0.81**	**0.91%**	**75.16%**
	GST		5.00%	4.42		5.00%	4.46	0.04	0.91%	4.76%
	Total Bill			**92.76**			**93.60**	**0.85**	**0.91%**	**79.92%**

RESIDENTIAL

		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge			12.33			18.81	6.48	52.55%	16.59%
1,000	Distribution (kWh)	1,000	0.0139	13.90	1,000	0.0088	8.80	(5.10)	(36.69%)	7.76%
	Smart Meter Disposition Rider (per month)			2.11			0.45	(1.66)	(78.67%)	0.40%
	LRAM & SSM Rider (kWh)	1,000			1,000	0.0000	0.00	0.00	0.00%	0.00%
	Regulatory Assets (kWh)	1,000	0.0000	0.00	1,000	0.0002	0.19	0.19	100.00%	0.17%
	Sub-Total			**28.34**			**28.25**	**(0.09)**	**(0.31%)**	**24.92%**
	RTSR - Network	1,047	0.0048	5.03	1,044	0.0047	4.91	(0.12)	(2.33%)	4.33%
	RTSR - Connection	1,047	0.0041	4.29	1,044	0.0043	4.49	0.20	4.61%	3.96%
	Sub- Total			**37.66**			**37.65**	**(0.01)**	**(0.02%)**	**33.21%**
	Wholesale Market Rate	1,047	0.0052	5.44	1,044	0.0052	5.43	(0.01)	(0.25%)	4.79%
	RRRP	1,047	0.0013	1.36	1,044	0.0013	1.36	(0.00)	(0.25%)	1.20%
	DRC	1,047	0.007	7.33	1,044	0.007	7.31	(0.02)	(0.25%)	6.45%
	Cost of Power Commodity	600	0.0500	30.00	600	0.0500	30.00	0.00	0.00%	26.46%
	Cost of Power Commodity (kWh)	447	0.0590	26.37	444	0.0590	26.22	(0.16)	(0.59%)	23.13%
	Total Bill Before Taxes			**108.17**			**107.97**	**(0.20)**	**(0.18%)**	**95.24%**
	GST		5.00%	5.41		5.00%	5.40	(0.01)	(0.18%)	4.76%
	Total Bill			**113.57**			**113.37**	**(0.21)**	**(0.18%)**	**100.00%**

RESIDENTIAL

		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge			12.33			18.81	6.48	52.55%	11.56%
1,500	Distribution (kWh)	1,500	0.0139	20.85	1,500	0.0088	13.20	(7.65)	(36.69%)	8.11%
	Smart Meter Disposition Rider (per month)			2.11			0.45	(1.66)	(78.67%)	0.28%
	LRAM & SSM Rider (kWh)	1,500			1,500	0.0000	0.00	0.00	0.00%	0.00%
	Regulatory Assets (kWh)	1,500	0.0000	0.00	1,500	0.0002	0.29	0.29	100.00%	0.18%
	Sub-Total			**35.29**			**32.75**	**(2.54)**	**(7.20%)**	**20.12%**
	RTSR - Network	1,571	0.0048	7.54	1,567	0.0047	7.36	(0.18)	(2.33%)	4.52%
	RTSR - Connection	1,571	0.0041	6.44	1,567	0.0043	6.74	0.30	4.61%	4.14%
	Sub- Total			**49.27**			**46.85**	**(2.42)**	**(4.91%)**	**28.78%**
	Wholesale Market Rate	1,571	0.0052	8.17	1,567	0.0052	8.15	(0.02)	(0.25%)	5.00%
	RRRP	1,571	0.0013	2.04	1,567	0.0013	2.04	(0.01)	(0.25%)	1.25%
	DRC	1,571	0.007	10.99	1,567	0.007	10.97	(0.03)	(0.25%)	6.74%
	Cost of Power Commodity	600	0.0500	30.00	600	0.0500	30.00	0.00	0.00%	18.43%
	Cost of Power Commodity (kWh)	971	0.0590	57.26	967	0.0590	57.02	(0.24)	(0.41%)	35.03%
	Total Bill Before Taxes			**157.73**			**155.02**	**(2.71)**	**(1.72%)**	**95.24%**
	GST		5.00%	7.89		5.00%	7.75	(0.14)	(1.72%)	4.76%
	Total Bill			**165.62**			**162.77**	**(2.84)**	**(1.72%)**	**100.00%**

RESIDENTIAL

		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge			12.33			18.81	6.48	52.55%	8.87%
2,000	Distribution (kWh)	2,000	0.0139	27.80	2,000	0.0088	17.60	(10.20)	(36.69%)	8.29%
	Smart Meter Disposition Rider (per month)			2.11			0.45	(1.66)	(78.67%)	0.21%
	LRAM & SSM Rider (kWh)	2,000			2,000	0.0000	0.00	0.00	0.00%	0.00%
	Regulatory Assets (kWh)	2,000	0.0000	0.00	2,000	0.0002	0.39	0.39	100.00%	0.18%
	Sub-Total			**42.24**			**37.25**	**(4.99)**	**(11.82%)**	**17.55%**
	RTSR - Network	2,094	0.0048	10.05	2,089	0.0047	9.82	(0.23)	(2.33%)	4.63%
	RTSR - Connection	2,094	0.0041	8.59	2,089	0.0043	8.98	0.40	4.61%	4.23%
	Sub- Total			**60.88**			**56.05**	**(4.83)**	**(7.94%)**	**26.41%**
	Wholesale Market Rate	2,094	0.0052	10.89	2,089	0.0052	10.86	(0.03)	(0.25%)	5.12%
	RRRP	2,094	0.0013	2.72	2,089	0.0013	2.72	(0.01)	(0.25%)	1.28%
	DRC	2,094	0.007	14.66	2,089	0.007	14.62	(0.04)	(0.25%)	6.89%
	Cost of Power Commodity	600	0.0500	30.00	600	0.0500	30.00	0.00	0.00%	14.14%
	Cost of Power Commodity (kWh)	1,494	0.0590	88.15	1,489	0.0590	87.83	(0.31)	(0.36%)	41.40%
	Total Bill Before Taxes			**207.29**			**202.08**	**(5.34)**	**(2.58%)**	**95.24%**
	GST		5.00%	10.36		5.00%	10.10	(0.26)	(2.52%)	4.76%
	Total Bill			**217.66**			**212.18**	**(5.60)**	**(2.57%)**	**100.00%**

GENERAL SERVICE < 50 kW

		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Consumption	Monthly Service Charge			31.01			34.43	3.42	11.03%	26.45%
1,000	Distribution (kWh)	1,000	0.0092	9.20	1,000	0.0110	11.00	1.80	19.57%	8.45%
	Smart Meter Disposition Rider (per month)			2.11			0.45	(1.66)	(78.67%)	0.35%
	Regulatory Assets (kWh)	1,000	0.0000	0.00	1,000	(0.0007)	(0.69)	(0.69)	100.00%	(0.53%)
	Sub-Total			**42.32**			**45.19**	**2.87**	**6.78%**	**34.72%**
	RTSR - Network	1,047	0.0043	4.50	1,044	0.0042	4.39	(0.12)	(2.57%)	3.37%
	RTSR - Connection	1,047	0.0037	3.87	1,044	0.0039	4.07	0.20	5.14%	3.13%
	Sub- Total			**50.70**			**53.65**	**2.95**	**5.83%**	**41.22%**
	Wholesale Market Rate	1,047	0.0052	5.44	1,044	0.0052	5.43	(0.01)	(0.25%)	4.17%
	RRRP	1,047	0.0013	1.36	1,044	0.0013	1.36	(0.00)	(0.25%)	1.04%
	DRC	1,047	0.007	7.33	1,044	0.007	7.31	(0.02)	(0.25%)	5.62%
	Cost of Power Commodity	600	0.0500	30.00	600	0.0500	30.00	0.00	0.00%	23.05%
	Cost of Power Commodity (kWh)	447	0.0590	26.37	444	0.0590	26.22	(0.16)	(0.59%)	20.14%
	Total Bill Before Taxes			**121.20**			**123.96**	**2.69**	**2.22%**	**95.24%**
	GST		5.00%	6.06		5.00%	6.20	0.14	2.28%	4.76%
	Total Bill			**127.26**			**130.16**	**2.83**	**2.23%**	**100.00%**

GENERAL SERVICE < 50 kW

		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Consumption	Monthly Service Charge			31.01			34.43	3.42	11.03%	15.01%
2,000	Distribution (kWh)	2,000	0.0092	18.40	2,000	0.0110	22.00	3.60	19.57%	9.59%
	Smart Meter Disposition Rider (per month)			2.11			0.45	(1.66)	(78.67%)	0.20%
	Regulatory Assets (kWh)	2,000	0.0000	0.00	2,000	(0.0007)	(1.38)	(1.38)	100.00%	(0.60%)
	Sub-Total			**51.52**			**55.50**	**3.98**	**7.73%**	**24.20%**
	RTSR - Network	2,094	0.0043	9.00	2,089	0.0042	8.77	(0.23)	(2.57%)	3.82%
	RTSR - Connection	2,094	0.0037	7.75	2,089	0.0039	8.15	0.40	5.14%	3.55%
	Sub- Total			**68.27**			**72.42**	**4.15**	**6.07%**	**31.57%**
	Wholesale Market Rate	2,094	0.0052	10.89	2,089	0.0052	10.86	(0.03)	(0.25%)	4.74%
	RRRP	2,094	0.0013	2.72	2,089	0.0013	2.72	(0.01)	(0.25%)	1.18%
	DRC	2,094	0.007	14.66	2,089	0.007	14.62	(0.04)	(0.25%)	6.37%
	Cost of Power Commodity	750	0.0500	37.50	600	0.0500	30.00	(7.50)	(20.00%)	13.08%
	Cost of Power Commodity (kWh)	1,344	0.0590	79.30	1,489	0.0590	87.83	8.54	10.77%	38.29%
	Total Bill Before Taxes			**213.34**			**218.45**	**4.98**	**2.33%**	**95.24%**
	GST		5.00%	10.67		5.00%	10.92	0.26	2.40%	4.76%
	Total Bill			**224.00**			**229.37**	**5.24**	**2.34%**	**100.00%**

GENERAL SERVICE < 50 kW

		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Consumption	Monthly Service Charge			31.01			34.43	3.42	11.03%	6.53%
5,000	Distribution (kWh)	5,000	0.0092	46.00	5,000	0.0110	55.00	9.00	19.57%	10.44%
	Smart Meter Disposition Rider (per month)			2.11			0.45	(1.66)	(78.67%)	0.09%
	Regulatory Assets (kWh)	5,000	0.0000	0.00	5,000	(0.0007)	(3.45)	(3.45)	100.00%	(0.65%)
	Sub-Total			**79.12**			**86.43**	**7.31**	**9.24%**	**16.40%**
	RTSR - Network	5,235	0.0043	22.51	5,222	0.0042	21.93	(0.58)	(2.57%)	4.16%
	RTSR - Connection	5,235	0.0037	19.37	5,222	0.0039	20.36	1.00	5.14%	3.86%
	Sub- Total			**121.00**			**128.73**	**7.73**	**6.39%**	**24.43%**
	Wholesale Market Rate	5,235	0.0052	27.22	5,222	0.0052	27.15	(0.07)	(0.25%)	5.15%
	RRRP	5,235	0.0013	6.81	5,222	0.0013	6.79	(0.02)	(0.25%)	1.29%
	DRC	5,235	0.007	36.65	5,222	0.007	36.55	(0.09)	(0.25%)	6.94%
	Cost of Power Commodity	750	0.0500	37.50	600	0.0500	30.00	(7.50)	(20.00%)	5.69%
	Cost of Power Commodity (kWh)	4,485	0.0590	264.62	4,622	0.0590	272.68	8.07	3.05%	51.74%
	Total Bill Before Taxes			**493.79**			**501.90**	**8.11**	**1.64%**	**95.24%**
	GST		5.00%	24.69		5.00%	25.10	0.41	1.64%	4.76%
	Total Bill			**518.48**			**527.00**	**8.52**	**1.64%**	**100.00%**

GENERAL SERVICE < 50 kW

		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Consumption	Monthly Service Charge			31.01			34.43	3.42	11.03%	3.37%
10,000	Distribution (kWh)	10,000	0.0092	92.00	10,000	0.0110	110.00	18.00	19.57%	10.75%
	Smart Meter Disposition Rider (per month)			2.11			0.45	(1.66)	(78.67%)	0.04%
	Regulatory Assets (kWh)	10,000	0.0000	0.00	10,000	(0.0007)	(6.90)	(6.90)	100.00%	(0.67%)
	Sub-Total			**125.12**			**137.98**	**12.86**	**10.28%**	**13.49%**
	RTSR - Network	10,470	0.0043	45.02	10,443	0.0042	43.86	(1.16)	(2.57%)	4.29%
	RTSR - Connection	10,470	0.0037	38.74	10,443	0.0039	40.73	1.99	5.14%	3.98%
	Sub- Total			**208.88**			**222.57**	**13.69**	**6.56%**	**21.76%**
	Wholesale Market Rate	10,470	0.0052	54.44	10,443	0.0052	54.31	(0.14)	(0.25%)	5.31%
	RRRP	10,470	0.0013	13.61	10,443	0.0013	13.58	(0.03)	(0.25%)	1.33%
	DRC	10,470	0.007	73.29	10,443	0.007	73.10	(0.19)	(0.25%)	7.15%
	Cost of Power Commodity	750	0.0500	37.50	600	0.0500	30.00	(7.50)	(20.00%)	2.93%
	Cost of Power Commodity (kWh)	9,720	0.0590	573.48	9,843	0.0590	580.76	7.28	1.27%	56.77%
	Total Bill Before Taxes			**961.21**			**974.32**	**13.12**	**1.36%**	**95.24%**
	GST		5.00%	48.06		5.00%	48.72	0.66	1.36%	4.76%
	Total Bill			**1,009.27**			**1,023.04**	**13.77**	**1.36%**	**100.00%**

GENERAL SERVICE < 50 kW

		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Consumption	Monthly Service Charge			31.01			34.43	3.42	11.03%	2.27%
15,000	Distribution (kWh)	15,000	0.0092	138.00	15,000	0.0110	165.00	27.00	19.57%	10.86%
	Smart Meter Disposition Rider (per month)			2.11			0.45	(1.66)	(78.67%)	0.03%
	Regulatory Assets (kWh)	15,000	0.0000	0.00	15,000	(0.0007)	(10.35)	(10.35)	100.00%	(0.68%)
	Sub-Total			**171.12**			**189.53**	**18.41**	**10.76%**	**12.48%**
	RTSR - Network	15,705	0.0043	67.53	15,665	0.0042	65.79	(1.74)	(2.57%)	4.33%
	RTSR - Connection	15,705	0.0037	58.11	15,665	0.0039	61.09	2.99	5.14%	4.02%
	Sub- Total			**296.76**			**316.42**	**19.66**	**6.63%**	**20.83%**
	Wholesale Market Rate	15,705	0.0052	81.67	15,665	0.0052	81.46	(0.21)	(0.25%)	5.36%
	RRRP	15,705	0.0013	20.42	15,665	0.0013	20.36	(0.05)	(0.25%)	1.34%
	DRC	15,705	0.007	109.94	15,665	0.007	109.66	(0.28)	(0.25%)	7.22%
	Cost of Power Commodity	750	0.0500	37.50	600	0.0500	30.00	(7.50)	(20.00%)	1.97%
	Cost of Power Commodity (kWh)	14,955	0.0590	882.35	15,065	0.0590	888.84	6.50	0.74%	58.51%
	Total Bill Before Taxes			**1,428.62**			**1,446.75**	**18.12**	**1.27%**	**95.24%**
	GST		5.00%	71.43		5.00%	72.34	0.91	1.27%	4.76%
	Total Bill			**1,500.05**			**1,519.08**	**19.03**	**1.27%**	**100.00%**

GENERAL SERVICE > 50 kW

		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Consumption	Monthly Service Charge			159.37			98.15	(61.22)	(38.41%)	3.50%
30,000	Distribution (kWh)	30,000	0.0000	0.00	30,000	0.0000	0.00	0.00	0.00%	0.00%
60	Distribution (kW)	60	1.5717	94.30	60	4.8468	290.81	196.51	208.38%	10.38%
	Smart Meter Disposition Rider (per month)			2.11			0.45	(1.66)	(78.67%)	0.02%
	Regulatory Assets (kW)	60	0.0000	0.00	60	(0.6859)	(41.15)	(41.15)	100.00%	(1.47%)
	Sub-Total			**255.78**			**348.26**	**92.47**	**36.15%**	**12.42%**
	RTSR - Network	63	1.7720	111.32	63	1.7495	109.62	(1.69)	(1.52%)	3.91%
	RTSR - Connection	63	1.4556	91.44	63	1.5439	96.74	5.30	5.80%	3.45%
	Sub- Total			**458.54**			**554.62**	**96.08**	**20.95%**	**19.79%**
	Wholesale Market Rate	31,410	0.0052	163.33	31,330	0.0052	162.92	(0.41)	(0.25%)	5.81%
	RRRP	31,410	0.0013	40.83	31,330	0.0013	40.73	(0.10)	(0.25%)	1.45%
	DRC	31,410	0.0070	219.87	31,330	0.0070	219.31	(0.56)	(0.25%)	7.82%
	Cost of Power Commodity (kWh)	31,410	0.0540	1,696.14	31,330	0.0540	1,691.84	(4.30)	(0.25%)	60.36%
	Total Bill Before Taxes			**2,578.71**			**2,669.42**	**90.70**	**3.52%**	**95.24%**
	GST		5.00%	128.94		5.00%	133.47	4.54	3.52%	4.76%
	Total Bill			**2,707.65**			**2,802.89**	**95.24**	**3.52%**	**100.00%**

GENERAL SERVICE > 50 kW

		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge			159.37			98.15	(61.22)	(38.41%)	1.52%
75,000	Distribution (kWh)	75,000	0.0000	0.00	75,000	0.0000	0.00	0.00	0.00%	0.00%
100	Distribution (kW)	100	1.5717	157.17	100	4.8468	484.68	327.51	208.38%	7.51%
	Smart Meter Disposition Rider (per month)			2.11			0.45	(1.66)	(78.67%)	0.01%
	Regulatory Assets (kW)	100	0.0000	0.00	100	(0.6859)	(68.59)	(68.59)	100.00%	(1.06%)
	Sub-Total			**318.65**			**514.69**	**196.04**	**61.52%**	**7.98%**
	RTSR - Network	105	1.7720	185.53	104	1.7495	182.71	(2.82)	(1.52%)	2.83%
	RTSR - Connection	105	1.4556	152.40	104	1.5439	161.24	8.83	5.80%	2.50%
	Sub- Total			**656.58**			**858.64**	**202.06**	**30.77%**	**13.31%**
	Wholesale Market Rate	78,525	0.0052	408.33	78,326	0.0052	407.29	(1.04)	(0.25%)	6.31%
	RRRP	78,525	0.0013	102.08	78,326	0.0013	101.82	(0.26)	(0.25%)	1.58%
	DRC	78,525	0.0070	549.68	78,326	0.0070	548.28	(1.39)	(0.25%)	8.50%
	Cost of Power Commodity (kWh)	78,525	0.0540	4,240.35	78,326	0.0540	4,229.59	(10.76)	(0.25%)	65.55%
	Total Bill Before Taxes			**5,957.02**			**6,145.63**	**188.61**	**3.17%**	**95.24%**
	GST		5.00%	297.85		5.00%	307.28	9.43	3.17%	4.76%
	Total Bill			**6,254.87**			**6,452.91**	**198.04**	**3.17%**	**100.00%**

GENERAL SERVICE > 50 kW

		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge			159.37			98.15	(61.22)	(38.41%)	1.04%
99,000	Distribution (kWh)	99,000	0.0000	0.00	99,000	0.0000	0.00	0.00	0.00%	0.00%
250	Distribution (kW)	250	1.5717	392.93	250	4.8468	1,211.70	818.78	208.38%	12.85%
	Smart Meter Disposition Rider (per month)			2.11			0.45	(1.66)	(78.67%)	0.00%
	Regulatory Assets (kW)	250	0.0000	0.00	250	(0.6859)	(171.47)	(171.47)	100.00%	(1.82%)
	Sub-Total			**554.41**			**1,138.83**	**584.43**	**105.42%**	**12.08%**
	RTSR - Network	262	1.7720	463.82	261	1.7495	456.77	(7.05)	(1.52%)	4.85%
	RTSR - Connection	262	1.4556	381.00	261	1.5439	403.09	22.09	5.80%	4.28%
	Sub- Total			**1,399.23**			**1,998.69**	**599.47**	**42.84%**	**21.20%**
	Wholesale Market Rate	103,653	0.0052	539.00	103,390	0.0052	537.63	(1.37)	(0.25%)	5.70%
	RRRP	103,653	0.0013	134.75	103,390	0.0013	134.41	(0.34)	(0.25%)	1.43%
	DRC	103,653	0.0070	725.57	103,390	0.0070	723.73	(1.84)	(0.25%)	7.68%
	Cost of Power Commodity (kWh)	103,653	0.0540	5,597.26	103,390	0.0540	5,583.06	(14.20)	(0.25%)	59.23%
	Total Bill Before Taxes			**8,395.81**			**8,977.52**	**581.72**	**6.93%**	**95.24%**
	GST		5.00%	419.79		5.00%	448.88	29.09	6.93%	4.76%
	Total Bill			**8,815.60**			**9,426.40**	**610.80**	**6.93%**	**100.00%**

GENERAL SERVICE > 50 kW

Consumption
200,000
500

	2009 BILL			2010 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			159.37			98.15	(61.22)	(38.41%)	0.52%
Distribution (kWh)	200,000	0.0000	0.00	200,000	0.0000	0.00	0.00	0.00%	0.00%
Distribution (kW)	500	1.5717	785.85	500	4.8468	2,423.40	1,637.55	208.38%	12.82%
Smart Meter Disposition Rider (per month)			2.11			0.45	(1.66)	(78.67%)	0.00%
Regulatory Assets (kW)	500	0.0000	0.00	500	(0.6859)	(342.93)	(342.93)	100.00%	(1.81%)
Sub-Total			**947.33**			**2,179.07**	**1,231.74**	**130.02%**	**11.53%**
RTSR - Network	524	1.7720	927.64	522	1.7495	913.54	(14.10)	(1.52%)	4.83%
RTSR - Connection	524	1.4556	762.01	522	1.5439	806.18	44.17	5.80%	4.27%
Sub- Total			**2,636.98**			**3,898.79**	**1,261.81**	**47.85%**	**20.63%**
Wholesale Market Rate	209,400	0.0052	1,088.88	208,869	0.0052	1,086.12	(2.76)	(0.25%)	5.75%
RRRP	209,400	0.0013	272.22	208,869	0.0013	271.53	(0.69)	(0.25%)	1.44%
DRC	209,400	0.0070	1,465.80	208,869	0.0070	1,462.08	(3.72)	(0.25%)	7.74%
Cost of Power Commodity (kWh)	209,400	0.0540	11,307.60	208,869	0.0540	11,278.92	(28.68)	(0.25%)	59.69%
Total Bill Before Taxes			**16,771.48**			**17,997.43**	**1,225.96**	**7.31%**	**95.24%**
GST		5.00%	838.57		5.00%	899.87	61.30	7.31%	4.76%
Total Bill			**17,610.05**			**18,897.31**	**1,287.25**	**7.31%**	**100.00%**

GENERAL SERVICE > 50 kW

Consumption
800,000
2,000

	2009 BILL			2010 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			159.37			98.15	(61.22)	(38.41%)	0.13%
Distribution (kWh)	800,000	0.0000	0.00	800,000	0.0000	0.00	0.00	0.00%	0.00%
Distribution (kW)	2,000	1.5717	3,143.40	2,000	4.8468	9,693.60	6,550.20	208.38%	12.88%
Smart Meter Disposition Rider (per month)			2.11			0.45	(1.66)	(78.67%)	0.00%
Regulatory Assets (kW)	2,000	0.0000	0.00	2,000	(0.6859)	(1,371.73)	(1,371.73)	100.00%	(1.82%)
Sub-Total			**3,304.88**			**8,420.47**	**5,115.59**	**154.79%**	**11.19%**
RTSR - Network	2,094	1.7720	3,710.57	2,089	1.7495	3,654.16	(56.41)	(1.52%)	4.85%
RTSR - Connection	2,094	1.4556	3,048.03	2,089	1.5439	3,224.73	176.70	5.80%	4.28%
Sub- Total			**10,063.47**			**15,299.36**	**5,235.88**	**52.03%**	**20.32%**
Wholesale Market Rate	837,600	0.0052	4,355.52	835,475	0.0052	4,344.47	(11.05)	(0.25%)	5.77%
RRRP	837,600	0.0013	1,088.88	835,475	0.0013	1,086.12	(2.76)	(0.25%)	1.44%
DRC	837,600	0.0070	5,863.20	835,475	0.0070	5,848.33	(14.87)	(0.25%)	7.77%
Cost of Power Commodity (kWh)	837,600	0.0540	45,230.40	835,475	0.0540	45,115.66	(114.74)	(0.25%)	59.93%
Total Bill Before Taxes			**66,601.47**			**71,693.94**	**5,092.46**	**7.65%**	**95.24%**
GST		5.00%	3,330.07		5.00%	3,584.70	254.62	7.65%	4.76%
Total Bill			**69,931.55**			**75,278.63**	**5,347.08**	**7.65%**	**100.00%**

GENERAL SERVICE > 50 kW

Consumption
1,600,000
4,000

	2009 BILL			2010 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			159.37			98.15	(61.22)	(38.41%)	0.07%
Distribution (kWh)	1,600,000	0.0000	0.00	1,600,000	0.0000	0.00	0.00	0.00%	0.00%
Distribution (kW)	4,000	1.5717	6,286.80	4,000	4.8468	19,387.20	13,100.40	208.38%	13.11%
Smart Meter Disposition Rider (per month)			2.11			0.45	(1.66)	(78.67%)	0.00%
Transformer Credit	4,000	(0.6000)	(2,400.00)	4,000	(0.6000)	(2,400.00)	0.00	0.00%	(1.62%)
Regulatory Assets (kW)	4,000	0.0000	0.00	4,000	(0.6859)	(2,743.46)	(2,743.46)	100.00%	(1.85%)
Sub-Total			**4,048.28**			**14,342.34**	**10,294.06**	**254.28%**	**9.70%**
RTSR - Network	4,188	1.7720	7,421.14	4,177	1.7495	7,308.32	(112.82)	(1.52%)	4.94%
RTSR - Connection	4,188	1.4556	6,096.05	4,177	1.5439	6,449.45	353.40	5.80%	4.36%
Sub- Total			**17,565.47**			**28,100.11**	**10,534.64**	**59.97%**	**19.00%**
Wholesale Market Rate	1,675,200	0.0052	8,711.04	1,670,951	0.0052	8,688.94	(22.10)	(0.25%)	5.87%
RRRP	1,675,200	0.0013	2,177.76	1,670,951	0.0013	2,172.24	(5.52)	(0.25%)	1.47%
DRC	1,675,200	0.0070	11,726.40	1,670,951	0.0070	11,696.65	(29.75)	(0.25%)	7.91%
Cost of Power Commodity (kWh)	1,675,200	0.0540	90,460.80	1,670,951	0.0540	90,231.33	(229.47)	(0.25%)	60.99%
Total Bill Before Taxes			**130,641.47**			**140,889.27**	**10,247.80**	**7.84%**	**95.24%**
GST		5.00%	6,532.07		5.00%	7,044.46	512.39	7.84%	4.76%
Total Bill			**137,173.54**			**147,933.73**	**10,760.19**	**7.84%**	**100.00%**

Intermediate Rate Class

Consumption
800,000
2,000

	2009 BILL			2010 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			4,705.58			795.83	(3,909.75)	(83.09%)	1.10%
Distribution (kWh)	800,000	0.0000	0.00	800,000	0.0000	0.00	0.00	0.00%	0.00%
Distribution (kW)	2,000	2.3623	4,724.60	2,000	3.5829	7,165.80	2,441.20	51.67%	9.95%
Smart Meter Disposition Rider (per month)			2.11			0.45	(1.66)	(78.67%)	0.00%
Transformer Credit	4,000	(0.6000)	(2,400.00)	4,000	(0.6000)	(2,400.00)	0.00	0.00%	(3.33%)
Regulatory Assets (kW)	2,000	0.0000	0.00	2,000	(0.3825)	(765.08)	(765.08)	100.00%	(1.06%)
Sub-Total			**7,032.29**			**4,797.00**	**(2,235.29)**	**(31.79%)**	**6.66%**
RTSR - Network	2,094	1.8882	3,953.89	2,089	1.8642	3,893.73	(60.16)	(1.52%)	5.40%
RTSR - Connection	2,094	1.5942	3,338.25	2,089	1.6909	3,531.76	193.51	5.80%	4.90%
Sub- Total			**14,324.44**			**12,222.49**	**(2,101.94)**	**(14.67%)**	**16.96%**
Wholesale Market Rate	837,600	0.0052	4,355.52	835,475	0.0052	4,344.47	(11.05)	(0.25%)	6.03%
RRRP	837,600	0.0013	1,088.88	835,475	0.0013	1,086.12	(2.76)	(0.25%)	1.51%
DRC	837,600	0.0070	5,863.20	835,475	0.0070	5,848.33	(14.87)	(0.25%)	8.12%
Cost of Power Commodity (kWh)	837,600	0.0540	45,230.40	835,475	0.0540	45,115.66	(114.74)	(0.25%)	62.62%
Total Bill Before Taxes			**70,862.44**			**68,617.07**	**(2,245.37)**	**(3.17%)**	**95.24%**
GST		5.00%	3,543.12		5.00%	3,430.85	(112.27)	(3.17%)	4.76%
Total Bill			**74,405.56**			**72,047.92**	**(2,357.63)**	**(3.17%)**	**100.00%**

Intermediate Rate Class

Consumption
1,600,000
4,000

	2009 BILL			2010 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			4,705.58			795.83	(3,909.75)	(83.09%)	0.54%
Distribution (kWh)	1,600,000	0.0000	0.00	1,600,000	0.0000	0.00	0.00	0.00%	0.00%
Distribution (kW)	4,000	2.3623	9,449.20	4,000	3.7334	14,933.60	5,484.40	58.04%	10.20%
Smart Meter Disposition Rider (per month)			2.11			0.45	(1.66)	(78.67%)	0.00%
Transformer Credit	4,000	(0.6000)	(2,400.00)	4,000	(0.6000)	(2,400.00)	0.00	0.00%	(1.64%)
Regulatory Assets (kW)	4,000	0.0000	0.00	4,000	(0.3825)	(1,530.17)	(1,530.17)	100.00%	(1.05%)
Sub-Total			**11,756.89**			**11,799.71**	**42.82**	**0.36%**	**8.06%**
RTSR - Network	4,188	1.8882	7,907.78	4,177	1.8642	7,787.46	(120.32)	(1.52%)	5.32%
RTSR - Connection	4,188	1.5942	6,676.51	4,177	1.6909	7,063.53	387.02	5.80%	4.82%
Sub- Total			**26,341.18**			**26,650.70**	**309.52**	**1.18%**	**18.20%**
Wholesale Market Rate	1,675,200	0.0052	8,711.04	1,670,951	0.0052	8,688.94	(22.10)	(0.25%)	5.93%
RRRP	1,675,200	0.0013	2,177.76	1,670,951	0.0013	2,172.24	(5.52)	(0.25%)	1.48%
DRC	1,675,200	0.0070	11,726.40	1,670,951	0.0070	11,696.65	(29.75)	(0.25%)	7.99%
Cost of Power Commodity (kWh)	1,675,200	0.0540	90,460.80	1,670,951	0.0540	90,231.33	(229.47)	(0.25%)	61.63%
Total Bill Before Taxes			**139,417.18**			**139,439.86**	**22.68**	**0.02%**	**95.24%**
GST		5.00%	6,970.86		5.00%	6,971.99	1.13	0.02%	4.76%
Total Bill			**146,388.04**			**146,411.85**	**23.81**	**0.02%**	**100.00%**

Street Lighting

Billing Determinants
10,751
450,000
1,414

	2009 BILL			2010 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge	10,751	0.4700	5,052.97	10,751	1.2300	13,223.73	8,170.76	161.70%	21.43%
Distribution (kWh)	450,000	0.0000	0.00	450,000	0.0000	0.00	0.00	0.00%	0.00%
Distribution (kW)	1,414	3.1115	4,399.66	1,414	7.9617	11,257.84	6,858.18	155.88%	18.24%
Regulatory Assets (kW)	1,414	0.0000	0.00	1,414	(0.8041)	(1,137.00)	(1,137.00)	100.00%	(1.84%)
Sub-Total			**9,452.63**			**23,344.57**	**13,891.94**	**146.96%**	**37.83%**
RTSR - Network	1,480	1.3363	1,978.34	1,477	1.3193	1,948.21	(30.12)	(1.52%)	3.16%
RTSR - Connection	1,480	1.1244	1,664.63	1,477	1.1926	1,761.12	96.49	5.80%	2.85%
Sub- Total			**13,095.59**			**27,053.90**	**13,958.31**	**106.59%**	**43.84%**
Wholesale Market Rate	471,150	0.0052	2,449.98	469,955	0.0052	2,443.77	(6.21)	(0.25%)	3.96%
RRRP	471,150	0.0013	612.50	469,955	0.0013	610.94	(1.55)	(0.25%)	0.99%
DRC	471,150	0.0070	3,298.05	469,955	0.0070	3,289.68	(8.37)	(0.25%)	5.33%
Cost of Power Commodity (kWh)	471,150	0.0540	25,442.10	469,955	0.0540	25,377.56	(64.54)	(0.25%)	41.12%
Total Bill Before Taxes			**44,898.22**			**58,775.85**	**13,877.63**	**30.91%**	**95.24%**
GST		5.00%	2,244.91		5.00%	2,938.79	693.88	30.91%	4.76%
Total Bill			**47,143.13**			**61,714.65**	**14,571.52**	**30.91%**	**100.00%**

Street Lighting

Billing Determinants		2009 BILL Volume	RATE $	CHARGE $	2010 BILL Volume	RATE $	CHARGE $	IMPACT Change $	Change %	% of Total Bill
10,800	Monthly Service Charge	10,800	0.4700	5,076.00	10,800	1.2300	13,284.00	8,208.00	161.70%	20.88%
470,000.00	Distribution (kWh)	470,000	0.0000	0.00	470,000	0.0000	0.00	0.00	0.00%	0.00%
1,450.00	Distribution (kW)	1,450.00	3.1115	4,511.68	1,450.00	7.9617	11,544.47	7,032.79	155.88%	18.14%
	Regulatory Assets (kW)	1,450.00	0.0000	0.00	1,450.00	(0.8041)	(1,165.95)	(1,165.95)	100.00%	(1.83%)
	Sub-Total			**9,587.68**			**23,662.52**	**14,074.84**	**146.80%**	**37.19%**
	RTSR - Network	1,518	1.3363	2,028.70	1,514	1.3193	1,997.81	(30.89)	(1.52%)	3.14%
	RTSR - Connection	1,518	1.1244	1,707.01	1,514	1.1926	1,805.95	98.95	5.80%	2.84%
	Sub- Total			**13,323.39**			**27,466.28**	**14,142.90**	**106.15%**	**43.17%**
	Wholesale Market Rate	492,090	0.0052	2,558.87	490,842	0.0052	2,552.38	(6.49)	(0.25%)	4.01%
	RRRP	492,090	0.0013	639.72	490,842	0.0013	638.09	(1.62)	(0.25%)	1.00%
	DRC	492,090	0.0070	3,444.63	490,842	0.0070	3,435.89	(8.74)	(0.25%)	5.40%
	Cost of Power Commodity (kWh)	492,090	0.0540	26,572.86	490,842	0.0540	26,505.45	(67.41)	(0.25%)	41.66%
	Total Bill Before Taxes			**46,539.46**			**60,598.10**	**14,058.64**	**30.21%**	**95.24%**
	GST		5.00%	2,326.97		5.00%	3,029.90	702.93	30.21%	4.76%
	Total Bill			**48,866.43**			**63,628.00**	**14,761.57**	**30.21%**	**100.00%**

Sentinel Lighting

Billing Determinants		2009 BILL Volume	RATE $	CHARGE $	2010 BILL Volume	RATE $	CHARGE $	IMPACT Change $	Change %	% of Total Bill
329	Monthly Service Charge	329	3.8800	1,276.52	329	7.8800	2,592.52	1,316.00	103.09%	45.41%
30,000	Distribution (kWh)	30,000	0.0000	0.00	30,000	0.0000	0.00	0.00	0.00%	0.00%
83	Distribution (kW)	83	2.9955	248.63	83	5.8248	483.46	234.83	94.45%	8.47%
	Regulatory Assets (kW)	83	0.0000	0.00	83	0.3111	25.82	25.82	100.00%	0.45%
	Sub-Total			**1,525.15**			**3,101.80**	**1,576.65**	**103.38%**	**54.33%**
	RTSR - Network	87	1.3460	116.97	87	1.3289	115.19	(1.78)	(1.52%)	2.02%
	RTSR - Connection	87	1.1475	99.72	87	1.2171	105.50	5.78	5.80%	1.85%
	Sub- Total			**1,741.83**			**3,322.49**	**1,580.65**	**90.75%**	**58.20%**
	Wholesale Market Rate	31,410	0.0052	163.33	31,330	0.0052	162.92	(0.41)	(0.25%)	2.85%
	RRRP	31,410	0.0013	40.83	31,330	0.0013	40.73	(0.10)	(0.25%)	0.71%
	DRC	31,410	0.0070	219.87	31,330	0.0070	219.31	(0.56)	(0.25%)	3.84%
	Cost of Power Commodity (kWh)	31,410	0.0540	1,696.14	31,330	0.0540	1,691.84	(4.30)	(0.25%)	29.63%
	Total Bill Before Taxes			**3,862.01**			**5,437.28**	**1,575.27**	**40.79%**	**95.24%**
	GST		5.00%	193.10		5.00%	271.86	78.76	40.79%	4.76%
	Total Bill			**4,055.11**			**5,709.15**	**1,654.04**	**40.79%**	**100.00%**

Sentinel Lighting

Billing Determinants		2009 BILL Volume	RATE $	CHARGE $	2010 BILL Volume	RATE $	CHARGE $	IMPACT $	%	% of Total Bill
350	Monthly Service Charge	350	3.8800	1,358.00	350	7.8800	2,758.00	1,400.00	103.09%	44.70%
33,000.00	Distribution (kWh)	33,000	0.0000	0.00	33,000	0.0000	0.00	0.00	0.00%	0.00%
90	Distribution (kW)	90.00	2.9955	269.60	90.00	5.8248	524.23	254.64	94.45%	8.50%
	Regulatory Assets (kW)	90.00	0.0000	0.00	90.00	0.3111	28.00	28.00	100.00%	0.45%
	Sub-Total			**1,627.60**			**3,310.23**	**1,682.63**	**103.38%**	**53.65%**
	RTSR - Network	94	1.3460	126.83	94	1.3289	124.90	(1.93)	(1.52%)	2.02%
	RTSR - Connection	94	1.1475	108.13	94	1.2171	114.40	6.27	5.80%	1.85%
	Sub- Total			**1,862.56**			**3,549.53**	**1,686.97**	**90.57%**	**57.53%**
	Wholesale Market Rate	34,551	0.0052	179.67	34,463	0.0052	179.21	(0.46)	(0.25%)	2.90%
	RRRP	34,551	0.0013	44.92	34,463	0.0013	44.80	(0.11)	(0.25%)	0.73%
	DRC	34,551	0.0070	241.86	34,463	0.0070	241.24	(0.61)	(0.25%)	3.91%
	Cost of Power Commodity (kWh)	34,551	0.0540	1,865.75	34,463	0.0540	1,861.02	(4.73)	(0.25%)	30.16%
	Total Bill Before Taxes			**4,194.75**			**5,875.81**	**1,681.06**	**40.08%**	**95.24%**
	GST		5.00%	209.74		5.00%	293.79	84.05	40.08%	4.76%
	Total Bill			**4,404.49**			**6,169.60**	**1,765.11**	**40.08%**	**100.00%**

Unmetered Scattered

		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge			194.17			194.33	0.17	0.09%	0.21%
1,041,782	Distribution (kWh)	1,041,782	0.0054	5,625.62	1,041,782	0.0067	6,979.94	1,354.32	24.07%	7.57%
	Regulatory Assets (kW)	1,041,782	0.0000	0.00	1,041,782	(0.0015)	(1,598.51)	(1,598.51)	100.00%	(1.73%)
	Sub-Total			**5,819.79**			**5,575.76**	**(244.03)**	**(4.19%)**	**6.05%**
	RTSR - Network	1,090,746	0.0043	4,690.21	1,087,979	0.0042	4,569.51	(120.70)	(2.57%)	4.96%
	RTSR - Connection	1,090,746	0.0037	4,035.76	1,087,979	0.0039	4,243.12	207.36	5.14%	4.60%
	Sub- Total			**14,545.76**			**14,388.39**	**(157.36)**	**(1.08%)**	**15.60%**
	Wholesale Market Rate	1,090,746	0.0052	5,671.88	1,087,979	0.0052	5,657.49	(14.39)	(0.25%)	6.13%
	RRRP	1,090,746	0.0013	1,417.97	1,087,979	0.0013	1,414.37	(3.60)	(0.25%)	1.53%
	DRC	1,090,746	0.0070	7,635.22	1,087,979	0.0070	7,615.85	(19.37)	(0.25%)	8.26%
	Cost of Power Commodity (kWh)	1,090,746	0.0540	58,900.27	1,087,979	0.0540	58,750.86	(149.41)	(0.25%)	63.71%
	Total Bill Before Taxes			**88,171.09**			**87,826.96**	**(344.13)**	**(0.39%)**	**95.24%**
	GST		5.00%	4,408.55		5.00%	4,391.35	(17.21)	(0.39%)	4.76%
	Total Bill			**92,579.65**			**92,218.31**	**(361.34)**	**(0.39%)**	**100.00%**

Unmetered Scattered

		2009 BILL			2010 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge			194.17			194.33	0.17	0.09%	0.20%
1,100,000	Distribution (kWh)	1,100,000	0.0054	5,940.00	1,100,000	0.0067	7,370.00	1,430.00	24.07%	7.57%
	Regulatory Assets (kW)	1,100,000	0.0000	0.00	1,100,000	(0.0015)	(1,687.84)	(1,687.84)	100.00%	(1.73%)
	Sub-Total			**6,134.17**			**5,876.49**	**(257.67)**	**(4.20%)**	**6.04%**
	RTSR - Network	1,151,700	0.0043	4,952.31	1,148,778	0.0042	4,824.87	(127.44)	(2.57%)	4.96%
	RTSR - Connection	1,151,700	0.0037	4,261.29	1,148,778	0.0039	4,480.24	218.95	5.14%	4.60%
	Sub- Total			**15,347.77**			**15,181.60**	**(166.17)**	**(1.08%)**	**15.59%**
	Wholesale Market Rate	1,151,700	0.0052	5,988.84	1,148,778	0.0052	5,973.65	(15.19)	(0.25%)	6.14%
	RRRP	1,151,700	0.0013	1,497.21	1,148,778	0.0013	1,493.41	(3.80)	(0.25%)	1.53%
	DRC	1,151,700	0.0070	8,061.90	1,148,778	0.0070	8,041.45	(20.45)	(0.25%)	8.26%
	Cost of Power Commodity (kWh)	1,151,700	0.0540	62,191.80	1,148,778	0.0540	62,034.04	(157.76)	(0.25%)	63.72%
	Total Bill Before Taxes			**93,087.52**			**92,724.15**	**(363.37)**	**(0.39%)**	**95.24%**
	GST		5.00%	4,654.38		5.00%	4,636.21	(18.17)	(0.39%)	4.76%
	Total Bill			**97,741.89**			**97,360.35**	**(381.54)**	**(0.39%)**	**100.00%**

Standby Class

Consumption
2,500,000
8,000

	2009 BILL			2010 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			4,705.58			6,099.12	1,393.54	29.61%	2.64%
Distribution (kWh)	2,500,000	0.0000	0.00	2,500,000	0.0000	0.00	0.00	0.00%	0.00%
Distribution (kW)	8,000	2.3623	18,898.40	8,000	3.8455	30,764.00	11,865.60	62.79%	13.30%
Smart Meter Disposition Rider (per month)			2.11			0.45	(1.66)	(78.67%)	0.00%
Transformer Credit	4,000	(0.6000)	(2,400.00)	4,000	(0.6000)	(2,400.00)	0.00	0.00%	(1.04%)
Regulatory Assets (kW)	8,000	0.0000	0.00	8,000	(0.6859)	(5,486.92)	(5,486.92)	100.00%	(2.37%)
Sub-Total			**21,206.09**			**28,976.65**	**7,770.56**	**36.64%**	**12.53%**
RTSR - Network	8,376	2.0819	17,437.99	8,355	1.8642	15,574.93	(1,863.06)	(10.68%)	6.73%
RTSR - Connection	8,376	1.8253	15,288.71	8,355	1.6909	14,127.05	(1,161.66)	(7.60%)	6.11%
Sub- Total			**53,932.80**			**58,678.63**	**4,745.83**	**8.80%**	**25.37%**
Wholesale Market Rate	2,387,797	0.0052	12,416.54	2,393,847	0.0052	12,448.00	31.46	0.25%	5.38%
RRRP	2,387,797	0.0013	3,104.14	2,393,847	0.0013	3,112.00	7.87	0.25%	1.35%
DRC	2,387,797	0.0070	16,714.58	2,393,847	0.0070	16,756.93	42.35	0.25%	7.25%
Cost of Power Commodity (kWh)	2,387,797	0.0540	128,941.02	2,393,847	0.0540	129,267.74	326.73	0.25%	55.89%
Total Bill Before Taxes			**215,109.07**			**220,263.31**	**5,154.24**	**2.40%**	**95.24%**
GST		5.00%	10,755.45		5.00%	11,013.17	257.71	2.40%	4.76%
Total Bill			**225,864.52**			**231,276.47**	**5,411.95**	**2.40%**	**100.00%**

Standby Class

Consumption
3,500,000
9,000

	2009 BILL			2010 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			4,705.58			6,099.12	1,393.54	29.61%	1.99%
Distribution (kWh)	3,500,000	0.0000	0.00	3,500,000	0.0000	0.00	0.00	0.00%	0.00%
Distribution (kW)	9,000	2.3623	21,260.70	9,000	3.8455	34,609.50	13,348.80	62.79%	11.30%
Smart Meter Disposition Rider (per month)			2.11			0.45	(1.66)	(78.67%)	0.00%
Transformer Credit	9,000	(0.6000)	(5,400.00)	4,000	(0.6000)	(2,400.00)	3,000.00	(55.56%)	(0.78%)
Regulatory Assets (kW)	9,000	0.0000	0.00	9,000	(0.6859)	(6,172.79)	(6,172.79)	100.00%	(2.01%)
Sub-Total			**20,568.39**			**32,136.28**	**11,567.89**	**56.24%**	**10.49%**
RTSR - Network	9,423	2.0819	19,617.74	9,399	1.8642	17,521.80	(2,095.95)	(10.68%)	5.72%
RTSR - Connection	9,423	1.8253	17,199.80	9,399	1.6909	15,892.93	(1,306.87)	(7.60%)	5.19%
Sub- Total			**57,385.94**			**65,551.01**	**8,165.08**	**14.23%**	**21.40%**
Wholesale Market Rate	3,342,915	0.0052	17,383.16	3,351,386	0.0052	17,427.21	44.05	0.25%	5.69%
RRRP	3,342,915	0.0013	4,345.79	3,351,386	0.0013	4,356.80	11.01	0.25%	1.42%
DRC	3,342,915	0.0070	23,400.41	3,351,386	0.0070	23,459.70	59.29	0.25%	7.66%
Cost of Power Commodity (kWh)	3,342,915	0.0540	180,517.42	3,351,386	0.0540	180,974.84	457.42	0.25%	59.07%
Total Bill Before Taxes			**283,032.71**			**291,769.56**	**16,901.93**	**5.97%**	**95.24%**
GST		5.00%	14,151.64		5.00%	14,588.48	436.84	3.09%	4.76%
Total Bill			**297,184.35**			**306,358.04**	**17,338.77**	**5.83%**	**100.00%**

Exhibit	Tab	Schedule	Appendix	Contents
9 – Deferral and Variance Accounts				
	1			Deferral/Variance Accounts
		1		Description of Deferral and Variance Accounts & Balances
		2		Accounts Requested for Disposition by way of a Deferral and Variance Account Rate Rider
		3		Method of Disposition of Accounts
		4		Proposed Rates and Bill Impacts
	2			Smart Meter
		1		Smart Meter Riders and Adder
			A	Smart Meter Detail Cost
			B	Smart Meter Model for Disposition Rider and Permanent Rate
			C	Smart Meter Model for Rate Adder

DEFERRAL/VARIANCE ACCOUNTS:

DESCRIPTION OF DEFERRAL AND VARIANCE ACCOUNTS & BALANCES:

This Schedule contains descriptions of Deferral and Variance Accounts ("DVAs") currently used by Chatham-Kent Hydro as well as providing the balances of the DVAs as at December 31, 2008 that are being requested for disposition in this proceeding.

COMMODITY ACCOUNTS ARE CLASSIFIED AS FOLLOWS

1588 Retail Settlement Variance Account – Power

Description: This account is used to recover the net difference between the energy amount billed to customers and the energy charge to Chatham-Kent Hydro using the settlement invoice from the Independent Electricity System Operator ("IESO").

1588 Retail Settlement Variance Account - Power, Sub-account Global Adjustments

Description: This account is used to recover the net difference between the provincial benefit amount billed to customers and the global adjustment charge to Chatham-Kent Hydro using the settlement invoice from the IESO.

NON-COMMODITY ACCOUNTS ARE CLASSIFIED IN TWO CATEGORIES AS FOLLOWS

Wholesale and Retail Market Variance Accounts:

1518 Retail Cost Variance Account – Retail

Description: This account is used to record the net of revenues derived from establishing retailer services agreements, distributor-consolidated billing, retailer-consolidated billing and the costs of entering into retailer service agreements and related contract administration, as well as incremental costs to provide distributor-consolidated and split billing and any avoided costs credit arising from retailer-consolidated billing.

1548 Retail Cost Variance 1 **Account – STR**

Description: This account is used to record the net of revenues derived from service transaction requests charged by Chatham-Kent Hydro in the form of a request fee, processing fee, information request fee, default fee and other associated costs and the incremental cost of labour, internal information system maintenance costs and delivery costs related to the provision of retail transaction services.

1550 Low Voltage Variance Account

Description: This account is used to record the net of amounts charged by Hydro One for low voltage services and the amount billed to customers using the OEB approved rates.

1580 Retail Settlement Variance Account - Wholesale Market Service Charges

Description: This account is used to record the net of the amount charged by the IESO based on the settlement invoice for the operation of the IESO-administered markets and the operation of the IESO-controlled grid, and the amount billed to customers using the OEB-approved Wholesale Market Service Rate. This account also includes that net difference between the amounts charged by the host distributor for wholesale market services and the amount billed to customers using the OEB-approved Wholesale market Service Rate.

1582 Retail Settlement Variance Account - One-time Wholesale Market Service

Description: This account is used to record the net of non-recurring amounts not included in the Wholesale Market Service Rate charged by the IESO based on the settlement invoice and the amount charged to customers for the same services using the OEB-approved rate.

1584 Retail Settlement Variance Account - Retail Transmission Network Charges

Description: This account is used to record the net of the amount charged by the IESO, based on the settlement invoice for transmission network services, and the amount billed to customers using the OEB-approved Transmission Network Charge. This account also includes that net difference between the amounts charged by the host distributor for Transmission Network Charge and the amount billed to customers using the OEB-approved Transmission Network Rate.

1586 Retail Settlement Variance Account - Retail Transmission Connection Charges

Description: This account is used to record the net of the amount charged by the IESO, based on the settlement invoice for transmission connection services, and the amount billed to customers using the OEB-approved Transmission Connection Charge. This account also includes that net difference between the amounts charged by the host distributor for wholesale market services and the amount billed to customers using the OEB-approved Transmission Connection Rate.

Utility Deferral and Variance Accounts

In EB-2005-0350, Chatham-Kent Hydro's 2006 EDR rate filing, Chatham-Kent Hydro obtained approval for the recovery of costs recorded in variance accounts up to December 31, 2004. In some of the following accounts they include costs for the same activities that were approved in variance accounts up to December 31, 2004, however, the timing of these activities are from January 1, 2005 to April 30, 2006. These costs have not been approved by the OEB for recovery as of yet.

1508 Other Regulatory Assets

Description: This account includes amounts of regulatory activities, not included in other accounts, resulting from the ratemaking actions of the OEB.

1508 Other Regulatory Assets - Sub-account OEB Cost Assessments

Description: This account includes amounts paid for OEB Cost Assessment for the period January 1, 2005 to April 30, 2006 in excess of amounts previously included in rates (1999 OEB costs).

1508 Other Regulatory Assets - Sub-account Pension Contributions

Description: This account includes amounts paid for OMERS pension expense for the period January 1, 2005 to April 30, 2006 not included in rates.

1525 Miscellaneous Deferred Debits

Description: This account includes all debits not provided for elsewhere. Specifically, Customer Information System expenses with respect to Ontario Price Credit (“OPC”) rebate cheques are tracked in this account.

1555 Smart Meter Capital and Recovery Offset Variance

Description: This account records the net of the amounts paid for capitalized direct costs related to the smart meter program and the amounts charged to customers using the OEB-approved smart meter rate rider.

1556 Smart Meter OM&A Variance

Description: This account records the incremental operating, maintenance, amortization and administrative expenses directly related to smart meters.

1562 Deferred Payments in Lieu of Taxes

Description: This account records the amount resulting from the OEB-approved PILs methodology for determining the 2001 deferral account allowance and the PILs proxy amount determined for 2002 and subsequent periods ending April 30, 2006.

1563 PILs contra account

Description: This account records the amounts relating to the third accounting method approved for recording entries in Account 1562 in accordance with the OEB’s accounting instructions for PILs as set out in the April 2003 Frequently Asked Questions on the AP Handbook.

Disposal of balances in this account is not being requested at this time.

The administrations of PILs from 2001 to 2006 resulted in many LDCs reflecting the deduction / add back of commodity pass through amounts in their Ministry of Finance PILs return. Since the original PILs proxy did not assume any timing differences between the payment of commodity related costs and their recoveries from customers, PILs true up obligations/recoveries were recorded by some LDCs in the PILs related deferral and variance accounts. The 3 approaches used by LDCs to calculate the value of such true-ups have not been consistent in part because not all PILs circumstances were addressed in the PILs Proxy and SIMPIL filing models and in part because LDC interpretation of the same circumstance resulted in different treatment on the PILs returns and/or Deferred PILs account.

The OEB is currently reviewing the treatment of the PILs deferral account in EB-2008-0381. It is a combined proceeding with EnWin Utilities, Halton Hills Hydro and Barrie Hydro Distribution. The purpose of the proceeding is to clarify the calculations of the PILs deferral accounts and to recommend disposition of these accounts. The outcome of the proceeding will set the guidelines for all other LDCs. For this reason Chatham-Kent Hydro will not be seeking disposition of the deferred PILs accounts at this time.

1565 Conservation and Demand Management Expenditures and Recoveries

Description: This account records the net of amounts incurred for conservation and demand management (CDM) activities and expenditures, the revenue proxy amount equivalent to the third tranche of market adjusted revenue requirement (MARR) and the amount charged to customers using the OEB approved CDM rate rider as well as 2006 CDM revenues and costs.

1566 CDM Contra

Description: This account records the offsetting entry for amounts recorded in account 1565, CDM Expenditures and Recoveries, pertaining to third tranche CDM programming for the reversal of entries to the accounts of original entries.

1572 Extraordinary Event Losses

Description: This account is used to record extraordinary event costs that meet the qualifying criteria established by the OEB.

1574 Deferred Rate Impact Amounts

Description: As authorized by the OEB in its decision in EB-2008-0663 (PILs), this account shall be used to record the difference between the revised Distribution Rates and actual Distribution Rates charged to customers for the period

1590 Recovery of Regulatory Asset Balances

Description: This account records the net of amounts collected from customers from the 2006 EDR Regulatory Asset filing. This Regulatory Asset rate rider was removed from Distribution Rates effective May 1, 2008. Separate sub-accounts are maintained for expenses, interest, and recovery amounts.

ACCOUNT BALANCES

The following Table 9-1 contains account balances from the 2008 Audited Financial Statements as at December 31, 2008. The balances do not include the smart meter deferral account balances as the evidence and disposition request related to smart meters is found in Tab 2 of this Exhibit.

Table 9-1
December 2008, Regulatory Assets

Account Description	Account Number	Closing Principal Balance as of Dec-31-08	Closing Interest Amounts as of Dec-31-08	Total Principle and Interest
RSVA - Wholesale Market Service Charge	1580	(1,837,213.8)	(65,471.5)	(1,902,685.4)
RSVA - One-time Wholesale Market Service	1582	50,162.0	8,284.1	58,446.1
RSVA - Retail Transmission Network Charge	1584	482,989.8	24,628.6	507,618.4
RSVA - Retail Transmission Connection Charge	1586	(1,124,316.1)	(99,366.5)	(1,223,682.7)
RSVA - Power (including Global Adjustment)	1588	1,134,049.9	63,905.8	1,197,955.7
Sub-Totals		(1,294,328.3)	(68,019.5)	(1,362,347.8)
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	86,973.5	9,087.7	96,061.2
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	230,244.5	24,396.7	254,641.3
Other Regulatory Assets - Sub-Account - Other	1508	$ -	$ -	$ -
Other Regulatory Assets - Sub-Account - Other	1508	547,970.5	9,497.5	557,468.0
Other Regulatory Assets - Sub-Account - Other	1508	16,954.9	1,176.0	18,130.9
Retail Cost Variance Account - Retail	1518	(152,680.9)	(9,127.2)	(161,808.0)
Misc. Deferred Debits	1525	27,418.1	1,274.1	28,692.1
Retail Cost Variance Account - STR	1548	102,572.6	7,653.1	110,225.8
LV Variance Account	1550	(209,999.2)	23,715.2	(186,284.0)
Qualifying Transition Costs	1570	13,100.0	1,140.7	14,240.7
Extra-Ordinary Event Costs	1572	93,462.8	8,138.3	101,601.0
Deferred Rate Impact Amounts	1574	$ -	$ -	$ -
Recovery of Regulatory Asset Balances	1590	80,690.2	53,863.6	134,553.8
Other Deferred Credits	2425	$ -	$ -	$ -
Sub-Totals		836,707.0	130,815.7	967,522.6
Total Regulatory Assets		(457,621.3)	62,796.2	(394,825.1)

ACCOUNTS REQUESTED FOR DISPOSITION BY WAY OF A DEFERRAL AND VARIANCE ACCOUNT RATE RIDER:

Commodity (RSVA / RCVA) deferral and variance accounts

Chatham-Kent Hydro is requesting disposition of the balances in the deferral and variance accounts listed in Table 9-1 but will also include the carrying costs up to April 30, 2010 which are found in Table 9-2.

1580 Retail Settlement Variance Account - Wholesale Market Service Charges

Disposal of balances including carrying costs to April 30, 2010 over a one-year period is requested.

Method of recovery: Allocation to rate classes on basis of kWh consumed.

1582 Retail Settlement Variance Account - One-time Wholesale Market Service

Disposal of balances including carrying costs to April 30, 2010 over a one-year period is requested.

Method of recovery: Allocation to rate classes on basis of kWh consumed.

1584 Retail Settlement Variance Account - Retail Transmission Network Charges

Disposal of balances including carrying costs to April 30, 2010 over a one-year period is requested.

Method of recovery: Allocation to rate classes on basis of kWh consumed.

1586 Retail Settlement Variance Account - Retail Transmission Connection Charges

Disposal of balances including carrying costs to April 30, 2010 over a one-year period is requested.

Method of recovery: Allocation to rate classes on basis of kWh consumed.

1588 Retail Settlement Variance Account – Power

Disposal of balances including carrying costs to April 30, 2010 over a one-year period is requested.

Method of recovery: Allocation to rate classes on basis of kWh consumed.

1518 Retail Cost Variance Account – Retail

Disposal of balances including carrying costs to April 30, 2010 over a one-year period is requested.

Method of recovery: Allocation to rate classes on basis of number of customers.

1548 Retail Cost Variance Account – STR

Disposal of balances including carrying costs to April 30, 2010 over a one-year period is requested.

Method of recovery: Allocation to rate classes on basis of number of customers.

Utility (non-RSVA / RCVA) Deferral and Variance Accounts

Chatham-Kent Hydro is requesting disposition of the balances in the deferral and variance accounts listed in Table 9-1 but will also include the carrying costs up to April 30, 2010 which are found in Table 9-2.

1508 Other Regulatory Assets - Sub-account OEB Cost Assessments

Disposal of balances including carrying costs to April 30, 2010 over a one-year period is requested.

Method of recovery: Allocation to rate classes on basis of distribution revenue.

1508 Other Regulatory Assets - Sub-account Pension Costs

Disposal of balances including carrying costs to April 30, 2010 over a one-year period is requested.

Method of recovery: Allocation to rate classes on basis of distribution revenue.

1525 Miscellaneous Deferred Debits

Disposal of balances including carrying costs to April 30, 2010 over a one-year period is requested.

Method of recovery: Allocation to rate classes on basis of distribution revenue.

1550 Low Voltage Variance Account

Disposal of balances including carrying costs to April 30, 2010 over a one-year period is requested.

Method of recovery: Allocation to rate classes on basis of kWh consumed.

1570 Qualifying Transition Costs

Disposal of balances including carrying costs to April 30, 2010 over a one-year period is requested.

Method of recovery: Allocation to rate classes on basis number of customers.

1572 Extraordinary Event Losses

Disposal of balances including carrying costs to April 30, 2010 over a one-year period is requested.

Method of recovery: Allocation to rate classes on basis of kWh consumed.

1590 Recovery of Regulatory Asset Balances

Disposal of balances including carrying costs to April 30, 2010 over a one-year period is requested.

Method of recovery: Allocation to rate classes on basis of kWh consumed.

Table 9-2
Deferral Account Balances Including Carrying Costs

Table 2

Account Description	Account Number	Principal Amounts as of Dec-31 2008	Interest to Dec31-08	Interest Jan-1 to Dec31-09	Interest Jan1-10 to Apr30-10	Total Claim
RSVA - Wholesale Market Service Charge	1580	$ (1,837,214)	$ (65,472)	$ (23,700)	$ (7,900.00)	$ (1,934,285)
RSVA - One-time Wholesale Market Service	1582	$ 50,162	$ 8,284	$ 647	$ 216.00	$ 59,309
RSVA - Retail Transmission Network Charge	1584	$ 482,990	$ 24,629	$ 6,231	$ 2,077.00	$ 515,926
RSVA - Retail Transmission Connection Charge	1586	$ (1,124,316)	$ (99,367)	$ (14,504)	$ (4,835.00)	$ (1,243,022)
RSVA - Power	1588/1589	$ 1,134,050	$ 63,906	$ 14,629	$ 4,876.00	$ 1,217,461
Sub-Totals		$ (1,294,328)	$ (68,019)	$ (16,697)	$ (5,566)	$ (1,384,611)
Other Regulatory Assets	1508	$ 882,143	$ 44,158	$ 11,380	$ 3,793.00	$ 941,474
Retail Cost Variance Account - Retail	1518	$ (152,681)	$ (9,127)	$ (1,970)	$ (657.00)	$ (164,435)
Misc. Deferred Debits	1525	$ 27,418	$ 1,274	$ 354	$ 118.00	$ 29,164
Retail Cost Variance Account - STR	1548	$ 102,573	$ 7,653	$ 1,323	$ 441.00	$ 111,990
Low Voltage	1550	$ (209,999)	$ 23,715	$ (2,709)	$ (903.00)	$ (189,896)
Qualifying Transition Costs	1570	$ 13,100	$ 1,141	$ 169	$ 56.00	$ 14,466
Extra-Ordinary Event Costs	1572	$ 93,463	$ 8,138	$ 1,206	$ 402.00	$ 103,209
Recovery of Regulatory Asset Balances	1590	$ 80,690	$ 53,864	$ 1,041	$ 347.00	$ 135,942
Other Deferred Credits	2425	$ -	$ -			$ -
Sub-Totals		$ 836,707	$ 130,816	$ 10,794	$ 3,597	$ 981,914
Totals per column		$ (457,621)	$ 62,796	$ (5,903)	$ (1,969)	$ (402,697)

	Jan 2009 to Apr 2010
Annual interest rate:	1.29%

Enter the appropriate 2010 data in the cells below.
Once the data in the yellow fields on Sheet 1 has been entered, the relevant allocations will appear on Sheet 2.
Go to Sheets 3 and 4 and enter the appropriate data in the yellow cells.

2010 Data By Class	kW	kWhs	Cust. Num.'s	Number of Metered Customers	Dx Revenue
RESIDENTIAL CLASS		199,501,364	28,644	28,644	$ 6,887,599
GENERAL SERVICE <50 KW CLASS		86,923,094	3,038	3,038	$ 1,876,182
GENERAL SERVICE >50 KW	456,548	183,018,503	421	421	$ 1,409,221
INTERMEDIATE	353,322	134,791,341	28	25	$ 2,297,175
STANDBY	80,671	31,031,687	1	1	$ 225,256
LARGE USER CLASS	0	0	0		$ -
UNMETERED & SCATTERED LOADS	0	1,041,782	194	194	$ 12,675
SENTINEL LIGHTS	997	334,470	327	327	$ 18,016
STREET LIGHTING	16,969	5,547,412	10,751	10,751	$ 112,056
Totals	908,507	642,189,652	43,403	43,401	$ 12,838,181

Allocators	kW	kWhs	Cust. Num.'s	Number of Metered Customers	Dx Revenue
RESIDENTIAL CLASS	0.0%	31.1%	66.0%	66.0%	53.6%
GENERAL SERVICE <50 KW CLASS	0.0%	13.5%	7.0%	7.0%	14.6%
GENERAL SERVICE >50 KW NON TIME OF USE	50.3%	28.5%	1.0%	1.0%	11.0%
GENERAL SERVICE >50 KW TIME OF USE	38.9%	21.0%	0.1%	0.1%	17.9%
STANDBY	8.9%	4.8%	0.0%	0.0%	1.8%
LARGE USER CLASS	0.0%	0.0%	0.0%	0.0%	0.0%
UNMETERED & SCATTERED LOADS	0.0%	0.2%	0.4%	0.4%	0.1%
SENTINEL LIGHTS	0.1%	0.1%	0.8%	0.8%	0.1%
STREET LIGHTING	1.9%	0.9%	24.8%	24.8%	0.9%
Totals	100%	100%	100%	100%	100%

METHOD OF DISPOSITION OF ACCOUNTS:

Chatham-Kent Hydro is preparing to dispose of the regulatory assets in the same method as was approved in EB-2005-0350, the 2006 EDR process.

Table 9-3 summarizes the method of disposing the regulatory assets and determining the rates.

Chatham-Kent Hydro's Regulatory Assets Continuity Schedule and related spreadsheets are provided on the pages following Table 9-3.

Table 9-3
Disposition of Accounts

The following shows the details and calculations of the proposed regulatory asset rate riders by customer classification.

Deferral and Variance Accounts:	**Amount**	**ALLOCATOR**	**Residential**	**GS < 50 KW**	**GS > 50 kw**	**Intermediate**	**Standby**	**Large Users**	**Small Scattered Load**	**Sentinel Lighting**	**Street Lighting**	**Total**
WMSC - Account 1580	$ (1,934,285)	kWh	$ (600,901)	$ (261,814)	$ (551,255)	$ (405,994)	$ (93,468)	$ -	$ (3,138)	$ (1,007)	$ (16,709)	$ (1,934,285)
One-Time WMSC - Account 1582	$ 59,309	kWh	$ 18,425	$ 8,028	$ 16,903	$ 12,449	$ 2,866	$ -	$ 96	$ 31	$ 512	$ 59,309
Network - Account 1584	$ 515,926	kWh	$ 160,277	$ 69,833	$ 147,035	$ 108,290	$ 24,930	$ -	$ 837	$ 269	$ 4,457	$ 515,926
Connection - Account 1586	$ (1,243,022)	kWh	$ (386,155)	$ (168,248)	$ (354,250)	$ (260,902)	$ (60,065)	$ -	$ (2,016)	$ (647)	$ (10,738)	$ (1,243,022)
Power - Account 1588	$ 1,217,461	kWh	$ 378,214	$ 164,788	$ 346,966	$ 255,537	$ 58,830	$ -	$ 1,975	$ 634	$ 10,517	$ 1,217,461
Subtotal - RSVA	$ (1,384,611)		$ (430,140)	$ (187,413)	$ (394,602)	$ (290,621)	$ (66,907)	$ -	$ (2,246)	$ (721)	$ (11,961)	$ (1,384,611)
Other Regulatory Assets - Account 1508	$ 941,474	Dx Revenue	$ 505,095	$ 137,588	$ 103,344	$ 168,461	$ 16,519	$ -	$ 930	$ 1,321	$ 8,217	$ 941,474
Retail Cost Variance Account - Acct 1518	$ (164,435)	# of Customers	$ (108,520)	$ (11,508)	$ (1,594)	$ (105)	$ (4)	$ -	$ (736)	$ (1,237)	$ (40,732)	$ (164,435)
Misc. Deferred Account - Acct 1525	$ 29,164	# of Customers	$ 15,646	$ 4,262	$ 3,201	$ 5,218	$ 512	$ -	$ 29	$ 41	$ 255	$ 29,164
Retail Cost Variance Account (STR) Acct 1548	$ 111,990	# of Customers	$ 73,908	$ 7,838	$ 1,085	$ 71	$ 3	$ -	$ 501	$ 843	$ 27,741	$ 111,990
Low Voltage - Account 1550	$ (189,896)	kWh	$ (58,993)	$ (25,703)	$ (54,119)	$ (39,858)	$ (9,176)	$ -	$ (308)	$ (99)	$ (1,640)	$ (189,896)
Qualifying Transition Costs - Acct 1570	$ 14,466	# of Customers	$ 9,547	$ 1,012	$ 140	$ 9	$ 0	$ -	$ 65	$ 109	$ 3,583	$ 14,466
Extra-Ordinary Event Costs - Acct 1572	$ 103,209	kWh	$ 32,063	$ 13,970	$ 29,414	$ 21,663	$ 4,987	$ -	$ 167	$ 54	$ 892	$ 103,209
Other Deferred Credits - Acct 2425	$ -	Dx Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Recovery of Regulatory Asset Balances	$ 135,942	kWh	$ 42,231	$ 18,400	$ 38,742	$ 28,533	$ 6,569	$ -	$ 221	$ 71	$ 1,174	$ 135,942
Subtotal - Non RSVA, Variable	$ 981,914		$ 468,746	$ 127,458	$ 81,472	$ 155,460	$ 12,841	$ -	$ 648	$ 1,031	$ (1,685)	$ 845,972
Smart Meters Revenue and Capital, 1555 (Fixed)	$ -	# of Metered Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Smart Meter Expenses, 1556 (Fixed)	$ -	# of Metered Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal - Non RSVA Fixed	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total to be Recovered	$ (402,697)		$ 38,606	$ (59,955)	$ (313,130)	$ (135,160)	$ (54,066)	$ -	$ (1,599)	$ 310	$ (13,645)	$ (538,639)

Balance to be collected or refunded, Variable	$ (402,697)	$ 38,606	$ (59,955)	$ (313,130)	$ (135,160)	$ (54,066)	$ -	$ (1,599)	$ 310	$ (13,645)	$ (538,639)
Balance to be collected or refunded, Fixed	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Number of years for Variable	1										
Number of years for Fixed	1										
Balance to be collected or refunded per year, Variable	$ (402,697)	$ 38,606	$ (59,955)	$ (313,130)	$ (135,160)	$ (54,066)	$ -	$ (1,599)	$ 310	$ (13,645)	$ (538,639)
Balance to be collected or refunded per year, Fixed	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Class			**Residential**	**GS < 50 KW**	**GS > 50 kw**	**Intermediate**	**Standby**	**Large Users**	**Scattered Load**	**Sentinel Lighting**	**Street Lighting**
Deferral and Variance Account Rate Riders, Variable			$ 0.0002	$ (0.0007)	$ (0.6859)	$ (0.3825)	$ (0.6702)		$ (0.0015)	$ 0.3111	$ (0.8041)
Billing Determinants			kWh	kWh	kW	kW	kW	kW	kWh	kW	kW
Deferral and Variance Account Rate Riders, Fixed (per month)			$ -	$ -	$ -	$ -	$ -		$ -		$ -
Billing Determinants			# metered cust.	# metered cust.	# metered cust.			# metered cust.			
	Components of 2010 Riders:										
	Variable	RSVA	$ (0.0022)	$ (0.0022)	$ (0.8643)				$ (0.0022)	$ (0.7235)	$ (0.7048)
	Variable	Non RSVA	$ 0.0023	$ 0.0015	$ 0.1785				$ 0.0006	$ 1.0346	$ (0.0993)

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Chatham-Kent Hydro Inc.	**LICENCE NUMBER**	ED-2002-0563
NAME OF CONTACT	Jim Hogan	**DOCID NUMBER**	EB-2009-0261
E-mail Address	jimhogan@ckenergy.com		
VERSION NUMBER	v3.0	**PHONE NUMBER**	519-352-6300
Date	31-Aug-09	**(extension)**	277

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

Annual
Interest Rate

		2005								
Account Description	**Account Number**	**Opening Principal Amounts as of Jan-1-05**	**Transactions (additions) during 2005, excluding interest and adjustments**	**Transactions (reductions) during 2005, excluding interest and adjustments**	**Adjustments during 2005 - instructed by Board**	**Adjustments during 2005 - other**	**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	$ 1,245,857	$ 704,784				$ 1,950,641	$ 355,111	$ 12,678	$ 367,789
RSVA - One-time Wholesale Market Service	1582	$ 81,700	$ 50,969			$ (807)	$ 131,862	$ 13,456	$ 1,113	$ 14,569
RSVA - Retail Transmission Network Charge	1584	$ (272,120)	$ (108,145)				$ (380,265)	$ (47,436)	$ (8,428)	$ (55,864)
RSVA - Retail Transmission Connection Charge	1586	$ 1,146,572	$ 266,799				$ 1,413,371	$ (127,924)	$ 6,726	$ (121,198)
Sub-Totals		$ 2,202,009	$ 914,406		$ -	$ (807)	$ 3,115,608	$ 193,207	$ 12,089	$ 205,296
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508		$ 73,354				$ 73,354	$ -	$ 1,515	$ 1,515
Other Regulatory Assets - Sub-Account - Pension Contributions	1508		$ 167,152				$ 167,152	$ -	$ 4,348	$ 4,348
Other Regulatory Assets - Sub-Account - Other	1508	$ 113,977					$ 113,977	$ 6,279		$ 6,279
Other Regulatory Assets - Sub-Account - Other	1508		$ 5,701				$ 5,701		$ 232	$ 232
Other Regulatory Assets - Sub-Account - Other	1508						$ -			$ -
Retail Cost Variance Account - Retail	1518	$ (49,827)	$ (21,806)				$ (71,633)	$ (9,019)		$ (9,019)
Retail Cost Variance Account - STR	1548	$ 75,484	$ 30,171				$ 105,655	$ 12,856		$ 12,856
Misc. Deferred Debits	1525	$ 11,803	$ 153,578				$ 165,381	$ 2,766	$ 1,175	$ 3,941
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 Meter C	1555						$ -			$ -
Smart Meter OM&A Variance	1556						$ -			$ -
Conservation and Demand Management Expenditures and Recoveries	1565	$ 296,135	$ (373,085)				$ (76,950)	$ -	$ 33,080	$ 33,080
CDM Contra	1566	$ (296,135)	$ 373,085				$ 76,950		$ (33,080)	$ (33,080)
Qualifying Transition Costs	1570	$ 361,937	n/a	n/a		$ 13,100	$ 375,037	$ 113,412		$ 113,412
Pre-Market Opening Energy Variances Total	1571	$ (612,900)	n/a	n/a			$ (612,900)	$ (177,741)		$ (177,741)
Extra-Ordinary Event Costs	1572	$ 326,464	$ 75,325				$ 401,789	$ 31,559		$ 31,559
Deferred Rate Impact Amounts	1574						$ -			$ -
Other Deferred Credits	2425						$ -			$ -
Sub-Totals		$ 226,938	$ 483,475	$ -	$ -	$ 13,100	$ 723,513	$ (19,888)	$ 7,269	$ (12,619)
Deferred Payments in Lieu of Taxes	1562				**see PILs reconciliation requested**					
2006 PILs & Taxes Variance	1592				**see PILs reconciliation requested**					
Sub-Totals					**see PILs reconciliation requested**					
Total		$ 2,428,947	$ 1,397,881	$ -	$ -	$ 12,293	$ 3,839,121	$ 173,319	$ 19,358	$ 192,677
The following is not included in the total claim but is included on a memo basis:										
Deferred PILs Contra Account	1563				**see PILs reconciliation requested**					
RSVA - Power (including Global Adjustment)	1588	$ 24,965	$ (248,423)				$ (223,458)	$ 58,870		$ 58,870
RSVA - Power - Sub-Account - Global Adjustment	1588		$ (248,423)				$ (248,423)			$ -
Recovery of Regulatory Asset Balances	1590	$ (380,943)	$ (588,426)				$ (969,369)			$ -

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Chatham-Kent Hydro Inc.
NAME OF CONTACT	Jim Hogan
E-mail Address	jimhogan@ckenergy.com
VERSION NUMBER	v3.0
Date	31-Aug-09

Annual
Interest Rate

Account Description	**Account Number**	**2006** Opening Principal Amounts as of Jan-1-06	Transactions (additions) during 2006, excluding interest and adjustments	Transactions (reductions) during 2006, excluding interest and adjustments	Adjustments during 2006 - instructed by Board	Adjustments during 2006 - other	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	$ 1,950,641	$ (1,037,468)					$ 913,173	$ 367,789	$ 21,165		$ 388,953
RSVA - One-time Wholesale Market Service	1582	$ 131,862						$ 131,862	$ 14,569	$ 2,768		$ 17,338
RSVA - Retail Transmission Network Charge	1584	$ (380,265)	$ 255,421					$ (124,845)	$ (55,864)	$ (3,090)		$ (58,954)
RSVA - Retail Transmission Connection Charge	1586	$ 1,413,371	$ (967,566)					$ 445,804	$ (121,198)	$ 9,524		$ (111,674)
Sub-Totals		$ 3,115,608	$ (1,749,614)		$ -	$ -	$ -	$ 1,365,994	$ 205,296	$ 30,367	$ -	$ 235,663
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 73,354	$ 13,620					$ 86,974	$ 1,515	$ -		$ 1,515
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ 167,152	$ 63,093					$ 230,245	$ 4,348	$ -		$ 4,348
Other Regulatory Assets - Sub-Account - Other	1508	$ 113,977						$ 113,977	$ 6,279			$ 6,279
Other Regulatory Assets - Sub-Account - Other	1508	$ 5,701	$ 99,154					$ 104,855	$ 232			$ 232
Other Regulatory Assets - Sub-Account - Other	1508	$ -						$ -	$ -			$ -
Retail Cost Variance Account - Retail	1518	$ (71,633)	$ (40,295)					$ (111,928)	$ (9,019)			$ (9,019)
Retail Cost Variance Account - STR	1548	$ 105,655	$ 37,111					$ 142,766	$ 12,856			$ 12,856
Misc. Deferred Debits	1525	$ 165,381	$ (4,636)					$ 160,745	$ 3,941			$ 3,941
LV Variance Account	1550	$ -	$ 280,770					$ 280,770	$ -	$ 7,185		$ 7,185
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555	$ -	$ 2,386,393					$ 2,386,393	$ -	$ 2,824		$ 2,824
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555	$ -	$ (97,798)					$ (97,798)	$ -			$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter C	1555	$ -						$ -	$ -			$ -
Smart Meter OM&A Variance	1556	$ -	$ 13,000					$ 13,000	$ -			$ -
Conservation and Demand Management Expenditures and Recoveries	1565	$ (76,950)	$ (19,813)					$ (96,762)	$ 33,080	$ (33,080)		$ (0)
CDM Contra	1566	$ 76,950	$ 19,813					$ 96,762	$ (33,080)	$ 33,080		$ 0
Qualifying Transition Costs	1570	$ 375,037	n/a	n/a				$ 375,037	$ 113,412			$ 113,412
Pre-Market Opening Energy Variances Total	1571	$ (612,900)	n/a	n/a				$ (612,900)	$ (177,741)			$ (177,741)
Extra-Ordinary Event Costs	1572	$ 401,789	$ 18,138					$ 419,927	$ 31,559			$ 31,559
Deferred Rate Impact Amounts	1574	$ -						$ -	$ -			$ -
Other Deferred Credits	2425	$ -						$ -	$ -			$ -
Sub-Totals		$ 723,513	$ 2,768,549	$ -	$ -	$ -	$ -	$ 3,492,062	$ (12,619)	$ 10,010	$ -	$ (2,610)
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		$ 3,839,121	$ 1,018,935	$ -	$ -	$ -	$ -	$ 4,858,056	$ 192,677	$ 40,376	$ -	$ 233,053
The following is not included in the total claim but is included on a memo basis:												
Deferred PILs Contra Account	1563						**see PILs reconciliation requested**					
RSVA - Power (including Global Adjustment)	1588	$ (223,458)	$ 1,120,267					$ 896,808	$ 58,870			$ 58,870
RSVA - Power - Sub-Account - Global Adjustment	1588	$ (248,423)	$ 1,120,267					$ 871,843	$ -			$ -
Recovery of Regulatory Asset Balances	1590	$ (969,369)	$ (686,518)					$ (1,655,886)	$ -			$ -

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Chatham-Kent Hydro Inc.
NAME OF CONTACT	Jim Hogan
E-mail Address	jimhogan@ckenergy.com
VERSION NUMBER	v3.0
Date	31-Aug-09

Annual
Interest Rate

		2007										
Account Description	**Account Number**	**Opening Principal Amounts as of Jan-1-07**	**Transactions (additions) during 2007, excluding interest and adjustments**	**Transactions (reductions) during 2007, excluding interest and adjustments**	**Adjustments during 2007 - instructed by Board**	**Adjustments during 2007 - other**	**Transfer of Board-approved amounts to 1590 as per 2006 EDR**	**Closing Principal Balance as of Dec-31-07**	**Opening Interest Amounts as of Jan-1-07**	**Interest Jan-1 to Dec31-07**	**Transfer of Board-approved amounts to 1590 as per 2006 EDR**	**Closing Interest Amounts as of Dec-31-07**
RSVA - Wholesale Market Service Charge	1580	$ 913,173	$ (1,089,746)				$ (1,245,857)	$ (1,422,431)	$ 388,953	$ (34,640)	$ (355,111)	$ (797)
RSVA - One-time Wholesale Market Service	1582	$ 131,862					$ (81,700)	$ 50,162	$ 17,338	$ 2,410	$ (13,457)	$ 6,291
RSVA - Retail Transmission Network Charge	1584	$ (124,845)	$ 404,601				$ 272,120	$ 551,876	$ (58,954)	$ 16,494	$ 47,436	$ 4,975
RSVA - Retail Transmission Connection Charge	1586	$ 445,804	$ (485,069)			$ (380,360)	$ (1,146,572)	$ (1,566,197)	$ (111,674)	$ (49,703)	$ 127,924	$ (33,453)
Sub-Totals		$ 1,365,994	$ (1,170,215)		$ -	$ (380,360)	$ (2,202,009)	$ (2,386,589)	$ 235,663	$ (65,439)	$ (193,208)	$ (22,984)
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 86,974						$ 86,974	$ 1,515	$ 4,112		$ 5,626
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ 230,245						$ 230,245	$ 4,348	$ 10,885		$ 15,233
Other Regulatory Assets - Sub-Account - Other	1508	$ 113,977					$ (113,977)	$ -	$ 6,279		$ (6,279)	$ -
Other Regulatory Assets - Sub-Account - Other	1508	$ 104,855						$ 104,855	$ 232	$ 4,957		$ 5,189
Other Regulatory Assets - Sub-Account - Other	1508	$ -	$ 16,455					$ 16,455	$ -	$ 512		$ 512
Retail Cost Variance Account - Retail	1518	$ (111,928)	$ (45,643)				$ 49,827	$ (107,744)	$ (9,019)	$ (4,083)	$ 9,019	$ (4,083)
Retail Cost Variance Account - STR	1548	$ 142,766	$ 25,368				$ (75,484)	$ 92,650	$ 12,856	$ 3,786	$ (12,856)	$ 3,786
Misc. Deferred Debits	1525	$ 160,745	$ 64,535				$ (11,803)	$ 213,478	$ 3,941	$ 7,637	$ (2,766)	$ 8,812
LV Variance Account	1550	$ 280,770	$ (287,939)					$ (7,170)	$ 7,185	$ 16,929		$ 24,114
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555	$ 2,386,393	$ 2,852,030		$ (2,869,928)	$ (83,292)		$ 2,285,204	$ 2,824	$ 1,771		$ 4,596
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555	$ (97,798)	$ (648,497)		$ 778,606			$ 32,311	$ -			$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter C	1555	$ -	$ 129,735					$ 129,735	$ -			$ -
Smart Meter OM&A Variance	1556	$ 13,000	$ 479,375		$ (326,555)	$ 83,292		$ 249,112	$ -	$ 13,544		$ 13,544
Conservation and Demand Management Expenditures and Recoveries	1565	$ (96,762)	$ 141,692					$ 44,930	$ (0)			$ (0)
CDM Contra	1566	$ 96,762	$ (141,692)					$ (44,930)	$ 0			$ 0
Qualifying Transition Costs	1570	$ 375,037	n/a	n/a			$ (361,937)	$ 13,100	$ 113,412	$ 619	$ (113,412)	$ 619
Pre-Market Opening Energy Variances Total	1571	$ (612,900)	n/a	n/a			$ 612,900	$ -	$ (177,741)		$ 177,741	$ -
Extra-Ordinary Event Costs	1572	$ 419,927					$ (326,464)	$ 93,463	$ 31,559	$ 4,418	$ (31,559)	$ 4,418
Deferred Rate Impact Amounts	1574	$ -						$ -	$ -			$ -
Other Deferred Credits	2425	$ -						$ -	$ -			$ -
Sub-Totals		$ 3,492,062	$ 2,585,419	$ -	$ (2,417,877)	$ (0)	$ (226,938)	$ 3,432,666	$ (2,610)	$ 65,088	$ 19,888	$ 82,367
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		$ 4,858,056	$ 1,415,204	$ -	$ (2,417,877)	$ (380,360)	$ (2,428,947)	$ 1,046,077	$ 233,053	$ (351)	$ (173,320)	$ 59,383
The following is not included in the total claim but is included on a memo basis:												
Deferred PILs Contra Account	1563						**see PILs reconciliation requested**					
RSVA - Power (including Global Adjustment)	1588	$ 896,808	$ (144,890)				$ (24,965)	$ 726,953	$ 58,870	$ 32,267	$ (58,870)	$ 32,267
RSVA - Power - Sub-Account - Global Adjustment	1588	$ 871,843	$ (144,890)					$ 726,953	$ -	$ 32,267		$ 32,267
Recovery of Regulatory Asset Balances	1590	$ (1,655,886)	$ (709,938)				$ 2,044,926	$ (320,899)	$ -	$ 53,864	$ 193,490	$ 247,354

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Chatham-Kent Hydro Inc.
NAME OF CONTACT	Jim Hogan
E-mail Address	jimhogan@ckenergy.com
VERSION NUMBER	v3.0
Date	31-Aug-09

Annual
Interest Rate

2008

Account Description	**Account Number**	**Opening Principal Amounts as of Jan-1-08**	**Transactions (additions) during 2008, excluding interest and adjustments**	**Transactions (reductions) during 2008, excluding interest and adjustments**	**Adjustments during 2008 - instructed by Board**	**Adjustments during 2008 - other**	**Transfer of Board-approved amounts to 1590 as per 2006 EDR**	**Closing Principal Balance as of Dec-31-08**	**Opening Interest Amounts as of Jan-1-08**	**Interest Jan-1 to Dec31-08**	**Transfer of Board-approved amounts to 1590 as per 2006 EDR**	**Closing Interest Amounts as of Dec-31-08**
RSVA - Wholesale Market Service Charge	1580	$ (1,422,431)	$ (414,783)					$ (1,837,214)	$ (797)	$ (64,674)		$ (65,472)
RSVA - One-time Wholesale Market Service	1582	$ 50,162	$ -					$ 50,162	$ 6,291	$ 1,993		$ 8,284
RSVA - Retail Transmission Network Charge	1584	$ 551,876	$ (68,886)					$ 482,990	$ 4,975	$ 19,653		$ 24,629
RSVA - Retail Transmission Connection Charge	1586	$ (1,566,197)	$ 441,881					$ (1,124,316)	$ (33,453)	$ (65,913)		$ (99,367)
Sub-Totals		$ (2,386,589)	$ (41,789)		$ -	$ -	$ -	$ (2,428,378)	$ (22,984)	$ (108,941)	$ -	$ (131,925)
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 86,974						$ 86,974	$ 5,626	$ 3,462		$ 9,088
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ 230,245						$ 230,245	$ 15,233	$ 9,164		$ 24,397
Other Regulatory Assets - Sub-Account - Other	1508	$ -						$ -	$ -			$ -
Other Regulatory Assets - Sub-Account - Other	1508	$ 104,855	$ 443,115					$ 547,970	$ 5,189	$ 4,309		$ 9,497
Other Regulatory Assets - Sub-Account - Other	1508	$ 16,455	$ 500					$ 16,955	$ 512	$ 664		$ 1,176
Retail Cost Variance Account - Retail	1518	$ (107,744)		$ (44,937)				$ (152,681)	$ (4,083)	$ (5,045)		$ (9,127)
Retail Cost Variance Account - STR	1548	$ 92,650	$ 9,923					$ 102,573	$ 3,786	$ 3,867		$ 7,653
Misc. Deferred Debits	1525	$ 213,478	$ 17,200	$ (203,260)				$ 27,418	$ 8,812	$ (7,538)		$ 1,274
LV Variance Account	1550	$ (7,170)		$ (202,829)				$ (209,999)	$ 24,114	$ (399)		$ 23,715
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555	$ 2,285,204	$ 406,266		$ (1,747,126)			$ 944,344	$ 4,596	$ 14,585		$ 19,181
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555	$ 32,311	$ (482,815)		$ 521,720			$ 71,216	$ -			$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter C	1555	$ 129,735						$ 129,735	$ -			$ -
Smart Meter OM&A Variance	1556	$ 249,112	$ 211,047		$ (60,389)			$ 399,770	$ 13,544	$ 13,441	$ (12,211)	$ 14,774
Conservation and Demand Management Expenditures and Recoveries	1565	$ 44,930	$ 7,775	$ (44,930)				$ 7,775	$ (0)			$ (0)
CDM Contra	1566	$ (44,930)	$ (7,775)	$ 44,930				$ (7,775)	$ 0			$ 0
Qualifying Transition Costs	1570	$ 13,100	n/a	n/a				$ 13,100	$ 619	$ 521		$ 1,141
Pre-Market Opening Energy Variances Total	1571	$ -	n/a	n/a				$ -	$ -			$ -
Extra-Ordinary Event Costs	1572	$ 93,463						$ 93,463	$ 4,418	$ 3,720		$ 8,138
Deferred Rate Impact Amounts	1574	$ -						$ -	$ -			$ -
Other Deferred Credits	2425	$ -						$ -	$ -			$ -
Sub-Totals		$ 3,432,666	$ 605,236	$ (451,025)	$ (1,285,795)	$ -	$ -	$ 2,301,082	$ 82,367	$ 40,751	$ (12,211)	$ 110,907
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		$ 1,046,077	$ 563,448	$ (451,025)	$ (1,285,795)	$ -	$ -	$ (127,296)	$ 59,383	$ (68,190)	$ (12,211)	$ (21,018)

The following is not included in the total claim but is included on a memo basis:

Deferred PILs Contra Account	1563					**see PILs reconciliation requested**						
RSVA - Power (including Global Adjustment)	1588	$ 726,953	$ 407,096					$ 1,134,050	$ 32,267	$ 31,639		$ 63,906
RSVA - Power - Sub-Account - Global Adjustment	1588	$ 726,953	$ 407,096					$ 1,134,050	$ 32,267	$ 31,639		$ 63,906
Recovery of Regulatory Asset Balances	1590	$ (320,899)	$ (239,584)				$ 641,173	$ 80,690	$ 247,354		$ (193,490)	$ 53,864

Proposed Rates and Bill Impacts:

The proposed rates for the RSVA and non-RSVA deferral balances from Table 9-3 are summarized along with the bill impacts in Table 9-4.

Table 9-4
Proposed Rates and Bill Impacts

Rate Class	Proposed Rates	Bill Impacts
Residential	$ 0.0002	0.4200%
GS < 50 KW	$ (0.0007)	-0.4300%
GS > 50 kw	$ (0.6859)	-0.4900%
Intermediate	$ (0.3825)	-1.8000%
Standby	$ (0.6702)	-2.1700%
Large Users		
Small Scattered Load	$ (0.0015)	-0.3000%
Sentinel Lighting	$ 0.3111	0.5000%
Street Lighting	$ (0.8041)	-2.0100%

SMART METER:

Smart Meter Riders and Adder

Chatham-Kent Hydro is requesting the following relating to smart meters;

- The revenue requirement for smart meters installed between January 1, 2008 and December 31, 2008 that relates to 2008 and 2009.
- All operating costs including amortization for 2008 and 2009
- Permanent rate for the smart meter assets to be transferred to fixed assets
- Rate Adder to assist in smart meter investments for 2009 and 2010 for the <50 kW general service class

Chatham-Kent Hydro has previously applied for the recovery of all costs for smart meters installed up to December 31, 2007 in EB-2007-0063 and EB-2007-0155.

EB-2007-0063 was the combined proceeding that Chatham-Kent Hydro participated in with 12 other LDCs, the first group of LDCs that were approved to deploy their smart meter solutions. In that proceeding Chatham-Kent Hydro was able to recover all smart meters installed up to April 30, 2007.

In EB-2007-0881 Chatham-Kent Hydro applied for recovery of costs for smart meters installed between May 1, 2007 and December 31, 2007.

The previous smart meter applications were for recovery of the residential installations up to December 31, 2007; in 2008 Chatham-Kent Hydro began the General Service installations.

The intent of this request is to seek recovery of the revenue requirement for the smart meter assets installed in 2008 along with recovering all operating costs not previously recovered. The revenue requirement for the smart meters installed in 2008 will be offset by the rate rider revenue received from May 1, 2008 to April 30, 2010. The rate requested would be Smart Meter Disposition Rider.

Chatham-Kent Hydro is also requesting to have a permanent rate approved for 2010 which relates to the smart meter assets installed in 2008 but not yet in rate base, which is the Permanent Smart Meter Rate.

Chatham-Kent Hydro is also requesting a Smart Meter Adder which will provide cash flow to assist in continuing to fund smart meter installations in 2009 and 2010 for the < 50 kW general service class

Current Smart Meter Installation Program

Chatham-Kent Hydro was named in Ontario Regulation 427/06 as a priority installation. In a commitment to the Ministry of Energy, Chatham-Kent Hydro had agreed to install smart meters for all members of the residential class, (27,872) by the end of December 2007.

Chatham-Kent Hydro has been working with the Independent Electricity System Operator (IESO) and the Meter Data Management Repository ("MDMR") to interface the smart meter data so that time-of-use pricing can be passed on to Chatham-Kent Hydro's customers. The MDMR project has been successful. Milestones achieved include:

- Chatham-Kent Hydro has been certified with the MDMR
- Chatham-Kent Hydro has entered into a pilot program with the MDMR that requires more than 2,000 customers' information to be transferred and tested on a daily basis.
- Chatham-Kent Hydro will be enrolling all meters with the MDMR in the fall of 2009
- Chatham-Kent Hydro will begin enrolling customers with TOU billing in January 2010 with the expectation of completion by March 2011

CKH continue to read all smart meters on a daily basis and continue to attain read reliability of 99.8% of all hourly meter reads. The IESO mandated target is 98%.

Combined Proceeding – Smart Metering EB-2007-0063

Chatham-Kent Hydro was one of thirteen utilities that participated in the above noted proceeding. In that preceding the Applicants sought the OEB's approval of:

1. The Applicants' interpretation of Minimum Functionality.
2. The Applicants' prudence in the purchasing of smart meters.
3. The Applicants' proposed methodology for dealing with stranded smart meter costs.
4. The Applicants' proposed methodology for recovering smart meter costs through rates.
5. The Applicants' proposed MDMR expenditures related to the smart meter costs.

In its Decision, the OEB:

1. Determined that there are fourteen cost categories in relation to smart meter minimum functionality.[1] The cost categories were set out in Appendix A of the Decision;
2. Found that the purchasing decisions of the thirteen utilities involved in this proceeding were implemented with the necessary due diligence, and the terms of the contracts each had concluded with suppliers, including the pricing, were prudent;[2]
3. Decided that Utilities could, if they choose, bring forward applications for the recovery of stranded costs in the 2008 rates; and
4. Approved the rate relief for smart meter investments.

Chatham-Kent Hydro made the necessary accounting changes to reflect the OEB's Decision.

[1] Ontario Energy Board Confidential Decision EB-2007-0063, page 7, paragraph 2
[2] Ontario Energy Board Confidential Decision EB-2007-0063, page 16, paragraph 2

Current Application

Minimum Functionality – Capital Costs

Chatham-Kent Hydro is providing the costs for the minimum functionality in the same cost categories and format as provided for in EB-2007-0063. Appendix B in that Decision is the "bundling" of the various detailed costs. In that preceding the Board stated that "the general consensus was that the public interest could be met by bundling smart meter costs on a cost per installation basis and publicly disclosing only these bundled costs".[3]

The costs incurred between January 1, 2008 and Dec 31, 2008 are the same type of costs as filed in the previous application (see Table 9-5 below). These costs are for smart meters installed and do not include any smart meters or other material that are purchased and not installed. These costs have also been audited as part of the 2008 year- end audit, in respect of which the financial statements have been filed with the Board previously.

Table 9-5
Comparison of Capital Costs

	Costs in EB-2008-0155	Costs in this application
Installed	9,820	1,198
Capital Costs	$1,820,000	$435,064
Avg / Unit	$185.33	$ 363.16

Capital cost

There are two main cost categories that have affected the difference in capital costs for this period:

- Cost of meters
- Installation costs

[3] Ontario Energy Board Confidential Decision EB-2007-0063, page 5, paragraph 2

The General Service customer class requires more new meters than the Residential class. The General Service meter population was much older than the Residential class, therefore Chatham-Kent Hydro was not able to reuse as many meters. Also the new meters for the General Service class are more expensive than Residential meters.

The installation costs are higher due to the fact that it requires more travel time as these customers are spread out further compared to Residential customers. The installation time is longer as the technical connections are different for the General Service customer compared to the Residential customer.

O&M Costs

Chatham-Kent Hydro has incurred O&M costs during the last year that reflect the costs of the smart meters installed and are for minimum functionality including MDMR interface and testing ($291,923) ; O&M costs relating to 2008 installs only ($32,084); and other O&M which was for a TOU / smart meter / CDM report from Navigant Consulting (Exhibit 9, Tab 2, Schedule 1, Appendix C); and the costs for the 2007 combined smart meter proceeding EB-2007-0063 ($99,813).

Details of the capital and O & M costs are provided below.

Table 9-6
Average Capital Costs

Capital costs	$	435,064
Smart meters installed		1,198
Average Capital Cost	$	363.16

Table 9-7
O & M for all Meters

Operation & Maintenance for all installed smart meters		
Labour Cost/Project Management	$	83,392
Trouble Shooting - labour	$	106,631
Software Support - Tantalus	$	18,731
Radio Licenses	$	3,401
Interest Charges	$	15,444
Repair customer door/meter guard	$	535
Misc Inventory items	$	738
Equipment in scada room	$	1,356
MDMR cost	$	61,695
	$	291,923
Total smart meters installed		29,070
Average cost per meter	$	10.04
Total customers		32,132
Average per customer	$	9.09

Table 9-8
O & M for meters installed in 2008

Operation & Maintenance for meters installed in 2008		
Meter Base Repairs	$	25,043
Small Tools & Supplies	$	3,435
Courier	$	3,606
	$	32,084
Smart meters installed in 2008		1,198
Average cost per meter	$	26.78
Total customers		32,132
Average per customer	$	1.00

Table 9-9
O & M Other

Operation & Maintenance Other		
TOU and smart emter impact study - Navigant Consulting	$	14,350
Smart meter combined proceeding EB-2007-0063	$	85,463
	$	99,813
Total smart meters installed		29,070
Average cost per meter	$	3.43
Total customers		32,132
Average per customer	$	3.11

Prudency Review

Chatham-Kent Hydro continued to purchase and install the smart meters under the same contracts and methods brought forward in evidence in EB-2007-0063 and EB-2008-0155. Chatham-Kent Hydro submits that the smart meter program continues to be "prudent" and therefore a detailed prudency review is not required in the context of this Application.

Stranded Costs

Chatham-Kent Hydro is requesting recovery of stranded meter costs. The stranded meter costs total $126,000. This cost is minimal because Chatham-Kent Hydro's smart meter solution is a retro fit solution. Therefore meters that are less than 15 years old have continued to be used and useful. While Chatham-Kent Hydro did have to replace approximately 50% of its meter population these were older meters with minimal or no net book value.

Smart Meter Installations

The schedule provided illustrates the number of smart meters installed by rate class. The 2006 and 2007 deferral capital and operating costs are not in the deferral account as these costs were previously approved by the OEB (EB-2007-0063 and EB-2008-0155). The smart meter adder and disposition riders that have been approved in the previous decisions are also not recorded in the deferred accounts as Chatham-Kent has obtained approval to dispose of those revenues.

The Funding Adder revenues collected in 2008 are the actual amounts collected and the 2009 and 2010 are forecasted revenue based upon the proposed Adder in this application.

Table 9-10
Smart Meter Activity

	Smart Meters Installed			Account 1555			Account 1556
Year	Residential	GS<50KW	Other	Percentage of applicable customers converted (%)	Funding Adder Revenues collected	Capital Expenditures	Operating Expenses
2006	18,052	-	-	56%			
2007	9,820	-	-	31%			
2008	123	963	112	4%	34,421	435,064	423,820
2009	649	862	144	5%	208,215	600,000	
2010		1,213	100		404,738	750,000	
2011 (and beyond if required)			94				

Approval requested – Revenue Requirement

Chatham-Kent Hydro has filed pricing information with respect to smart meters in confidence for the reasons set out in the cover letter to this Application. That information is designated as Exhibit 9, Tab 2, Schedule 1, Appendix A to this Application. Appendices B and C to this Schedule, the OEB's 2010 Smart Meter Rate Calculation Model and the summary of Chatham-Kent Hydro's Smart Meter Revenue Requirement and Proposed Rates, are being filed on the public record.

The smart meter revenue requirement set out in page 5 of Appendix B is highlighted in Table 9-11, below.

Table 9-11
Smart Meter Revenue Requirement

Smart Meter Revenue Requirement	Amount
Return on rate base	$ 58,283
Operating expenses	$ 471,929.75
Stranded costs	$ 114,623.02
Grossed up for PILs	$ 12,598
Subtotal	$ 657,434
Carrying costs	$ 2,988
Net Revenue Requirement	$ 660,422

Notes on the revenue requirement:

- Since the revenue relates to 2009 the Return on rate base reflects the capital structure at May 1, 2009 from 53 / 47 Debt.
- Operating costs includes depreciation.
- PILs reflects current tax rates.

Approval Requested - Smart Meter Disposition Rider

The schedule that calculates the revenue requirement, "Smart Meter Revenue Requirement & Proposed Rates – Summary" Appendix B, also calculates the proposed rates to recover the revenue requirement for the Smart Meter Disposition Rider. This is summarized in Table 9-12.

Table 9-12
Smart Meter Disposition Rider

Smart Meter Recovery	Rate Adder	Metered Customers	No. of Mths	Amount Recovered
November 2008 to April 30, 2009	$ 0.54	31,872	6	$ 103,265
May 1, 2009 to April 30, 2010	$ 0.54	32,132	12	$ 208,215
May 1, 2010 to April 30, 2012	$ 0.45	32,132	24	$ 347,026
Total Revenue				$ 658,506
Revenue Requirement				$ 660,422
Under recovery				($1,916)

The Smart Meter Disposition Rider is determined after reducing the revenue requirement from the Smart Meter Adder from November 2008 to April 30, 2010. Chatham-Kent Hydro is requesting approval of the Smart Meter Disposition Rider over a two year period, and this would be reflected in the May 2010 rates. Two years is being proposed to mitigate the impact on the customers' rates. The rate being proposed for implementation from May 2010 to April 30, 2012, as calculated in the model, is $0.45 per customer per month.

Approval Requested – Smart Meter Permanent Rate for Assets Invested in 2008

Chatham-Kent Hydro is proposing a permanent rate to be added to the service charge that is to reflect the smart meter assets that were installed in 2008. The revenue requirement for the permanent smart meter rate is summarized in Table 9-13 and was calculated on the "Smart Meter Revenue Requirement & Proposed Rates Summary" Appendix B. The permanent smart meter rate is calculated on the same page in Appendix B and is summarized in Table 9-14.

Table 9-13
Smart Meter Permanent Rate Adder Revenue Requirement

Net Fixed Assets	$	370,919
Return on Net Fixed Assets	$	29,263
Depreciation	$	32,073
Gross up for PILs	$	8,616
Total Revenue Requirement	$	69,952

The permanent rate is $0.18 per customer per month which is summarized in Table 9-14.

Table 9-14
Smart Meter Permanent Rate

Revenue Requirement	$	69,952
Customers		32,132
Monthly Rate	$	0.18

Approval Requested - Smart Meter Rate Adder

Chatham-Kent Hydro is also requesting that a smart meter rate rider be approved. The rate rider will allow for Chatham-Kent Hydro to continue investing in smart meters for 2009 and 2010. The investments will be for the General Service <50 kWclass and will be recorded in a deferral account. Chatham-Kent Hydro will file an application with the OEB in 2011 for final recovery and disposition of the investments made in 2009 and 2010. A summary of the anticipated revenue requirement and the Smart Meter Adder is provided in Table 9-15 and was calculated in Appendix C of this Exhibit.

1 **Table 9-15**
Smart Meter Adder Revenue Requirement and Rate

Net Fixed Assets	$	922,500
Return on Net Fixed Assets	$	92,291
Amortization	$	85,000
Groos up for PILs	$	19,231
Total Revenue Requirement	$	196,523
Number of Customers		32,132
Rate per Month	$	0.51

APPENDIX A
SMART METER DETAIL COST

[FILED IN CONFIDENCE]

APPENDIX B

SMART METER MODEL FOR DISPOSTION RIDER AND PERMANENT RATE

2010 EDR Smart Meter Rate Calculation Model

Sheet 1 Utility Information Sheet

Legend:	Input Cell	Pull-Down Menu Option	Output Cell
	From Another Sheet		To Another Sheet

Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.

Name of LDC:	Chatham-Kent Hydro Inc.		
Licence Number:	ED-2002-0563	Smart Meter Grouping:	Listed
EB Number:	EB-2009-0277		
EDR 2006 RP Number:	RP-2005-0020	EDR 2006 EB Number:	EB-2005-0350
Date of Submission:	September 29, 2009	Revision:	0
Version:	1.0		

Contact Information

Name:	Cheryl Decaire
Title:	Co-ordinator of Regulatory and Rates
Phone Number:	519-352-6300 ext 405
E-Mail Address:	cheryldecaire@ckenergy.com

Chatham-Kent Hydro Inc.
EB-2009-0277
Tuesday, September 29, 2009

Sheet 2. Smart Meter Capital Cost and Operational Expense Data

Smart Meter Unit Installation Plan:

assume calendar year installation

	2008	2009	2010	2011	2012	2013	Total
Planned number of Residential smart meters to be installed	123						123
Planned number of General Service Less Than 50 kW smart meters	963						
Planned number of General Service Greater Than 50 kW smart meters	112						112
Planned Meter Installation (Residential and Less Than 50 kW only)	1,198	-	-	-	-	-	1,198
Planned Meter Installation Completed before January 1, 2008		1,198	1,198	1,198	1,198	1,198	

Other Unit Installation Plan:

assume calendar year installation

	2008	2009	2010	2011	2012	2013	Total
Planned number of Collectors to be installed							-
Planned number of Repeaters to be installed							
Other : Please specify							
							-
							-
							-
							-

Capital Costs

1.1 ADVANCED METERING COMMUNICATION DEVICE (AMCD)

	Asset Type	2008	2009	2010	2011	2012	2013	Total
1.1.1 Smart Meter *may include new meters and modules, etc.*	**Smart Meter**	$ 313,705		*3. LDC Assumptions and Data*				$ 313,705
1.1.2 Installation Cost *may include socket kits plus shipping, labour, benefits, vehicle, etc.*	**Smart Meter**	$ 105,411		*3. LDC Assumptions and Data*				$ 105,411
1.1.3a Workforce Automation Hardware *may include fieldworker handhelds, barcode hardware, etc.*	**Comp. Hard.**			*3. LDC Assumptions and Data*				$ -
1.1.3b Workforce Automation Software *may include fieldworker handhelds, barcode hardware, etc.*	**Comp. Soft.**			*3. LDC Assumptions and Data*				$ -
Total Advanced Metering Communication Device (AMCD)		**$ 419,116**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 419,116**

1.2 ADVANCED METERING REGIONAL COLLECTOR (AMRC) (includes LAN)

	Asset Type	2008	2009	2010	2011	2012	2013	Total
1.2.1 Collectors	**Smart Meter**			*3. LDC Assumptions and Data*				$ -
1.2.2 Repeaters *may include radio licence, etc.*	**Smart Meter**			*3. LDC Assumptions and Data*				$ -
1.2.3 Installation *may include meter seals and rings, collector computer hardware, etc.*	**Smart Meter**			*3. LDC Assumptions and Data*				$ -
Total Advanced Metering Regional Collector (AMRC) (includes LAN)		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

1.3 ADVANCED METERING CONTROL COMPUTER (AMCC)

	Asset Type	2008	2009	2010	2011	2012	2013	Total
1.3.1 Computer Hardware	**Comp. Hard.**	$ 8,883		*3. LDC Assumptions and Data*				$ 8,883
1.3.2 Computer Software	**Comp. Soft.**			*3. LDC Assumptions and Data*				$ -
1.3.3 Computer Software Licence & Installation (includes hardware & software) *may include AS/400 disc space, backup & recovery computer, UPS, etc*	**Comp. Soft.**			*3. LDC Assumptions and Data*				$ -
Total Advanced Metering Control Computer (AMCC)		**$ 8,883**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 8,883**

1.4 WIDE AREA NETWORK (WAN)

	Asset Type	2008	2009	2010	2011	2012	2013	Total
1.4.1 Activation Fees	**Comp. Soft.**	$ 7,066		*3. LDC Assumptions and Data*				$ 7,066
Total Wide Area Network (WAN)		**$ 7,066**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 7,066**

1.5 OTHER AMI CAPITAL COSTS RELATED TO MINIMUM FUNCTIONALITY

	Asset Type	2008	2009	2010	2011	2012	2013	Total
1.5.1 Customer equipment (including repair of damaged equipment)	**Comp. Hard.**			*3. LDC Assumptions and Data*				$ -
1.5.2 AMI Interface to CIS	**Comp. Hard.**			*3. LDC Assumptions and Data*				$ -
1.5.3 Professional Fees	**Comp. Hard.**							$ -

Chatham-Kent Hydro Inc.
EB-2009-0277
Tuesday, September 29, 2009

Sheet 2. Smart Meter Capital Cost and Operational Expense Data

		2008	2009	2010	2011	2012	2013	Total
		3. LDC Assumptions and Data						
1.5.4 Integration	**Comp. Hard.**							$ -
		3. LDC Assumptions and Data						
1.5.5 Program Management	**Comp. Hard.**							$ -
		3. LDC Assumptions and Data						
1.5.6 Other AMI Capital	**Comp. Hard.**		$ -					$ -
		3. LDC Assumptions and Data						
Total Other AMI Capital Costs Related To Minimum Functionality		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Capital Costs		**$ 435,064**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 435,064**

Chatham-Kent Hydro Inc.
EB-2009-0277
Tuesday, September 29, 2009

Sheet 2. Smart Meter Capital Cost and Operational Expense Data

O M & A

2.1 ADVANCED METERING COMMUNICATION DEVICE (AMCD)

	2008	2009	2010	2011	2012	2013	Total
2.1.1 Maintenance *may include meter reverification costs, etc.*							$ -
			3. LDC Assumptions and Data				
Total Incremental AMI Operation Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

2.2 ADVANCED METERING REGIONAL COLLECTOR (AMRC) (includes LAN)

	2008	2009	2010	2011	2012	2013	Total
2.2.1 Maintenance							$ -
			3. LDC Assumptions and Data				
Total Advanced Metering Regional Collector (AMRC) (includes LAN)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

2.3 ADVANCED METERING CONTROL COMPUTER (AMCC)

	2008	2009	2010	2011	2012	2013	Total
2.3.1 Hardware Maintenance *may include server support, etc*							$ -
			3. LDC Assumptions and Data				
2.3.2 Software Maintenance *may include maintenance support, etc.*							$ -
			3. LDC Assumptions and Data				
Total Advanced Metering Control Computer (AMCC)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

2.4 WIDE AREA NETWORK (WAN)

	2008	2009	2010	2011	2012	2013	Total
2.4.1 WIDE AREA NETWORK (WAN) *may include serial to Ethernet hardware, etc.*							$ -
			3. LDC Assumptions and Data				
Total Incremental Other Operation Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

2.5 OTHER AMI OM&A COSTS RELATED TO MINIMUM FUNCTIONALITY

	2008	2009	2010	2011	2012	2013	Total
2.5.1 Business Process Redesign	$ -	$ -					$ -
			3. LDC Assumptions and Data				
2.5.2 Customer Communication *may include project communication. etc.*							$ -
			3. LDC Assumptions and Data				
2.5.3 Program Management							$ -
			3. LDC Assumptions and Data				
2.5.4 Change Management *may include training, etc.*							$ -
			3. LDC Assumptions and Data				
2.5.5 Administration Cost	$ 105,594						$ 105,594
			3. LDC Assumptions and Data				
2.5.6 Other AMI Expenses	$ 318,226						$ 318,226
			3. LDC Assumptions and Data				
Total 2.5 Other AMI OM&A Costs Related To Minimum Functionality	**$ 423,820**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 423,820**

	2008	2009	2010	2011	2012	2013	Total
Total O M & A Costs	**$ 423,820**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 423,820**

Chatham-Kent Hydro Inc.
EB-2009-0277
Tuesday, September 29, 2009

Sheet 3. LDC Assumptions and Data

Assumptions:
1. Planned meter installations occur evenly through the year.
2. Year assumed January to December
3. Amortization is straight line and has half year rule applied in first year

2006 EDR Data Information	2007	2008	2009
Deemed Debt (from 2006 EDR Sheet "3-2 COST OF CAPITAL (Input)" Cell C 18)	50%	53%	57%
Deemed Equity (from 2006 EDR Sheet "3-2 COST OF CAPITAL (Input)" Cell C 19)	50%	47%	43%
Weighted Debt Rate (from 2006 EDR Sheet "3-2 COST OF CAPITAL (Input)" Cell C 25)	7.04%		
Proposed ROE (from 2006 EDR Sheet "3-2 COST OF CAPITAL (Input)" Cell E 32)	9.00%		
Weighted Average Cost of Capital	8.02%		

Working Capital Allowance %	15.00%

2006 EDR Total Metered Customers		
Residential	28,200	
General Service Less Than 50 kW	3,291	
Other Metered Customers	381	
Sum of Residential, General Service, and Large User	31,872	*4. Smart Meter Rate Calc*
from 2006 EDR Sheet "7-1 ALLOCATION - Base Rev. Req." Cells H16 thru H93	-	

Smart Meter Rate Adders	Residential	GS and LU
2006 EDR Smart Meter Rate Adder		
2007 EDR Smart Meter Rate Adder		
2008 EDR Smart Meter Rate Adder	$ 0.54	$ 0.54
2009 EDR Smart Meter Rate Adder	$ 0.54	$ 0.54
2010 EDR Smart Meter Rate Adder	$ -	$ -

2006 EDR Tax Rate	2006		2008
Corporate Income Tax Rate	36.12%	*5. PILs*	33.50%
(from 2006 PILs Sheet "Test Year PILs,Tax Provision" Cell D 14)			

Capital Data:	2008	2009	2010	2011	2012	2013	Total
Smart Meter	$ 419,116	$ -	$ -	$ -	$ -	$ -	$ 419,116
Computer Hardware	$ 8,883	$ -	$ -	$ -	$ -	$ -	$ 8,883
Computer Software	$ 7,066	$ -	$ -	$ -	$ -	$ -	$ 7,066
Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Capital Costs	$ 435,064	$ -	$ -	$ -	$ -	$ -	$ 435,064

LDC Amortization Policy:	Amortization		CCA Class	CCA Rate	
Smart Meter Amortization Rate *Enter Amortization Policy*	15	Years	47	8	%
Computer Hardware Amortization Rate *Enter Amortization Policy*	5	Years	45	45	%
Computer Software Amortization Rate *Enter Amortization Policy*	3	Years	45	45	%
Tools & Equipment Amortization Rate *Enter Amortization Policy*	10	Years	8	20	%
Other Equipment Amortization Rate *Enter Amortization Policy*	10	Years	8	20	%

Operating Expense Data:	2008	2009	2010	2011	2012	2013	Total
2.1 Advanced Metering Communication Device (AMCD)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2.2 Advanced Metering Regional Collector (AMRC) (includes LAN)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2.3 Advanced Metering Control Computer (AMCC)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2.4 Wide Area Network (WAN)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2.5 Other AMI OM&A Costs Related To Minimum Functionality	$ 423,820	$ -	$ -	$ -	$ -	$ -	$ 423,820
Total O M & A Costs	$ 423,820	$ -	$ -	$ -	$ -	$ -	$ 423,820

Per Meter Cost Split:	Per Meter	Installed	Investment	% of Invest
Smart meter including installation	$ 349.85	1,198	$ 419,116	49%
Computer Hardware Costs	$ 7.41	1,198	$ 8,883	1%
Computer Software Costs	$ 5.90	1,198	$ 7,066	1%
Tools & Equipment	$ -	1,198	$ -	0%
Other Equipment	$ -	1,198	$ -	0%
Smart meter incremental operating expenses	$ 353.77	1,198	$ 423,820	49%
Total Smart Meter Capital Costs per meter	$ 716.93		$ 858,885	100%

Smart Meter Revenue Requirement & Proposed Rates- Summary

Chatham-Kent Hydro Inc.

Summary of Actual Costs claimed in this application	2008	2008	2009	Total Actual	Perm Adjust 2009
Capital Costs ***(must be installed, and used and useful)***					
Smart Meters	$ 419,116		$ -	$ 419,116	$ 419,116
Computer Hardware	$ 8,883		$ -	$ 8,883	$ 8,883
Computer Software	$ 7,066		$ -	$ 7,066	$ 7,066
Tools & Equipment	$ -		$ -	$ -	$ -
Other Equipment *(please specify)*	$ -		$ -	$ -	$ -
Total Capital Costs	$ 435,064		$ -	$ 435,064	$ 435,064
O M & A					
2.1 Advanced metering communication device (AMCD)	$ -		$ -	$ -	
2.2 Advanced metering regional collector (AMRC) (includes LAN)	$ -		$ -	$ -	
2.3 Advanced metering control computer (AMCC)	$ -		$ -	$ -	
2.4 Wide area network (WAN)	$ -		$ -	$ -	
2.5 Other AMI OM&A costs related to minimum functionality	$ 423,820		$ -	$ 423,820	
Total O M & A Costs	$ 423,820		$ -	$ 423,820	

Summary of Revenue Requirement Calculation	2008	2008	2009	Total Actual	Perm Adjust 2009
Net Fixed Assets					
Net Fixed Assets Beginning of Year	$ -	$ 419,028	$ 386,955		$ 386,955
Net Fixed Assets End of Year	$ 419,028	$ 386,955	$ -		$ 354,882
Average Net Fixed Asset Values	$ 209,514	$ 402,992	$ 193,478		$ 370,919
Working Capital Allowance					
Operation Expense	$ 423,820	$ -	$ -		$ -
Working Capital Allowance 15% (from approved 2006 EDR application)	$ 63,573	$ -	$ -		$ -
Smart Meters Rate Base	$ 273,087	$ 402,992	$ 193,478		$ 370,919
Return on Rate Base					
Deemed Debt 53.3% Times Weighted Debt Rate 7.04%	$ 10,247	$ 15,122	$ 7,260	$ 32,629	$ 14,798
Deemed Equity 46.7% Times ROE 9%	$ 11,478	$ 6,045	$ 8,132	$ 25,655	$ 14,465
Return on Rate Base	$ 21,725	$ 21,166	$ 15,392	$ 58,283	$ 29,263
Operating Expenses					
Incremental Operating Expenses	$ 423,820	$ -	$ -	$ 423,820	$ -
Amortization Expenses	$ 16,036	$ 32,073	$ -	$ 48,109	$ 32,073
Total Operating Expenses	$ 439,857	$ 32,073	$ -	$ 471,930	$ 32,073
Stranded Cost	$ 114,623			$ 114,623	
Total Operating Expenses	$ 554,480	$ 32,073	$ -	$ 586,553	

	2008	2008	2009	Total Actual	Perm Adjust 2009
Revenue Requirement Before PILs	$ 576,205	$ 53,239	$ 15,392	$ 644,836	$ 61,336
Grossed up PILs	$ 5,765	$ 6,833	$ -	$ 12,598	$ 8,616
Revenue Requirement for Smart Meters	**$ 581,970**	**$ 60,073**	**$ 15,392**	**$ 657,434**	**$ 69,952**

Rate Rider to Clear Actual Expenses to December 2008	Rate Adder	Metered Customers per 2006 EDR	No. of Mths	Amount Recovered	
Revenue Requirement for Smart Meters Installed					$ 657,434
Carrying costs — The last available Board prescribed interest rate for approved accounts to be applied against deferral accounts is assumed to continue without change for the completion of recovery of actual costs.					$ 2,984
Less Smart Meter Adder Recovery					
November 2008 to April 30, 2009	$ 0.54	31,872	6	$ 103,265	
May 1, 2009 to April 30, 2010	$ 0.54	32,132	12	$ 208,215	
May 1, 2010 to April 30, 2012	**$ 0.45**	32,132	24	$ 348,937	-$ 660,418
					$ 0

Permanent Capital Rate Adjustustment	Rate Adder	Metered Customers per 2006 EDR	No. of Mths	Amount Recovered
May 2010	**$ 0.18**	32,132	12	$ 69,952

Clearing Actuals Smart Meter Revenue Requirement

Chatham-Kent Hydro Inc.

	Opening	2008 Rev Req	2008 Rev Req	2009 Rev Req	Recovery	Int. Rate	Interest	Closing
Nov-08	$ -	$ 24,249			-$ 17,211	1.29%	$ -	$ 7,038
Dec-08	$ 7,038	$ 24,249			-$ 17,211	1.29%	$ 8	$ 14,083
Jan-09	$ 14,083	$ 24,249			-$ 17,211	1.29%	$ 15	$ 21,136
Feb-09	$ 21,136	$ 24,249			-$ 17,211	1.29%	$ 23	$ 28,197
Mar-09	$ 28,197	$ 24,249			-$ 17,211	1.29%	$ 30	$ 35,265
Apr-09	$ 35,265	$ 24,249			-$ 17,211	1.29%	$ 38	$ 42,341
May-09	$ 42,341	$ 24,249			-$ 17,351	1.29%	$ 46	$ 49,284
Jun-09	$ 49,284	$ 24,249			-$ 17,351	1.29%	$ 53	$ 56,234
Jul-09	$ 56,234	$ 24,249			-$ 17,351	1.29%	$ 60	$ 63,192
Aug-09	$ 63,192	$ 24,249			-$ 17,351	1.29%	$ 68	$ 70,158
Sep-09	$ 70,158	$ 24,249			-$ 17,351	1.29%	$ 75	$ 77,130
Oct-09	$ 77,130	$ 24,249			-$ 17,351	1.29%	$ 83	$ 84,111
Nov-09	$ 84,111	$ 24,249			-$ 17,351	1.29%	$ 90	$ 91,099
Dec-09	$ 91,099	$ 24,249			-$ 17,351	1.29%	$ 98	$ 98,094
Jan-10	$ 98,094	$ 24,249			-$ 17,351	1.29%	$ 105	$ 105,097
Feb-10	$ 105,097	$ 24,249			-$ 17,351	1.29%	$ 113	$ 112,107
Mar-10	$ 112,107	$ 24,249			-$ 17,351	1.29%	$ 121	$ 119,125
Apr-10	$ 119,125	$ 24,249			-$ 17,351	1.29%	$ 128	$ 126,151
May-10	$ 126,151	$ 24,249	$ 2,503	$ 641	-$ 14,539	1.29%	$ 136	$ 139,141
Jun-10	$ 139,141	$ 24,249	$ 2,503	$ 641	-$ 14,539	1.29%	$ 150	$ 152,144
Jul-10	$ 152,144	$ 24,249	$ 2,503	$ 641	-$ 14,539	1.29%	$ 164	$ 165,162
Aug-10	$ 165,162	$ 24,249	$ 2,503	$ 641	-$ 14,539	1.29%	$ 178	$ 178,193
Sep-10	$ 178,193	$ 24,249	$ 2,503	$ 641	-$ 14,539	1.29%	$ 192	$ 191,239
Oct-10	$ 191,239	$ 24,249	$ 2,503	$ 641	-$ 14,539	1.29%	$ 206	$ 204,299
Nov-10	$ 204,299		$ 2,503	$ 641	-$ 14,539	1.29%	$ 220	$ 193,123
Dec-10	$ 193,123		$ 2,503	$ 641	-$ 14,539	1.29%	$ 208	$ 181,936
Jan-11	$ 181,936		$ 2,503	$ 641	-$ 14,539	1.29%	$ 196	$ 170,737
Feb-11	$ 170,737		$ 2,503	$ 641	-$ 14,539	1.29%	$ 184	$ 159,526
Mar-11	$ 159,526		$ 2,503	$ 641	-$ 14,539	1.29%	$ 171	$ 148,303
Apr-11	$ 148,303		$ 2,503	$ 641	-$ 14,539	1.29%	$ 159	$ 137,068
May-11	$ 137,068		$ 2,503	$ 641	-$ 14,539	1.29%	$ 147	$ 125,820
Jun-11	$ 125,820		$ 2,503	$ 641	-$ 14,539	1.29%	$ 135	$ 114,561
Jul-11	$ 114,561		$ 2,503	$ 641	-$ 14,539	1.29%	$ 123	$ 103,289
Aug-11	$ 103,289		$ 2,503	$ 641	-$ 14,539	1.29%	$ 111	$ 92,006
Sep-11	$ 92,006		$ 2,503	$ 641	-$ 14,539	1.29%	$ 99	$ 80,710
Oct-11	$ 80,710		$ 2,503	$ 641	-$ 14,539	1.29%	$ 87	$ 69,402
Nov-11	$ 69,402		$ 2,503	$ 641	-$ 14,539	1.29%	$ 75	$ 58,082
Dec-11	$ 58,082		$ 2,503	$ 641	-$ 14,539	1.29%	$ 62	$ 46,750
Jan-12	$ 46,750		$ 2,503	$ 641	-$ 14,539	1.29%	$ 50	$ 35,405
Feb-12	$ 35,405		$ 2,503	$ 641	-$ 14,539	1.29%	$ 38	$ 24,048
Mar-12	$ 24,048		$ 2,503	$ 641	-$ 14,539	1.29%	$ 26	$ 12,680
Apr-12	$ 12,680		$ 2,503	$ 641	-$ 14,539	1.29%	$ 14	$ 1,298
Revenue Requirement		**$ 581,970**	**$ 60,073**	**$ 15,392**		**Carrying Costs**	$ 2,984	

Smart Meter Rate Adder Recovery

Chatham-Kent Hydro Inc.

Month	Residential	GS & LU	Total	Cummulative
Nov-08	$ 15,228.00	$ 1,983	$ 17,211	$ 17,211
Dec-08	$ 15,228.00	$ 1,983	$ 17,211	$ 34,422
Jan-09	$ 15,228.00	$ 1,983	$ 17,211	$ 51,633
Feb-09	$ 15,228.00	$ 1,983	$ 17,211	$ 68,844
Mar-09	$ 15,228.00	$ 1,983	$ 17,211	$ 86,054
Apr-09	$ 15,228.00	$ 1,983	$ 17,211	$ 103,265
May-09	$ 15,467.76	$ 1,884	$ 17,351	$ 120,617
Jun-09	$ 15,467.76	$ 1,884	$ 17,351	$ 137,968
Jul-09	$ 15,467.76	$ 1,884	$ 17,351	$ 155,319
Aug-09	$ 15,467.76	$ 1,884	$ 17,351	$ 172,670
Sep-09	$ 15,467.76	$ 1,884	$ 17,351	$ 190,022
Oct-09	$ 15,467.76	$ 1,884	$ 17,351	$ 207,373
Nov-09	$ 15,467.76	$ 1,884	$ 17,351	$ 224,724
Dec-09	$ 15,467.76	$ 1,884	$ 17,351	$ 242,076
Jan-10	$ 15,467.76	$ 1,884	$ 17,351	$ 259,427
Feb-10	$ 15,467.76	$ 1,884	$ 17,351	$ 276,778
Mar-10	$ 15,467.76	$ 1,884	$ 17,351	$ 294,129
Apr-10	$ 15,467.76	$ 1,884	$ 17,351	$ 311,481
May-10	$ 12,960.81	$ 1,578	$ 14,539	$ 326,020
Jun-10	$ 12,960.81	$ 1,578	$ 14,539	$ 340,559
Jul-10	$ 12,960.81	$ 1,578	$ 14,539	$ 355,098
Aug-10	$ 12,960.81	$ 1,578	$ 14,539	$ 369,637
Sep-10	$ 12,960.81	$ 1,578	$ 14,539	$ 384,176
Oct-10	$ 12,960.81	$ 1,578	$ 14,539	$ 398,715
Nov-10	$ 12,960.81	$ 1,578	$ 14,539	$ 413,254
Dec-10	$ 12,960.81	$ 1,578	$ 14,539	$ 427,793
Jan-11	$ 12,960.81	$ 1,578	$ 14,539	$ 442,332
Feb-11	$ 12,960.81	$ 1,578	$ 14,539	$ 456,871
Mar-11	$ 12,960.81	$ 1,578	$ 14,539	$ 471,410
Apr-11	$ 12,960.81	$ 1,578	$ 14,539	$ 485,949
May-11	$ 12,960.81	$ 1,578	$ 14,539	$ 500,488
Jun-11	$ 12,960.81	$ 1,578	$ 14,539	$ 515,027
Jul-11	$ 12,960.81	$ 1,578	$ 14,539	$ 529,566
Aug-11	$ 12,960.81	$ 1,578	$ 14,539	$ 544,106
Sep-11	$ 12,960.81	$ 1,578	$ 14,539	$ 558,645
Oct-11	$ 12,960.81	$ 1,578	$ 14,539	$ 573,184
Nov-11	$ 12,960.81	$ 1,578	$ 14,539	$ 587,723
Dec-11	$ 12,960.81	$ 1,578	$ 14,539	$ 602,262
Jan-12	$ 12,960.81	$ 1,578	$ 14,539	$ 616,801
Feb-12	$ 12,960.81	$ 1,578	$ 14,539	$ 631,340
Mar-12	$ 12,960.81	$ 1,578	$ 14,539	$ 645,879
Apr-12	$ 12,960.81	$ 1,578	$ 14,539	$ 660,418

Smart Meter Rate Adder Recovery - Residential

Chatham-Kent Hydro Inc.

Month	SM Rate Adder	Customers	Recovery	Cummulative
Nov-08	$ 0.54	28200	$ 15,228	$ 15,228
Dec-08	$ 0.54	28200	$ 15,228	$ 30,456
Jan-09	$ 0.54	28200	$ 15,228	$ 45,684
Feb-09	$ 0.54	28200	$ 15,228	$ 60,912
Mar-09	$ 0.54	28200	$ 15,228	$ 76,140
Apr-09	$ 0.54	28200	$ 15,228	$ 91,368
May-09	$ 0.54	28644	$ 15,468	$ 106,836
Jun-09	$ 0.54	28644	$ 15,468	$ 122,304
Jul-09	$ 0.54	28644	$ 15,468	$ 137,771
Aug-09	$ 0.54	28644	$ 15,468	$ 153,239
Sep-09	$ 0.54	28644	$ 15,468	$ 168,707
Oct-09	$ 0.54	28644	$ 15,468	$ 184,175
Nov-09	$ 0.54	28644	$ 15,468	$ 199,642
Dec-09	$ 0.54	28644	$ 15,468	$ 215,110
Jan-10	$ 0.54	28644	$ 15,468	$ 230,578
Feb-10	$ 0.54	28644	$ 15,468	$ 246,046
Mar-10	$ 0.54	28644	$ 15,468	$ 261,513
Apr-10	$ 0.54	28644	$ 15,468	$ 276,981
May-10	$ 0.45	28644	$ 12,961	$ 289,942
Jun-10	$ 0.45	28644	$ 12,961	$ 302,903
Jul-10	$ 0.45	28644	$ 12,961	$ 315,864
Aug-10	$ 0.45	28644	$ 12,961	$ 328,824
Sep-10	$ 0.45	28644	$ 12,961	$ 341,785
Oct-10	$ 0.45	28644	$ 12,961	$ 354,746
Nov-10	$ 0.45	28644	$ 12,961	$ 367,707
Dec-10	$ 0.45	28644	$ 12,961	$ 380,668
Jan-11	$ 0.45	28644	$ 12,961	$ 393,628
Feb-11	$ 0.45	28644	$ 12,961	$ 406,589
Mar-11	$ 0.45	28644	$ 12,961	$ 419,550
Apr-11	$ 0.45	28644	$ 12,961	$ 432,511
May-11	$ 0.45	28644	$ 12,961	$ 445,472
Jun-11	$ 0.45	28644	$ 12,961	$ 458,432
Jul-11	$ 0.45	28644	$ 12,961	$ 471,393
Aug-11	$ 0.45	28644	$ 12,961	$ 484,354
Sep-11	$ 0.45	28644	$ 12,961	$ 497,315
Oct-11	$ 0.45	28644	$ 12,961	$ 510,276
Nov-11	$ 0.45	28644	$ 12,961	$ 523,236
Dec-11	$ 0.45	28644	$ 12,961	$ 536,197
Jan-12	$ 0.45	28644	$ 12,961	$ 549,158
Feb-12	$ 0.45	28644	$ 12,961	$ 562,119
Mar-12	$ 0.45	28644	$ 12,961	$ 575,080
Apr-12	$ 0.45	28644	$ 12,961	$ 588,041

Smart Meter Rate Adder Recovery - GS & LU

Chatham-Kent Hydro Inc.

Month	SM Rate Adder	Customers	Recovery	Cummulative
Nov-08	$ 0.54	3672	$ 1,983	$ 1,983
Dec-08	$ 0.54	3672	$ 1,983	$ 3,966
Jan-09	$ 0.54	3672	$ 1,983	$ 5,949
Feb-09	$ 0.54	3672	$ 1,983	$ 7,932
Mar-09	$ 0.54	3672	$ 1,983	$ 9,914
Apr-09	$ 0.54	3672	$ 1,983	$ 11,897
May-09	$ 0.54	3488	$ 1,884	$ 13,781
Jun-09	$ 0.54	3488	$ 1,884	$ 15,664
Jul-09	$ 0.54	3488	$ 1,884	$ 17,548
Aug-09	$ 0.54	3488	$ 1,884	$ 19,431
Sep-09	$ 0.54	3488	$ 1,884	$ 21,315
Oct-09	$ 0.54	3488	$ 1,884	$ 23,198
Nov-09	$ 0.54	3488	$ 1,884	$ 25,082
Dec-09	$ 0.54	3488	$ 1,884	$ 26,965
Jan-10	$ 0.54	3488	$ 1,884	$ 28,849
Feb-10	$ 0.54	3488	$ 1,884	$ 30,732
Mar-10	$ 0.54	3488	$ 1,884	$ 32,616
Apr-10	$ 0.54	3488	$ 1,884	$ 34,500
May-10	$ 0.45	3488	$ 1,578	$ 36,078
Jun-10	$ 0.45	3488	$ 1,578	$ 37,656
Jul-10	$ 0.45	3488	$ 1,578	$ 39,234
Aug-10	$ 0.45	3488	$ 1,578	$ 40,813
Sep-10	$ 0.45	3488	$ 1,578	$ 42,391
Oct-10	$ 0.45	3488	$ 1,578	$ 43,969
Nov-10	$ 0.45	3488	$ 1,578	$ 45,547
Dec-10	$ 0.45	3488	$ 1,578	$ 47,125
Jan-11	$ 0.45	3488	$ 1,578	$ 48,704
Feb-11	$ 0.45	3488	$ 1,578	$ 50,282
Mar-11	$ 0.45	3488	$ 1,578	$ 51,860
Apr-11	$ 0.45	3488	$ 1,578	$ 53,438
May-11	$ 0.45	3488	$ 1,578	$ 55,017
Jun-11	$ 0.45	3488	$ 1,578	$ 56,595
Jul-11	$ 0.45	3488	$ 1,578	$ 58,173
Aug-11	$ 0.45	3488	$ 1,578	$ 59,751
Sep-11	$ 0.45	3488	$ 1,578	$ 61,330
Oct-11	$ 0.45	3488	$ 1,578	$ 62,908
Nov-11	$ 0.45	3488	$ 1,578	$ 64,486
Dec-11	$ 0.45	3488	$ 1,578	$ 66,064
Jan-12	$ 0.45	3488	$ 1,578	$ 67,643
Feb-12	$ 0.45	3488	$ 1,578	$ 69,221
Mar-12	$ 0.45	3488	$ 1,578	$ 70,799
Apr-12	$ 0.45	3488	$ 1,578	$ 72,377

Chatham-Kent Hydro Inc.
EB-2009-0277
Tuesday, September 29, 2009
Sheet 4. Smart Meter Rate Calc

Smart Meter Rate Calculation

	2008			2009			2010			2009			2010		
Average Asset Values															
Net Fixed Assets Smart Meters	$ 202,572.73			$ 391,174.93			$ 363,233.87			$ 335,292.80			$ 307,351.73		
Net Fixed Assets Computer Hardware	$ 3,997.17			$ 7,106.08			$ 5,329.56			$ 3,553.04			$ 1,776.52		
Net Fixed Assets Computer Software	$ 2,944.07			$ 4,710.51			$ 2,355.25			$ 588.81			$ -		
Net Fixed Assets Tools & Equipment	$ -			$ -			$ -			$ -			$ -		
Net Fixed Assets Other Equipment	$ -			$ -			$ -			$ -			$ -		
Total Net Fixed Assets	$ 209,513.97	$ 209,513.97		$ 402,991.52	$ 402,991.52		$ 370,918.68	$ 370,918.68		$ 339,434.65	$ 339,434.65		$ 309,128.25	$ 309,128.25	
Working Capital															
Operation Expense	$ 423,820.49			$ -			$ -			$ -			$ -		
Working Capital 15 %	$ 63,573.07	$ 63,573.07		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -	
Smart Meters included in Rate Base		$ 273,087.04			$ 402,991.52			$ 370,918.68			$ 339,434.65			$ 309,128.25	
Return on Rate Base															
Deemed Debt *(3. LDC Assumptions and Data)*	50.0%	$ 136,543.52		53.3%	$ 214,794.48		53.3%	$ 197,699.66		50.0%	$ 169,717.33		50.0%	$ 154,564.13	
Deemed Equity *(3. LDC Assumptions and Data)*	50.0%	$ 136,543.52		46.7%	$ 188,197.04		46.7%	$ 173,219.02		50.0%	$ 169,717.33		50.0%	$ 154,564.13	
		$ 273,087.04			$ 402,991.52			$ 370,918.68			$ 339,434.65			$ 309,128.25	
Weighted Debt Rate *(3. LDC Assumptions and Data)*	7.0%	$ 9,612.66		7.0%	$ 15,121.53		7.0%	$ 13,918.06		7.0%	$ 11,948.10		7.0%	$ 10,881.31	
Proposed ROE *(3. LDC Assumptions and Data)*	9.0%	$ 12,288.92		9.0%	$ 16,937.73		9.0%	$ 15,589.71		9.0%	$ 15,274.56		9.0%	$ 13,910.77	
Return on Rate Base		$ 21,901.58	$ 21,901.58		$ 32,059.26	$ 32,059.26		$ 29,507.77	$ 29,507.77		$ 27,222.66	$ 27,222.66		$ 24,792.09	$ 24,792.09
Operating Expenses															
Incremental Operating Expenses *(3. LDC Assumptions and Data)*			$ 423,820.49			$ -			$ -			$ -			$ -
Amortization Expenses															
Amortization Expenses - Smart Meters		$ 13,970.53			$ 27,941.07			$ 27,941.07			$ 27,941.07			$ 27,941.07	
Amortization Expenses - Computer Hardware		$ 888.26			$ 1,776.52			$ 1,776.52			$ 1,776.52			$ 1,776.52	
Amortization Expenses - Computer Software		$ 1,177.63			$ 2,355.25			$ 2,355.25			$ 1,177.63			$ -	
Amortization Expenses - Tools & Equipment		$ -			$ -			$ -			$ -			$ -	
Amortization Expenses - Other Equipment		$ -			$ -			$ -			$ -			$ -	
Total Amortization Expenses			$ 16,036.42			$ 32,072.84			$ 32,072.84			$ 30,895.21			$ 29,717.59
Revenue Requirement Before PILs			$ 461,758.49			$ 64,132.10			$ 61,580.61			$ 58,117.87			$ 54,509.67
Calculation of Taxable Income															
Incremental Operating Expenses			-$ 423,820.49			$ -			$ -			$ -			$ -
Depreciation Expenses			-$ 16,036.42			-$ 32,072.84			-$ 32,072.84			-$ 30,895.21			-$ 29,717.59
Interest Expense			-$ 9,612.66			-$ 15,121.53			-$ 13,918.06			-$ 11,948.10			-$ 10,881.31
Taxable Income For PILs			$ 12,288.92			$ 16,937.73			$ 15,589.71			$ 15,274.56			$ 13,910.77
Grossed up PILs *(5. PILs)*			$ 5,764.91			$ 6,833.44			$ 8,616.20			$ 9,658.41			$ 9,768.36
Revenue Requirement Before PILs			$ 461,758.49			$ 64,132.10			$ 61,580.61			$ 58,117.87			$ 54,509.67
Grossed up PILs *(5. PILs)*			$ 5,764.91			$ 6,833.44			$ 8,616.20			$ 9,658.41			$ 9,768.36
Revenue Requirement for Smart Meters			**$ 467,523.40**			**$ 70,965.54**			**$ 70,196.81**			**$ 67,776.29**			**$ 64,278.03**
2007 Smart Meter Rate Adder															
Revenue Requirement for Smart Meters			$ 467,523.40			$ 70,965.54			$ 70,196.81			$ 67,776.29			$ 64,278.03
2006 EDR Total Metered Customers *(3. LDC Assumptions and Data)*			31,872			31,872			31,872			31,872			31,872
Annualized amount required per metered customer			$ 14.67			$ 2.23			$ 2.20			$ 2.13			$ 2.02
Number of months in year			12			12			12			12			12
2007 Smart Meter Rate Adder			**$ 1.22**			**$ 0.19**			**$ 0.18**			**$ 0.18**			**$ 0.17**

Chatham-Kent Hydro Inc.
EB-2009-0277
Tuesday, September 29, 2009
Sheet 5. PILs

PILs Calculation

	2007	2008	2008	2009	2010
INCOME TAX					
Net Income	$ 12,288.92	$ 16,937.73	$ 15,589.71	$ 15,274.56	$ 13,910.77
Amortization	$ 16,036.42	$ 32,072.84	$ 32,072.84	$ 30,895.21	$ 29,717.59
CCA - Class 47 (8%) Smart Meters	-$ 16,764.64	-$ 32,188.11	-$ 29,613.06	-$ 27,244.02	-$ 25,064.49
CCA - Class 45 (45%) Computers	-$ 3,588.38	-$ 5,561.99	-$ 3,059.09	-$ 1,682.50	-$ 925.38
CCA - Class 8 (20%) Other Equipment	$ -	$ -	$ -	$ -	$ -
Change in taxable income	$ 7,972.32	$ 11,260.47	$ 14,990.40	$ 17,243.26	$ 17,638.49
Tax Rate *(3. LDC Assumptions and Data)*	36.12%	33.50%	33.50%	33.50%	33.50%
Income Taxes Payable	$ 2,879.60	$ 3,772.26	$ 5,021.78	$ 5,776.49	$ 5,908.89
ONTARIO CAPITAL TAX					
Smart Meters	$ 405,145.47	$ 377,204.40	$ 349,263.33	$ 321,322.27	$ 293,381.20
Computer Hardware	$ 7,994.34	$ 6,217.82	$ 4,441.30	$ 2,664.78	$ 888.26
Computer Software	$ 5,888.13	$ 3,532.88	$ 1,177.63	$ -	$ -
Tools & Equipment	$ -	$ -	$ -	$ -	$ -
Other Equipment	$ -	$ -	$ -	$ -	$ -
Rate Base	$ 419,027.94	$ 386,955.10	$ 354,882.26	$ 323,987.05	$ 294,269.46
Less: Exemption	$ -	$ -	$ -	$ -	$ -
Deemed Taxable Capital	$ 419,027.94	$ 386,955.10	$ 354,882.26	$ 323,987.05	$ 294,269.46
Ontario Capital Tax Rate	0.300%	0.300%	0.300%	0.300%	0.300%
Net Amount (Taxable Capital x Rate)	$ 1,257.08	$ 1,160.87	$ 1,064.65	$ 971.96	$ 882.81

Gross Up

	PILs Payable	PILs Payable	PILs Payable	PILs Payable	PILs Payable
Change in Income Taxes Payable	$ 2,879.60	$ 3,772.26	$ 5,021.78	$ 5,776.49	$ 5,908.89
Change in OCT	$ 1,257.08	$ 1,160.87	$ 1,064.65	$ 971.96	$ 882.81
PIL's	$ 4,136.68	$ 4,933.12	$ 6,086.43	$ 6,748.45	$ 6,791.70

4. Smart Meter Rate Calc

	Gross Up	Gross Up	Gross Up	Gross Up	Gross Up
	36.12%	33.50%	33.50%	33.50%	33.50%

	Grossed Up PILs	Grossed Up PILs	Grossed Up PILs	Grossed Up PILs	Grossed Up PILs
Change in Income Taxes Payable	$ 4,507.83	$ 5,672.57	$ 7,551.55	$ 8,686.45	$ 8,885.55
Change in OCT	$ 1,257.08	$ 1,160.87	$ 1,064.65	$ 971.96	$ 882.81
PIL's	**$ 5,764.91**	**$ 6,833.44**	**$ 8,616.20**	**$ 9,658.41**	**$ 9,768.36**

Smart Meter Average Net Fixed Assets

Net Fixed Assets - Smart Meters

	2007	2008	2008	2009	2010
Opening Capital Investment	$ -	$ 419,116.00	$ 419,116.00	$ 419,116.00	$ 419,116.00
Capital Investment *(3. LDC Assumptions and Data)*	$ 419,116.00	$ -	$ -	$ -	$ -
Closing Capital Investment	$ 419,116.00	$ 419,116.00	$ 419,116.00	$ 419,116.00	$ 419,116.00
Opening Accumulated Amortization	$ -	$ 13,970.53	$ 41,911.60	$ 69,852.67	$ 97,793.73
Amortization Year 1 (15 Years Straight Line)	$ 13,970.53	$ 27,941.07	$ 27,941.07	$ 27,941.07	$ 27,941.07
Closing Accumulated Amortization	$ 13,970.53	$ 41,911.60	$ 69,852.67	$ 97,793.73	$ 125,734.80
Opening Net Fixed Assets	$ -	$ 405,145.47	$ 377,204.40	$ 349,263.33	$ 321,322.27
Closing Net Fixed Assets	$ 405,145.47	$ 377,204.40	$ 349,263.33	$ 321,322.27	$ 293,381.20
Average Net Fixed Assets	$ 202,572.73	$ 391,174.93	$ 363,233.87	$ 335,292.80	$ 307,351.73

Net Fixed Assets - Computer Hardware

	2007	2008	2008	2009	2010
Opening Capital Investment	$ -	$ 8,882.60	$ 8,882.60	$ 8,882.60	$ 8,882.60
Capital Investment *(3. LDC Assumptions and Data)*	$ 8,882.60	$ -	$ -	$ -	$ -
Closing Capital Investment	$ 8,882.60	$ 8,882.60	$ 8,882.60	$ 8,882.60	$ 8,882.60
Opening Accumulated Amortization	$ -	$ 888.26	$ 2,664.78	$ 4,441.30	$ 6,217.82
Amortization Year 1 (5 Years Straight Line)	$ 888.26	$ 1,776.52	$ 1,776.52	$ 1,776.52	$ 1,776.52
Closing Accumulated Amortization	$ 888.26	$ 2,664.78	$ 4,441.30	$ 6,217.82	$ 7,994.34
Opening Net Fixed Assets	$ -	$ 7,994.34	$ 6,217.82	$ 4,441.30	$ 2,664.78
Closing Net Fixed Assets	$ 7,994.34	$ 6,217.82	$ 4,441.30	$ 2,664.78	$ 888.26
Average Net Fixed Assets	$ 3,997.17	$ 7,106.08	$ 5,329.56	$ 3,553.04	$ 1,776.52

Net Fixed Assets - Computer Software

	2007	2008	2008	2009	2010
Opening Capital Investment	$ -	$ 7,065.76	$ 7,065.76	$ 7,065.76	$ 7,065.76
Capital Investment *(3. LDC Assumptions and Data)*	$ 7,065.76	$ -	$ -	$ -	$ -
Closing Capital Investment	$ 7,065.76	$ 7,065.76	$ 7,065.76	$ 7,065.76	$ 7,065.76
Opening Accumulated Amortization	$ -	$ 1,177.63	$ 3,532.88	$ 5,888.13	$ 7,065.76
Amortization Year 1 (3 Years Straight Line)	$ 1,177.63	$ 2,355.25	$ 2,355.25	$ 1,177.63	$ -
Closing Accumulated Amortization	$ 1,177.63	$ 3,532.88	$ 5,888.13	$ 7,065.76	$ 7,065.76
Opening Net Fixed Assets	$ -	$ 5,888.13	$ 3,532.88	$ 1,177.63	$ -
Closing Net Fixed Assets	$ 5,888.13	$ 3,532.88	$ 1,177.63	$ -	$ -
Average Net Fixed Assets	$ 2,944.07	$ 4,710.51	$ 2,355.25	$ 588.81	$ -

Net Fixed Assets - Tools & Equipment

	2007	2008	2008	2009	2010
Opening Capital Investment	$ -	$ -	$ -	$ -	$ -
Capital Investment *(3. LDC Assumptions and Data)*	$ -	$ -	$ -	$ -	$ -
Closing Capital Investment	$ -	$ -	$ -	$ -	$ -
Opening Accumulated Amortization	$ -	$ -	$ -	$ -	$ -
Amortization Year 1 (10 Years Straight Line)	$ -	$ -	$ -	$ -	$ -

Chatham-Kent Hydro Inc.
EB-2009-0277
Tuesday, September 29, 2009

Sheet 6. SM Avg Net Fixed Assets &UCC

Closing Accumulated Amortization	$ -	$ -	$ -	$ -	$ -
Opening Net Fixed Assets	$ -	$ -	$ -	$ -	$ -
Closing Net Fixed Assets	$ -	$ -	$ -	$ -	$ -
Average Net Fixed Assets	$ -	$ -	$ -	$ -	$ -

Net Fixed Assets - Other Equipment

	2007	2008	2008	2009	2010
Opening Capital Investment	$ -	$ -	$ -	$ -	$ -
Capital Investment *(3. LDC Assumptions and Data)*	$ -	$ -	$ -	$ -	$ -
Closing Capital Investment	$ -	$ -	$ -	$ -	$ -
Opening Accumulated Amortization	$ -	$ -	$ -	$ -	$ -
Amortization Year 1 (10 Years Straight Line)	$ -	$ -	$ -	$ -	$ -
Closing Accumulated Amortization	$ -	$ -	$ -	$ -	$ -
Opening Net Fixed Assets	$ -	$ -	$ -	$ -	$ -
Closing Net Fixed Assets	$ -	$ -	$ -	$ -	$ -
Average Net Fixed Assets	$ -	$ -	$ -	$ -	$ -

Chatham-Kent Hydro Inc.
EB-2009-0277
Tuesday, September 29, 2009
Sheet 6. SM Avg Net Fixed Assets &UCC

For PILs Calculation

UCC - Smart Meters

CCA Class 47 (8%)	2007	2008	2008	2009	2010
Opening UCC	$ -	$ 402,351.36	$ 370,163.25	$ 340,550.19	$ 313,306.18
Capital Additions	$ 419,116.00	$ -	$ -	$ -	$ -
UCC Before Half Year Rule	$ 419,116.00	$ 402,351.36	$ 370,163.25	$ 340,550.19	$ 313,306.18
Half Year Rule (1/2 Additions - Disposals)	$ 209,558.00	$ -	$ -	$ -	$ -
Reduced UCC	$ 209,558.00	$ 402,351.36	$ 370,163.25	$ 340,550.19	$ 313,306.18
CCA Rate Class 47	8.0%	8.0%	8.0%	8.0%	8.0%
CCA	$ 16,764.64	$ 32,188.11	$ 29,613.06	$ 27,244.02	$ 25,064.49
Closing UCC	$ 402,351.36	$ 370,163.25	$ 340,550.19	$ 313,306.18	$ 288,241.68

UCC - Computer Equipment

CCA Class 45 (45%)	2007	2008	2008	2009	2010
Opening UCC	$ -	$ 12,359.98	$ 6,797.99	$ 3,738.89	$ 2,056.39
Capital Additions Computer Hardware	$ 8,882.60	$ -	$ -	$ -	$ -
Capital Additions Computer Software	$ 7,065.76	$ -	$ -	$ -	$ -
UCC Before Half Year Rule	$ 15,948.36	$ 12,359.98	$ 6,797.99	$ 3,738.89	$ 2,056.39
Half Year Rule (1/2 Additions - Disposals)	$ 7,974.18	$ -	$ -	$ -	$ -
Reduced UCC	$ 7,974.18	$ 12,359.98	$ 6,797.99	$ 3,738.89	$ 2,056.39
CCA Rate Class 45	45%	45%	45%	45%	45%
CCA	$ 3,588.38	$ 5,561.99	$ 3,059.09	$ 1,682.50	$ 925.38
Closing UCC	$ 12,359.98	$ 6,797.99	$ 3,738.89	$ 2,056.39	$ 1,131.02

UCC - General Equipment

CCA Class 8 (20%)	2007	2008	2008	2009	2010
Opening UCC	$ -	$ -	$ -	$ -	$ -
Capital Additions Tools & Equipment	$ -	$ -	$ -	$ -	$ -
Capital Additions Other Equipment	$ -	$ -	$ -	$ -	$ -
UCC Before Half Year Rule	$ -	$ -	$ -	$ -	$ -
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ -	$ -	$ -
Reduced UCC	$ -	$ -	$ -	$ -	$ -
CCA Rate Class 8	20%	20%	20%	20%	20%
CCA	$ -	$ -	$ -	$ -	$ -
Closing UCC	$ -	$ -	$ -	$ -	$ -

Chatham-Kent Hydro Inc.
EB-2009-0277
Tuesday, September 29, 2009
Sheet 4. Smart Meter Rate Calc

Smart Meter Rate Calculation

	2009			2010			2011			2012		
Average Asset Values												
Net Fixed Assets Smart Meters	$ -			$ -			$ -			$ -		
Net Fixed Assets Computer Hardware	$ -			$ -			$ -			$ -		
Net Fixed Assets Computer Software	$ -			$ -			$ -			$ -		
Net Fixed Assets Tools & Equipment	$ -			$ -			$ -			$ -		
Net Fixed Assets Other Equipment	$ -			$ -			$ -			$ -		
Total Net Fixed Assets	$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -	
Working Capital												
Operation Expense	$ -			$ -			$ -			$ -		
Working Capital 15 %	$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -	
Smart Meters included in Rate Base		$ -			$ -			$ -			$ -	
Return on Rate Base												
Deemed Debt *(3. LDC Assumptions and Data)*	53.3%	$ -		53.3%	$ -		53.3%	$ -		50.0%	$ -	
Deemed Equity *(3. LDC Assumptions and Data)*	46.7%	$ -		46.7%	$ -		46.7%	$ -		50.0%	$ -	
		$ -			$ -			$ -			$ -	
Weighted Debt Rate *(3. LDC Assumptions and Data)*	7.0%	$ -		7.0%	$ -		7.0%	$ -		7.0%	$ -	
Proposed ROE *(3. LDC Assumptions and Data)*	9.0%	$ -		9.0%	$ -		9.0%	$ -		9.0%	$ -	
Return on Rate Base		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Operating Expenses												
Incremental Operating Expenses *(3. LDC Assumptions and Data)*			$ -			$ -			$ -			$ -
Amortization Expenses												
Amortization Expenses - Smart Meters		$ -			$ -			$ -			$ -	
Amortization Expenses - Computer Hardware		$ -			$ -			$ -			$ -	
Amortization Expenses - Computer Software		$ -			$ -			$ -			$ -	
Amortization Expenses - Tools & Equipment		$ -			$ -			$ -			$ -	
Amortization Expenses - Other Equipment		$ -			$ -			$ -			$ -	
Total Amortization Expenses			$ -			$ -			$ -			$ -
Revenue Requirement Before PILs			$ -			$ -			$ -			$ -
Calculation of Taxable Income												
Incremental Operating Expenses			$ -			$ -			$ -			$ -
Depreciation Expenses			$ -			$ -			$ -			$ -
Interest Expense			$ -			$ -			$ -			$ -
Taxable Income For PILs			$ -			$ -			$ -			$ -
Grossed up PILs *(5. PILs)*			$ -			$ -			$ -			$ -
Revenue Requirement Before PILs			$ -			$ -			$ -			$ -
Grossed up PILs *(5. PILs)*			$ -			$ -			$ -			$ -
Revenue Requirement for Smart Meters			**$ -**			**$ -**			**$ -**			**$ -**
2007 Smart Meter Rate Adder												
Revenue Requirement for Smart Meters			$ -			$ -			$ -			$ -
2006 EDR Total Metered Customers *(3. LDC Assumptions and Data)*			31,872			31,872			31,872			31,872
Annualized amount required per metered customer			$ -			$ -			$ -			$ -
Number of months in year			12			12			12			12
2007 Smart Meter Rate Adder			**$ -**			**$ -**			**$ -**			**$ -**

Chatham-Kent Hydro Inc.
EB-2009-0277
Tuesday, September 29, 2009
Sheet 5. PILs

PILs Calculation

	2009	2010	2011	2012
INCOME TAX				
Net Income	$ -	$ -	$ -	$ -
Amortization	$ -	$ -	$ -	$ -
CCA - Class 47 (8%) Smart Meters	$ -	$ -	$ -	$ -
CCA - Class 45 (45%) Computers	$ -	$ -	$ -	$ -
CCA - Class 8 (20%) Other Equipment	$ -	$ -	$ -	$ -
Change in taxable income	$ -	$ -	$ -	$ -
Tax Rate *(3. LDC Assumptions and Data)*	33.50%	33.50%	33.50%	33.50%
Income Taxes Payable	$ -	$ -	$ -	$ -
ONTARIO CAPITAL TAX				
Smart Meters	$ -	$ -	$ -	$ -
Computer Hardware	$ -	$ -	$ -	$ -
Computer Software	$ -	$ -	$ -	$ -
Tools & Equipment	$ -	$ -	$ -	$ -
Other Equipment	$ -	$ -	$ -	$ -
Rate Base	$ -	$ -	$ -	$ -
Less: Exemption	$ -	$ -	$ -	$ -
Deemed Taxable Capital	$ -	$ -	$ -	$ -
Ontario Capital Tax Rate	0.300%	0.300%	0.300%	0.300%
Net Amount (Taxable Capital x Rate)	$ -	$ -	$ -	$ -

Gross Up

	PILs Payable	PILs Payable	PILs Payable	PILs Payable
Change in Income Taxes Payable	$ -	$ -	$ -	$ -
Change in OCT	$ -	$ -	$ -	$ -
PIL's	$ -	$ -	$ -	$ -

	Gross Up	Gross Up	Gross Up	Gross Up
	33.50%	33.50%	33.50%	33.50%

	Grossed Up PILs	Grossed Up PILs	Grossed Up PILs	Grossed Up PILs
Change in Income Taxes Payable	$ -	$ -	$ -	$ -
Change in OCT	$ -	$ -	$ -	$ -
PIL's	$ -	$ -	$ -	$ -

Smart Meter Average Net Fixed Assets

Net Fixed Assets - Smart Meters

	2009	2010	2011	2012
Opening Capital Investment	$ -	$ -	$ -	$ -
Capital Investment *(3. LDC Assumptions and Data)*	$ -	$ -	$ -	$ -
Closing Capital Investment	$ -	$ -	$ -	$ -
Opening Accumulated Amortization	$ -	$ -	$ -	$ -
Amortization Year 1 (15 Years Straight Line)	$ -	$ -	$ -	$ -
Closing Accumulated Amortization	$ -	$ -	$ -	$ -
Opening Net Fixed Assets	$ -	$ -	$ -	$ -
Closing Net Fixed Assets	$ -	$ -	$ -	$ -
Average Net Fixed Assets	$ -	$ -	$ -	$ -

Net Fixed Assets - Computer Hardware

	2009	2010	2011	2012
Opening Capital Investment	$ -	$ -	$ -	$ -
Capital Investment *(3. LDC Assumptions and Data)*	$ -	$ -	$ -	$ -
Closing Capital Investment	$ -	$ -	$ -	$ -
Opening Accumulated Amortization	$ -	$ -	$ -	$ -
Amortization Year 1 (5 Years Straight Line)	$ -	$ -	$ -	$ -
Closing Accumulated Amortization	$ -	$ -	$ -	$ -
Opening Net Fixed Assets	$ -	$ -	$ -	$ -
Closing Net Fixed Assets	$ -	$ -	$ -	$ -
Average Net Fixed Assets	$ -	$ -	$ -	$ -

Net Fixed Assets - Computer Software

	2009	2010	2011	2012
Opening Capital Investment	$ -	$ -	$ -	$ -
Capital Investment *(3. LDC Assumptions and Data)*	$ -	$ -	$ -	$ -
Closing Capital Investment	$ -	$ -	$ -	$ -
Opening Accumulated Amortization	$ -	$ -	$ -	$ -
Amortization Year 1 (3 Years Straight Line)	$ -	$ -	$ -	$ -
Closing Accumulated Amortization	$ -	$ -	$ -	$ -
Opening Net Fixed Assets	$ -	$ -	$ -	$ -
Closing Net Fixed Assets	$ -	$ -	$ -	$ -
Average Net Fixed Assets	$ -	$ -	$ -	$ -

Net Fixed Assets - Tools & Equipment

	2009	2010	2011	2012
Opening Capital Investment	$ -	$ -	$ -	$ -
Capital Investment *(3. LDC Assumptions and Data)*	$ -	$ -	$ -	$ -
Closing Capital Investment	$ -	$ -	$ -	$ -
Opening Accumulated Amortization	$ -	$ -	$ -	$ -
Amortization Year 1 (10 Years Straight Line)	$ -	$ -	$ -	$ -

Chatham-Kent Hydro Inc.
EB-2009-0277
Tuesday, September 29, 2009

Sheet 6. SM Avg Net Fixed Assets &UCC

Closing Accumulated Amortization	$ -	$ -	$ -	$ -
Opening Net Fixed Assets	$ -	$ -	$ -	$ -
Closing Net Fixed Assets	$ -	$ -	$ -	$ -
Average Net Fixed Assets	$ -	$ -	$ -	$ -

Net Fixed Assets - Other Equipment

	2009	2010	2011	2012
Opening Capital Investment	$ -	$ -	$ -	$ -
Capital Investment *(3. LDC Assumptions and Data)*	$ -	$ -	$ -	$ -
Closing Capital Investment	$ -	$ -	$ -	$ -
Opening Accumulated Amortization	$ -	$ -	$ -	$ -
Amortization Year 1 (10 Years Straight Line)	$ -	$ -	$ -	$ -
Closing Accumulated Amortization	$ -	$ -	$ -	$ -
Opening Net Fixed Assets	$ -	$ -	$ -	$ -
Closing Net Fixed Assets	$ -	$ -	$ -	$ -
Average Net Fixed Assets	$ -	$ -	$ -	$ -

Chatham-Kent Hydro Inc.
EB-2009-0277
Tuesday, September 29, 2009
Sheet 6. SM Avg Net Fixed Assets &UCC

For PILs Calculation

UCC - Smart Meters

CCA Class 47 (8%)	2009	2010	2011	2012
Opening UCC	$ -	$ -	$ -	$ -
Capital Additions	$ -	$ -	$ -	$ -
UCC Before Half Year Rule	$ -	$ -	$ -	$ -
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ -	$ -
Reduced UCC	$ -	$ -	$ -	$ -
CCA Rate Class 47	8.0%	8.0%	8.0%	8.0%
CCA	$ -	$ -	$ -	$ -
Closing UCC	$ -	$ -	$ -	$ -

UCC - Computer Equipment

CCA Class 45 (45%)	2009	2010	2011	2012
Opening UCC	$ -	$ -	$ -	$ -
Capital Additions Computer Hardware	$ -	$ -	$ -	$ -
Capital Additions Computer Software	$ -	$ -	$ -	$ -
UCC Before Half Year Rule	$ -	$ -	$ -	$ -
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ -	$ -
Reduced UCC	$ -	$ -	$ -	$ -
CCA Rate Class 45	45%	45%	45%	45%
CCA	$ -	$ -	$ -	$ -
Closing UCC	$ -	$ -	$ -	$ -

UCC - General Equipment

CCA Class 8 (20%)	2009	2010	2011	2012
Opening UCC	$ -	$ -	$ -	$ -
Capital Additions Tools & Equipment	$ -	$ -	$ -	$ -
Capital Additions Other Equipment	$ -	$ -	$ -	$ -
UCC Before Half Year Rule	$ -	$ -	$ -	$ -
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ -	$ -
Reduced UCC	$ -	$ -	$ -	$ -
CCA Rate Class 8	20%	20%	20%	20%
CCA	$ -	$ -	$ -	$ -
Closing UCC	$ -	$ -	$ -	$ -

Chatham-Kent Hydro Inc.
EB-2009-0277
Tuesday, September 29, 2009
Sheet 4. Smart Meter Rate Calc

Smart Meter Rate Calculation

	2010			2011			2012			2013		
Average Asset Values												
Net Fixed Assets Smart Meters	$ -			$ -			$ -			$ -		
Net Fixed Assets Computer Hardware	$ -			$ -			$ -			$ -		
Net Fixed Assets Computer Software	$ -			$ -			$ -			$ -		
Net Fixed Assets Tools & Equipment	$ -			$ -			$ -			$ -		
Net Fixed Assets Other Equipment	$ -			$ -			$ -			$ -		
Total Net Fixed Assets	$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -	
Working Capital												
Operation Expense	$ -			$ -			$ -			$ -		
Working Capital 15 %	$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -	
Smart Meters included in Rate Base		$ -			$ -			$ -			$ -	
Return on Rate Base												
Deemed Debt *(3. LDC Assumptions and Data)*	50.0%	$ -		50.0%	$ -		50.0%	$ -		50.0%	$ -	
Deemed Equity *(3. LDC Assumptions and Data)*	50.0%	$ -		50.0%	$ -		50.0%	$ -		50.0%	$ -	
		$ -			$ -			$ -			$ -	
Weighted Debt Rate *(3. LDC Assumptions and Data)*	7.0%	$ -		7.0%	$ -		7.0%	$ -		7.0%	$ -	
Proposed ROE *(3. LDC Assumptions and Data)*	9.0%	$ -		9.0%	$ -		9.0%	$ -		9.0%	$ -	
Return on Rate Base		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Operating Expenses												
Incremental Operating Expenses *(3. LDC Assumptions and Data)*			$ -			$ -			$ -			$ -
Amortization Expenses												
Amortization Expenses - Smart Meters		$ -			$ -			$ -			$ -	
Amortization Expenses - Computer Hardware		$ -			$ -			$ -			$ -	
Amortization Expenses - Computer Software		$ -			$ -			$ -			$ -	
Amortization Expenses - Tools & Equipment		$ -			$ -			$ -			$ -	
Amortization Expenses - Other Equipment		$ -			$ -			$ -			$ -	
Total Amortization Expenses			$ -			$ -			$ -			$ -
Revenue Requirement Before PILs			$ -			$ -			$ -			$ -
Calculation of Taxable Income												
Incremental Operating Expenses			$ -			$ -			$ -			$ -
Depreciation Expenses			$ -			$ -			$ -			$ -
Interest Expense			$ -			$ -			$ -			$ -
Taxable Income For PILs			$ -			$ -			$ -			$ -
Grossed up PILs *(5. PILs)*			$ -			$ -			$ -			$ -
Revenue Requirement Before PILs			$ -			$ -			$ -			$ -
Grossed up PILs *(5. PILs)*			$ -			$ -			$ -			$ -
Revenue Requirement for Smart Meters			**$ -**			**$ -**			**$ -**			**$ -**
2007 Smart Meter Rate Adder												
Revenue Requirement for Smart Meters			$ -			$ -			$ -			$ -
2006 EDR Total Metered Customers *(3. LDC Assumptions and Data)*			31,872			31,872			31,872			31,872
Annualized amount required per metered customer			$ -			$ -			$ -			$ -
Number of months in year			12			12			12			12
2007 Smart Meter Rate Adder			**$ -**			**$ -**			**$ -**			**$ -**

Chatham-Kent Hydro Inc.
EB-2009-0277
Tuesday, September 29, 2009
Sheet 5. PILs

PILs Calculation

	2010	2011	2012	2013
INCOME TAX				
Net Income	$ -	$ -	$ -	$ -
Amortization	$ -	$ -	$ -	$ -
CCA - Class 47 (8%) Smart Meters	$ -	$ -	$ -	$ -
CCA - Class 45 (45%) Computers	$ -	$ -	$ -	$ -
CCA - Class 8 (20%) Other Equipment	$ -	$ -	$ -	$ -
Change in taxable income	$ -	$ -	$ -	$ -
Tax Rate *(3. LDC Assumptions and Data)*	33.50%	33.50%	33.50%	33.50%
Income Taxes Payable	$ -	$ -	$ -	$ -
ONTARIO CAPITAL TAX				
Smart Meters	$ -	$ -	$ -	$ -
Computer Hardware	$ -	$ -	$ -	$ -
Computer Software	$ -	$ -	$ -	$ -
Tools & Equipment	$ -	$ -	$ -	$ -
Other Equipment	$ -	$ -	$ -	$ -
Rate Base	$ -	$ -	$ -	$ -
Less: Exemption	$ -	$ -	$ -	$ -
Deemed Taxable Capital	$ -	$ -	$ -	$ -
Ontario Capital Tax Rate	0.300%	0.300%	0.300%	0.300%
Net Amount (Taxable Capital x Rate)	$ -	$ -	$ -	$ -

Gross Up

	PILs Payable	PILs Payable	PILs Payable	PILs Payable
Change in Income Taxes Payable	$ -	$ -	$ -	$ -
Change in OCT	$ -	$ -	$ -	$ -
PIL's	$ -	$ -	$ -	$ -
	Gross Up 33.50%	Gross Up 33.50%	Gross Up 33.50%	Gross Up 33.50%

	Grossed Up PILs	Grossed Up PILs	Grossed Up PILs	Grossed Up PILs
Change in Income Taxes Payable	$ -	$ -	$ -	$ -
Change in OCT	$ -	$ -	$ -	$ -
PIL's	$ -	$ -	$ -	$ -

Chatham-Kent Hydro Inc.
EB-2009-0277
Tuesday, September 29, 2009
Sheet 6. SM Avg Net Fixed Assets &UCC

Smart Meter Average Net Fixed Assets

Net Fixed Assets - Smart Meters

	2010	2011	2012	2013
Opening Capital Investment	$ -	$ -	$ -	$ -
Capital Investment *(3. LDC Assumptions and Data)*	$ -	$ -	$ -	$ -
Closing Capital Investment	$ -	$ -	$ -	$ -
Opening Accumulated Amortization	$ -	$ -	$ -	$ -
Amortization Year 1 (15 Years Straight Line)	$ -	$ -	$ -	$ -
Closing Accumulated Amortization	$ -	$ -	$ -	$ -
Opening Net Fixed Assets	$ -	$ -	$ -	$ -
Closing Net Fixed Assets	$ -	$ -	$ -	$ -
Average Net Fixed Assets	$ -	$ -	$ -	$ -

Net Fixed Assets - Computer Hardware

	2010	2011	2012	2013
Opening Capital Investment	$ -	$ -	$ -	$ -
Capital Investment *(3. LDC Assumptions and Data)*	$ -	$ -	$ -	$ -
Closing Capital Investment	$ -	$ -	$ -	$ -
Opening Accumulated Amortization	$ -	$ -	$ -	$ -
Amortization Year 1 (5 Years Straight Line)	$ -	$ -	$ -	$ -
Closing Accumulated Amortization	$ -	$ -	$ -	$ -
Opening Net Fixed Assets	$ -	$ -	$ -	$ -
Closing Net Fixed Assets	$ -	$ -	$ -	$ -
Average Net Fixed Assets	$ -	$ -	$ -	$ -

Net Fixed Assets - Computer Software

	2010	2011	2012	2013
Opening Capital Investment	$ -	$ -	$ -	$ -
Capital Investment *(3. LDC Assumptions and Data)*	$ -	$ -	$ -	$ -
Closing Capital Investment	$ -	$ -	$ -	$ -
Opening Accumulated Amortization	$ -	$ -	$ -	$ -
Amortization Year 1 (3 Years Straight Line)	$ -	$ -	$ -	$ -
Closing Accumulated Amortization	$ -	$ -	$ -	$ -
Opening Net Fixed Assets	$ -	$ -	$ -	$ -
Closing Net Fixed Assets	$ -	$ -	$ -	$ -
Average Net Fixed Assets	$ -	$ -	$ -	$ -

Net Fixed Assets - Tools & Equipment

	2010	2011	2012	2013
Opening Capital Investment	$ -	$ -	$ -	$ -
Capital Investment *(3. LDC Assumptions and Data)*	$ -	$ -	$ -	$ -
Closing Capital Investment	$ -	$ -	$ -	$ -
Opening Accumulated Amortization	$ -	$ -	$ -	$ -
Amortization Year 1 (10 Years Straight Line)	$ -	$ -	$ -	$ -

Chatham-Kent Hydro Inc.
EB-2009-0277
Tuesday, September 29, 2009

Sheet 6. SM Avg Net Fixed Assets &UCC

Closing Accumulated Amortization	$ -	$ -	$ -	$ -
Opening Net Fixed Assets	$ -	$ -	$ -	$ -
Closing Net Fixed Assets	$ -	$ -	$ -	$ -
Average Net Fixed Assets	$ -	$ -	$ -	$ -

Net Fixed Assets - Other Equipment

	2010	2011	2012	2013
Opening Capital Investment	$ -	$ -	$ -	$ -
Capital Investment *(3. LDC Assumptions and Data)*	$ -	$ -	$ -	$ -
Closing Capital Investment	$ -	$ -	$ -	$ -
Opening Accumulated Amortization	$ -	$ -	$ -	$ -
Amortization Year 1 (10 Years Straight Line)	$ -	$ -	$ -	$ -
Closing Accumulated Amortization	$ -	$ -	$ -	$ -
Opening Net Fixed Assets	$ -	$ -	$ -	$ -
Closing Net Fixed Assets	$ -	$ -	$ -	$ -
Average Net Fixed Assets	$ -	$ -	$ -	$ -

Chatham-Kent Hydro Inc.
EB-2009-0277
Tuesday, September 29, 2009
Sheet 6. SM Avg Net Fixed Assets &UCC

For PILs Calculation

UCC - Smart Meters

CCA Class 47 (8%)	2010	2011	2012	2013
Opening UCC	$ -	$ -	$ -	$ -
Capital Additions	$ -	$ -	$ -	$ -
UCC Before Half Year Rule	$ -	$ -	$ -	$ -
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ -	$ -
Reduced UCC	$ -	$ -	$ -	$ -
CCA Rate Class 47	8.0%	8.0%	8.0%	8.0%
CCA	$ -	$ -	$ -	$ -
Closing UCC	$ -	$ -	$ -	$ -

UCC - Computer Equipment

CCA Class 45 (45%)	2010	2011	2012	2013
Opening UCC	$ -	$ -	$ -	$ -
Capital Additions Computer Hardware	$ -	$ -	$ -	$ -
Capital Additions Computer Software	$ -	$ -	$ -	$ -
UCC Before Half Year Rule	$ -	$ -	$ -	$ -
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ -	$ -
Reduced UCC	$ -	$ -	$ -	$ -
CCA Rate Class 45	45%	45%	45%	45%
CCA	$ -	$ -	$ -	$ -
Closing UCC	$ -	$ -	$ -	$ -

UCC - General Equipment

CCA Class 8 (20%)	2010	2011	2012	2013
Opening UCC	$ -	$ -	$ -	$ -
Capital Additions Tools & Equipment	$ -	$ -	$ -	$ -
Capital Additions Other Equipment	$ -	$ -	$ -	$ -
UCC Before Half Year Rule	$ -	$ -	$ -	$ -
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ -	$ -
Reduced UCC	$ -	$ -	$ -	$ -
CCA Rate Class 8	20%	20%	20%	20%
CCA	$ -	$ -	$ -	$ -
Closing UCC	$ -	$ -	$ -	$ -

Smart Meter Rate Carrying Cost Recovery Required

Chatham-Kent Hydro Inc.

	Opening	Rev Req	Recovery	Int. Rate	Interest	Closing
Nov-07	$ -	$ -	$ -	4.59%	$ -	$ -
Dec-07	$ -	$ -	$ -	4.59%	$ -	$ -
Jan-08	$ -	$ -	$ -	4.59%	$ -	$ -
Feb-08	$ -	$ -	$ -	4.59%	$ -	$ -
Mar-08	$ -	$ -	$ -	4.59%	$ -	$ -
Apr-08	$ -	$ -	$ -	4.59%	$ -	$ -
May-08	$ -	$ -	$ -	4.59%	$ -	$ -
Jun-08	$ -	$ -	$ -	4.59%	$ -	$ -
Jul-08	$ -	$ -	$ -	4.59%	$ -	$ -
Aug-08	$ -	$ -	$ -	4.59%	$ -	$ -
Sep-08	$ -	$ -	$ -	4.59%	$ -	$ -
Oct-08	$ -	$ -	$ -	4.59%	$ -	$ -
Nov-08	$ -	$ -	$ -	4.59%	$ -	$ -
Dec-08	$ -	$ -	$ -	4.59%	$ -	$ -
Jan-09	$ -	$ -	$ -	4.59%	$ -	$ -
Feb-09	$ -	$ -	$ -	4.59%	$ -	$ -
Mar-09	$ -	$ -	$ -	4.59%	$ -	$ -
Apr-09	$ -	$ -	$ -	4.59%	$ -	$ -
May-09	$ -	$ -	$ -	4.59%	$ -	$ -
Jun-09	$ -	$ -	$ -	4.59%	$ -	$ -
Jul-09	$ -	$ -	$ -	4.59%	$ -	$ -
Aug-09	$ -	$ -	$ -	4.59%	$ -	$ -
Sep-09	$ -	$ -	$ -	4.59%	$ -	$ -
Oct-09	$ -	$ -	$ -	4.59%	$ -	$ -
Nov-09	$ -	#REF!	$ -	4.59%	$ -	#REF!
Dec-09	#REF!	#REF!	$ -	4.59%	#REF!	#REF!
Jan-10	#REF!	#REF!	$ -	4.59%	#REF!	#REF!
Feb-10	#REF!	#REF!	$ -	4.59%	#REF!	#REF!
Carrying Cost Recovery Required on Permanent Adder					**#REF!**	

Monthly	Months	Perm Rev Req
#REF!	12	#REF!

APPENDIX C

SMART METER MODEL FOR RATE ADDER

Smart Meter Revenue Requirement & Proposed Rates- Summary

Summary of Actual Costs claimed in this application	2009 Capital		2010 Capital	Total
Capital Costs ***(must be installed, and used and useful)***				
Smart Meters	$ 600,000		$ 750,000	$ 1,350,000
Computer Hardware	$ -		$ -	$ -
Computer Software	$ -		$ -	$ -
Tools & Equipment	$ -		$ -	$ -
Other Equipment *(please specify)*	$ -		$ -	$ -
Total Capital Costs	$ 600,000		$ 750,000	$ 1,350,000
O M & A				
2.1 Advanced metering communication device (AMCD)	$ -		$ -	$ -
2.2 Advanced metering regional collector (AMRC) (includes LAN)	$ -		$ -	$ -
2.3 Advanced metering control computer (AMCC)	$ -		$ -	$ -
2.4 Wide area network (WAN)	$ -		$ -	$ -
2.5 Other AMI OM&A costs related to minimum functionality	$ -		$ -	$ -
Total O M & A Costs	$ -		$ -	$ -

Summary of Revenue Requirement Calculation	2009 Capital		2010 Capital	Total
Net Fixed Assets				
Net Fixed Assets Beginning of Year	$ -		$ 580,000	
Net Fixed Assets End of Year	$ 580,000		$ 1,265,000	
Average Net Fixed Asset Values	$ 290,000	$ -	$ 922,500	
Working Capital Allowance				
Operation Expense	$ -	$ -	$ -	
Working Capital Allowance	$ -	$ -	$ -	
Smart Meters Rate Base	$ 290,000	$ -	$ 922,500	
Return on Rate Base				
Deemed Debt	$ 11,570		$ 39,856	$ 51,425
Deemed Equity	$ 11,309		$ 29,557	$ 40,866
Return on Rate Base	$ 22,879	$ -	$ 69,413	$ 92,291
Operating Expenses				
Incremental Operating Expenses	$ -	$ -	$ -	$ -
Amortization Expenses	$ 20,000	$ -	$ 65,000	$ 85,000
Total Operating Expenses	$ 20,000	$ -	$ 65,000	$ 85,000

	2009 Capital		2010 Capital	Total
Revenue Requirement Before PILs	$ 42,879		$ 134,413	$ 177,291
Grossed up PILs	$ 5,322		$ 13,909	$ 19,231
Revenue Requirement for Smart Meters	**$ 48,201**		**$ 148,322**	**$ 196,523**

Rate Adder for Capital In 2009 and 2010	Rate Adder	Metered Customers per 2010	No. of Mths	Amount Recovered
May 1, 2010 to April 30, 2011	**$ 0.51**	**32,132**	**12**	**$ 196,523**

Deemed Capital Structure	**2009**	**2010**
STD	0.0%	4%
LTD	56.7%	56%
Equity	43.3%	40.0%
Capitl Rates		
STD	0.0%	1.33%
LTD	7.04%	7.62%
Equity	9.0%	8.01%
Tax Rate	32%	

Overview:

Chatham-Kent Hydro hired EnerSpectrum Group, a consulting group that has extensive experience in providing LDCs with advice on many issues and especially in LRAM/SSM calculations. The Lost Revenue Adjustment Mechanism ("LRAM") and Shared Savings Mechanism ("SSM") calculations and evidence provided in this submission are mainly as a result of the report from EnerSpectrum Group which can be found in Appendix A. Chatham-Kent Hydro is also providing evidence and reports from Navigator (Appendix B), a consultant that performed research on behalf of the Independent Electricity System Operator ("IESO") and from Navigant Consulting Inc (Appendix C).

On May 31, 2004, the Minister of Energy granted approval to all electricity distributors in Ontario to apply to the OEB for adjustments to their 2005 electricity distribution rates that would enable them to recover the third tranche of their incremental market adjusted revenue requirements ("MARR"). The Minister's approval was conditional on a commitment to reinvest an equivalent amount in Conservation and Demand Management ("CDM") initiatives. The CDM Plans of Chatham-Kent Hydro were approved by the OEB in December 2004 (with a Final Order issued in February 2005) and February 2005, respectively.

Chatham-Kent Hydro's CDM efforts have been successful, but as a result, with decreases in kWh consumption and kW demand, Chatham-Kent Hydro has experienced distribution revenue losses. Chatham-Kent Hydro has also been a strong supporter of CDM programs offered by the Ontario Power Authority ("OPA"). The success of these programs has also caused distribution revenue losses.

The OEB has authorized distributors to apply for LRAM and SSM adjustments. The authorization to apply for LRAM and SSM adjustments for 2006 to 2009 is derived from the OEB's December 2004 Decision on the Pollution Probe motion in file No. RP-2004-0203; and the OEB's May 2005 Report on the 2006 Electricity Distribution Rate Handbook (the "Report", OEB File No. RP-2004-0188). Chatham-Kent Hydro is requesting LRAM adjustments for 2006 to 2009. Chatham-Kent Hydro is applying for SSM adjustments for 2006 to 2008 that relate to conservation programs offered by Chatham-Kent Hydro. The SSM claim follows the OEB guidelines. The 2009 LRAM adjustment only reflects programs implemented in 2008 and earlier; the 2009 programs and the LRAM adjustments that relate to those programs will be applied for in future applications.

At page 107 of the Report, the OEB addressed LRAM recoveries, stating:

> "In its December 2004 Decision RP-2004-0203, the board concluded that an LRAM was appropriate and that it should apply to 3rd tranche expenditures. The Board indicated, at that time, that the LRAM formula would be established as part of the 2006 proceeding.
>
> The Board continues to believe that an LRAM is appropriate and concludes that it will be retrospective, not prospective. At this time, greater accuracy will be achieved if the LRAM is calculated after-the-fact, based on actual results.
>
> Accordingly, a distributor will be expected to calculate the energy savings by customer class and to value those energy savings by the board-approved distribution charge appropriate to that class. The resulting amount may be claimed in a subsequent rate year as compensation for lost revenue".

With respect to SSM, at page 110 of its Report, the OEB wrote:

> "The Board, in its RP-2004-0203 Decision, found that a distributor shareholder incentive was an appropriate way to encourage distributors to pursue CDM programs. The Board continues to be of this view. Distributors should be rewarded with 5 percent of the net savings established by the TRC test. The Board recognizes that it will be essential to establish certain inputs and to define avoided costs. Accordingly, the Board's Conservation Manual will address these matters. This will allow parties to screen CDM programs and calculate the relevant incentives."

At page 111 of the Report, the OEB wrote:

> "The SSM will apply to TRC benefits achieved by 3rd tranche expenditures as well as any incremental expenditures that are approved in 2006. However, as in the case of the Board's Decision with respect to 2005, the incentive will not apply to utility-side activities. Because the SSM will be retrospective, no claims for a shareholder incentive should be made in the 2006 rate applications.
>
> There has been considerable discussion in this proceeding as to whether CDM expenditures on the utility side should be differentiated from customer-side expenditures. The Board recognizes that conservation programs should have a balance between the two. It is important to recall however, the Board's earlier finding that the SSM incentive does not apply to utility-side investments. The Board previously ruled with respect to the 2005 SSM that the inclusion of capitalised assets into rate base provides sufficient incentives. The Board continues to hold that view."

In accordance with the OEB Report, Chatham-Kent Hydro's LRAM/SSM request includes only customer-side activities. For Chatham-Kent Hydro programs the energy savings has been calculated by customer class and their value has been determined using the OEB-approved distribution charge appropriate to each class, as required by the Report. For OPA-sponsored programs the energy savings calculations are provided by the OPA. The value of those savings is calculated by Chatham-Kent Hydro using OEB-approved distribution charges appropriate to each class, as required by the Report.

In its April 28, 2005 "Guidelines for Electricity Distributors Wishing to Apply for SSM Incentive for 2005 Implementation of CDM Plans" (referred to here as the "SSM Guidelines"), the OEB stated (at page 2):

> "Inputs and assumptions of the TRC Test have to be clearly stated in the pre-filed evidence. Applicants may use the standard inputs for TRC calculation which are contained in the Board's Conservation Manual (available late June 2005). Where an applicant wishes to use other inputs, the applicant must provide supporting evidence, an explanation of its choice and, for comparison, the TRC Test results using the inputs contained in the Conservation Manual."

On September 8, 2005 the OEB issued its Conservation Manual, under the name of the Total Resource Cost Guide (the "TRC Guide"). The TRC Guide set out an OEB-approved methodology and associated parameters for the financial evaluation of CDM programs. The TRC Guide was revised October 2, 2006 to reflect the OEB's Decision in the EB-2005-0523 proceeding concerning the attribution of benefits between utilities and non-rate-regulated third parties.

In addition to the requirements with respect to the other aspects of this Application, the Filing Requirements contain provisions relating to applications for LRAM and SSM adjustments, and Chatham-Kent Hydro submits that it has relied on and complied with the LRAM/SSM provisions of the Report and, the OEB's TRC Guide and the Filing Requirements in preparing this request for LRAM/SSM adjustments for the years 2006 to 2009.

This request is also consistent with the OEB's September 11, 2007 Decision and Order in EB-2007-0096 – the application by Toronto Hydro-Electric System Limited for an Order or Orders granting approval and recovery of amounts related to CDM activities (the "Toronto Hydro Decision").

APPENDIX A

ENERSPECTRUM GROUP LRAM AND SSM REPORT

EnerSpectrum Group

The preferred source for utility management expertise.

Chatham-Kent Hydro Inc.

LRAM and SSM Support

August 25, 2009

Prepared by: Bart Burman, MBA, BA.Sc. P.Eng., Managing Partner

Introduction

Chatham Kent Hydro Inc. serves more than 32,000 customers in south-western Ontario, and has been a proponent of energy efficiency and conservation for many years. Through innovative communications such as Code Green television, Turn it Off, Turn it Down, Trade it In program, educational initiatives, and others with the same message, Chatham-Kent Hydro has raised community awareness of, and commitment to, conservation. This awareness and commitment served the LDC well during its Third Tranche CDM programming, and continues to help keep Chatham-Kent Hydro customers among the most CDM supportive customers in Ontario.

Chatham-Kent Hydro’s awareness efforts have proven fertile ground for one of Ontario’s first pilot programs on the impacts of smart metering on customer behavioural change, and the early installation of 28,552 residential smart meters by the end of 2007. As supporting studies appended to this document demonstrate, there is a relationship between awareness of the conservation imperative and reduced energy consumption, and a relationship between time-of-use (TOU) electricity rates and reduced energy consumption.

Chatham Kent Hydro was also active in the refitting of street lighting with more energy-efficient technologies during the Third Tranche CDM years. More than 1869 streetlights were relamped or removed in 2006, resulting in annual energy savings of more than 3.7 million kWh for municipal infrastructure between 2007 and 2009.

As an incentive to LDCs to participate in Conservation and Demand Management (CDM) programs, the Ontario Energy Board (OEB) introduced a process for rates-based applications to recover revenues lost to customer energy conservation, and to share in gains from effective CDM programs. The mechanisms developed by the OEB to calculate lost revenue or savings are the Lost Revenue Adjustment Mechanism (LRAM) and the Shared Savings Mechanism (SSM).

SSM is calculated as 5% of the net present value of the future net benefits from CDM investments. LRAM calculations are performed using energy savings data from measured CDM program results, or other documented results as applied to the affected rate class. OPA sponsored programs, such as Every Kilowatt Counts, although not eligible for SSM, represent the potential for lost revenue, and may be claimed under LRAM.

Chatham-Kent Hydro is considering filing application for LRAM and SSM adjustments based on its CDM results from its smart meter installations and street lighting retrofits.

Required

Chatham-Kent Hydro has asked EnerSpectrum Group to assist with LRAM and SSM assessment on three levels:

1. Prepare Total Resource Cost (TRC) calculations for Chatham-Kent Hydro with regard to both the smart meter and street lighting programs and calculate an SSM claim as appropriate
2. Assess energy savings to calculate lost revenue consistent with Chatham-Kent Hydro Inc.'s CDM program results; prepare LRAM calculations suitable for submission
3. Summarize SSM and LRAM calculations and assumptions suitable for inclusion in Chatham-Kent Hydro Inc.'s rates application, with supporting details.
4. In performing the above tasks, EnerSpectrum Group's involvement is intended to constitute 3rd party review as specified in OEB Guidelines.
5. As OPA CDM program results became available, additional LRAM calculations were completed.

About SSM/LRAM

LRAM/SSM application is governed by the OEB issued GUIDELINES FOR ELECTRICITY DISTRIBUTOR CONSERVATION AND DEMAND MANAGEMENT, EB-2008-0037.

For SSM, a distributor may recover 5% of the net benefits (TRC) created by CDM portfolio investments. An SSM claim applies only to customer focused initiatives that reduce the demand for electricity and/or the amount of energy used. Programs designed to improve Distribution System efficiency (eg. loss reduction) and OPA sponsored programs (eg., Every Kilowatt Counts) are excluded from SSM considerations.

LRAM is calculated as the product of the demand/energy savings by customer class and the Board-approved variable distribution charge appropriate to the class (net of Regulatory Asset Recovery rate riders).

Methodology

To optimize the calculation of LRAM and SSM amounts, EnerSpectrum Group:

1. Reviewed existing LRAM and SSM guidelines and precedents set through LDC submissions to the OEB, to identify the most prudent course to complete its LRAM and SSM applications.
2. Sought counsel within OEB staff to validate assumptions and processes to complete LRAM and SSM submissions consistent with other LDC submissions.
3. Researched and reviewed studies in the elasticity of energy demand for residential customers with time-of-use (TOU) rates, as a means of corroborating the findings for Chatham-Kent Hydro's TOU pilot with residential customers
4. Reviewed Third Tranche CDM program results and TRC calculations, verified assumptions and calculations, identified variances with reported values, and recommended adjustments as appropriate
5. Performed LRAM/SSM calculations based on verified results, and approved rates by class

6. Prepared report and recommendations related to LRAM and SSM calculations

Elasticity of Demand from TOU Rates

As part of a pilot program to assess the impact of TOU rates on residential energy consumption, Chatham-Kent Hydro installed some 1000 smart meters in 2005. The LDC also engaged a consulting firm, Navigant, in 2007 to analyze energy consumption patterns related to TOU rates for 213 residential customers in one subdivision, compared to a control group in a similar subdivision who remained on a Regulated Price Plan structure. Chatham-Kent Hydro installed an additional 27,552 smart meters between 2006 and 2007 as part of its planned deployment of smart meters, and were not part of the pilot program. In aggregate, 28,522 smart meters were installed between 2005 and the end of 2007.

Navigant found that lower consumption in the morning hours (Off-Peak and mid peak period), slightly higher consumption in the later evening hours than the control group, and that pilot participants marginally shifted their consumption away from the On-Peak period to later in the evening, in comparison to the control group. However, there were no statistically significant differences in the percentage of overall consumption by TOU period between the pilot participants and the control group during the evaluation period. This was attributed in part to the impacts of Chatham-Kent Hydro's CDM awareness and education programs since 2002, meaning that both pilot and control participants had likely adjusted their consumption patterns prior to the TOU pilot. Overall, Chatham-Kent Hydro residential customers showed a greater reduction in consumption compared to comparable LDC customers between 2002 and 2007, due in part to aggressive conservation promotions and education.

However, research of studies completed on the impact of TOU rates on residential energy consumption in North America, Europe and Australia reveal that there are consistently lower consumption patterns with TOU rates as compared to regulated price plans or tiered rates not based on the time of consumption. Notably, work by Ahmad Faruqui and Sanem Sergici1of the Brattle Group subsequently posted on the Harvard University website for electricity policy papers, found a link between price elasticity and TOU rates in a review of the 15 most recent studies:

> *We find conclusive evidence that residential customers respond to higher prices by lowering their electricity usage. The magnitude of price response depends on several factors, such as the magnitude of the price increase, the presence of central air conditioning and the availability of enabling technologies such as two-way programmable communicating thermostats and always-on gateway systems that allow multiple end-uses to be controlled remotely. Across the range of experiments studied, time-of use rates induce a drop in peak demand that ranges between three to six percent*

> *and critical-peak pricing rates induce a drop in peak demand that ranges between 13 to 20 percent.* [1]

Significantly, one of the studies reviewed was the Ontario Energy Board's residential Ontario Smart Price Pilot (OSPP) between August 2006 and March 2007 applied to a sample of Hydro Ottawa residential customers. The pilot demonstrated that the average impact of TOU rates compared to regulated price plan averaged a 6 % reduction in energy consumption over the test period.[2] The 373 participants also showed a significant propensity to shift loads to off-peak times.

EnerSpectrum Group believes that it is both consistent with the review of multiple TOU studies undertaken by Faruqui and Sergicil, and specifically the OEB's Smart Price Pilot, that a 4% reduction in energy consumption can be reasonably attributed to the 28,522 smart meters installed, combined with its customer education and awareness programs. Based on customer feedback, the education activities undertaken motivated them to behave as though they were already on TOU rates once a smart meter was installed. Therefore it is reasonable to attribute some savings for LRAM purposes to all smart meters installed. This attribution recognizes that the LDC was both an early promoter of conservation and implementer of smart meter technology. It is also reasonable to attribute the largest energy savings under TOU rates during peak demand periods when electricity prices also peak. However, the magnitude of the savings at peak load periods over different times of year are not known, so savings have been assumed to be distributed equally over a 24-hour period for the purpose of LRAM and SSM calculations. Although it appears to be an oversimplification, it is more prudent for the purposes of this evaluation.

Results

CDM Programs and Timing

In assessing and applying results from CDM programming to TRC, LRAM or SSM calculations, program results are assumed to begin after the program implementation has been completed. For this reason, the results of specific programs have been staggered into subsequent months or years to more accurately reflect the timing of the impacts from CDM programs. Where the results from a CDM program are reasonably expected to begin flowing in the same year, LRAM calculations will be prorated to the end of that year.

---

[1] SMART METERS AND SMART PRICING—A SURVEY OF THE EXPERIMENTAL EVIDENCE, Appendix A

[2] **HOUSEHOLD RESPONSE TO DYNAMIC PRICING OF ELECTRICITY—A SURVEY OF THE EXPERIMENTAL EVIDENCE** Appendix B

Determination of SSM Amount

As set out in the Guidelines, program net benefits are determined by the present value of the avoided electricity costs over the technology's/program's life minus the present value of program costs, net of free ridership.

EnerSpectrum Group has validated and applied TRC methodology against the EB-2008-0037 Guidelines and calculated net TRC benefits for each CDM program that is part of this claim. CDM administrative and support costs were included as part of overall portfolio TRC costs. EnerSpectrum Group's TRC Calculator © was used to ensure appropriate application of avoided costs, free ridership, discounted future benefits, energy efficiency technology life. Since no TRC amounts were submitted as part of Chatham-Kent Hydro's previous CDM Annual Reports to the OEB, these values were calculated for both programs based on LDC-originated assumptions.

Utility-side programs, such as loss reduction initiatives, are not eligible for SSM treatment, which excludes the results of Chatham-Kent Hydro's voltage conversion (4 kV to 27.6kV) (system loss reduction) program from the calculations in this report. Also excluded from SSM calculations were results from OPA sponsored programs (e.g., Every Kilowatt Counts).

The Smart Meter program considered for this application is described in annually submitted year end CDM reports. For each eligible program, net load reductions were calculated (net of free ridership) for both SSM and LRAM calculations. Based on the TOU elasticity studies previously outlined, a 4% net load reduction is assumed for the calculation of TRC for all residential customers who received a smart meter. Load reductions applied to the Streetlight Program are reported by technology type as set out in the accompanying support binder. Attachment A summarizes the load reductions.

The discount rates applied for Chatham-Kent Hydro Inc.(approved Weighted Average Cost of Capital) were 8.02%, 8.02%, and 7.96% for the years 2006, 2007 and 2008 respectively.

The sum of all program NPVs, is $4,091,149, resulting in the SSM claim of $204,557.

Attachment C summarizes the calculation of the SSM amounts by program and in total.

Determination of LRAM Amount

LRAM amounts were identified by rate class consistent with the approved guidelines.
No forecast or other adjustment for the effects of CDM programs was made to the load quantities used in the preparation of Chatham-Kent Hydro's rate cases in prior years. It is Chatham-Kent Hydro's submission that the entire actual load reduction achieved by the two eligible CDM programs is subject to LRAM treatment. In addition, OPA sponsored programs, although ineligible for additional SSM incentives, represent lost revenue through their successful implementation and are included in LRAM calculations.

The sum of all program LRAM calculations, including OPA sponsored programs is $569,637 Attachment B summarizes the CDM load impacts by program and rate class and the resultant revenue impacts.

Allocation and Manner of Recovery for SSM/LRAM Amounts

The kWh savings arising from the CDM programs are attributed to the rate class where the savings originated to identify the dollar impacts for recovery purposes.

Rate Implementation

Chatham-Kent Hydro will determine the appropriate rate riders for recovery of the following revenue adjustments.

Rate Class	LRAM $	SSM $	Total
Residential Third Tranche	$347,010.21	$181,266.20	$528,276.41
Street Light Third Tranche	$4,136.53	$23,291.25	$27,427.79
Residential OPA Conservation Programs	$204,896.77		$204,896.77
Commercial OPA Conservation Programs	$13,593.86		$13,593.86
TOTALS	$569,637.37	$204,557.46	$774,194.83

Recommendations

EnerSpectrum Group recommends the following:

1. SSM/LRAM amounts arising from CDM programs in each rate class should be allocated to that class for recovery.
2. Incorporate impacts of CDM programming which occurred during the period 2005 to 2008 In future Cost of Service rate applications inclusive. This recognizes CDM as an established customer service element in the years ahead, with identifiable costs and benefits.

3. Use SSM calculation as one of the methods to assess the potential value of CDM programs considered for implementation.

4. Monitor OPA information and reports pursuant to its email of July 14, 2009 to all LDC conservation officers and program managers. The OPA stated that "2008 results are still preliminary and are subject to change" If final program results for KWHI subsequently change for any OPA program, updates or adjustments may need to be considered for the LRAM and SSM amounts calculated in this report. This report did not consider any OPA programs implemented or operated during 2009, as the results for these programs will not be available until sometime in 2010. Any savings attributed to 2009 for LRAM purposes are based on assumed results carried over from OPA programs implemented in previous years only.

Attachment A

CDM Load Impacts by Class and Program

Class / Program	Year Implemented	2006 kWh	2006 kW	2007 kWh	2007 kW	2008 kWh	2008 kW	2009 kWh	2009 kW	Total kWh	Total kW
Residential											
Third Tranche											
Smart Meters	2006			4,535,875.42		10,126,539.60		10,126,539.60		**14,662,415.02**	**0.00**
Street Lighting											
Third Tranche											
Street Lights	2006			1,866,950.05	443.18	1,866,950.05	443.18	1,866,950.05	443.18	**3,733,900.10**	**886.36**
Residential											
OPA Conservation Programs											
Every Kilowatt Counts (spring)	2006	813,348.19	5.30	813,348.19	5.30	813,348.19	5.30	813,348.19	5.30	**2,440,044.56**	**15.90**
Cool Savings Rebate Program	2006 & 2007 & 2008	61,992.72	63.50	235,408.05	177.34	338,027	260	338,027	260	**635,427.74**	**501.05**
Secondary Fridge Retirement Pilot	2006	33,297.71	7.55	33,297.71	7.55	33,298	8	33,298	8	**99,893.14**	**22.64**
Every Kilowatt Counts (fall)	2006	1,319,497.16	19.85	1,319,497.16	19.85	1,319,497	20	1,319,497	20	**3,958,491.47**	**59.56**
Great Refrigerator Roundup	2007 & 2008			152,797.07	17.24	330,186	34	330,186	34	**482,983.38**	**51.36**
Aboriginal – Pilot	2007 & 2008			0.00	0.00	0	0	0	0	**0.00**	**0.00**
Every Kilowatt Counts	2007			758,448.66	29.12	749,251	26	749,251	26	**1,507,699.52**	**55.51**
peaksaver®	2007 & 2008			0.00	61.09	0	131	0	131	**0.00**	**191.93**
Summer Savings	2007			454,501.19	252.50	454,501	253	0	0	**909,002.37**	**505.00**
Affordable Housing – Pilot	2007			93,753.67	3.09	93,754	3	93,754	3	**187,507.34**	**6.18**
Social Housing – Pilot	2007			68,353.88	8.04	68,354	8	68,354	8	**136,707.75**	**16.08**
Energy Efficiency Assistance for Houses – Pilot	2007			0.00	0.00	0	0	0	0	**0.00**	**0.00**
Summer Sweepstakes	2008					0	1	0	0	**0.00**	**1.01**
Every Kilowatt Counts Power Savings Event	2008					256,618	17	254,509	17	**256,618.37**	**17.16**
General Service (< 50 kW Demand)											
OPA Conservation Programs											
Toronto Comprehensive	2007 & 2008			0.00	0.00	0	0	0	0	**0.00**	**0.00**
Electricity Retrofit Incentive Program	2007 & 2008			0.00	0.00	142,653	63	142,653	63	**142,652.61**	**62.57**
High Performance New Construction	2008					2,090	1	2,090	1	**2,090.21**	**0.92**
Power Savings Blitz	2008					5,186	1	5,186	1	**5,185.84**	**0.71**
Chiller Plant Re-Commissioning	2008					0	0	0	0	**0.00**	**0.00**
General Service (> 50 kW Demand)											
OPA Conservation Programs											
Demand Response 1	2006 & 2007 & 2008	0.00	1,430.45	0	2,311.62	0	2,312	0	0	**0.00**	**6,053.90**
Other Demand Response	2007 & 2008			0.00	192.27	0	213	0	0	**0.00**	**405.01**
Demand Response 3	2008					0	581	0	0	**0.00**	**581.47**
Unmetered Scattered Load											
OPA Conservation Programs											
LDC Custom	2008					0	0	0	0	**0.00**	**0.00**
Other Customer Based Generation	2008					0	0	0	0	**0.00**	**0.00**
Renewable Energy Standard Offer Program (RESOP)	2007 & 2008			0.00	0.00	0	0	0	0	**0.00**	**0.00**
TOTALS		2,228,135.77	1,526.65	10,332,231.03	3,528.20	16,600,252.62	4,379.47	16,143,641.97	1,019.29	**29,160,619.43**	**9,434.32**

Attachment B

Foregone Revenue by Class and Program

Class		2006			2007			2008			2009			
Program	**Year Implemented**	Load Unit (kWh)	Rate per Unit	Revenue	Load Unit (kWh)	Rate per Unit	Revenue	Load Unit (kWh)	Rate per Unit	Revenue	Load Unit (kWh)	Rate per Unit	Revenue	**Total Revenue**
Residential														
Third Tranche														
Smart Meters	2006				4,535,875.42	0.0141	$63,804.65	10,126,539.60	0.0140	$142,109.11	10,126,539.60	0.0139	$141,096.45	**$347,010.21**
Street Lighting														
Third Tranche														
Street Lights	2006				443.18	3.1232	$1,380.01	443.18	3.1045	$1,378.61	443.18	3.1115	$1,377.91	**$4,136.53**
Residential														
OPA Conservation Programs														
Every Kilowatt Counts (spring)	2006	813,348.19	0.0140	$11,441.10	813,348.19	0.0141	$11,441.10	813,348.19	0.0140	$11,413.99	813,348.19	0.0139	$11,332.65	**$45,628.83**
Cool Savings Rebate Program	2006 & 2007 & 2008	61,992.72	0.0140	$872.03	235,408.05	0.0141	$3,311.41	338,027	0.0140	$4,743.65	338,027	0.0139	$4,709.84	**$13,636.93**
Secondary Fridge Retirement Pilot	2006	33,297.71	0.0140	$468.39	33,297.71	0.0141	$468.39	33,298	0.0140	$467.28	33,298	0.0139	$463.95	**$1,868.00**
Every Kilowatt Counts (fall)	2006	1,319,497.16	0.0140	$18,560.93	1,319,497.16	0.0141	$18,560.93	1,319,497	0.0140	$18,516.94	1,319,497	0.0139	$18,384.99	**$74,023.79**
Great Refrigerator Roundup	2007 & 2008				152,797.07	0.0141	$2,149.35	330,186	0.0140	$4,633.61	330,186	0.0139	$4,600.60	**$11,383.56**
Aboriginal – Pilot	2007 & 2008				0.00	0.0141	$0.00	0	0.0140	$0.00	0	0.0139	$0.00	**$0.00**
Every Kilowatt Counts	2007				758,448.66	0.0141	$10,668.84	749,251	0.0140	$10,514.49	749,251	0.0139	$10,439.56	**$31,622.89**
peaksaver®	2007 & 2008				0.00	0.0141	$0.00	0	0.0140	$0.00	0	0.0139	$0.00	**$0.00**
Summer Savings	2007				454,501.19	0.0141	$6,393.32	454,501	0.0140	$6,378.17	0	0.0139	$0.00	**$12,771.48**
Affordable Housing – Pilot	2007				93,753.67	0.0141	$1,318.80	93,754	0.0140	$1,315.68	93,754	0.0139	$1,306.30	**$3,940.78**
Social Housing – Pilot	2007				68,353.88	0.0141	$961.51	68,354	0.0140	$959.23	68,354	0.0139	$952.40	**$2,873.14**
Energy Efficiency Assistance for Houses – Pilot	2007				0.00	0.0141	$0.00	0	0.0140	$0.00	0	0.0139	$0.00	**$0.00**
Summer Sweepstakes	2008							0	0.0140	$0.00	0	0.0139	$0.00	**$0.00**
Every Kilowatt Counts Power Savings Event	2008							256,618	0.0140	$3,601.21	254,509	0.0139	$3,546.16	**$7,147.37**
General Service (< 50 kW Demand)														
OPA Conservation Programs														
Toronto Comprehensive	2007 & 2008				0.00	0.0093	$0.00	0	0.0092	$0.00	0	0.0092	$0.00	**$0.00**
Electricity Retrofit Incentive Program	2007 & 2008				0.00	0.0093	$0.00	142,653	0.0092	$1,317.16	142,653	0.0092	$1,312.40	**$2,629.56**
High Performance New Construction	2008							2,090	0.0092	$19.30	2,090	0.0092	$19.23	**$38.53**
Power Savings Blitz	2008							5,186	0.0092	$47.88	5,186	0.0092	$47.71	**$95.59**
Chiller Plant Re-Commissioning	2008							0	0.0092	$0.00	0	0.0092	$0.00	**$0.00**
General Service (> 50 kW Demand)														
OPA Conservation Programs														
Demand Response 1	2006 & 2007 & 2008	1,430.45	1.5636	$2,010.83	2,312	1.5777	$3,636.17	2,312	1.5682	$3,632.74	0	1.5717	$0.00	**$9,279.74**
Other Demand Response	2007 & 2008				192.27	1.5777	$302.44	213	1.5682	$334.29	0	1.5717	$0.00	**$636.73**
Demand Response 3	2008							581	1.5682	$913.71	0	1.5717	$0.00	**$913.71**
Unmetered Scattered Load														
OPA Conservation Programs														
LDC Custom	2008							0	0.0054	$0.00	0	0.0054	$0.00	**$0.00**
Other Customer Based Generation	2008							0	0.0054	$0.00	0	0.0054	$0.00	**$0.00**
Renewable Energy Standard Offer Program (RESOP)	2007 & 2008				0.00	0.0054	$0.00	0	0.0054	$0.00	0	0.0054	$0.00	**$0.00**
TOTALS		2,229,566.22	1.6196	$33,353.27	8,468,228.04	6.4859	$124,396.91	14,736,851.79	8.0813	$212,297.03	14,277,135.09	8.10	$199,590.16	$569,637.37

Attachment C

SSM Amounts by Class and Program

Class / Program	Admin Costs $	Total Costs $	Total Benefits $	Net Benefits $ NPV	Benefits/ Cost Ratio	SSM Amount $
2006						
Residential						
Third Tranche						
Smart Meters	$357,780.00	$5,961,601.32	$9,586,925.38	$3,625,324.06	$1.61	$181,266.20
Street Lighting						
Third Tranche						
Street Lights	$21,203.58	$201,203.58	$667,028.65	$465,825.07	$3.32	$23,291.25
TOTALS	$378,983.58	$6,162,804.90	$10,253,954.03	$4,091,149.13	$4.92	$204,557.46

Attachment D

LRAM and SSM Totals and Rate Riders by Class - 1 Year Recovery

Rate Class

	LRAM $	SSM $	Total
Residential / **Third Tranche**	$347,010.21	$181,266.20	$528,276.41
Street Light / **Third Tranche**	$4,136.53	$23,291.25	$27,427.79
Residential / **OPA Conservation Programs**	$204,896.77		$204,896.77
Commercial / **OPA Conservation Programs**	$13,593.86		$13,593.86
TOTALS	$569,637.37	$204,557.46	$774,194.83

SMART METERS AND SMART PRICING—A SURVEY OF THE EXPERIMENTAL EVIDENCE

Ahmad Faruqui and Sanem Sergici[1]
The Brattle Group

All around the globe, regulators and utilities are focused on smart meters. In the EU, smart meters are widely regarded as central to achieving the 20-20-20 goals. However, without providing customers with smart price signals, it is doubtful that the purported benefits of smart meters would accrue. Much of the policy debate over smart meters thus far has focused on how to get the meters installed and who should pay for them. An equally important challenge for European policy makers and regulators is to ensure that utilities have an incentive to use smart meters fully- to make smart prices part of an offer that will attract new customers.

If smart prices are offered in conjunction with smart meters, what will be the likely impacts on customer energy use and peak demand? To help inform this assessment, we have surveyed the evidence from the 15 most recent experiments conducted in the U.S., Canada, Australia, and France with dynamic pricing of electricity. We find conclusive evidence that residential customers respond to higher prices by lowering their electricity usage. The magnitude of price response depends on several factors, such as the magnitude of the price increase, the presence of central air conditioning and the availability of enabling technologies such as two-way programmable communicating thermostats and always-on gateway systems that allow multiple end-uses to be controlled remotely. Across the range of experiments studied, time-of-use rates induce a drop in peak demand that ranges between three to six percent and critical-peak pricing rates induce a drop in peak demand that ranges between 13 to 20 percent. When accompanied with enabling technologies, the latter set of rates lead to a drop in peak demand in the 27 to 44 percent range.

All experiments reviewed in our survey are based on panel data, involving repeated measurements on a cross-section of customers. Some of the customers are placed on the dynamic pricing rate (or rates) and fall into the treatment group. Others stay on existing rates and fall into the control group. Technically, the control group should be randomly chosen. Otherwise, the design becomes a quasi experiment. The better designs feature measurement during the pre-treatment period which allows self-selection bias in the treatment group to be detected. It also allows for the application of the "difference in differences" estimator which computes the difference in usage between the treatment and pre-treatment periods and subtracts from it the pre-existing difference between treatment and control group customers. Finally, the superior designs feature multiple price points, allowing for the estimation of demand models and price and substitution elasticities. Otherwise, all that can be done is a comparison of means using either ANOVA or ANCOVA. The results then are only valid for the rates tested in the experiment.

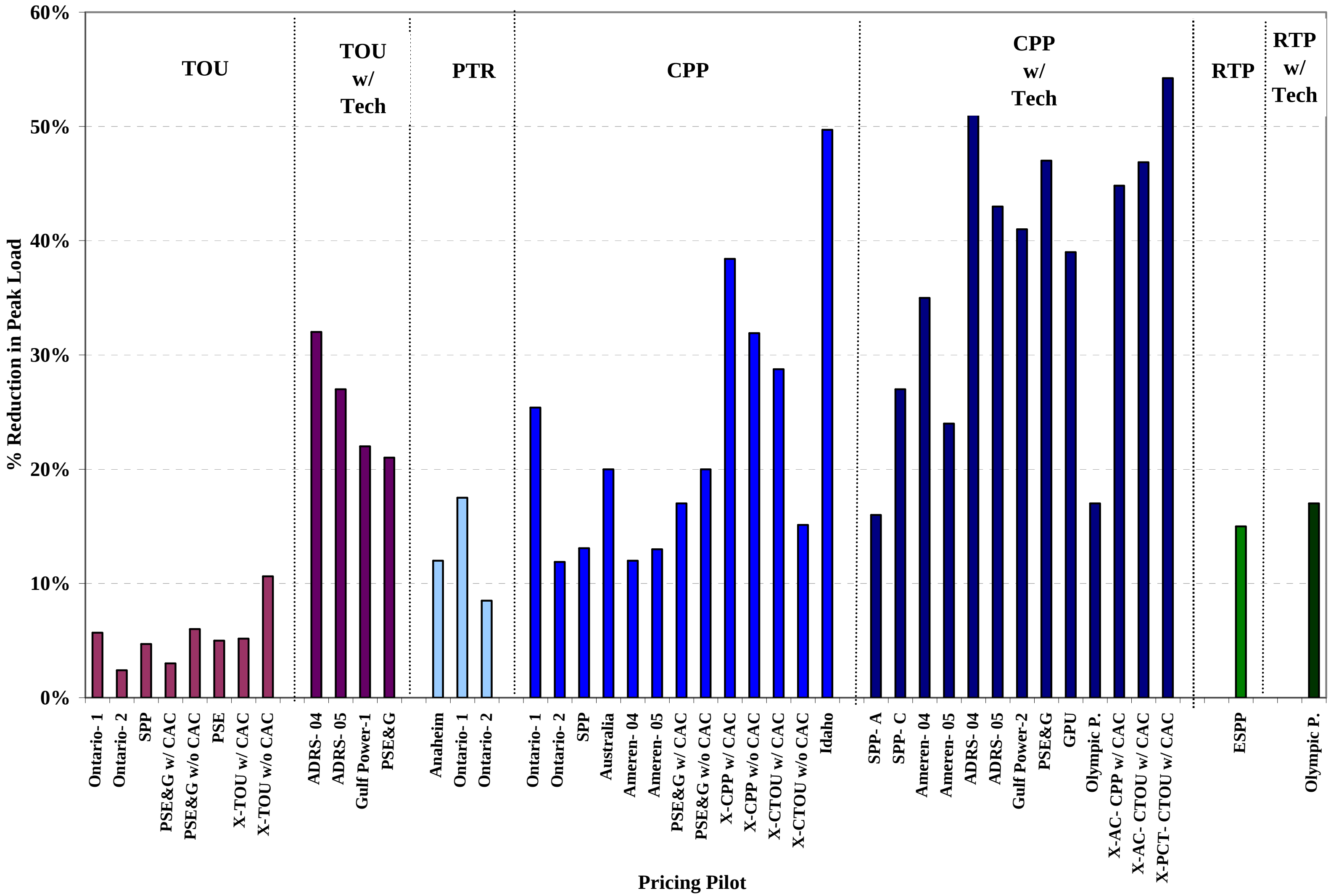
Our review of the 15 pricing experiments reveals that the demand response impacts from different pilot programs vary widely due to the difference in the rate designs tested, use of enabling technologies, ownership of central air conditioning and more generally, due to the variations in sample design. Figure 1 presents a summary. "TOU", "PTR", "CPP", and "RTP"

---

[1] For additional details, please consult our paper which is posted on the website of the Harvard Electricity Policy Group: http://www.hks.harvard.edu/hepg/Papers/2009/The%20Power%20of%20Experimentation%20_01-11-09_.pdf

acronyms respectively stand for time-of-use, peak time rebate, critical peak pricing and real-time pricing. When pricing programs are paired with enabling technologies such as smart thermostats, they are represented with “w/ Tech” acronym in Figure 1.

Figure 1:



60%
50%
40%
30%
20%
10%
0%
% Reduction in Peak Load
TOU
TOU w/ Tech
PTR
CPP
CPP w/ Tech
RTP
RTP w/ Tech
Ontario- 1
Ontario- 2
SPP
PSE&G w/ CAC
PSE&G w/o CAC
PSE
X-TOU w/ CAC
X-TOU w/o CAC
ADRS- 04
ADRS- 05
Gulf Power-1
PSE&G
Anaheim
Ontario- 1
Ontario- 2
Ontario- 1
Ontario- 2
SPP
Australia
Ameren- 04
Ameren- 05
PSE&G w/ CAC
PSE&G w/o CAC
X-CPP w/ CAC
X-CPP w/o CAC
X-CTOU w/ CAC
X-CTOU w/o CAC
Idaho
SPP- A
SPP- C
Ameren- 04
Ameren- 05
ADRS- 04
ADRS- 05
Gulf Power-2
PSE&G
GPU
Olympic P.
X-AC- CPP w/ CAC
X-AC- CTOU w/ CAC
X-PCT- CTOU w/ CAC
ESPP
Olympic P.
Pricing Pilot

To synthesize the information from the 15 pricing experiments, we have constructed a dataset of 28 observations where the impacts are grouped with respect to the rate designs and the existence of an enabling technology. Table 1 provides the mean impact estimates and the 95% confidence intervals associated with the mean values from this dataset.

Table 1- Summary Impacts

Rate Design	Number of Observations	Mean	95% Lower Bound	95% Upper Bound	Min	Max
TOU	5	4%	3%	6%	2%	6%
TOU w/ Technology	4	26%	21%	30%	21%	32%
PTR	3	13%	8%	18%	9%	18%
CPP	8	17%	13%	20%	12%	25%
CPP w/ Technology	8	36%	27%	44%	16%	51%

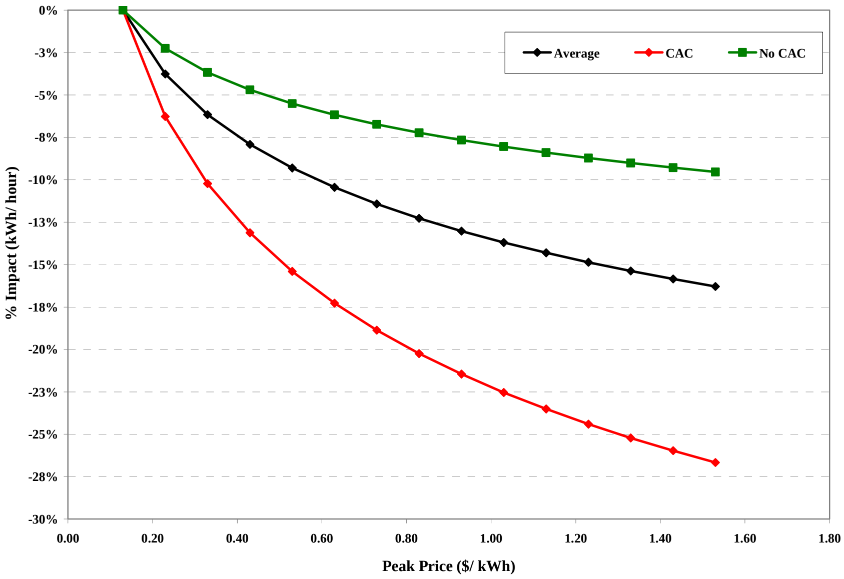
On average, TOU programs are associated with a mean reduction of four percent in peak usage, and a 95 percent confidence interval ranges from three to six percent. CPP programs reduce peak usage by 17 percent and a 95 confidence interval ranges from 13 to 20 percent. CPP programs supported with enabling technologies reduce peak usage by 36 percent and a 95 confidence interval ranges from 27 to 44 percent. Impacts associated with PTR and TOU supported with enabling technology programs are also provided in Table 1. However, these should be interpreted with caution due to the small number of observations underlying the distributions. Nine out of the twelve impact estimates with enabling technologies are tested on customers with CAC ownership, so these impacts also capture impacts due to CAC ownership.

Our survey finds that in addition to displaying a wide variation in the size of impact due to different rate designs, the impacts also vary widely among the experiments using the same rate design. The residual variation comes from variation in price elasticities and in sample design. Substitution elasticities (between peak and offpeak usage) from the experiments range from 0.07 to 0.40 while the own price elasticities range from -0.02 to -0.10. Availability of the enabling technologies, ownership of central air conditioning and the type of the days examined (weekend vs. weekday) are some of the factors that lead to variations in the demand elasticities.

Another interesting question is how the impact estimates vary for different critical peak prices. To address this question, we have simulated the demand response to increasing levels of critical prices using the PRISM (Price Impact Simulation Model) software that was developed in the California statewide pricing pilot. The PRISM model predicts the changes in electricity usage that are induced by time-varying rates by utilizing a constant elasticity of substitution (CES) demand system. This demand system consists of two equations. The substitution equation predicts the ratio of peak to off-peak quantities as a function of the ratio of peak to off-peak prices and other factors. The daily energy usage equation predicts the daily electricity usage as a function of daily price and other factors. Once the demand system is estimated, the resulting equations are solved to determine the changes in electricity usage associated with a time-varying rate. PRISM has the capability to predict these changes for peak and off-peak hours for both critical and non-critical peak days. Moreover, PRISM allows predictions to vary by other exogenous factors such as the saturation of central air conditioning and variations in climate. The model can be set to demonstrate these impacts on different customer types.

Since we would like to determine how the usage impacts vary as the critical prices are increased, we have run a series of simulations with the PRISM model. To clarify how PRISM models the relationship between the prices and the percentage impact on load in a non-linear fashion, consider the following example. For the average customer, peak period energy usage decreases by 4% when the peak-price increases from $0.13 per kWh to $0.23 per kWh. However, peak period energy usage decreases by only 8% when the peak price is increased from $0.13 per kWh to $0.43 per kWh. This example demonstrates that the load impact increases by one-fold (rather than two-fold) when the change in the price increases by two-fold. We can also observe the differences between customer types in their price-responsiveness from these response curves. For a given price increase, Non-CAC customers (without CAC ownership) are the least responsive group while CAC customers (with CAC ownership) are the most responsive. The response curves in Figure 2 demonstrate how the percent impact on peak period energy usage varies with the peak-period price on critical days. These curves show that the percentage impact on the peak period energy usage increases as prices increase, but at a decreasing rate. This non-linear relation between usage impacts and prices is reflected in the concave shape of the response curves.

Figure 2- Residential Demand Response Curves on Critical Days



These results have important implications for the reliability and least cost operation of an electric power system facing ever increasing demand for power and surging capacity costs. Demand response programs that blend together customer education initiatives, enabling technology investments, and carefully designed time-varying rates can achieve demand impacts that can alleviate the pressure on the power system. Uncertainties involving the fuel prices and carbon prices emphasize the importance of the demand-side resources. Dynamic pricing regimes also incorporate some uncertainties such as the responsiveness of customers, cost of implementation and revenue impacts. However, these uncertainties can be addressed to a large extent by implementing pilot programs that can help guide the deployment of dynamic pricing rates.

HOUSEHOLD RESPONSE TO DYNAMIC PRICING OF ELECTRICITY—A SURVEY OF THE EXPERIMENTAL EVIDENCE

Ahmad Faruqui and Sanem Sergici[1]

January 10, 2009

[1] The authors are economists with The Brattle Group located respectively in San Francisco, California and Cambridge, Massachusetts. We are grateful to the analysts who worked on the pricing experiments reviewed in this paper for providing us their reports and presentations. Our research was funded in part by the Edison Electric Institute and the Electric Power Research Institute. Questions can be directed to ahmad.faruqui@brattle.com.

HOUSEHOLD RESPONSE TO DYNAMIC PRICING OF ELECTRICITY—A SURVEY OF THE EXPERIMENTAL EVIDENCE

Since the energy crisis of 2000-2001 in the western United States, much attention has been given to boosting demand response in electricity markets. One of the best ways to let that happen is to pass through wholesale energy costs to retail customers. This can be accomplished by letting retail prices vary dynamically, either entirely or partly. For the overwhelming majority of customers, that requires a changeout of the metering infrastructure, which may cost as much as $40 billion for the US as a whole. While a good portion of this investment can be covered by savings in distribution system costs, about 40 percent may remain uncovered. This investment gap could be covered by reductions in power generation costs that could be brought about through demand response. Thus, state regulators in many states are investigating whether customers will respond to the higher prices by lowering demand and if so, by how much.

To help inform this assessment, we survey the evidence from the 15 most recent experiments with dynamic pricing of electricity. We find conclusive evidence that households (residential customers) respond to higher prices by lowering usage. The magnitude of price response depends on several factors, such as the magnitude of the price increase, the presence of central air conditioning and the availability of enabling technologies such as two-way programmable communicating thermostats and always-on gateway systems that allow multiple end-uses to be controlled remotely. Across the range of experiments studied, time-of-use rates induce a drop in peak demand that ranges between three to six percent and critical-peak pricing tariffs induce a drop in peak demand that ranges between 13 to 20 percent. When accompanied with enabling technologies, the latter set of tariffs lead to a drop in peak demand in the 27 to 44 percent range.

1.0 INTRODUCTION

The optimality of peak load pricing of electricity is well established in the literature on public utility economics.[2] To maximize the social surplus, prices during the off peak period should be set equal to the marginal cost of energy and prices during the peak period should be set equal to the marginal cost of energy and capacity. However, practice has vastly lagged theory. There are several reasons, with the foremost being the cost of installing the advanced metering infrastructure (AMI) that would allow peak load pricing to be implemented. For the US as a whole, this cost may be as high as $40 billion, as shown later.

[2] For a survey, see Crew, Fernando and Kleindorfer (1995). A case for dynamic as opposed to static time-varying rates was provided by Vickrey (1971). Chao (1983) introduced uncertainty into the analysis. Littlechild (2003) made a case for passing through wholesale costs to retail customers. Borenstein (2005) compared the efficiency gains of dynamic and static time-varying rates.

But an equally important reason is political, which stems from the fear of a consumer backlash that could ensue as higher peak prices are implemented.[3] Of course, lower off-peak prices would be implemented simultaneously so that the customer with the load profile of the class would see no change in bill. In fact, those with higher load factors than the class profile would see lower bills. But those with poorer load factors would be instant losers (unless they curtailed peak usage) and that problem has stymied innovate rate design.

However, there are signs of change in the policy-setting environment. It is now widely recognized that the energy crisis in the Western US that occurred during the years 2000-01 was caused in part by a failure to engage the demand side of the California power market. When prices skyrocketed in wholesale markets, retail customers had no incentive to reduce demand. Governor Gray Davis famously observed that he could have solved the crisis in 20 minutes had he been able to pass through the rising prices to customers. By freezing retail prices, he rendered inoperative the automatic stabilizer that could have brought demand and supply back into balance.[4]

After the crisis, twenty one economists put forward a manifesto which argued:[5]

> Any structural model for the industry should include a mechanism for charging consumers for the cost of the production and delivery of electricity at the time of its consumption. Electricity at midnight in April is completely different from electricity at noon on a hot August day. …Prices to most end users don't signal when electricity is cheap or dear for the industry to produce. Nor are consumers offered the true economic benefit of their conservation efforts at times of peak demand. Customers suffer further when unchecked peak demands grow too fast, pushing up costs for all. Wholesale electricity markets also become more volatile and subject to manipulation when rising prices have no impact on demand. Indeed, a functioning demand side to the electricity market in California would have greatly reduced the likely private benefits, and consequent social cost, of any strategic behavior engaged in during the crisis…Regardless of other reform efforts that are pursued in California, real-time pricing or other forms of flexible pricing is a key to enhanced conservation, more efficient use of electricity, and the avoidance of both unnecessary new power plants as well as concerns about the competitiveness of wholesale electricity markets.

---

[3] Faruqui (2007) and Wolak (2007).

[4] Borenstein (2002) and Faruqui, Chao, Niemeyer, Platt and Stahlkopf (2001a) and (2001b).

[5] Bandt, Campbell, Danner, Demsetz, Faruqui, Kleindorfer, Lawrence, Levine, McLeod, Michaels, Oren, Ratliff, Riley, Rumelt, Smith, Spiller, Sweeney, Teece, Verleger, Wilk and Williamson (2003).

The manifesto left two questions unanswered. First, whether or not customers would respond to higher prices by reducing demand.[6] And second, whether it would make economic sense to equip ten million residential and small commercial and industrial customers with the AMI that would be necessary to transmit such dynamic price signals to them.[7] To answer these questions, the California Public Utilities Commission (CPUC) initiated a proceeding on advanced metering, demand response and dynamic pricing.[8]

As part of the proceeding, the state carried out an elaborate experiment with dynamic pricing. It showed conclusively that customers responded to high prices by lowering peak usage by 13 percent.[9] The three investor-owned utilities in the state relied on the results from the experiment to develop their AMI business cases. They showed that while AMI yielded many operational benefits to the distribution system, such benefits only covered about sixty percent of the total investment. The remaining forty percent had to be covered through demand response.

The CPUC has approved all three business cases. Over the next five years, California will deploy 11.8 million smart meters for electricity (and about five million for gas) for a total investment of $4.564 billion.[10] Capitalizing on this transformation of the metering landscape, the CPUC issued a decision this past summer that calls for placing all customers who have advanced meters on critical-peak pricing.[11] If dynamic pricing becomes the default tariff, substantial benefits can accrue to customers. If it is offered only as an optional tariff, benefits would be about a quarter to a tenth as large.[12]

---

[6] This question was answered at least temporarily in San Diego where wholesale prices were allowed to flow through to retail customers in the summer of 2000. When prices doubled, customers lowered their usage by 13 percent. See Reiss and White (2008).

[7] The question of whether meter changeout is cost-effective does not arise for large commercial and industrial customers since such a changeout is prima facie cost-effective. In addition, there is substantial evidence on the price responsiveness of such customers. See, for example, Taylor, Schwarz and Cochell (2005) and the case studies in Faruqui and Eakin (2000) and (2002).

[8] CPUC R. 02-06-001. http://docs.cpuc.ca.gov/published/proceedings/R0206001.htm.

[9] Faruqui and George (2005), Herter (2007) and Herter, McAuliffe and Rosenfeld (2007).

[10] California Energy Commission (2008). In addition to the electric meters, about 5 million gas meters are also being upgraded.

[11] CPUC, Decision adopting dynamic pricing timetable and rate design guidance for Pacific Gas & Electric Company, D. 08-07-045, July 31, 2008.

[12] Pfannenstiel and Faruqui (2008).

Similar discussions are taking place in many jurisdictions throughout North America, spurred in part by two federal laws.[13] A survey of state regulatory activity carried out in August 2008 found that 38 commissions had initiated regulatory consideration of smart meters and demand response in response to federal legislation and 32 had completed their consideration.[14]

Echoing views that were espoused in the 21 Economists Manifesto, Frederick Butler of the New Jersey Board of Public Utilities Commission, who is also the president of the National Association of Regulatory Utility Commissioners, reminded EnergyWashington in December 2008 that for more than a century "most people have paid for their electricity at the same rate every day of every year, every hour of every day." Butler said, "That's going to have to change," noting that "If you're going to have a smart grid, that allows you to measure and have two-way communication between the end-use premises, the utility company, the RTO, and other entities, rates will have to change to be more time-of-use rates or critical peak period rates."

The momentum toward dynamic pricing and demand response has also extended to wholesale markets. Many regional transmission organizations and independent system operators around the US including those in California, the Midwest, New England and PJM are giving serious consideration to introducing demand response in wholesale markets. A recent analysis showed that even a five percent reduction in US demand during the top one percent of the hours of the years would yield a present value of $35 billion in benefits.[15]

To effectuate demand response, some type of dynamic pricing will have to be instituted in retail markets.[16] The central question in all of these assessments is: Will customers respond to higher prices by lowering peak demand and if so, by how much? The answer will help state regulators determine whether or not to proceed with authorizing the deployment of AMI in their jurisdictions. The question applies a fortiori to residential and small commercial and industrial

[13] The Energy Policy Act of 2005 and The Energy Independence and Security Act of 2007 ask state commissions to consider the deployment of smart meters and demand response. The latter act also asks the Federal Energy Regulatory Commission to carry out a state-by-state assessment of the potential for demand response.

[14] US Demand Response Coordinating Committee, (2008).

[15] Faruqui, Hledik, Newell and Pfeiffenberger (2007). With updated assumptions about the cost of peaking capacity, the benefit estimate might be closer to $66 billion.

[16] Wellinghoff and Morenoff (2007).

customers because only five percent are equipped with smart meters.[17] In the US, there are a total of 144 million customers. Of this number, the overwhelming majority –some 125 million—are residential.[18] They account for a third of over-all energy consumption and for a larger share of peak demand.

The cost of upgrading all residential meters in the US would be staggering. Using the California cost estimates as a proxy, the nationwide cost would be around $40 billion. Is it worthwhile to pursue AMI? Yes, if two conditions are met. First, AMI is accompanied by dynamic pricing. This represents a major change in the pricing paradigm and is the subject of much deliberation by state commissions. Second, if customers respond to dynamic pricing sufficiently to offset the net investment in AMI (i.e., that amount which is not offset by savings in distribution system costs). That, of course, is an empirical issue and is the focus on this paper.

In Section 2, we provide an overview of the most recent 15 pricing experiments. We tabulate their design characteristics and summarize the analytical process through which the experimental data are analyzed. In Section 3, we review in detail the design of each individual experiment and present its results. In Section 4, we compare the results across experiments and illustrate the likely effect of dynamic pricing on customer peak loads by relying on the results of one widely-cited pricing experiment. In Section 5, we present our conclusions.

2.0 THE FIFTEEN EXPERIMENTS

In the late 1970s and early 1980s, the first wave of electricity pricing experiments was carried out under the auspices of the Federal Energy Administration. Those experiments were focused on measuring customer response to simple (static) time-of-day and seasonal rates.[19] The data from the top five experiments were analyzed by Christensen Associates for the Electric Power Research Institute.[20] The results were conclusive: customers responded to higher prices during the peak period by reducing peak period usage and/or shifting it to less expensive off-

[17] FERC (2008).
[18] http://www.eia.doe.gov/cneaf/electricity/esr/table5.html.
[19] Faruqui and Malko (1983).
[20] Caves, Christensen, and Herriges (1984).

peak periods. The results were consistent around the country once weather conditions and appliance holdings were held constant. Customer response was higher in warmer climates and for customers with all electric homes. The elasticity of substitution for the average customer was 0.14. Over the entire set of customers, it ranged between 0.07 and 0.21.

However, despite the conclusive findings, time-varying rates were not widely accepted across the country. There were three reasons for this. First, the high cost of time-of-use metering. Second, the peak periods that were offered in these rate designs were too broad to garner customer acceptance. And third, the utilities did not market the programs effectively. Most customers did not even know such rates existed.

California's energy crisis rekindled interest in time-varying rates but not of the garden variety (traditional, static time-of-use rates). A variety of academics, researchers and consultants called for the institution of rates that would be dynamically dispatchable during critical-price periods. These occur typically during the top one percent of the hours of the year where somewhere between 9-17 percent of the annual peak demand is concentrated. It is very expensive to serve power during these critical periods and even a modest reduction in demand can be very cost-effective. In addition, the introduction of digital technology in meters has brought with it the availability of AMI, making dynamic pricing a cost-effective option in most situations.

The experimental designs are shown in Table 1. All experiments are based on panel data, involving repeated measurements on a cross-section of customers. Some of the customers are placed on the dynamic pricing rate (or rates) and fall into the treatment group. Others stay on existing rates and fall into the control group. Technically, the control group should be randomly chosen. Otherwise, the design becomes a quasi experiment. The better designs feature measurement during the pre-treatment period which allows self-selection bias in the treatment group to be detected. It also allows for the application of the "difference in differences" estimator which computes the difference in usage between the treatment and pre-treatment periods and subtracts from it the pre-existing difference between treatment and control group customers. Finally, the superior designs feature multiple price points, allowing for the estimation of demand models and price and substitution elasticities. Otherwise, all that can be done is a comparison of means using either ANOVA or ANCOVA. The results then are only valid for the rates tested in the experiment.

One of the versatile model specifications is the constant elasticity of substitution (CES) demand system. As an example, consider an experimental rate with peak and off-peak pricing periods.

Equation (1) depicts the substitution equation. The equation expresses the peak to off-peak quantity ratio as a function of the peak to off-peak price ratio, a weather term representing the difference in cooling degree hours between the peak and off peak periods[21] and fixed effects variable for each customer.

$$\ln\left(\frac{Q_p}{Q_{op}}\right) = \alpha + \sigma \ln\left(\frac{P_p}{P_{op}}\right) + \delta(CDH_p - CDH_{op}) + \sum_{i=1}^{N} \theta_i D_i + \varepsilon \qquad (1)$$

where

Q_p = average energy use per hour in the peak period for the average day

Q_{op} = average energy use per hour in the off-peak period for the average day

σ = the elasticity of substitution between peak and off-peak energy use (following convention, this is taken to be a positive number for substitutes and a negative number for complements)

P_p = average price during the peak pricing period

P_{op} = average price during the off-peak pricing period

δ = measure of weather sensitivity

CDH_p = cooling degree hours per hour during the peak pricing period

CDH_{op} = cooling degree hours per hour during the off-peak pricing period

θ_i = fixed effect coefficient for customer i

[21] The difference in cooling degree hours per hour between peak and off-peak periods is used rather than the ratio because on some days, there are zero cooling degree hours in the off-peak period and using the ratio would result in division by zero on these days.

D_i = a binary variable equal to 1 for the i^{th} customer, 0 otherwise, where there are a total of N customers.

ε = random error term

Equation (2) expresses daily energy use as a function of daily average price, daily cooling degree hours and the fixed effects variables.

$$\ln\left(Q_d\right) = \alpha + \eta_d \ln\left(P_d\right) + \delta(CDH_d) + \sum_{i=1}^{N} \theta_i D_i + \varepsilon \qquad (2)$$

where

Q_d = average daily energy use per hour

η_d = the price elasticity of demand for daily energy (defined below)

P_d = average daily price (e.g., a usage weighted average of the peak and off-peak prices for the day)

CDH_d = cooling degree hours per hour during the day

ε = regression error term

The two summary measures of price responsiveness in the CES demand system are the elasticity of substitution (σ) and the daily price elasticity of demand (η).

It is plausible that the elasticity of substitution and/or the daily price elasticity would differ across customers who have different socio-economic characteristics (e.g., different appliance ownership, different income levels, etc.). The elasticity may also vary between hot and cool days. The CES model can be modified to allow the elasticities to vary with weather and socio-economic factors, such as central air conditioning (CAC) ownership. Equation (3) provides an example of the substitution equation that allows price responsiveness to vary with CAC ownership and weather. Equation (4) shows how the elasticity of substitution would be calculated from this model specification. Equations (5) and (6) show the demand models for daily energy use and the corresponding equation for the daily price elasticity as a function of weather and CAC ownership.

$$\ln\left(\frac{Q_p}{Q_{op}}\right) = \alpha + \sum_{i=1}^{N}\theta_i D_i + \sigma \ln\left(\frac{P_p}{P_{op}}\right) + \delta(CDH_p - CDH_{op}) + \lambda(CDH_p - CDH_{op})\ln\left(\frac{P_p}{P_{op}}\right)$$
$$+\phi(CAC)\ln\left(\frac{P_p}{P_{op}}\right) + \varepsilon \qquad (3)$$

The elasticity of substitution (ES) in this model is a function of three terms, as shown below:

$$\text{ES}=\sigma + \lambda(CDH_p - CDH_{op}) + \phi(CAC) \qquad (4)$$

Other customer characteristics, such as income, household size, and number of people in the household, may also influence the elasticities in the CES model. They can be included in the specification by introducing additional price interaction terms in a similar manner to the CAC and weather terms shown above.

$$\ln\left(Q_D\right) = \alpha + \sum_{i=1}^{N}\theta_i D_i + \eta \ln\left(P_D\right) + \rho(CDH_D) + \chi(CDH_D)\ln\left(P_D\right)$$
$$+\xi(CAC)\ln\left(P_D\right) + \varepsilon \qquad (5)$$

where

Q_D = average daily energy use per hour

η = the daily price elasticity

P_D = average daily price

ρ = measure of weather sensitivity

χ = the change in daily price elasticity due to weather sensitivity

CDH_D = average daily cooling degree hours per hour (base 72 degrees)

ξ = the change in daily price elasticity due to the presence of central air conditioning

CAC = 1 if a household owns a central air conditioner, 0 otherwise

θ_i = fixed effect for customer i

D_i = a binary variable equal to 1 for the i^{th} customer, 0 otherwise, where there are a total of N customers.

ε = error term.

The composite daily price elasticity in this model is a function of three terms, as shown below:

$$\text{Daily}=\eta + \chi(CDH_D) + \xi(CAC) \qquad (6)$$

Table 1- Overview of the Experiments

No	State/ Province	Experiment	Utility	Year	Number of Customers	Number of Rates Tested	Link to Figure 1
1	California	Anaheim Critical Peak Pricing Experiment	Anaheim Public Utilities (APU)	2005	52 control, 71 treatment	1	Anaheim
2	California	California Automated Demand Response System Pilot (ADRS)	Pacific Gas & Electric (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E)	2004-2005	In 2004: 104 control, 122 treatment In 2005: 101 control, 98 treatment	1	ADRS-04, ADRS-05
3	California	California Statewide Pricing Pilot (SPP)	Pacific Gas & Electric (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E)	2003-2004	2,500 customers	3	SPP, SPP-A, SPP-C
4	Colorado	Xcel Experimental Residential Price Response Pilot Program	Xcel Energy	2006-2007	1350 control, 2349 treatment	3	XCEL-TOU, XCEL-CPP, XCEL-CTOU
5	Florida	The Gulf Power Select Program	Gulf Power	2000-2001	2300 customers participating in the RSVP program	2	GulfPower-1, GulfPower-2
6	France	Electricite de France (EDF) Tempo Program	Electricite de France (EDF)	Since 1996	400,000 customers	1	-
7	Idaho	Idaho Residential Pilot Program	Idaho Power Company	2005-2006	TOD Program- 420 control, 85 treatment EW Program- 355 control, 68 treatment	2	Idaho
8	Illinois	The Community Energy Cooperative's Energy-Smart Pricing Plan (ESPP)	Commonwealth Edison	2003-2005	1,500 customers	2	ESPP
9	Missouri	AmerenUE Residential TOU Pilot Study	AmerenUE	2004-2005	TOU - 89 control, 88 treatment TOU/CPP- 89 control , 85 treatment TOU/CPP w/ Technology- 117 control, 77 treatment	2	Ameren-04, Ameren-05
10	New Jersey	GPU Pilot	GPU	1997	Not Available	2	GPU
11	New Jersey	Public Service Electric and Gas (PSE&G) Residential Pilot Program	Public Service Electric and Gas Company (PSE&G)	2006-2007	450 control, 836 treatment	1	PSE&G
12	New South Wales (Australia)	Energy Australia's Network Tariff Reform	Energy Australia	2005	TOU program: 50,000 customers SPS: 1300 treatment	Tested several dynamic tariffs	Australia
13	Ontario (Canada)	Ontario Energy Board Smart Price Pilot	Hydro Ottawa	2006-2007	125 control, 373 treatment	3	Ontario-1, Ontario-2
14	Washington	Puget Sound Energy (PSE)'s TOU Program	Puget Sound Energy	2001-2002	300,000 customers	1	PSE
15	Washington and Oregon	Olympic Peninsula Project	Bonneville Power Administration, Clallam County PUD, The City of Port Angeles, Portland General Electric, and PacifiCorp	2005	28 control, 84 treatment	3	Olympic P.

3.0 EXPERIMENT-BY-EXPERIMENT ASSESSMENT

This section provides information for each of the 15 experiments. Salient design features are presented along with the estimated impacts and price elasticities.

3.1 CALIFORNIA- ANAHEIM CRITICAL PEAK PRICING EXPERIMENT

The City of Anaheim Public Utilities (APU) conducted a residential dynamic pricing experiment between June 2005 and October 2005.[22] A total of 123 customers participated in the experiment: 52 in the control group and 71 in the treatment group. Despite its name, this experiment did not provide a critical peak pricing rate to participants. Instead, it provided them a rebate for each kWh reduction during critical times. The magnitude of the peak time rebate (PTR) was $0.35 for each kWh reduction below the reference level peak-period consumption on non-CPP days (i.e., the baseline consumption). The rate design is presented in Table 2.

Table 2- Anaheim PTR Rate Design

Group	Charge	Applicable Period
Control	Standard increasing-block residential tariff: $0.0675/kWh if consumption <=240kWh per month $0.1102/kWh if consumption >240kWh per month	All hours
Treatment	Standard increasing-block residential tariff	All hours except except peak hours (12 a.m. - 6 p.m.) on CPP days
Treatment	$0.35 rebate for each kWh reduction relative to their typical peak consumption on non-CPP days.	Peak hours (12 a.m. - 6 p.m.) on CPP days

Statistical comparisons during the pre-treatment period between treatment and control group customers were not statistically significant indicating that the two groups were balanced and there was no self-selection bias.

The data showed that the treatment group used 12 percent less electricity on average during the peak hours of the CPP days than the control group. Demand response by treatment customers was greater on higher temperature CPP days than on lower temperature CPP days.

[22] Wolak (2006).

3.2 California- Automated Demand Response System Pilot[23]

California's Advanced Demand Response System (ADRS) pilot program was carried out on a subset of the customers who were included in the Statewide Pricing Pilot which is discussed in the next sub-section. The experiment was initiated in 2004 and extended through the end of 2005. ADRS operated under a critical peak pricing tariff that was identical to that in the SPP which was supported with a residential-scale, automated demand response technology. Participants of the pilot installed the GoodWatts system, an advanced home climate control system that allowed users to web-program their preferences for the control of home appliances. Under the CPP tariff, prices were higher during the peak period (2 p.m. to 7 p.m. on weekdays). All other hours, weekends, and holidays were subject to the base rate. When the "super peak events" were called, the peak price was three times higher than the regular peak price.

Program participants achieved substantial load reductions in both 2004 and 2005 compared to the control group. Load reductions on super peak event days were consistently about twice the size of load reductions during the peak periods on non-event days. Peak reductions were as high as 51 percent on event days and 32 percent on non-event days. Enabling technology emerged as the main driver of the load reductions especially on super peak event days and for the high consumption customers. Overall, load reductions of the ADRS participants were consistently larger than those of the other demand response program participants without the technology.

Table 3 presents the impact estimates from the ADRS for high consumption customers on CPP event days and non-event days.

Table 3- Peak Period Load Reductions for High Consumption Customers

	Event Days		Non-Event Days	
Program Year	Average Reduction (kW)	% Reduction	Average Reduction (kW)	% Reduction
2004	1.84	51%	0.86	32%
2005	1.42	43%	0.73	27%

23 Rocky Mountain Institute (2006).

3.3 CALIFORNIA- STATEWIDE PRICING PILOT[24]

California's three investor-owned utilities, Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E), together with the two regulatory commissions conducted the Statewide Pricing Pilot (SPP) that ran from July 2003 to December 2004 to test the impact of several time-varying rates. The SPP included about 2,500 participants including residential and small-to-medium commercial and industrial (C&I) customers. SPP tested several rate structures:

- TOU-only rate where the peak price was twice the value of the off-peak price.
- CPP rate where the peak price during the critical days was roughly five times greater than the off-peak price; on non-critical days, a TOU rate applied. The SPP tested two variations of the CPP rates.
    - The CPP-F rate had a fixed period of critical peak and day-ahead notification. CPP-F customers did not have an enabling technology.
    - The CPP-V rate had a variable-length of peak duration during critical days and day-of notification. CPP-V customers had the choice of adopting an enabling technology.

The SPP utilized the CES demand model described in Section 2.0. In this paper, we cover only the residential customer impacts for three rate structures: CPP-F, TOU, and CPP-V.

CPP-F Impacts

The average price for customers on the standard rate was about $0.13 per kWh. Under the CPP-F rate, the average peak-period price on critical days was roughly $0.59 per kWh, the peak price on non-critical days was $0.22 per kWh, and the average off-peak price was $0.09 per kWh. CPP-F rate impacts are as follows:

- On critical days, statewide average reduction in peak-period energy use was estimated to be 13.1 percent. Impacts varied across climate zones from a low of 7.6 percent to a high of 15.8 percent.

[24] Charles River Associates (2005), Faruqui and George (2005), Herter (2007) and Herter, McAuliffe and Rosenfeld (2007).

- The average peak-period impact on critical days during the inner summer months (July- September) was estimated to be 14.4 percent while the same impact was 8.1 percent during the outer summer months (May, June, and October).
- On normal weekdays, the average impact was 4.7 percent, with a range across climate zones from 2.2 percent to 6.5 percent.
- No change in total energy use across the entire year was found based on the average SPP prices.
- The impact of different customer characteristics on energy use by rate period was also examined. Central AC ownership and college education are the two customer characteristics that were associated with the largest reduction in energy use on critical days.

Table 4- Residential CPP-F Rate Impacts on Critical Days for Inner Summer Months (July, August, September)

Year			Start Value (kWh/hr)	Impact (kWh/hr)	Elasticity Estimate	T-stat	Impact (%)
2003	Rate Period	Peak	1.28	-0.163	-	-20.94	-12.71
		Off-peak	0.8	0.021	-	7.8	2.57
		Daily	0.9	-0.018	-	-6.88	-1.95
	Elasticity	Substitution	-	-	0.086	-20.51	-
		Daily	-	-	-0.032	-6.8	-
2004	Rate Period	Peak	1.28	-0.178	-	-18.49	-13.93
		Off-peak	0.8	0.01	-	2.95	1.25
		Daily	0.9	-0.029	-	-8.7	-3.24
	Elasticity	Substitution	-	-	0.087	-16.84	-
		Daily	-	-	-0.054	-8.55	-

Notes:

[1] Estimations are based on average customer approach. The average customer approach involves using the input values (e.g., weather, AC saturations and starting energy use values by rate period) for the average customer across all climate zones.

[2] All the numbers are based on average critical day weather in 2003/2004.

TOU Impacts

The average price for customers on the standard rate was about $0.13 per kWh. Under the TOU rate, the average peak-period price was roughly $0.22 per kWh and the average off-peak price was $ 0.09 per kWh.

- The reduction in peak period energy use during the inner summer months of 2003 was estimated to be 5.9 percent. However, this impact completely disappeared in 2004.
- Due to small sample problems in the estimation of TOU impacts, normal weekday elasticities from the CPP-F treatment may serve as better predictors of the impact of TOU rates on energy demand than the TOU price elasticity estimates.

CPP-V Impacts

The average price for customers on the standard rate was about $0.14 per kWh. Under the CPP-V rate, the average peak-period price on critical days was roughly $0.65 per kWh and the average off-peak price was $0.10 per kWh. This rate schedule was tested on two different treatment groups. Track A customers were drawn from a population with energy use greater than 600kWh per month. In this group, average income and central AC saturation was much higher than the general population. Track A customers were given a choice of installing an enabling technology and about two thirds of them opted for the enabling technology. The Track C group was formed from customers who previously volunteered for a smart thermostat pilot. All Track C customers had central AC and smart thermostats. Hence, two-thirds of Track A customers and all Track C customers had enabling technologies.

- As shown in Table 5, Track A customers reduced their peak-period energy use on critical days by about 16 percent (about 25 percent higher than the CPP-F rate impact).
- Track C customers reduced their peak-period use on critical days by about 27 percent.

Comparing the CPP-F and the CPP-V results suggest that usage impacts are significantly larger with an enabling technology than without it.

Table 5- Residential CPP-V Rate Impacts for Summer for All Customers

			Start Value (kWh/hr)	Impact (kWh/hr)	Elasticity Estimate	t-stat	Impact (%)
Track A	Rate Period	Peak	2.14	-0.3374	-	-10.89	-15.76
		Off-peak	1.33	0.0445	-	4.26	3.34
		Daily	1.46	-0.0187	-	-1.71	-1.28
		Weekend Daily	1.3	0.0173	-	2.72	1.33
	Elasticity	Substitution	-	-	-0.111	-11.76	-
		Daily	-	-	-0.027	-1.7	-
		Weekend Daily	-	-	-0.043	-2.74	-
Track C	Rate Period	Peak	2.33	-0.635	-	-35.03	-27.23
		Off-peak	1.26	0.044	-	3.19	3.52
		Daily	1.43	-0.059	-	-9.85	-4.17
		Weekend Daily	1.34	0.016	-	4.1	1.2
	Elasticity	Substitution	-	-	-0.077	-10.61	-
		Technology Impact-Substitution	-	-	-0.214	-24.04	-
		Daily	-	-	-0.044	-3.49	-
		Technology Impact-Daily	-	-	-0.019	-3.49	-
		Weekend Daily	-	-	-0.041	-4.12	-

Notes:

[1] Estimations are based on average customer approach.
[2] Track A analysis was conducted for summer 2004.
[3] Track C analysis pools summers 2003 and 2004 and estimates a single model.

3.4 Colorado- Xcel Energy TOU Pilot[25]

In the summer of 2006, Xcel Energy initiated a pilot program that tested the impact of TOU and CPP rates, as well as enabling technologies, on demand in the Denver metropolitan area. The effective treatment period lasted about a year, from July 15, 2006 through July 15, 2007. Approximately 3,700 residential customers initially volunteered into the pilot program; approximately 26 percent of those customers left the pilot by the end, leaving a final sample of about 2,900 participants.[26] The program made use of Advanced Meter Reading (AMR) infrastructure. All customers had interval meters installed, prior to the pilot program, which could wirelessly transmit consumption to mobile vehicles collecting the household data. Some customers were offered enabling technologies—AC cycling switches and Programmable Communicating Thermostats (PCT)—in addition to the tested rate structures. Customers were subject to one of the three rate options:

- Time-of-use (RTOU)

[25] Based on Energy Insights, Inc, (2008a) and (2008b).
[26] The report notes that, because customers who want to participate are included in the pilot, there is an inherent self selection bias involved.

- Higher price during on-peak periods and a lower price during off-peak periods
- Critical peak (RCPP)
  - Critical peak prices up to 10 summer days; lower off-peak prices at all other times
  - Notification of the peak days by 4 pm the day before.
- Time-of-use+ critical peak (RCTOU)
  - Higher on-peak price (lower than the RTOU on-peak prices), lower off-peak prices, and critical peak prices up to 10 summer days

Table 6 illustrates the demand response impacts from the treatment groups during critical peak, on-peak, and off-peak hours in the summer months of pilot period.[27] All results presented below were determined to be statistically significant. Participants subject to critical peak pricing reduced demand during peak hours substantially more so than customers not subject to CPP. Nevertheless, all groups experienced some reduction in demand. Important to note again, however, is that self-selection may have played a role in the observed demand response impacts.

Table 6- Demand Response Impacts

Rate	Enabling Technology	Central AC	Critical Peak	On Peak	Off Peak
TOU	None	No	-	-10.63%	-2.95%
TOU	None	Yes	-	-5.19%	-0.27%
CPP	None	No	-31.91%	-	-0.08%
CPP	None	Yes	-38.42%	-	0.59%
CPP	AC Cycling Switch	Yes	-44.81%	-	1.34%
CTOU	None	No	-15.12%	-2.51%	8.69%
CTOU	None	Yes	-28.75%	-8.21%	3.56%
CTOU	AC Cycling Switch	Yes	-46.86%	-10.63%	4.00%
CTOU	PCT	Yes	-54.22%	-10.29%	2.96%

[27] As defined above, the summer months of the pilot included June, July, August, and September. As the pilot started in July of 2006 and ended in July of 2007, impacts were not measured for the months of June of 2006, and August and September of 2007.

Xcel Energy notes in the conclusion to its report that the pilot was conducted as a proof of concept rather than a technology test.[28] While the demand reduction was significant, the meters implemented in the pilot were too expensive to make the offerings cost-effective.

3.5 FLORIDA- THE GULF POWER SELECT PROGRAM[29]

In 2000, Gulf Power started a unique demand response program that provides customers with three different service options as described below.

- The standard residential service (RS) pricing option which involved a standard flat rate with no time varying rates.
- A conventional TOU pricing option (RST) which is a two-period TOU tariff.
- The Residential Service Variable Price (RSVP) pricing option which is a three-period CPP tariff.

Under the RSVP option, the energy company provides the price signals and customers modify their usage patterns through a combination of the price signals and advanced metering and appliance control. Gulf Power markets the RSVP option under the GoodCents Select program and charges the participants a monthly participation fee. By the end of 2001, approximately 2,300 homes were served by the RSVP.

Table 7 shows the rates under the Gulf Power demand response program.

Table 7- Residential Tariffs for Summer Months

28 Energy Insights, Inc. (2008b).

29 See Appendix B of Borenstein, Jaske, and Rosenfeld (2002), which is adapted from Levy, Abbott and Hadden (2002).

Program	Period	Charge	Applicable
RS	Base	$0.057/kWh	All hours
RST	Off-peak	$0.027/kWh	12 a.m.-12 p.m. and 9 p.m.-12 a.m.
RST	Peak	$0.104/kWh	12 p.m.- 9 p.m.
RSVP	Off-peak	$0.035/kWh	12 a.m.-6 a.m. and 11 p.m.-12 a.m.
RSVP	Mid-peak	$0.046 /kWh	6 a.m.-11 a.m. and 8 p.m.-11 p.m.
RSVP	Peak	$0.093/kWh	11 a.m.-8 p.m.
RSVP	CPP	$0.29/kWh	When called

Gulf Power reports the base coincident peak demand as 6.1 KW per household (hh). RSVP program performance results presented in Table 8 show that RSVP program participants reduce their demand by 2.75 KW per household during the critical peak period corresponding to a 41 percent reduction in energy usage during the critical peak period.

Table 8- RSVP Program Performance by Period

Impact Type	Period	Impact
Average Demand Reduction	Peak	2.1 kW/hh
	Critical Peak	2.75 kW/hh
Average Energy Reduction	Peak	22%
	Critical Peak	41%

3.6 France- Électricité de France (EDF) Tempo Program[30]

Électricité de France (EDF) initiated the Tempo program in 1996. The rate design entails two pricing periods, peak and off-peak. The peak period is 16 hours long, from 6 am to 10 pm, and the off-peak period is 8 hours long. A distinctive feature of the Tempo program is day-of-the-year pricing which groups the 365 days into three day-types:

- *Blue days* are the least expensive 300 days.
- *White days* are moderately priced 43 days.
- *Red days* are the most expensive 22 days.

The prices per kWh, expressed as Euro cents, are shown below:

[30] For a recent presentation, see Giraud (2004). For earlier analysis, see Giraud and Aubin (1994) and Aubin, Fougere, Husson and Ivaldi (1995). For the current tariff, consult http://www.edf-bleuciel.fr/accueil/mon-quotidien-avec-bleu-ciel-d-edf/option-tempo-41090.html&onglet=5.

	Blue Days	White Days	Red Days
Off-Peak Period	4.64	9.48	17.62
Peak Period	5.77	11.25	49.29

Customers learn which day would be in effect the next day through the use of several resources including the web, call-centers, subscription to e-mail alerts and plugging in an electrical device into their electrical sockets.

EDF implemented a pilot program before launching the Tempo rate on a full-scale basis. The pilot program set prices that were much higher than the Tempo prices. The own-price elasticity for peak demand was estimated at -0.79, much higher than any of the estimates for U.S. pilots, and the own-price elasticity for off-peak usage was estimated to be -0.18.[31]

3.7 IDAHO- IDAHO RESIDENTIAL PILOT PROGRAM[32]

Idaho Power Company initiated two residential pilot programs in the Emmett area of Idaho in the summer of 2005 and the summer of 2006: Time-of-day (TOD) and Energy Watch (EW).

Time-of-Day Pilot

The TOD pilot was designed as a conventional TOU program where the participants were charged different rates by time of the day as shown in Table 9. The TOD pilot included 85 treatment and 420 control group customers as of August 2006.

Table 9- Rate Design for the Time-of-Day Pilot

[31] Matsukawa (2001) also found similarly high price elasticities using data on 279 households in Japan. For households with electric water heaters, he estimated an own-price elasticity of -0.768 for the peak period -0.561 for the off-peak period. Generally similar estimates were obtained for households without electric water heaters and for households on standard rates. Filippini (1995) also found price elasticities in this range using Swiss data.

[32] Idaho Power Company, (2006).

Period	Charge	Applicable
On-Peak	$0.083/kWh	Weekdays from 1pm to 9pm
Mid-Peak	$0.061/kWh	Weekdays from 7am to 1pm
Off-Peak	$0.045/kWh	Weekdays from 9pm to 7am and all hours on weekends and holidays

As shown in Table 10, the results from the TOD pilot for the summer of 2006 show that, on average, the peak period percentage of total summer usage was the same for the treatment and control groups – about 22 percent. In fact, the percentage of usage during the mid-peak and off-peak periods was also the same between the two groups. This indicates that the TOD rates had no effect on shifting usage. However, in light of the very low ratio of on-peak to off-peak rates (about 1.84), this result is not so surprising. It suggests that a higher ratio of peak to off-peak rates is needed to induce customers to shift usage from peak to off peak periods.

Table 10- Summer 2006 (June-August) Usage under the TOD Pilot

	Average Use (kWh)		% of Total Summer Use		Program Impact	
Period	Treatment	Control	Treatment	Control	Difference (Control- Treatment)	T-stat
On-Peak	800	763	22%	22%	-36.46	0.66
Mid-Peak	591	568	16%	16%	-22.43	0.52
Off-Peak	2307	2162	62%	62%	-145.78	0.99
Summer 06 Usage	3698	3493	100%	100%	-204.67	0.87

Energy Watch Pilot

The Idaho Power Company Energy Watch (EW) pilot was designed as a CPP pilot where the participants were notified of the CPP event on a day-ahead basis. A total of 10 EW days were called during the summer of 2006. EW was designed as follows:

- CPP hours from 5 p.m. to 9 p.m.
- Day-ahead notification
- CPP energy price of $0.20/kWh
- Non-CPP energy price of $0.054/kWh

The EW pilot included 68 treatment and 355 control group customers as of August 2006.

Table 11 shows the reduction in load (kW) on CPP days for each of the event days. Average hourly demand reduction ranged from 0.64 kW (on June 29) to 1.70 kW (on July 27). Average hourly load reduction for all ten event days was 1.26 kW. The average total load reduction for a 4-hour event was 5.03 kW.

Table 11- Energy Watch Day: Load Reductions (kW) On Each of the Ten Event Days

Hour Beginning	Hour Ending	29-Jun	11-Jul	14-Jul	18-Jul	19-Jul	25-Jul	27-Jul	3-Aug	9-Aug	15-Aug	Average
5pm	6pm	0.64	1.31	1.09	1.39	1.2	1.33	1.58	1.14	0.83	1.02	1.17
6pm	7pm	0.69	1.5	1.17	1.43	1.32	1.45	1.62	1.27	1.14	1.15	1.29
7pm	8pm	0.77	1.58	1.16	1.57	1.41	1.55	1.7	1.24	1.02	0.96	1.33
8pm	9pm	0.8	1.48	1.11	1.47	1.27	1.4	1.6	1.13	0.95	0.89	1.25
4-Hour Total		2.89	5.87	4.53	5.85	5.2	5.74	6.5	4.77	3.94	4.02	5.03
Average Hourly		0.72	1.47	1.13	1.46	1.3	1.43	1.62	1.19	0.99	1.01	1.26
Min Temp		68	65	65	61	62	75	68	59	62	67	65
Max Temp		85	100	98	94	98	99	104	92	85	92	95
Avg Temp		75	84	83	79	80	87	87	76	73	80	80

3.8 Illinois- Energy Smart Pricing Plan

The Community Energy Cooperative's ("CEC") Energy-Smart Pricing Plan (ESPP) was the first large-scale residential real-time pricing (RTP) program in the US. It took place in the service territory of Commonwealth Edison in northern Illinois and ran between 2003 and 2006. ESPP initially included 750 participants and expanded to nearly 1,500 customers in 2005. The same number of participants was maintained for the 2006 program year. ESPP focused on low cost technology and tested the hypothesis that major benefits may result from RTP without the adoption of expensive technology.

The ESPP design included:

- Day-ahead announcement of the hourly electricity prices for the next day (on the day of the event, customers were charged the hourly prices that had been posted the day before).
- High-price day notification via phone or email when the price of electricity climbed over \$0.10 per kWh (in 2006, the notification threshold was set to above \$0.13 per kWh).

- A price cap of $0.50 per kWh for participants meaning that the maximum hourly price is set at $0.50 per kWh during their participation in the program.
- In 2005 (continued in 2006), cycling switches for central air conditioners were installed at participants homes, which effectively reduced energy consumption by AC units during high price periods.
- In 2006, the Energy PriceLight, a glass orb similar in design to the Energy Orb of PG&E, was distributed. The Energy PriceLight is a glass orb that receives wireless price information and relays this information, i.e. high or low electricity prices, by glowing in different colors.
- Energy usage education for participants.

Pilot Program Results for 2005[33]

The main goals of the pilot were to determine the price elasticity of demand and the overall impact on energy conservation. A regression analysis using a simple double-log specification with hourly usage as the dependent variable and hourly price and weather as the independent variables was used to estimate the price elasticity of demand for the summer months. Overall, the price elasticity during the summer of 2005 was estimated to be -0.047.

With enabling technology, i.e. automatic cycling of the central-air conditioners during high-price periods, the overall price elasticity increased to -0.069. The largest response occurred on high-price notification days. For instance, on the day with the highest prices during the summer of 2005, participants reduced their peak hour consumption by 15 percent compared to what they would have consumed under the flat ComEd residential rate. Price responsiveness varied over the course of a day. Own price elasticities by time of day are presented in Table 12.

Table 12- Elasticity Estimates from ESPP

Time of the Day	Elasticity Estimate
Daytime (8 a.m. to 4 p.m.)	-0.02
Late afternoon/evening hours (4 p.m. to midnight)	-0.03
Daytime+ High-Price Notification	-0.02
Late Daytime/Evening+High-Price Notification	-0.05

33 Summit Blue Consulting (2006).

The impact analysis indicated that ESPP participants consumed 35.2 kWh less per month during the summer months compared to what they would have consumed without the ESPP. These savings represented roughly three to four percent of summer electricity usage. Statistically significant savings were not found for winter usage which is not surprising since most high price days occur in the summer months in this area. Overall, ESPP resulted in a net decrease in monthly energy consumption.

Pilot Program Results for 2006[34]

Results from the analysis of the ESPP in 2006 supported the findings of program's previous years. The price elasticity during the summer of 2006, for hours when the price of electricity was equal to or below $0.13 per kWh, was estimated to be -0.047. The price elasticity for the same period, but for hours when the price of electricity was above $0.13 per kWh, was estimated to be -0.082. The Energy PriceLight improved customer responsiveness resulting in an elasticity of -0.067 across all hours. For customers with A/C cycling, the price elasticity for high price periods was estimated at -0.098.

Results of the energy impact analysis indicated that ESPP participants consumed 16.7 kWh less per month, year round, relative to individuals not on the ESPP rate. During the summer months, participants consumed an additional 10.0 kWh less per month, or equivalently 26.7 kWh less per month total. This translates to approximately three percent of summer electricity usage, similar to the savings results of the 2005 program year. Again, on the whole, ESPP resulted in a decrease in monthly energy consumption.

3.9 MISSOURI- AMERENUE CRITICAL PEAK PRICING PILOT

First Year of the Pilot Program (2004)[35]

AmerenUE in collaboration with Missouri Collaborative formed by Office of Public Counsel (OPC), the Missouri Public Service Commission (MPSC), the Department of Natural Resources (DNR) and two industrial intervener groups initiated a residential TOU pilot study in Missouri during the spring of 2004. Program impacts associated with three different TOU programs were evaluated:

---

34 Summit Blue Consulting, (2007).

35 RLW Analytics, (2004).

- TOU with peak, mid-peak, and off-peak rates
- TOU with a CPP component
- TOU with a CPP component and an enabling technology (smart thermostat)

Table 13 shows the rates evaluated in the pilot.

Table 13- Residential TOU Experiment Summer Rate Design

Program	Time	Charge	Applicable
TOU	Off Peak	$0.048/kWh	Weekday 10pm–10am, weekends, holidays
TOU	Mid Peak	$0.075/kWh	Weekdays 10am– 3pm and 7pm-10pm
TOU	Peak	$0.183/kWh	Weekdays 3pm – 7pm
TOU-CPP	Off Peak	$0.048/kWh	Weekdays 10pm–10am, weekends, holidays
TOU-CPP	Mid Peak	$0.075/kWh	Weekdays 10am– 3pm and 7pm-10pm
TOU-CPP	Peak	$0.168/kWh	Weekdays 3pm – 7pm
TOU-CPP	CPP	$0.30/kWh	Weekdays 3pm – 7pm, 10 times per summer

Table 14 shows the number of participants in the treatment and control groups by type of rate.

Table 14- Experiment Sample Allocation

Treatment	Treatment Sample Size	Control Sample Size
TOU	88	89
TOU-CPP	85	89
TOU-CPP-Tech	77	117
Total	250	295

The following results are based on the data compiled from the pilot between June 1, 2004 and September 30, 2004. Average usage and demand by participants during the pilot is provided in Tables 15 and 16:

- Results from Table 15 show that the participants in the TOU and TOU-CPP groups did not shift a statistically significant amount of load from the on-peak to off-peak or mid-peak periods. Off-peak consumption increased and peak consumption decreased only slightly for the treatment groups compared to the control groups for both TOU and TOU-CPP programs. However, none of these differences in consumption between the treatment and control groups are statistically significant.

- Results from Table 16 show that the TOU-CPP-Tech group reduced their average CPP period demand by 35 percent compared to the control group on the event days. TOU-CPP group reduced their demand by 12 percent during the same period. Both impacts are statistically significant at the five percent level.

Table 15- Average Participant Use by Program and Time Period- 2004

Program	June 1-September 30 Period	Control Group (kWh)	Treatment Group (kWh)	Difference (Control-Treatment)	T-test	Pr> |t|	Statistical Significance of the Difference
TOU	Off Peak	33.63	34.87	-1.24	-0.71	0.479	Not Significant.
TOU	Mid Peak	23.59	22.78	0.81	0.71	0.476	Not Significant.
TOU	On Peak	13.81	13.36	0.45	0.67	0.505	Not Significant.
TOU	Seasonal	60.00	60.34	-0.34	-0.12	0.905	Not Significant.
TOU-CPP	Off Peak	35.84	38.36	-2.52	-1.19	0.235	Not Significant.
TOU-CPP	Mid Peak	24.11	24.54	-0.43	-0.34	0.733	Not Significant.
TOU-CPP	On Peak	13.82	13.29	0.53	0.73	0.466	Not Significant.
TOU-CPP	CPP	19.8	18.85	0.95	0.86	0.390	Not Significant.
TOU-CPP	Daily	62.87	65.3	-2.43	-0.72	0.473	Not Significant.
TOU-CPP-Tech	Off Peak	37.61	33.31	4.3	2.44	0.002	Significant.
TOU-CPP-Tech	Mid Peak	25.86	22.47	3.39	3	0.003	Significant.
TOU-CPP-Tech	On Peak	14.86	12.77	2.09	3.09	0.002	Significant.
TOU-CPP-Tech	CPP	21.39	15.48	5.91	6.5	0.000	Significant.
TOU-CPP-Tech	Daily	66.63	58.28	8.35	2.88	0.000	Significant.

Table 16- Average CPP Period Demand on the 6 Event Days in Summer 2004

Program	Control Group (kW)	Treatment Group (kW)	Difference (Control-Treatment)	% Difference	T-test	Pr> |t|	Statistical Significance of the Difference
TOU-CPP	4.98	4.37	0.61	12%	2.09	0.038	Significant.
TOU-CPP-Tech	5.36	3.49	1.87	35%	8.09	0.000	Significant.

Second Year of the Pilot Program (2005)[36]

During the second year of AmerenUE Critical Peak Pricing Pilot, the first year rate design described earlier remained in effect (see Table 13). Table 17 provides average participant usage by time period and program while Table 18 summarizes the average demand on peak periods of eight CPP days in the summer of 2005.

36 Voytas (2006).

- In 2005, the TOU-CPP and TOU-CPP-Tech customers reduced their usage during CPP periods by statistically significant amounts. However, seasonal usage reductions are not statistically significant at five percent level.
- Average CPP period demand reduction during eight event days is 13 percent for TOU-CPP customers and 24 percent for TOU-CPP-Tech customers. Both impacts are statistically significant at five percent.

Table 17- Average Participant Use by Program and Time Period – 2005

Program	Jun 1- Aug 31 Period	Control Group (kWh)	Treatment Group (kWh)	Difference (Control-Treatment)	T-test	Pr> |t|	Statistical Significance of the Difference
TOU-CPP	Off Peak	4495	4450	45	0.28	0.78	Not Significant.
TOU-CPP	Mid Peak	2054	2019	35	0.54	0.59	Not Significant.
TOU-CPP	On Peak	927	896	31	0.96	0.34	Not Significant.
TOU-CPP	CPP	252	219	33	3.92	0.00	Significant.
TOU-CPP	Seasonal	7,729	7,584	145	0.58	0.56	Not Significant.
TOU-CPP-Tech	Off Peak	4147	4017	130	0.91	0.37	Not Significant.
TOU-CPP-Tech	Mid Peak	1934	1901	33	0.46	0.65	Not Significant.
TOU-CPP-Tech	On Peak	884	863	21	0.64	0.52	Not Significant.
TOU-CPP-Tech	CPP	240	182	58	5.99	0.00	Significant.
TOU-CPP-Tech	Seasonal	7,205	6,963	242	0.98	0.33	Not Significant.

Table 18- Average CPP Period Demand on Eight Event Days in Summer 2005

Program	Control Group (kW)	Treatment Group (kW)	Difference (Control-Treatment)	% Difference	T-test	Pr> |t|	Statistical Significance of the Difference
TOU-CPP	5.56	4.84	0.72	13%	3.9	0.0001	Significant.
TOU-CPP-Tech	5.29	4.05	1.14	24%	6.05	0.0001	Significant.

3.10 NEW JERSEY- GPU PILOT[37]

GPU offered a residential TOU pilot program with a critical peak price and enabling technology component in the summer of 1997. The rate design involved three price tiers (peak, shoulder, and off-peak) and a critical peak price that is only effective for a limited number of high-cost summer hours. Moreover, the pilot program tested the impacts from two sets of

[37] Braithwait (2000).

alternative rates by allocating treatment customers to two groups and subjecting each group to one of the two sets. Table 19 shows the control and treatment group rate designs.

Table 19- Experimental Rate Design

Group	Charge	Applicable
Control	Standard increasing-block residential tariff: $0.12/kWh if consumption <=600kWh per month $0.153/kWh if consumption >600kWh per month	All hours
Treatment Group 1 (High shoulder/peak design)	Off-peak: $0.065/kWh	1a.m.-8a.m. and 9p.m.-12p.m. weekdays; All day on weekends and holidays.
	Shoulder:$0.175/kWh	9a.m.-2p.m. and 7p.m.-8p.m. weekdays.
	Peak:$0.30/kWh	3p.m.-6p.m. weekdays
	Critical:$0.50/kWh	When called during peak period
Treatment Group 2 (Low shoulder/peak design)	Off-peak:$0.09/kWh	1a.m.-8a.m. and 9p.m.-12p.m. weekdays; All day on weekends and holidays.
	Shoulder:$0.125/kWh	9a.m.-2p.m. and 7p.m.-8p.m. weekdays.
	Peak:$0.25/kWh	3p.m.-6p.m. weekdays
	Critical:$0.50/kWh	When called during peak period

One important feature of this pilot is that the treatment customers were installed communication equipment that allowed them to preset their usage patterns in response to the time-varying rates and receive price signals from the utility during the critical hours.

Analysis of the hourly load data for each of the treatment and control group customers collected for the period of June through September 1997 revealed the following results:

- On non-critical weekdays, the largest usage reductions in the average hourly load were observed during the peak period and averaged to 0.53 KW or 26 percent relative to the control group. Load reductions were also observed during the late-morning shoulder period, but these reductions were limited compared to those during the peak period. The treatment group with the high rate design reduced usage by roughly 50 percent more during each of peak and shoulder periods than the treatment group with the low-rate design.
- On CPP days, the results were similar to those on the non-CPP weekdays; though larger in magnitude, especially during the peak period. In the first hour of the peak period, average load reduction was 1.24 KW or a 50 percent reduction compared to the control group. During the next two peak hours, the reduction was around 1 KW, later falling to 0.59 KW on the last peak hour. Also, the treatment group usage was

substantially larger than the control group during the shoulder and off-peak periods following the critical peak hours.

- On weekends, average usage was similar for the control and treatment customers, with slightly lower (though not statistically significant) levels for the treatment customers.

- Average usage over all days by the treatment group decreased compared to the control group, but the result was not statistically significant. A large portion of these reductions can be attributed to the changes in the weekday usage. Average daily usage on weekend, weekdays, and all days are presented in Table 20.

Table 20- Average Daily Usage for Summer 1997 (kWh)

	Control	Treatment	Usage Difference	% Difference
Weekdays	30.4	28.3	-2.1	-6.9%
Weekends	34.1	33.7	-0.4	-1.2%
All days	32.5	30.9	-1.6	-4.9%

The data were also utilized for the estimation of the substitution elasticities. Elasticity estimates were based on two different demand models: the constant elasticity of substitution (CES) model and the generalized Leontief (GL) model.

- The substitution elasticity from the CES model was estimated to be 0.30. This estimate was larger than 0.14, the average of previous estimates from several other studies. Larger substitution elasticities from this pilot can be attributed to the presence of interactive communication equipment through which the customers preset their usage patterns of air conditioning (AC) and other appliances.

- The GL model allows substitution elasticity estimates to vary by the time-period. With this model, the substitution elasticity between peak and off-peak periods was estimated as 0.40. Substitution elasticities between other time-periods can be seen in Table 21.

Table 21- Substitution Elasticities

Month	Time Period	CES	GL High Rate Tariff	GL Low Rate Tariff
1	Overall	0.306	-	-
	Peak-shoulder	-	0.155	0.166
	Peak-off-peak	-	0.395	0.356
	Shoulder-off-peak	-	0.191	0.187
2	Overall	0.295	-	-
	Peak-shoulder	-	0.055	0.06
	Peak-off-peak	-	0.407	0.366
	Shoulder-off-peak	-	0.178	0.176

3.11 New Jersey- PSE&G Residential Pilot Program [38]

Public Service Electric and Gas Company (PSE&G) offered a residential TOU/CPP pilot pricing program in New Jersey during 2006 and 2007. The PSE&G pilot had two sub-programs. Under the first sub-program, *myPower Sense*, participants were educated about the TOU/CPP tariff and were notified of the CPP event on a day-ahead basis. The program assessed the reduction in energy use when a CPP event was called. Under the second sub-program, *myPower Connection*, participants were given a free programmable communicating thermostat (PCT) that received price signals from PSE&G and adjusted their air conditioning settings based on previously programmed set points. A total of 1,148 customers participated in the pilot program; 450 in the control group, 379 in *myPower Sense*, and 319 in *myPower Connection*. PSE&G recruited the participants separately for each group through direct mail with follow-up telemarketing[39]. Customers didn't have the opportunity to choose the treatment they would be receiving. *myPower Sense* customers received a $25 incentive upon enrollment and another $75 was paid upon the conclusion of the program. *myPower Connection* participants were provided free PCTs and received $75 at the end of the program.

The TOU/CPP tariff included a night discount, a base rate, an on-peak adder, and a critical peak adder for the summer months as shown in Table 22.

38 PSE&G and Summit Blue Consulting, (2007).

39 PSE&G recruited pilot participants from Cherry Hill and Hamilton towns as they had high percentages of residents on standard rates and high predicted penetrations of CAC.

Table 22- TOU/CPP Rate Design: Summer Months (June to September 2006 and 2007)

Period	Charge (June to September 2006)	Charge (June to September 2007)	Applicable
Base Price	$0.09/kWh	$0.087/kWh	All hours
Night Discount	-$0.05/kWh	-$0.05/kWh	10 p.m.-9 a.m. daily
On Peak Adder	$0.08/kWh	$0.15/kWh	1 p.m.-6 p.m. weekdays
Critical Peak Adder	$0.69/kWh	$1.37/kWh	1 p.m.-6 p.m. weekdays when called (Added to the base price when called)

PSE&G called two CPP events in Summer 2006 and five CPP events in Summer 2007. Table 23 summarizes the peak demand impacts on these 7 CPP event days. Results show that:

- *myPower Connection* customers reduced their peak demand by 21 percent due to TOU-only pricing. These customers reduced their peak load by an additional 26 percent on CPP event days.
- *myPower Sense* customers with CAC ownership reduced their peak demand by three percent on TOU-only days. On CPP event days, their peak load reductions reached 17 percent. Interestingly, *myPower Sense* customers without CAC ownership achieved six percent peak reductions on TOU-only days while the reductions reached 20 percent on CPP event days.
- *myPower Connection* customers reduced their peak-demand consistently more than *myPower Sense* customers because they had the PCT enabling technology.

Table 23- Estimated Peak Demand Impacts on 2006 and 2007 Summer CPP Event Days (Average kW per Hour)

Impact Estimate	Base Average Peak Consumption (kW)	TOU Impact		CPP Impact		Total Impact	
		kW	%	kW	%	kW	%
myPower Connection	2.85	-0.59	-21%	-0.74	-26%	-1.33	-47%
myPower Sense with CAC	2.6	-0.07	-3%	-0.36	-14%	-0.43	-17%
myPower Sense without CAC	1.61	-0.09	-6%	-0.23	-14%	-0.32	-20%

Source: Summit Blue Consulting

Summit Blue also estimated summer substitution elasticities for *myPower Connection and myPower Sense* customers. Table 24 presents the elasticity estimates and the associated lower and upper bounds for 90 percent confidence level.

As expected, *myPower Connection* customers have the largest elasticity of substitution, followed respectively by *myPower Sense* customers with and without CAC ownership.

Table 24- Estimated Substitution Elasticity for Summers 2006 and 2007

Impact Estimate	Substitution Elasticity	90% Confidence Interval
myPower Connection	0.125	0.12 to 0.131
myPower Sense with CAC	0.069	0.063 to 0.075
myPower Sense without CAC	0.063	0.055 to 0.072

3.12 NEW SOUTH WALES/AUSTRALIA- ENERGY AUSTRALIA'S NETWORK TARIFF REFORM [40]

The TOU pricing program is the largest demand management project by Energy Australia. The price elasticity estimates from the TOU tariffs are presented in Table 25.

Table 25- TOU Price Elasticity Estimates

Type	Season	Peak Own Price Elasticity	Peak to Shoulder Cross Price Elasticity	Peak to Off-Peak Cross Price Elasticity
Residential	Summer 2006 Winter 2006	-0.30 to -0.38 -0.47	-0.07 -0.12	-0.04 -
Business (less than 40 MWh)	Summer 2006 Winter 2006	-0.16 to -0.18 (ns) -0.2 (ns)	-0.03 -	- -
Business (40 MWh to 160 MWh)	Summer 2006 Winter 2006	-0.03 to -0.13 (ns) -0.02 to -0.09 (ns)	- -	- -

Note: ns refers to "not statistically significant"

The TOU results show that:

- Slight energy conservation effects resulted from residential consumption under TOU rates compared to residential consumption under the flat tariffs.
- Conservation effects were larger in winter than in summer for the residential customers.

[40] Colebourn (2006).

- Business customer price elasticities are not statistically significant. Therefore, they should be interpreted with caution.

Energy Australia started the Strategic Pricing Study in 2005 which included 1,300 voluntary customers (50 percent business, 50 percent residential customers). The study tested seasonal, dynamic, and information only tariffs and involved the use of in-house displays and online access to data. Study participants received dynamic peak price signals through Short Message Service (SMS), telephone, email, or the display unit.

Preliminary results that are available from three dynamic peak pricing (DPP) events show that:

- Residential customers reduced their dynamic peak consumption by roughly 24 percent for DPP high rates (A$2+/kWh) and roughly 20 percent for DPP medium rates (A$1+/kWh).
- Response to the 2nd DPP event was greater than that to the 1st DPP event. This may be attributed to the day-ahead notification under the 2nd DPP event (versus day-of notification under the 1st DPP event) and/or temperature differences.
- Response to the 2nd event was also greater than to the 3rd DPP event. This may be explained by lower temperatures on the 3rd DPP event which may have led to less discretionary appliances to turn off.

3.13 Ontario/Canada- Ontario Energy Board's Smart Price Pilot[41]

The Ontario Energy Board operated the residential Ontario Smart Price Pilot (OSPP) between August 2006 and March 2007. The OSPP used a sample of Hydro Ottawa residential customers and tested the impacts from three different price structures:

- The existing Regulated Price Plan (RPP) TOU: The RPP TOU rates are shown in Table 26.
- RPP TOU rates with a CPP component (TOU CPP). The CPP was set at C$0.30 per kWh based on the average of the 93 highest hourly Ontario electricity prices in the previous year. The RPP TOU off-peak price was decreased to C$0.031 (from C$0.035) per kWh to offset the increase in the critical peak price. The maximum number

[41] Ontario Energy Board, (2007).

of critical day events was set at nine days, however only seven CPP days were called during the pilot.

- RPP TOU rates with a critical peak rebate (TOU CPR): The CPR provided participants with a C$0.30 per kWh rebate for each kWh of reduction from estimated baseline consumption. The CPR baseline consumption was defined as the average usage during the same hours over the participants' last five non-event weekdays, increased by 25 percent.

Table 26- Regulated Price Plan (RPP) TOU Rate Design

Season	Time	Charge	Applicable
Summer (Aug 1- Oct 31)	Off-peak	C$0.035/kWh	10 p.m.- 7 a.m. weekdays; all day on weekends and holidays
Summer (Aug 1- Oct 31)	Mid-peak	C$0.075/kWh	7 a.m.- 11 a.m. and 5 p.m.- 10 p.m. weekdays
Summer (Aug 1- Oct 31)	On-peak	C$0.105/kWh	11 a.m.- 5 p.m. weekdays

A total of 373 customers participated in the pilot: 124 in TOU-only, 124 in TOU-CPP, and 125 in TOU-CPR. The control group included 125 participants who had smart meters installed but continued to pay non-TOU rates.

The OSPP results show that:

- The load shift during the critical hours of the four summer CPP events ranged between 5.7 percent and 25.4 percent. [42]
- The load shift during the entire peak period of the four summer CPP events ranged between 2.4 percent and 11.9 percent.

Table 27 shows the shift in load during the summer CPP events as a percentage of the load in critical peak hours and of the entire peak period. It is important to note that the percentage reductions for the TOU-only customers are not significant at the 90 percent confidence level.

[42] Under the OSPP, 3 to 4 hours of the peak period were defined as critical on a CPP day.

Table 27- Percentage Shift in Load during the Four Summer CPP Events

Period	TOU- only	TOU- CPP	TOU- CPR
Shift as % of critical peak hours	5.7%	25.4%	17.5%
Shift as % of all peak hours	2.4%	11.9%	8.5%

This study also analyzed the total conservation impact during the full pilot period. The total reduction in electricity consumption due to program impacts is reported in Table 28. The average conservation impact across all customers was estimated to be six percent.

Table 28- Total Conservation Effect for the Full Pilot Duration

Program	% Reduction in Total Electricity Usage
TOU-only	6.0%
TOU- CPP	4.7% (ns)
TOU- CPR	7.4%
Average Impact	6.0%

3.14 WASHINGTON (SEATTLE SUBURBS)- PUGET SOUND ENERGY (PSE)'S TOU PROGRAM[43]

PSE initiated a TOU program for its residential and small commercial customers in 2001. The rate design involved four price periods. Prices were most expensive during the morning and evening periods with mid-day and economy periods following these most expensive periods. Some 300,000 PSE customers were placed in the program and given the option to go back to the standard rates if they were not satisfied with the program. The peak price was roughly 15 percent higher than the average price that prevailed before the program and the off-peak price was 15 percent lower. In 2002, the second year of the program, customers were charged a monthly fee of $1 per month for meter-reading costs. The results of PSE's quarterly report revealed that the 94 percent of the customers paid an extra $0.80 (the total of $0.20 power savings and $1 meter reading costs) by participating in the pilot. This was in contrast with the first year results where customers were not charged meter reading costs and around 55 percent of them experienced bill savings. As a result of customer dissatisfaction and negative media coverage, PSE ceased its TOU program. Following are several lessons that were derived from this experience:

[43] Faruqui and George (2003).

- Modest price differentials between peak and off-peak may induce customers to shift their load if they are accompanied with unusual circumstances such as the energy crisis of 2000-2001 in the West. An independent analysis of the program found that customers lowered peak usage by five percent per month over a 15 month period, with reductions being slightly higher in the winter months and slightly lower in the summer months.
- It is important to provide the customers with accurate expectations about their bill savings.
- It is essential to offer a pilot program before implementing a full-scale program.

3.15 WASHINGTON- THE OLYMPIC PENINSULA PROJECT[44]

The Olympic Peninsula Project was a component of the Pacific Northwest GridWise Testbed Demonstration that took place in Washington and was led by the Pacific Northwest National Laboratory (PNNL). The Peninsula Project tested whether automated two-way communication systems between grid and passive resources (i.e., end use loads and idle distributed generation) and the use of price signals as instruments would be effective in reducing the stress on the system. Our review focuses on the residential response and does not cover the impacts associated with the distributed generation resources.

By the end of 2005, the project recruited participants with the assistance of the local utility companies. The project received a mailing list from the utilities of the potential participants who had high-speed internet, electric HVAC systems, electric water heater, and electric dryer. Letters were mailed to these customers to recruit potential participants. At the end of the recruiting process, 112 homes were installed with the two-way communication equipments that allowed utilities to send the market price signals to the consumers and allowed consumers to pre-program their demand response preferences. These residential participants were then evenly divided into three treatment groups and a control group. Equipment was also installed in the control group homes but they were given no additional information.

44 Pacific Northwest National Laboratory (2007).

Each treatment group was assigned to one of the three electricity contracts:

- Fixed-prices: prices remained constant at all times.
- Time-of-use/critical peak prices (TOU/CPP): prices differed between peak and off-peak time periods. Peak price were much higher during critical peak days.
- Real time prices: prices under this contract were unpredictable and varied every five minutes. Participants in this contract responded to real time prices by pre-setting their appliance controls for their preferences through the web but they still had the option to override their preferences at any time.

Table 29 shows the prices that prevailed under fixed price and TOU/CPP contracts.

Table 29- Experimental Rate Design

Contract	Season	Period	Charge	Applicable
Time-of-Use/ CPP	Spring (1 Apr-24 Jul) and Fall/Winter (1 Oct-31 Mar)	Off-peak	$0.04119/kWh	9 am-6pm and 9pm-6am
		On-peak	$0.1215/kWh	6am-9am and 6pm-9pm
		Critical	$0.35/kWh	Not called
	Summer (25 Jul- 30 Sep)	Off-peak	$0.05/kWh	9am-3pm
		On-peak	$0.135/kWh	3pm-9pm
		Critical	$0.35/kWh	When called
Fixed-Price	All seasons	All day	$0.081/kWh	All hours

Results from the pilot are as follows:

- The fixed-price group saved two percent on their average monthly bill compared to the control group; the time-of-use pricing group saved 30 percent and the real time pricing group saved 27 percent.
- Differences in average energy consumption between the contract groups were small but statistically significant. The time-of-use group consumed 21 percent less energy and achieved conservation benefits from time-of-use pricing. The real time group consumed as much as the control group. The fixed-price group used four percent more energy than the control group. The usage comparison across the contract groups is presented in Table 30.

Table 30- Average Daily Energy Consumption per Home (April 06- December 06)

Contract Type	Average Daily Energy Consumption (kWh)	Standard Deviation(kWh)	Percentage Difference (compared to the control)
Control	47	24	0%
Fixed	49	22	4%
Time-of-Use	39	29	-21%
Real-Time	47	26	0%

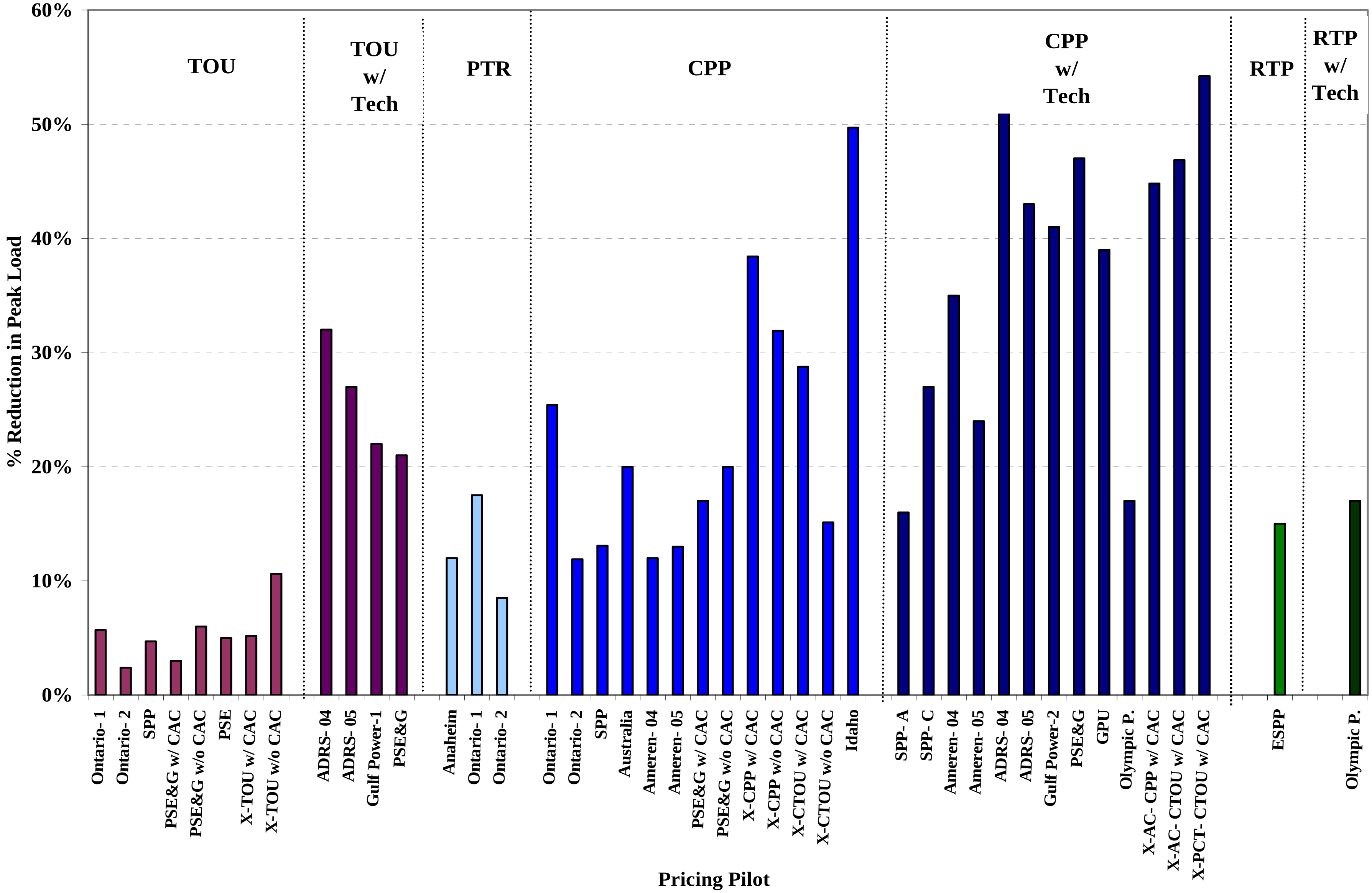
- Examination of the residential load shapes by contract and season revealed that the time-of-use/CPP contract was the most effective design at reducing peak-demand.
- On average, the real-time contract did not bring about the lowest average peak demand.
- Preliminary analysis of the data reveals that peak demand consumption fell by 15-17% for RTP group, while it fell by 20% for the TOU/CPP group relative to the fixed price group.[45]

4.0 CROSS-EXPERIMENTAL ASSESSMENT

Our review of the 15 pricing experiments reveals that the demand response impacts from different pilot programs vary widely due to the difference in the rate designs tested, use of enabling technologies, ownership of central air conditioning and more generally, due to the variations in sample design. Figure 1 presents a summary.

[45] Kiesling, Lynne (2008).

Figure 1:



60%
50%
40%
30%
20%
10%
0%
% Reduction in Peak Load
TOU
TOU w/ Tech
PTR
CPP
CPP w/ Tech
RTP
RTP w/ Tech
Ontario- 1
Ontario- 2
SPP
PSE&G w/ CAC
PSE&G w/o CAC
PSE
X-TOU w/ CAC
X-TOU w/o CAC
ADRS- 04
ADRS- 05
Gulf Power-1
PSE&G
Anaheim
Ontario- 1
Ontario- 2
Ontario- 1
Ontario- 2
SPP
Australia
Ameren- 04
Ameren- 05
PSE&G w/ CAC
PSE&G w/o CAC
X-CPP w/ CAC
X-CPP w/o CAC
X-CTOU w/ CAC
X-CTOU w/o CAC
Idaho
SPP- A
SPP- C
Ameren- 04
Ameren- 05
ADRS- 04
ADRS- 05
Gulf Power-2
PSE&G
GPU
Olympic P.
X-AC- CPP w/ CAC
X-AC- CTOU w/ CAC
X-PCT- CTOU w/ CAC
ESPP
Olympic P.
Pricing Pilot

Notes:

*Percentage reduction in load is defined relative to different bases in different pilots. The following notes are intended to clarify these different definitions.

1. TOU with Technology (TOU w/ Tech) and CPP with Technology (CPP w/ Tech) refer to the pricing programs that had some form of enabling technologies.
2. TOU program impacts are defined relative to the usage during peak hours unless otherwise noted.
3. CPP program impacts are defined relative to the usage during peak hours on CPP days unless otherwise noted.
4. Ontario- 1 refer to the percentage impacts during the critical hours that represent only 3-4 hours of the entire peak period on a CPP day. Ontario- 2 refer to the percentage impacts of the programs during the entire peak period on a CPP day.
5. TOU impact from the SPP is based on the CPP-F treatment effect for normal weekdays on which critical prices were not offered.
6. ADRS- 04 and ADRS- 05 refer respectively to the 2004 and 2005 impacts. ADRS impacts on non-event days are represented in the TOU with Technology section.
7. CPP impact for Idaho is derived from the information provided in the reviewed study. Average of kW consumption per hour during the CPP hours (for all 10 event days) is approximately 2.5 kW for a control group customer while this value is 1.2 kW for a treatment group customer. Percentage impact from the CPP treatment is calculated as 50%.
8. Gulf Power-1 refers to the impact during peak hours on non-CPP days and therefore shown in the TOU with Technology section while Gulf Power- 2 refers to the impact during CPP hours on CPP days.
9. Ameren- 04 and Ameren- 05 refer to the impacts respectively from the summers of 2004 and 2005.
10. SPP- A refers to the impacts from the CPP-V program on Track A customers. Two thirds of Track A customers had some form of enabling technologies.
11. SPP- C refers to the impacts from the CPP-V program on Track C customers. All Track C customers had smart thermostats.
12. X-CPP program only differentiates between CPP and non-CPP hours while X-CTOU program differentiates between CPP, on-peak, and off-peak hours.

To synthesize the information from the 15 pricing experiments, we have constructed a dataset of 28 observations where the impacts are grouped with respect to the rate designs and the existence of an enabling technology. Table 31 provides the mean impact estimates and the 95% confidence intervals associated with the mean values from this dataset.

Table 31- Summary Impacts

Rate Design	Number of Observations	Mean	95% Lower Bound	95% Upper Bound	Min	Max
TOU	5	4%	3%	6%	2%	6%
TOU w/ Technology	4	26%	21%	30%	21%	32%
PTR	3	13%	8%	18%	9%	18%
CPP	8	17%	13%	20%	12%	25%
CPP w/ Technology	8	36%	27%	44%	16%	51%

Notes:

1- Confidence intervals are calculated assuming normal distribution of the impact estimates.

2- The pilot results from Xcel Energy are excluded from the summary statistics due to the role of self-selection bias, as reported in the study, in driving the large demand impacts.

3- The CPP impact for Idaho is also excluded from the summary statistics since it is an outlier.

On average, TOU programs are associated with a mean reduction of four percent in peak usage, and a 95 percent confidence interval ranges from three to six percent. CPP programs reduce peak usage by 17 percent and a 95 confidence interval ranges from 13 to 20 percent. CPP programs supported with enabling technologies reduce peak usage by 36 percent and a 95 confidence interval ranges from 27 to 44 percent. Impacts associated with PTR and TOU supported with enabling technology programs are also provided in Table 31. However, these should be interpreted with caution due to the small number of observations underlying the distributions. Nine out of the twelve impact estimates with enabling technologies are tested on customers with CAC ownership, so these impacts also capture impacts due to CAC ownership.

Our survey finds that in addition to displaying a wide variation in the size of impact due to different rate designs, the impacts also vary widely among the experiments using the same rate design. The residual variation comes from variation in price elasticities and in sample design. Substitution elasticities from the experiments range from 0.07 to 0.40 while the own price elasticities range from -0.02 to -0.10. Availability of the enabling technologies, ownership of central air conditioning and the type of the days examined (weekend vs. weekday) are some of the factors that lead to variations in the demand elasticities.

Another interesting question is how the impact estimates vary for different critical peak prices. To address this question, we have simulated the demand response to increasing levels of critical prices using the California SPP experiment data and the PRISM (Price Impact Simulation Model) that was developed in the experiment.[46]

The PRISM model predicts the changes in electricity usage that are induced by time-varying rates by utilizing a constant elasticity of substitution (CES) demand system. This demand system consists of two equations. The substitution equation predicts the ratio of peak to off-peak quantities as a function of the ratio of peak to off-peak prices and other factors. The daily energy usage equation predicts the daily electricity usage as a function of daily price and other factors. Once the demand system is estimated, the resulting equations are solved to determine the changes in electricity usage associated with a time-varying rate. PRISM has the capability to predict these changes for peak and off-peak hours for both critical and non-critical peak days. Moreover, PRISM allows predictions to vary by other exogenous factor such as the saturation of central air conditioning and variations in climate. The model can be set to demonstrate these impacts on different customer types.

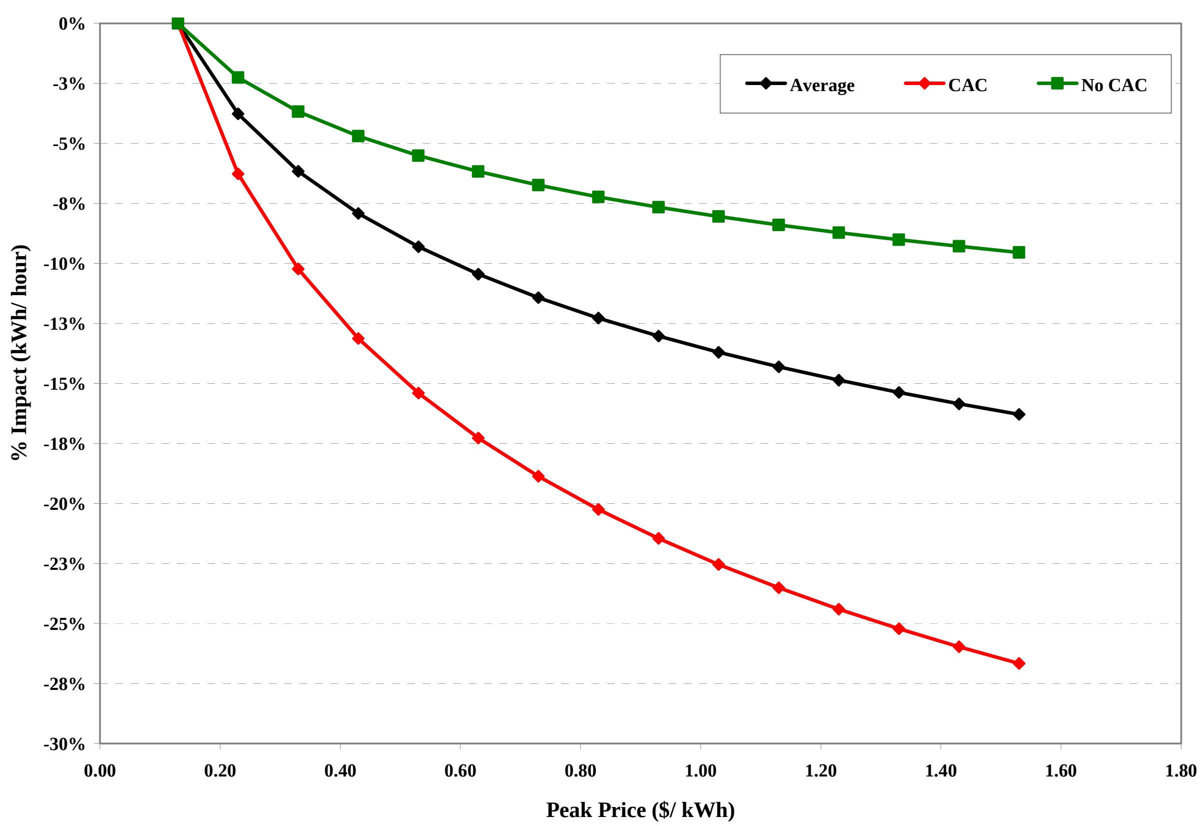
Since we would like to determine how the usage impacts vary as the critical prices are increased gradually, we have run the PRISM model using the data points provided in Table 32. To clarify how PRISM models the relationship between the prices and the percentage impact on load in a non-linear fashion, consider the following example. For the average customer, peak period energy usage decreases by 4% when the peak-price increases from $0.13 per kWh to $0.23 per kWh. However, peak period energy usage decreases by only 8% when the peak price is increased from $0.13 per kWh to $0.43 per kWh. This example demonstrates that the load impact increases by one-fold (rather than two-fold) when the price increases by two-fold. We can also observe the differences between customer types in their price-responsiveness from these response curves. For a given price increase, Non-CAC customers (without CAC ownership) are the least responsive group while CAC customers (with CAC Ownership) are the most responsive.

46 For model description, see Charles River Associates (2005).

Table 32- PRISM Impact Simulation

Critical Price (cents/kWh)	% Reduction in Quantity: Average Customer	Customer w/ CAC	Customer w/o CAC
0.13	0.0%	0.0%	0.0%
0.23	-3.8%	-6.3%	-2.3%
0.33	-6.2%	-10.2%	-3.7%
0.43	-7.9%	-13.1%	-4.7%
0.53	-9.3%	-15.4%	-5.5%
0.63	-10.4%	-17.3%	-6.2%
0.73	-11.4%	-18.9%	-6.7%
0.83	-12.3%	-20.2%	-7.2%
0.93	-13.0%	-21.5%	-7.7%
1.03	-13.7%	-22.5%	-8.0%
1.13	-14.3%	-23.5%	-8.4%
1.23	-14.9%	-24.4%	-8.7%
1.33	-15.4%	-25.2%	-9.0%
1.43	-15.8%	-26.0%	-9.3%
1.53	-16.3%	-26.7%	-9.5%

Figure 2- Residential Demand Response Curves on Critical Days



The response curves in Figure 2 demonstrate how the percent impact on peak period energy usage varies with the peak-period price on critical days. These curves show that the percentage impact on the peak period energy usage increases as prices increase, but at a decreasing rate. This non-linear relation between usage impacts and prices is reflected in the concave shape of the response curves.

5.0 CONCLUSIONS

This article reviews the most recent experimental evidence on the effectiveness of residential dynamic pricing programs. We find that demand responses vary from modest to substantial, largely depending on the data used in the experiments and the availability of enabling technologies. Across the range of experiments studied, time-of-use rates induce a drop in peak demand that ranges between three to six percent and critical-peak pricing tariffs lead to a drop in peak demand of 13 to 20 percent. When accompanied with enabling technologies, the latter set of tariffs lead to a drop in peak demand in the 27 to 44 percent range.

In future work, we intend to obtain the data from the best experiments and pool them, thereby enabling the estimation of a unified national model. However, even in the absence of a unified model, we can state with confidence that residential dynamic pricing designs can be very effective in reducing peak demand and lowering energy costs.

These results have important implications for the reliability and least cost operation of an electric power system facing ever increasing demand for power and surging capacity costs. Demand response programs that blend together customer education initiatives, enabling technology investments, and carefully designed time-varying rates can achieve demand impacts that can alleviate the pressure on the power system. Uncertainties involving the fuel prices and the form of a carbon pricing regime that is in the horizon emphasize the importance of the demand-side resources. Dynamic pricing regimes also incorporate some uncertainties such as the responsiveness of customers, cost of implementation and revenue impacts. However, these uncertainties can be addressed to a large extent by implementing pilot programs that can help guide the full-scale deployment of dynamic pricing rates.

Table 31- Summary of the Experimental Tariffs

Study	Control Group Tariff	Applicable Period	Treatment Group Tariff	Applicable Period
California- Anaheim Peak Time Rebate Pricing Experiment	$0.0675/kWh $0.1102/kWh	Usage<=240kWh per month Usage>240kWh per month	**PTR/** Control group tariff **PTR/** $0.35/kWh rebate for each kWh reduction from baseline	All hours except 12a.m.- 6p.m. on CPP days 12a.m.- 6p.m. on CPP days
California- Statewide Pricing Pilot	$0.13/kWh	All hours	**TOU/** Off-peak: $0.09/kWh **TOU/** Peak: $0.22/kWh **CPP-F/** Off-peak: $0.09/kWh **CPP-F/** Peak: $0.22/kWh **CPP-F/** CPP: $0.59/kWh **CPP-V/** Off-peak: $0.10/kWh **CPP-V/** Peak: $0.22/kWh **CPP-V/** CPP: $0.65 /kWh	12a.m.- 2 p.m. and from 7 p.m. until 12a.m. weekdays, all day on weekends 2 p.m. to 7 p.m. weekdays 12a.m.- 2 p.m. and from 7 p.m. until 12a.m. weekdays, all day on weekends 2 p.m. to 7 p.m. weekdays 2 p.m. to 7 p.m. weekdays when called 12a.m.- 2 p.m. and from 7 p.m. until 12a.m. weekdays, all day on weekends 2 p.m. to 7 p.m. weekdays 2 or 5 hours during 2 p.m. to 7 p.m., weekdays when called
Florida- The Gulf Power Select Program	$0.057/kWh	All hours	**RST/** Off-peak: $0.027/kWh **RST/** Peak: $0.104/kWh **RSVP/** Off-peak: $0.035/kWh **RSVP/** Mid-peak: $0.046 /kWh **RSVP/** Peak: $0.093/kWh **RSVP/** CPP: $0.29/kWh	12 a.m.-12p.m. and 9p.m.-12a.m. 12p.m.- 9p.m. 12a.m.-6a.m. and 11p.m.-12a.m. 6a.m.-11a.m. and 8p.m.-11p.m. 11a.m.-8p.m. Assigned hours on CPP days
Idaho- Idaho Residential Pilot Program	$0.054/kWh $0.061/kWh	Usage<= 300 kWh per month Usage>300 kWh per month	**TOU/** Off-peak: $0.045/kWh **TOU/** Mid-peak: $0.061 /kWh **TOU/** On-peak: $ 0.083/kWh **CPP/** Non-CPP hours: $0.054/kWh **CPP/** CPP: $0.20/kWh	9p.m. to 7a.m. weekdays, all day on weekends 7a.m. to 1p.m. weekdays 1p.m. to 9p.m. weekdays All hours except CPP hours 5 p.m. to 9 p.m. on CPP days
Missouri- AmerenUE Residential TOU Pilot Study	-	-	**TOU/** Off-peak: $0.048/kWh **TOU/** Mid-peak: $0.075/kWh **TOU/** On-peak: $0.1831/kWh **CPP/** same as TOU except that there is a CPP component set at $0.30/kWh and peak price is decreased to $0.1675 /kWh	10p.m.–10a.m. weekdays, all day on weekends 10a.m.– 3p.m. and 7p.m.-10p.m. weekdays 3p.m. – 7p.m. weekdays CPP days when called, otherwise same as TOU

Table 31- (Cont'd) Summary of the Experimental Tariffs from the Studies Reviewed

Study	Control Group Tariff	Applicable Period	Treatment Group Tariff	Applicable Period
New Jersey- GPU Pilot	$0.12/kWh $0.153/kWh	Usage<=600kWh Usage>600kWh	**High-rate Design** **CPP/** Off-peak: $0.065/kWh **CPP/** Shoulder:$0.175/kWh **CPP/** Peak:$0.30/kWh **CPP/** Critical:$0.50/kWh **Low-rate Design** **CPP/** Off-peak:$0.09/kWh **CPP/** Shoulder:$0.125/kWh **CPP/** Peak:$0.25/kWh **CPP/** Critical:$0.50/kWh	 1a.m.-8a.m. and 9p.m.-12p.m. weekdays, all day on weekends and holidays 9a.m.-2p.m. and 7p.m.-8p.m. weekdays 3p.m.-6p.m. weekdays When called during peak period 1a.m.-8a.m. and 9p.m.-12p.m. weekdays, all day on weekends and holidays 9a.m.-2p.m. and 7p.m.-8p.m. weekdays 3p.m.-6p.m. weekdays When called during peak period
New Jersey- PSE&G Residential Pilot Program	$0.087/kWh	All hours	**CPP/** Night: $0.037/kWh **CPP/** Peak: $0.24/kWh **CPP/** CPP: $1.46/kWh	10 p.m.-9a.m. daily 1p.m.-6p.m. weekdays 1p.m.-6p.m. weekdays when called
Ontario/ Canada- Ontario Energy Board Smart Price Pilot	$0.058/kWh $0.067/kWh	Usage<= 600 kWh per month Usage>600 kWh per month	**TOU/** Off-peak: $0.035/kWh **TOU/** Mid-peak: $0.075/kWh **TOU/** On-peak: $0.105/kWh **CPP/** same as TOU except that there is a CPP component set at $0.30/kWh and off-peak price is decreased to $0.031/kWh **PTR/** same as TOU with PTR at $0.30/kWh for each kWh reduction from the baseline	10 p.m.- 7 a.m. weekdays, all day on weekends and holidays 7 a.m.- 11 a.m. and 5 p.m.- 10 p.m. weekdays 11 a.m.- 5 p.m. weekdays CPP days when called, otherwise same as TOU CPP days when called, otherwise same as TOU
Washington - Olympic Peninsula Project	-	-	**Summer** **CPP/** Off-peak:$0.05/kWh **CPP/** On-peak:$0.135/kWh **CPP/** Critical:$0.35/kWh **Fall/ Spring/ Winter** **CPP/** Off-peak:$0.04119/kWh **CPP/** On-peak:$0.1215/kWh **CPP/** Critical:$0.35/kWh **Fixed Price/** All hours:$0.081/kWh	 9 am-6pm and 9pm-6am 6am-9am and 6pm-9pm When called 9am-3pm 3pm-9pm When called All hours

Table 32- Summary of the Experimental Elasticities

Pilot	Program	Substitution Elasticity	Own Price Elasticity	Cross Price Elasticity
New Jersey- PSE&G Residential Pilot Program	CPP w/ CAC	0.069	-	-
	CPP w/o CAC	0.063	-	-
	CPP w/ Tech.	0.125	-	-
Illinois- The Community Energy Cooperative's Energy-Smart Pricing Plan	RTP	-	-0.047 (Overall)	-
	RTP	-	-0.069 (Overall with AC cycling)	-
	RTP	-	-0.015 (Daytime)	-
	RTP	-	-0.026 (Late daytime/evening)	-
	RTP	-	-0.02 (Daytime+high price notification)	-
	RTP	-	-0.048 (Late daytime/evening+high price notification)	-
New South Wales/ Australia- Energy Australia's Network Tariff Reform	TOU	-	-0.30 to -0.38	-0.07 (Peak to shoulder)
	TOU	-	-	-0.04 (Peak to off-peak)
California- Statewide Pricing Pilot	CPP-F	0.087	-0.054 (daily)	-
	CPP-V/ Track A	0.111	-0.027 (daily)	-
	CPP-V/ Track A	-	-0.043 (weekend daily)	-
	CPP-V/ Track C	0.154 (*)	-0.044 (daily)	-
	CPP-V/ Track C	-	-0.041 (weekend daily)	-
New Jersey- GPU Pilot		**1st Month**		
	CPP w/ Tech.	0.306 (Overall)	-	-
	CPP w/ Tech.	0.155, 0.166 (Peak-shoulder)	-	-
	CPP w/ Tech.	0.395, 0.356 (Peak-off-peak)	-	-
	CPP w/ Tech.	0.191, 0.187 (Shoulder-off-peak)	-	-
		2nd Month		
	CPP w/ Tech.	0.295 (Overall)	-	-
	CPP w/ Tech.	0.055, 0.06 (Peak-shoulder)	-	-
	CPP w/ Tech.	0.407, 0.366 (Peak-off-peak)	-	-
	CPP w/ Tech.	0.178, 0.176 (Shoulder-off-peak)	-	-

(*) Elasticity of substitution for CPP-Track C customers is estimated to be 0.077 and excludes the impact of technology (0.214).
We calculated substitution elasticity including the impact of technology as 0.154 through simulation.

BIBLIOGRAPHY

Aubin, Christophe, Denis Fougere, Emmanuel Husson and Marc Ivaldi (1995). "Real-Time Pricing of Electricity for Residential Customers: Econometric Analysis of an Experiment," *Journal of Applied Econometrics*, 10, S171-191.

Bandt, William D., Tom Campbell, Carl Danner, Harold Demsetz, Ahmad Faruqui, Paul R. Kleindorfer, Robert Z. Lawrence, David Levine, Phil McLeod, Robert Michaels, Shmuel S. Oren, Jim Ratliff, John G. Riley, Richard Rumelt, Vernon L. Smith, Pablo Spiller, James Sweeney, David Teece, Philip Verleger, Mitch Wilk, and Oliver Williamson (2003). "2003 Manifesto on the California Electricity Crisis." The manifesto can be accessed at this web site: http://www.aei-brookings.org/publications/abstract.php?pid=341. May 2003.

Borenstein, Severin (2002). "The Trouble with Electricity Markets: Understanding California's Restructuring Disaster," *Journal of Economic Perspectives*, 16:1, 191-211, Winter.

Borenstein, Severin, Michael Jaske, and Arthur Rosenfeld (2002). "Dynamic Pricing, Advanced Metering and Demand Response in Electricity Markets." Center for the Study of Electricity Markets, Paper CSEMWP 105, October 31.

Borenstein, Severin (2005). "The Long-run Efficiency of Real-Time Pricing," *The Energy Journal*, 26:3, 93-116,

Braithwait, S. D. (2000). "Residential TOU Price Response in the Presence of Interactive Communication Equipment." In Faruqui and Eakin (2000).

California Energy Commission (2008). "Proposed Load Management Standards," Draft Committee Report, November, CEC-400-2008-027-CTD.

Caves, D. W., L. R. Christensen, and J. A. Herriges (1984). "Consistency of Residential Customer Response in Time-of-Use Electricity Pricing Experiments." *Journal of Econometrics* 26:179-203.

Chao, Hung-po (1983). "Peak-Load Pricing and Capacity Planning with Demand and Supply Uncertainty," *Bell Journal of Economics* 14:1, 170-90, Spring.

Chao, Hung-po and Robert Wilson (1987). "Priority Service: Pricing, Investment and Market Organization," *American Economic Review* 77:5, 899-916.

Charles River Associates (2005). "Impact Evaluation of the California Statewide Pricing Pilot." March 16. The report can be downloaded from:
http://www.calmac.org/publications/2005-03-24_SPP_FINAL_REP.pdf.

Colebourn H. (2006). "Network Price Reform." presented at BCSE Energy Infrastructure& Sustainability Conference. December.

Crew, Michael A., Chitru S. Fernando and Paul R. Kleindorfer (1995). "The Theory of Peak Load Pricing: A Survey," *Journal of Regulatory Economics*, 8:215-248.

Energy Insights Inc. (2008a). "Xcel Energy TOU Pilot Final Impact Report." March.

Energy Insights Inc. (2008b). "Experimental Residential Price Response Pilot Program March 2008 Update to the 2007 Final Report." March.

Faruqui, Ahmad (2007). "Breaking out of the bubble: using demand response to mitigate rate shock," 46-51, *Public Utilities Fortnightly*, March.

Faruqui, Ahmad, Hung-po Chao, Victor Niemeyer, Jeremy Platt and Karl Stahlkopf (2001a). "Analyzing California's power crisis," *The Energy Journal*, Vol. 22, No. 4, 29-52.

Faruqui, Ahmad, Hung-po Chao, Victor Niemeyer, Jeremy Platt and Karl Stahlkopf (2001b). "Getting out of the dark," *Regulation*, Fall, 58-62.

Faruqui, Ahmad and B. Kelly Eakin. 2002. *Electricity Pricing in Transition*, Kluwer Academic Publishers, 2002.

Faruqui, Ahmad and B. Kelly Eakin. 2000. *Pricing in Competitive Electricity Markets*, Kluwer Academic Publishers.

Faruqui, Ahmad and Stephen S. George. 2002. "The Value of Dynamic Pricing in Mass Markets." *The Electricity Journal* 15:6, 45-55.

Faruqui, Ahmad and Stephen S. George. 2003. "Demise of PSE's TOU Program Imparts Lessons." *Electric Light & Power* Vol. 81.01:14-15.

Faruqui, Ahmad and Stephen S. George. 2005. "Quantifying Customer Response to Dynamic Pricing," *The Electricity Journal*, May.

Faruqui, Ahmad, Ryan Hledik, Samuel Newell, and Johannes Pfeifenberger. 2007. "The Power of Five Percent." *The Electricity Journal* Vol. 20, Issue 8:68-77.

Faruqui, Ahmad and J. Robert Malko. 1983. "The Residential Demand for Electricity by Time-of-Use: A Survey of Twelve Experiments with Peak Load Pricing." *Energy* Vol. 8:10. 781-795.

Federal Energy Regulatory Commission. 2008. Assessment of Demand Response and Advanced Metering. Staff Report. Washington, D. C.

Filippini, Massimo. 1995. "Swiss Residential Demand for Electricity by Time-of-Use: An Application of the Almost Ideal Demand System," *Energy Journal*, 16:1, 27-39.

Giraud, Denise. 2004. "The tempo tariff," Efflocon Workshop, June 10. http://www.efflocom.com/pdf/EDF.pdf.

Giraud, Denise. 1994. “A New Real-Time Tariff for Residential Customers,” in Proceedings: 1994 Innovative Electricity Pricing Conference, EPRI TR-103629, February.

Herter, Karen. 2007. “Residential implementation of critical-peak pricing of electricity,” *Energy Policy*, 35:4, April, 2121-2130.

Herter, Karen, Patrick McAuliffe and Arthur Rosenfeld. 2007. “An exploratory analysis of California residential customer response to critical peak pricing of electricity,” *Energy*, 32:1, January, 25-34.

Idaho Power Company. 2006. “Analysis of the Residential Time-of-Day and Energy Watch Pilot Programs: Final Report.” December.

Kiesling, Lynne (2008). “Digital Technology, Demand Response, and Customer Choice: Efficiency Benefits,” NARUC Winter Meetings, Washington, DC, February 18.

Levy, Roger, Ralph Abbott and Stephen Hadden (2002). *New Principles for Demand Response Planning*. EPRI EP-P6035/C3047, March.

Littlechild, Stephen C. (2003). “Wholesale Spot Price Pass-Through,” *Journal of Regulatory Economics*, 23:1, January. 61-91.

Matsukawa, Isamu. 2001. “Household Response to Optional Peak-Load Pricing of Electricity,” *Journal of Regulatory Economics*. 20:3, 249-261.

Ontario Energy Board. 2007. “Ontario Energy Board Smart Price Pilot Final Report.” Toronto, Ontario, July.

Pacific Northwest National Laboratory. 2007. “Pacific Northwest GridWise Testbed Demonstration Projects Part 1: Olympic Peninsula Project.” Richland, Washington. October.

Pfannenstiel, Jackie and Ahmad Faruqui (2008). “Mandating Demand Response,” *The Public Utilities Fortnightly*, January.

PSE&G and Summit Blue Consulting (2007). “Final Report for the Mypower Pricing Segments Evaluation.” Newark, New Jersey. December.

Reiss, Peter C. and Matthew W. White (2008). “What changes energy consumption? Prices and public pressures,” *The Rand Journal of Economics*, Vol. 39, No. 3, Autumn, 636-663.

RLW Analytics (2004). “AmerenUE Residential TOU Pilot Study Load Research Analysis: First Look Results.” February.

Rocky Mountain Institute (2006). “Automated Demand Response System Pilot: Final Report.” Snowmass, Colorado. March.

Summit Blue Consulting, LLC. (2006). “Evaluation of the 2005 Energy-Smart Pricing Plan-Final Report.” Boulder, Colorado. August.

Summit Blue Consulting, LLC. (2007). “Evaluation of the 2006 Energy-Smart Pricing Plan-Final Report.” Boulder, Colorado.

Taylor, Thomas N., Peter M. Schwarz and James E. Cochell (2005). “24/7 Hourly Response to Electricity Real-Time Pricing with up to Eight Summers of Experience,” *Journal of Regulatory Economics*, 27:3, 235-262.

U.S. Demand Response Coordinating Committee (2008). “Demand Response and Smart Metering Policy Actions Since the Energy Policy Act of 2005: A Summary for State Officials,” The National Council on Electricity Policy, Fall.

U.S. Department of Energy (2006). “Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them: A Report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005.” February.

Vickrey, W. S. (1971). “Responsive Pricing of Public Utility Services,” *Bell Journal of Economics*, 2:1, 337-46, Spring.

Voytas, Rick (2006). “AmerenUE Critical Peak Pricing Pilot.” presented at U.S. Demand Response Research Center Conference, Berkeley, California, June.

Wellinghoff, Jon and David M. Morenoff (2007). “Recognizing the importance of demand response: The second half of the wholesale electric market equation,” *Energy Law Journal*, Volume 28, No. 2.

Wolak, Frank A. (2006). “Residential Customer Response to Real-Time Pricing: The Anaheim Critical-Peak Pricing Experiment.” Available from http://www.stanford.edu/~wolak.

Wolak, Frank A. (2007). “Managing Demand-Side Economic and Political Constraints on Electricity Industry Re-structuring Processes.” Available from http://www.stanford.edu/~wolak.

SUMMARY OF LRAM/SSM REQUEST:

Chatham-Kent Hydro seeks approval for the recovery of 2006 to 2009 LRAM and 2006 to 2008 SSM amounts as part of this Application. Recovery is to be based on a volumetric rate rider. Chatham-Kent Hydro is proposing a three year recovery period but is proposing to defer the rate rider implementation for one year in order to mitigate customer rate impacts. Therefore the rate rider would be in effect from May 1, 2011 until April 30, 2014.

The LRAM calculations are based on the kWh load reduction for each of the years 2006to 2009 times the applicable variable distribution rate for that rate class. The LRAM calculation, in the amount of $569,637, is net of "free ridership" in accordance with the OEB's TRC Guide, the applicable model and the Toronto Hydro Decision.

The SSM calculation, in the amount of $204,557, has been prepared in accordance with the SSM Guidelines and the TRC Guide which provide for 5 percent of the net savings established by the TRC test. As with the LRAM calculation, the SSM calculation is net of "free-ridership" in accordance with the TRC Guide and the Toronto Hydro Decision.

Chatham-Kent Hydro notes that it implemented four programs which were included in its CDM plans and approved by the OEB. These programs were previously summarized in Chatham-Kent Hydro's 2005, 2006 and 2007 Annual CDM Reports. Additionally, Chatham-Kent Hydro participated in two OPA programs in 2006 that have been included in the LRAM calculations.

Chatham-Kent Hydro is making an LRAM/SSM claim relating to the conservation effects by the by the customers as a result of the installation of smart meters and the related conservation education. Chatham-Kent Hydro was given priority status for smart meter installations through Ontario Regulation 427/06. As a result, Chatham-Kent Hydro began full deployment of smart meters in 2006 with the majority of residential homes being completed by the end of 2007, with 28,552 smart meters installed in its service area.

As a part of the smart meter deployment Chatham-Kent Hydro increased its communication and customer education with respect to smart meters and conservation. The effective communication plans were recognized by Navigator in their report to the IESO (Appendix B, page 4);

> "It was clear that participants had received relevant communication products (web, bill stuffers, smart meter packages etc.) from their local utility. The level of understanding of the technology and price changes was great than we had seen elsewhere. It may be useful to look at what Chatham-Kent has done to educate their customers in order to gain an understanding for similar LDCs"

Similar results were identified by Navigant in their review of Chatham-Kent Hydro's smart meter time-of-use pilot (Appendix C, page 13);

> "CK Hydro customers have responded to CK Hydro's conservation education efforts. Further, it is likely that given the broad nature of CK Hydro's efforts, both TOU pilot participants and control group customers had already reduced their consumption prior to the start of the TOU pilot"

It is clear from Navigator and Navigant that the education efforts surrounding the smart meter program and general conservation messages have contributed to significant reductions in electricity consumptions. Navigant reports that "CK Hydro average residential customer consumption decrease by 8% from 2002 to 2007, compared with a decline of only 3% for residential customers in fourteen similar Ontario LDCs. In 2007, CK Hydro's average residential customer consumption was 10% less than for residential customers in similar LDCs."

While Chatham-Kent Hydro has not yet implemented time-of-use pricing the installation of smart meters and the conservation education surrounding it has resulted in customer behavior as if the time-of-use prices were in effect. These were the findings of both Navigator and Navigant, as can be seen at Appendix B page 5 and Appendix C page 14 respectively;

> "many participants believed that the installation of the meters marked their live date. We heard stories of load shifting and the resulting drop in their monthly electricity bill because of the efforts they had taken"

> "the consumption for the pilot participants was also approximately 6-8% lower than the control group customers in the period preceding the pilot"

As a result of the findings from Navigator, Navigant and EnerSpectrum Chatham-Kent Hydro submits that the smart meter program and conservation education surrounding it have directly resulted in conservation efforts by its customers. Chatham-Kent Hydro also believes that the LRAM/SSM relating to those conservation efforts are reasonable and should be recovered from the customers who benefited from the programs.

The total combined LRAM and SSM amount for recovery is $774,194. The LRAM and SSM amounts and corresponding rate riders are set out by rate class in Table 10-1 (LRAM and SSM Total Amounts and Rate Riders by Class), below. Chatham-Kent Hydro proposes a single rate rider for recovery of the total LRAM and SSM.

Table 10-1
LRAM and SSM Total Amounts and Rate Riders by Class

	Amounts (2005 + 2006)		Billing Units (2010)		Rate Riders			Two Year Rate Rider	Three Year Rate Rider	Number of Years to Use	Rate Rider to Use
	LRAM	SSM			LRAM	SSM	Total	Total	Total	(2 or 3)	Total
Rate Class	$	$		Metrics	$/unit (kWh or kW)	$/unit (kWh or kW)	$/unit (kWh or kW)	$/unit (kWh or kW)	$/unit (kWh or kW)	3	$/unit (kWh or kW)
Residential	551,906.98	181,266.20	199,501,364	KWH	0.0028	0.0009	0.0037	0.0018	0.0012		
General Service < 50 kW	13,593.86	23,291.25	86,923,094	KWH	0.0002		0.0002	0.0001	0.0001		
Streetlights	4,136.53		16,969	kW	0.2438		0.2438	0.1219	0.0813		
Total	569,637.37	204,557.45									

Chatham-Kent Hydro considered recovery periods of 1, 2 or 3 years. To minimize monthly bill impacts over the period when the riders are in effect, a 3 year recovery period is proposed, as shown in Table 10-1 above.

Chatham-Kent Hydro is also proposing that the rider not start until May 1, 2011. This will also mitigate the impact to the customers.

APPENDIX B

NAVIGATOR REPORT

NAVIGATOR

Time of Use Rates Focus Groups

INDEPENDENT ELECTRICITY SYSTEM OPERATOR

RESULTS FROM VAUGHAN, OTTAWA, AND CHATHAM

DECEMBER 2007

QUALITATIVE RESEARCH RESULTS

INTRODUCTION

In October and December, 2007 Navigator conducted a series of focus groups for the IESO and their partners on Time of Use rates. What follows is our report on these focus groups, conducted in Vaughan in October and Ottawa and Chatham in December. While all of the groups focused on public opinion of Time of Use rates, Smart Meters, and the general feelings and motivations on conservation, the groups in Ottawa and Chatham focused more narrowly on the advertising concepts developed by Narrative for the IESO.

RESEARCH OBJECTIVES

During these focus groups, Navigator, together with the IESO and local utilities, attempted to provide a sense of the level of understanding of the public at-large of the extent to which, if any, targeted LDC customers understand and support the concept of Time of Use Rates. Navigator also attempted to gain an understanding of the underlying motivations for the conservation of electricity. We also tested three different advertising concepts for potential use in the targeted communities which were aimed at increasing public support and use of Time of Use rates. We briefly discussed Time of Use pricing charts for use in the home and questioned participants on their level of understanding and preference of charts.

METHODOLOGY

Navigator began its work in October with three focus groups on a Saturday in Vaughan. These groups were comprised of individuals from Power Stream's service area. In December Navigator facilitated two focus groups in Chatham comprised of people who each already had a Smart Meter installed in their home. Each group was comprised of ten participants from the Chatham Hydro service area. In Ottawa, Navigator also facilitated two focus groups. In this case, the groups were split with the first group of 10 all having a Smart Meter already installed on their home, and the second group of 10 all being without one installed to date.

The groups were comprised of participants who were owners or renters who were responsible for their own electricity bill and who lived in a community served by the targeted utility. Participants were of mixed genders and ages with no one selected under the age of 25. Participants were selected through random digit dialing of the service area and those who participated were given a $75 incentive.

Each focus group was two hours in length and was moderated by a Navigator consultant. Navigator, in conjunction with the IESO, drafted the screener for selecting the participants as well as a moderator's guide for the discussion designed to achieve the research objectives.

The guide, and each focus group, began with a general discussion on the electricity sector in Ontario. We then asked participants to review a number of advertising concepts provided by the IESO and their agency, Narrative. Navigator then educated the participants on TOU rates and allowed participants to ask questions in order to increase their confidence in the subject matter. We then exposed participants to a series of in-home products developed by the IESO to test their effectiveness.

KEY FINDINGS AND RECOMENDATIONS

GENERAL FINDINGS

Knowledge of the sector is vague

We found that in each community participant's knowledge of the electricity sector and the players in it, is still very vague. The exception to this was the near 100% recognition of the local LDC in each case. If the implementation of the Smart Meter project is to be successful, it is clear that the LDC must be involved in the role out, delivery, and communications efforts as they have the strongest brand to the customer. The brand association dwarfs all others including the government, OPA, and others.

Different Locations, Different Motivations

Navigator found that in each of the different locations, the participants were motivated in completely different ways when it came to conservation and Smart Meters. We found a high degree of homogeneity within the groups themselves, but each city was vastly different in their positions on the project.

In Vaughan, we found that most participants were motivated by lifestyle more than any other factor. That is to say that they put their own comfort, convenience, and habits above other factors when making the decision to conserve. Conservation was seen as a good concept, but they wanted to know how it would benefit them personally before committing.

In Ottawa, we clearly saw that participants were motivated by the greater good for the environment and were more likely to have already engaged in green initiatives. It was evident that Smart Meters would be another tool in their box to help to do what is right for the planet. They had a much higher degree of concern for the common good for the population.

In Chatham, we got yet another response. It was evident that the first and foremost concern of the participants there was price. We had a number of discussions around the bottom line cost of the meters, the cost of the electricity, and how they would go about saving money on their utility bill as a whole, not just on shifting their time of use. It appeared that the economic factors in their personal lives where weighing heavily on their minds during the discussion with talk of plant closures, shift cut backs, and the rising price of everything from food to electricity.

It was clear from our research that each LDC service area should be contemplated individually. The vast difference in motivating factors between these three communities illustrated to us that advertising approaches should, to the extent possible, reflect the actual motivating factors for the community in which they will run. While this may not be financially viable, it is our best advice.

Smart Meter Penetration

The groups conducted in Ottawa in which one group was comprised of those with Smart Meters, and the other those without, illustrated that there was no difference in the participant's level of knowledge about the meters or the concept. This would seem to indicate that provincial and local press, as well as the work of the LDC, had a considerable impact on the level of knowledge that participants had. The packages delivered at the door when the meters where installed would have re-enforced that message, but clearly those who had not had the meter installed (and thus not yet received the package accompanying the meter) had a similar level of knowledge indicating that information on the Smart Meters where getting to them through other means.

As noted above, Ottawa seemed to have a higher level of engagement on Green issues than other areas of research which could help to explain their higher than expected knowledge of the technology and pricing.

In Chatham, it was clear that participants had received relevant communications products (web, bill stuffers, Smart Meter packages, etc.) from their local utility. The level of understanding of the technology and price changes was great than we had seen elsewhere. It may be useful to look at what Chatham-Kent has done to educate their customers in order to gain an understanding for similar LDCs. This is not to say that Chatham-Kent's efforts should be duplicated across the province as we saw that different locations had different motivations. Learnings from Chatham-Kent Hydro's efforts could however serve as a helpful guide in similar communities.

Some confusion surrounding bill / price

During these three groups, participants continue to express concern about their inability to understand their bill. They cite the number of lines, the different charges for different amounts of use, and a general questioning of what some of the lines mean. We also saw that many participants do not even look at their bill or spent much time analysing it. Some more educated customers indicated that reducing the amount of electricity they used during peak times would not result in any significant savings as the commodity cost was not a big part of the bill. Many indicated they did not know how much their bill was or if action would result in big savings. Given the importance of the Smart Meter roll-out, we believe that using bill stuffers and other like material will not be sufficient for the purposes of communications.

Smart Meter Term Penetrating

In Vaughan, where not everyone had a Smart Meter, we found that the work done to date, coupled with the media coverage on Smart Meters has resulted in the term "Smart Meter" being recognized by many of the participants. We found that this message is penetrating.

We also found, however, that while participants did have some degree of recognition on the term, the function of the meter, what was different about it, and what it could do for them was still largely unknown by those who did not have one already. Given that the term is known, we found that there is a willingness from participants to find out what it is and what the technology can do.

Lag Time

Throughout all the groups, we found that there was a high degree of confusion surrounding the Smart Meters activation. To our knowledge, none of the participants, even those with Smart Meters currently installed, have the meter "go live" on the time of use rates. Many participants believed that the installation of the meters marked their live date. We heard many stories of load shifting and the resulting drop in their monthly electricity bill because of the efforts they had taken. We believe that this is not possible due to load shifting alone with all other factors being equal.

We found that when participants first get their new meter installed there is a high degree of a novelty factor associated with it. Many go out to the side of their houses to look at it, speak with their neighbours about it, and go on-line to read more about them. We believe that participants were highly engaged during that period of time immediately following the installation of the meter. By the time we spoke with many of the participants, this novelty factor had worn off or was significantly diminished. Many expressed outright frustration that the new meters did the same thing as the old meters "at twice the cost."

Navigator recommends that the lag time between the installation of the meter and the activation of the meter be as short as possible in order to capitalize on the novelty factor we observed in the focus groups. We understand that this lag time is effected by the technology and regulatory environment. In the event that a short lag time is not possible, we recommend that the IESO together with the LDC attempt to recreate this novelty effect to the extent possible immediately prior to the activation of the new features of the meter and the changes in rates.

Price Chart

We found in all groups that the price chart developed by the IESO was very well received by participants. It should be noted that small edits were made to the chart following the Vaughan groups to clarify some of the times of use. These edits did not fundamentally change the graph nor do the, in our opinion, change the findings. Participants found the chart easy to understand and indicated that they would likely post on their refrigerators as a reminder of the rates. Some indicated that it would find a home beside the garbage and recycling calendars that they all ready have posted. Some consideration should be given to the IESO making the chart available to municipalities and LDCs for inclusion in the yearly calendars of garbage pick up and there was a high degree of linkage between the two in the groups. Our groups also tested a different approach to the price chart in the form of a pie graph. We found this approach developed to illustrate price was rejected out of hand as being too confusing and too complicated.

No Concept of Price

During these groups, we had some interesting comments surrounding what a kWh was and how far one went. The discussion here was not about the actual price per kWh, or the increases that the participants could expect through time of use rates, rather the discussion was primarily about how many it took to power a light bulb, run a load of laundry, or keep the air conditioner going during the day. Participants lacked the connection between turning the lights on and the price per hour or the cost to leave the air conditioner running all day when they were not at home. Seeing as the ultimate success or failure of time of use rates will rest with the differences between the rates and consumer choice based in part on the rates, we recommend that some generic illustrations or calculations of kWh used per appliance may be a motivated for some.

Environmental and Cost Impacts

Much of the conversation in each of the groups centered around the belief or skepticism on statements made regarding the impacts of Smart Meters on electricity bill costs and environmental benefits. It seemed that, regardless of the group, there was a high degree of questioning surrounding how much this new technology would really help the environment and avoid the need for new power plants or how much load shifting would save verses other rising costs (DRC, delivery, transmission, commodity). Navigator understands that using examples of specific dollar amount impacts or environmental statements for communications purposes is a different task. We do believe, however, that there is a need to manage expectations by setting the terms of "success" on this at the outset. We firmly believe that customers be made to realize that they are not going to cut their bill in half, or more, by shifting their use. Failure to manage these expectations at the outset could result in a public backlash on electricity prices like Ontario saw in 2002.

ADVERTISING FINDINGS

In general, we found that the advertising concepts were well received by participants. With few exceptions, the ads were easily understood and conveyed the desired messages to the participants.

8 O'clock Received Better Than 10 O'clock

It is clear from our research that a switch to the off peak time at 8PM is far superior to the current 10PM. This was especially true when discussing during loads of laundry after 10PM when that load requires a change to the dryer and folding. While the other concepts for savings were not as heavily negative (dishwasher, air conditioning), it was clear that the majority of participants in all locations felt that 10PM was too late for them to take advantage of. Discussions surrounding personal habits and electricity consumption can best be summarized as a general feeling that 8PM was the time the kids go to bed, and 10PM is the time parents' sleep. The time between 8PM and 10PM is seen as the time parents get things done around the house before bed.

Smart, Smarter Advertising Concept

We found that the *Smart, Smarter* ad was the best received on the whole in all the communities. While this ad was the best received, it would be misleading to state that all participants grasped the concept that was being communicated. Having said that, participants did identify with the CFL bulb as many had already replaced their own and understood that changing the time they used electricity would help the system / environment. Some concern was raised that the clock was not clear, but that would likely be addressed by final artwork in the ad.

Connections Advertising Concept

Connections was well received, but not as positively as *Smart Smarter*. Some felt that the ad was "too childish" in its attempt to replicate a "See Spot Run" story, while others, most notably Chatham, felt that it was a nice softer approach to the message. Most participants in all locations felt that the ending of the sentence was confusing or awkward. They felt that it was a big leap from personal air conditioning use to global warming, to more power plants and back was a stretching the concept to some degree. If this ad is to be used, we recommend a simplification of the ending of the *Connections* sentence.

10 PM Advertising Concept

Our research indicated that *10 PM* as a concept worked. People readily understood what was being conveyed and immediately began to comment on the practicalities of washing clothes after 10PM. With this near instant reaction, we saw that the message cut to the core of the concept immediately. However, this was also the major problem with the ad. Participants felt that it was unreasonable to do one's laundry after 10PM at night and this ad evoked some of the most negative commentary surrounding Time of Use rates that we heard. In Vaughan, however, we tested a similar concept using a dishwasher and a dirty plate. While the dirty plate graphic was more difficult for people to understand, the illustration of shifting time in which laundry is done was not well received given the need for a change to the dryer and folding. The dishwasher concept was received better given that people are in the habit of leaving the washed dishes in the machine until a convenient time to empty. We recommend that the graphic for the 10PM ad on the dishwasher be fixed rather than changing to a laundry concept.

Use of Specific Terms

In each of our groups, individuals expressed concern with the use of the term "control" in the ads. Most participants indicated that they did not like the connotations of the term or that the government or big business would have a say in how they behaved. This is not to say, however, that the term was not effective or that including the term would make the ad less effective at motivating action, rather we do believe that the feeling that the word "control" evokes was negatively perceived by participants. We had the same finding each time the word was used in each of the concepts. We recommend the use of an alternative word.

We also heard some negative reaction to the concept that Smart Meters were "the next step." Many felt that the meters were not the be-all in conservation of electricity and that they represented one of many things people could do, not the one and only next step.

Potentially one of the most difficult areas for the IESO and partner LDCs to address was the concern around the use of the term "we can all save money." Many participants felt that this was not a truthful statement while others wanted to know how much money they would actually save with a Smart Meter. Some more informed participants also indicated that the price of the commodity was only part of the overall bill. They commented that the increases in DRC, Distribution, and Transmission, would more than eat up any load shifting savings regardless of what they did. Participants wanted to know the dollar amount saved so they could make a value judgment on whether or not to stay up to do their laundry.

On the positive side, we found that the lines "We all need to be smarter about our electricity use" received a great deal of support from participants. There was general agreement in all the groups that action needed to be taken on some level. The majority of the participants indicated that they had already changed many of their light bulbs and felt that they were contributing, but could do more.

APPENDIX C

NAVIGANT CONSULTING INC. REPORT

EVALUATION OF SMART METER TIME-OF-USE PILOT

Presented to

CHATHAM-KENT HYDRO

320 Queen St.

PO Box 70

Chatham ON N7M 5K2

FEBRUARY 10, 2009

Navigant Consulting Inc.
One Adelaide Street East, Suite 2601
Toronto, ON M5C 2V9
(416) 927-1641
www.navigantconsulting.com

EXECUTIVE SUMMARY

This report summarizes the results of the Chatham-Kent Hydro Inc. (CK Hydro) Smart Meter Time-of-Use (TOU) pricing pilot study undertaken from January 2007 through the end of June 2008.

Based on Navigant Consulting's analysis of the consumption patterns of the pilot participants and those of control group customers in a similar subdivision, the following conclusions can be drawn:

1. CK Hydro average residential customer consumption decreased by 8% from 2002 to 2007, compared with a decline of only 3% for residential customers in fourteen similar Ontario LDCs. In 2007, CK Hydro's average residential customer consumption was 10% less than for residential customers in similar LDCs. This observation was confirmed through Navigant Consulting's regression analysis, with a statistically significant downward trend in consumption among CK Hydro customers. Navigant Consulting attributes this effect to CK Hydro's aggressive conservation education efforts. Further, this effect appears to have dampened the conservation effect typically seen among customers switching to TOU rates. In effect, the CK Hydro customers had already reduced their consumption prior to the implementation of the TOU pilot, whereas TOU pilot participants elsewhere who had not been exposed to a similar level of conservation education pre-TOU would have more conservation opportunities available to them post-TOU (and would generally be expected to have greater conservation awareness post-TOU).

2. There was no discernable conservation effect observed when comparing the pilot participants' consumption in the pre-TOU and TOU period and with the control group customers' consumption in the same periods, likely due to the earlier conservation efforts of these and other CK Hydro customers.

3. There were no statistically significant differences in the percentage of overall consumption by TOU period between the pilot participants and the control group during the pilot period.

4. Given their level of monthly consumption and consumption patterns, pilot participants would pay less than the average RPP prices under either TOU prices or tiered prices, but the difference is slightly greater under tier prices. As a result, pilot participants paid, on average, just under $2 per month more under TOU prices than they would have paid under tiered prices.

Note that these results reflect short-term behaviour changes only and it is expected that the results will change over time.

It is important to keep in mind that all forms of "flat" (or non-time varying) electricity pricing such as the tiered RPP prices inherently result in cross-subsidies between consumers with different consumption patterns, as the actual cost of power changes on an hourly basis. Time-of-use prices better reflect the true cost of power and significantly reduce such cross-subsidies. Further, the impact of time-of-use prices on the average commodity charges experienced by customers is dependent on the relative percentage of their consumption in each of the two tiers under the RPP tiered pricing structure. Consumers, such as many in this pilot project, with most of their monthly consumption below the tier threshold pay somewhat less under tiered pricing than the average actual cost of electricity.

CONTENTS

NAVIGANT CONSULTING

LIST OF FIGURES

LIST OF TABLES

INTRODUCTION

This report summarizes the results of the Chatham-Kent Hydro Inc. (CK Hydro) Smart Meter Time-of-Use (TOU) pricing pilot study undertaken from January 2007 through the end of June 2008.

The pilot project tested the response of residential customers billed under the Ontario Energy Board's Regulated Price Plan (RPP) tiered pricing changing to Time-of-Use rates.

Results from the pilot study are drawn through quantitative analysis of the conservation impact or reduction in overall consumption for residents on TOU rates in comparison to similar residents on RPP tiered pricing and 2) the demand response via load shifting away from On-Peak hours to either Mid-Peak or Off-Peak hours.

Specifically, Navigant Consulting explored the following:

- Monthly consumption trend of TOU pilot participants and control group customers.
- Monthly consumption of the TOU pilot participants before and after switching to TOU rates, as compared to the monthly consumption of the control group in the same periods.
- Consumption of the TOU pilot participants in the three TOU periods compared to the consumption of the control group and random sample in the same periods. We expect to look at On-Peak, Mid-Peak and Off-Peak consumption as a percentage of total, and also on peak versus "non-On-Peak" and Off-Peak versus "non-Off-Peak."
- Commodity costs for pilot participants on TOU RPP rates compared what they would have paid under tiered RPP rates and against what the control group customers paid under tiered RPP rates.

Information gathered from this pilot study will enable CK Hydro, the Ontario Energy Board and other LDCs to expedite and enhance residential customer response to RPP TOU rates when they are implemented more broadly.

Pilot Objectives

The specific objectives of the CK Hydro pilot test are as follows:

- To quantify and measure any potential conservation effects related to TOU pricing.
- To determine how TOU pricing will affect the cost of electricity to the customer.
- To determine if TOU pricing encourages customers to use the web presentment energy management tool.

Ontario Energy Board Approval

On July 28, 2006, the Ontario Energy Board (the "Board" or "OEB)") amended the Standard Supply Service Code (the "SSS Code") to allow certain electricity distributors to charge time of use prices for consumers on the Regulated Price Plan (the "RPP") with eligible time-of-use (or "smart") meters as part of a pilot project. The amended SSS Code requires approval from the Board in order for any new pilot projects to be implemented.

Since CK Hydro planned to roll-out RPP TOU pricing to all of its customers with an eligible time-of-use meter, it was not considered as a pilot project under section 3.9.3 of the SSS Code. Instead, section 3.5 (Transition for Section 3.4) applied under which the LDC elects to implement the electricity commodity pricing mechanism set out in section 3.4 before the "mandatory TOU date". Unlike section 3.9.3, this section does not require CK Hydro to seek approval in order to proceed.

However, CK Hydro did provide notice of this election in accordance with section 3.5.3 (e.g., including an insert containing a notice to this effect with at least one bill submitted to all affected RPP consumers). The SSS code required this to be carried out no less than 30 days prior to the date on which the CK Hydro commenced charging RPP consumers the TOU commodity price for electricity under section 3.4.

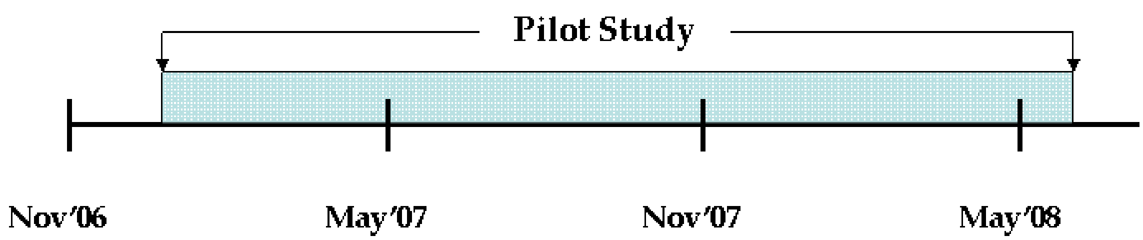
Standard and TOU Rate Structure

Under amendments to the *Ontario Energy Board Act, 1998* (the Act) contained in the *Electricity Restructuring Act, 2004*, the Board was mandated to develop a Regulated Price Plan (RPP) for electricity prices to be charged to consumers that have been designated by regulation. The first prices were implemented under the RPP effective on April 1, 2005, as set out in regulation by the Ontario Government.

The principles that have guided the Board in developing the RPP were established by the Ontario Government. In accordance with legislation, the prices paid for electricity by RPP consumers are based on forecasts of the cost of supplying them and must be set to recover those forecast costs. RPP prices are currently reviewed and adjusted if necessary by the OEB every six months.

During the CK Hydro pilot study, customers were exposed to four separate RPP prices since the OEB reset the prices on May 1st, 2007, November 1st, 2007 and May 1st, 2008. Figure 1 outlines the different RPP periods experienced during the pilot study.

Figure 1: RPP periods experienced during the pilot study



Standard Meter Regulated Price Plan

The conventional meter RPP has a two-tiered pricing structure, one price for monthly consumption under a tier threshold and a higher price for consumption over the tier threshold. Until October 31, 2005, the threshold was 750 kWh per month. From November 1, 2005, the tier threshold for residential consumers has changed twice a year on a seasonal basis: to 600 kWh per month during the summer season (May 1 to October 31) and to 1000 kWh per month during the winter season (November 1 to April 30). The threshold for non-residential RPP consumers remains constant at 750 kWh per month for the entire year.

Subsequent to April 2006, the RPP prices were reviewed by the Board every six months and adjusted, if necessary. The RPP prices in effect during this study reflect this resetting frequency and are shown in Table 1.

Table 1: Conventional Tiered RPP Prices

Cents per kWh	Nov'06-Apr'07	May'07-Oct-07	Nov'07-Apr'08	May'08-Oct-08
Tier 1	5.5	5.3	5.0	5.0
Tier 2	6.4	6.2	5.9	5.9

TOU Regulated Price Plan Prices

Subsequent to a date to be determined by the Ontario Energy Board, eligible RPP consumers with eligible time-of-use (or "smart") meters that can measure and record electricity consumption for hourly (or shorter) intervals will pay under a time-of-use (TOU) RPP price structure. The prices under this plan are based on three time-of-use periods, as shown in Table 2. These periods are referred to as Off-Peak, Mid-Peak and On-Peak. The lowest (Off-Peak) price is below the tier prices, while the other two are above them. The three prices are related to each other in approximately a 1:2:3 ratio.

The RPP TOU prices are also reviewed and adjusted every six months. The following table outlines the TOU prices in effect during the pilot. Note that TOU prices in effect prior to

January 2007 (when TOU prices came into effect for study participants) are not relevant to this study. Our analysis of the pilot participants' response to TOU prices reflects the existing RPP prices for the period being analyzed.

Table 2: Distribution of RPP TOU Prices during the Pilot Study

Cents per kWh	Nov'06-Apr'07	May'07-Oct-07	Nov'07-Apr'08	May'08-Oct-08
Off-Peak	3.4	3.2	3.0	2.7
Mid-Peak	7.1	7.2	7.0	7.3
On-Peak	9.7	9.2	8.7	9.3

The hours and prices for each of these three time-of-use (TOU) periods are set out in Table 3.

Table 3: Breakdown of RPP TOU Periods for Summer and Winter

Time	Summer Hours (May 1 – Oct 31)	Winter Hours (Nov 1 – April 30)
Off-Peak	10pm – 7am weekdays; all day on weekends and holidays	10pm – 7am weekdays; all day on weekends and holidays
Mid-Peak	7am – 11am and 5pm and 10pm weekdays	11am – 5pm and 8pm – 10pm weekdays
On-Peak	11am – 5pm weekdays	7am-11am and 5pm-8pm weekdays

Figure 2 graphically displays the winter TOU prices based on the Board's May 1 2007 RPP price setting, while Figure 3 shows summer TOU prices based on the same price setting.

Figure 2: Winter TOU Prices (May 1 2007 RPP Price Setting)[1]

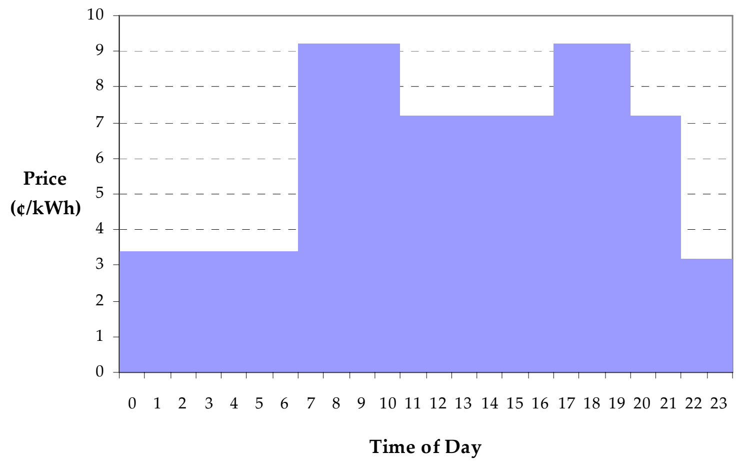
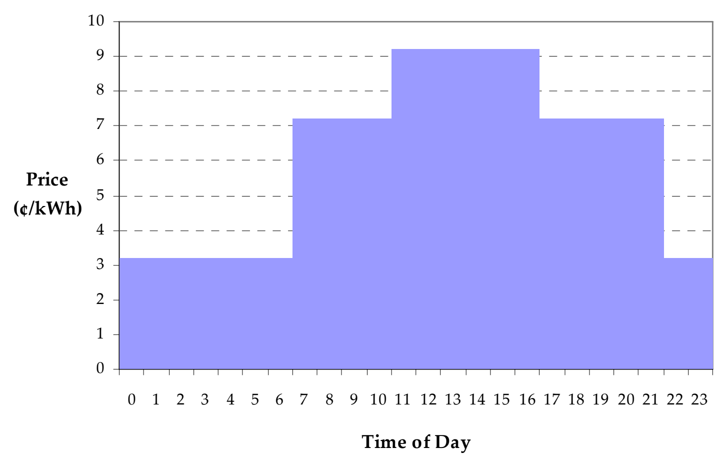


Figure 3: Summer TOU Prices (May 1 2007 RPP Price Setting)



The average price an RPP consumer on TOU prices will pay will depend on the consumer's load profile (i.e., how much electricity is used at what time). RPP prices are set so that a consumer with the average RPP consumption level and load profile will pay the same average price under either the tiered or TOU prices, as shown in Table 4. Specifically, this table shows the average RPP prices that were in effect during the May through October 2007 period for an average RPP consumer. This average price is equal to the average RPP supply cost of approximately 5.7¢/kWh.

---

1 The May 1 2007 RPP price resetting covered the subsequent 12 month period through April 30, 2008 and included both summer and winter TOU pricing. The winter TOU prices were reset on November 1, 2007 and became effective on the same date. The November 1, 2007 price setting also included summer TOU pricing, which were reset by the Ontario Energy Board on May 1, 2008.

Table 4: Average RPP Prices for an Average RPP Consumer (cents per kWh)

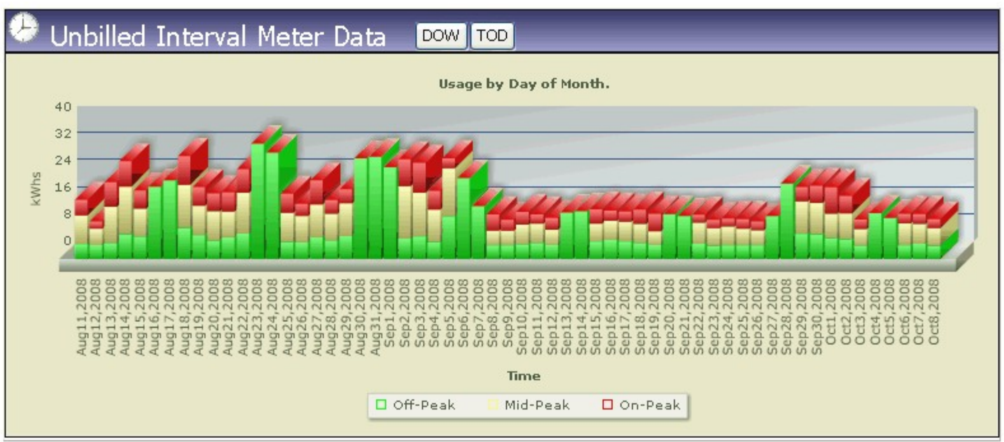
<table>
<tr><th>Tiered RPP Prices</th><th colspan="2">Tier 1</th><th colspan="2">Tier 2</th><th>Average Price</th></tr>
<tr><td>Price</td><td colspan="2">5.3¢</td><td colspan="2">6.2¢</td><td rowspan="2">5.7¢</td></tr>
<tr><td>% of RPP Consumption</td><td colspan="2">52%</td><td colspan="2">48%</td></tr>
<tr><th>TOU RPP Prices</th><th>Off Peak</th><th colspan="2">Mid Peak</th><th>On Peak</th><th>Average Price</th></tr>
<tr><td>Price</td><td>3.2¢</td><td colspan="2">7.2¢</td><td>9.2¢</td><td rowspan="2">5.7¢</td></tr>
<tr><td>% of RPP Consumption</td><td>48%</td><td colspan="2">29%</td><td>23%</td></tr>
</table>

PILOT PARTICIPANTS

A total of 213 participants for the pilot project were selected by CK Hydro from a representative subdivision in their territory. In this group, 31 customers were under contract to an electricity retailer and were removed from Navigant Consulting's analysis since they were not subject to TOU rates. Customers were hand delivered a smart meter package including the attached brochure to inform them they were now on TOU billing. A few months into TOU billing, a letter was sent along with an information brochure to remind them TOU pricing was in effect, along with additional energy conservation tips. Customers were also encouraged to access their account information online to view both their daily and hourly consumption. CK Hydro reported that a total of 35 customers of the TOU participants signed up to view their data online.

Figure 4 and Figure 5 provide examples of the consumption profiles available to pilot participants.

Figure 4: Example of Energy Consumption Profile Available Online for Pilot Participants



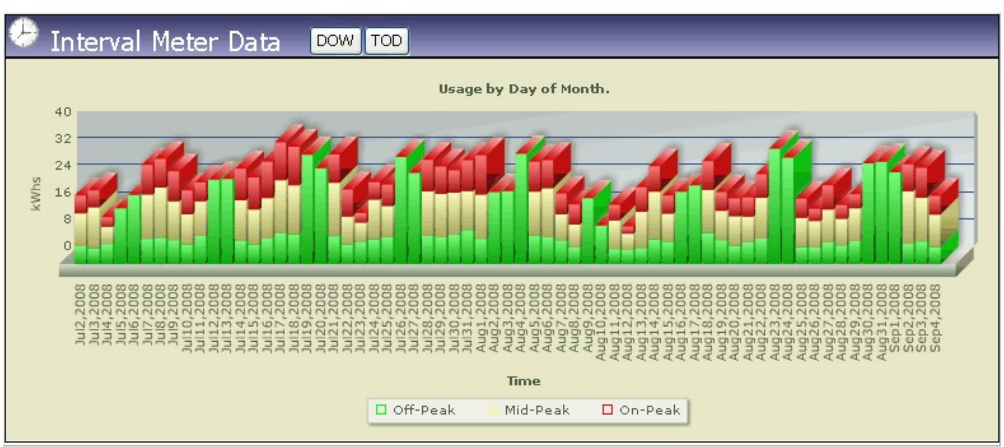
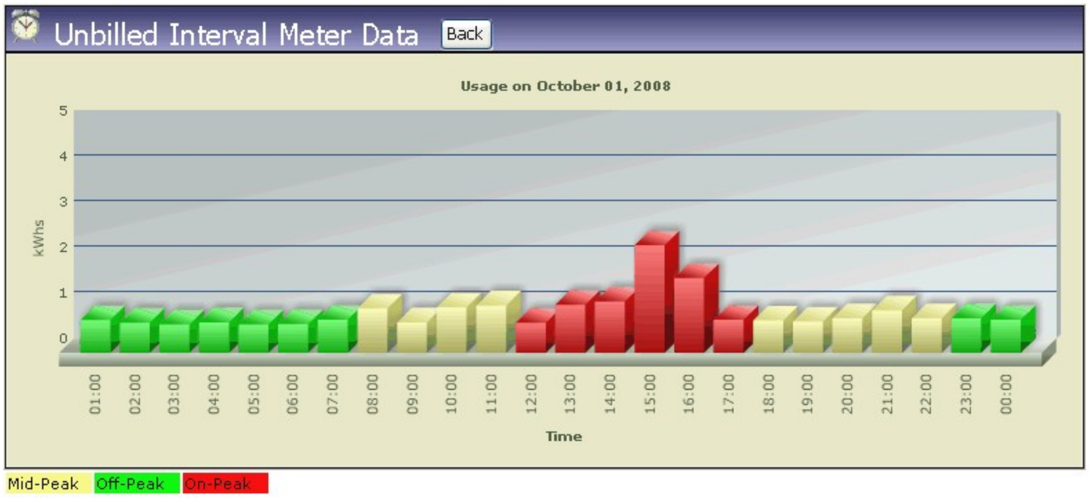


Figure 5: Example of Distribution of Daily Energy Consumption Available Online for Pilot Participants



A second neighbouring subdivision with similar housing characteristics was taken as the control group. The control group customers were equipped with smart meters but remained on the tiered RPP prices.

Test Structure and Design

Electricity data was provided by CK Hydro for each group. Specifically, the data provided was as follows:

- Individual pilot participant hourly meter reading data from January 2007 to June 2008;
- Individual control group hourly metering data from April 2007 to June 2008;
- Historical monthly billing consumption/meter reading data pilot participants from January 1997 to June 2008;
- Historical monthly billing consumption/meter reading data from control group customers from February 2002 to June 2008; and
- Flag for pilot participants who signed up online to view their consumption data; and
- Flag for pilot participants who were under contract with an electricity retailer.

The data set for the pilot participant group contained 213 original participants, while the control group contained 229 records. Once the 31 pilot participants who were subject to retail rates were removed, the remaining pilot participants and control group data was transposed so that each column represented a time series of that participant's hourly consumption. May 2007 and May 2008 were the first and final full months of data that was shared by both groups. Given this, Navigant Consulting limited the time period assessed to May 2007 through May 2008 so that the period of analysis was uniform for the two groups. Additionally, Navigant Consulting eliminated outliers from the group. Eleven (11) outliers from the pilot participants and twenty-four (24) from the control, tiered-pricing group were eliminated. Thus, hourly consumption records were analyzed for each of 202 TOU participants and 202 control group members as shown in Table 5.

Table 5: Breakdown of Participants Analyzed by Group

	Total Customers Provided	Number of Retail Customers Removed	Number of Customer Analyzed	Percentage of Group Population Analyzed
Pilot Participants	213	31	171[2]	80%
Control Group	226	0	202	89%

[2] Includes 34 pilot participants who signed up online to view their consumption data.

CUSTOMER DEMAND RESPONSE

One of the main questions this pilot was intended to address was how and to what extent residents will change their consumption patterns in response to time-of-use rates. It is expected that customers will shift consumption away from On-Peak periods (which are relatively more expensive under TOU rates) and toward Off-Peak periods (which are relatively less expensive under TOU rates). Total consumption could increase or decrease. This chapter estimates the magnitudes of these responses.

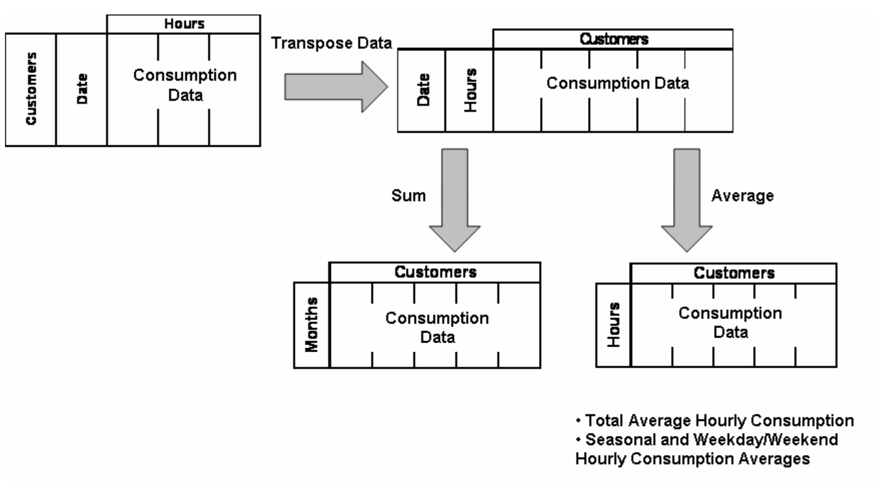
It should be noted that this study only captures short-term responses to time-of-use rates. This will include primarily changes in behaviour that are easy to make – for example, turning lights off during On-Peak periods. It is expected that additional changes will occur over time as customers further adjust their actions and acquire equipment that helps them control their electricity use – for example, installing timers on lights. Thus, the magnitudes of the changes in consumption observed in this study are expected to increase over time.

Analytical Approach

Post TOU Consumption Data

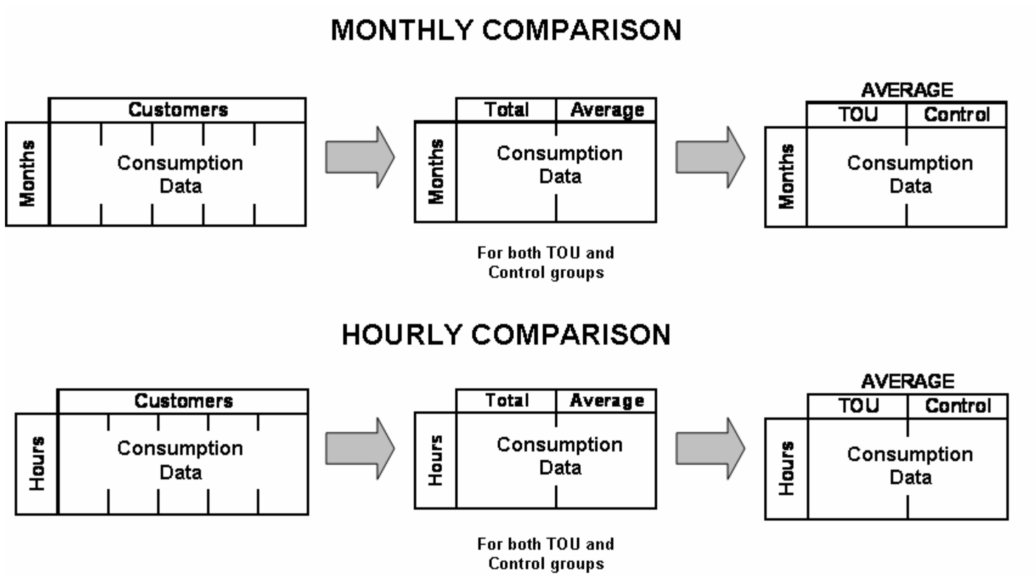
As previously mentioned, Navigant Consulting transformed the raw data provided by CK Hydro in order to facilitate analysis of the results and to eliminate any outliers or customers with invalid meter readings. Navigant Consulting used structured query language (SQL) queries to tabulate the average and total consumption data for each useable participant record in each group, as shown in Figure 6.

Figure 6: Structuring the Hourly Consumption Data



Within the groups, each customer's consumption time series was aggregated by their total monthly consumption, average hourly consumption across all periods, and average hourly weekday and weekend consumption by season. Taking the averages across all participants within each group, the two groups were compared side-by-side, graphically, and statistically, as shown in Figure 7. Navigant Consulting also calculated the proportions of consumption attributable to each TOU period (i.e., On-Peak, Mid-Peak, Off-Peak weekdays, and Off-Peak weekends and holidays) as well as the implied average tiered and TOU hourly rates. In addition, Navigant Consulting compared those TOU participants who accessed their consumption profile online to determine if their consumption distribution was different from other TOU participants who did not access their consumption profile online.

Figure 7: Analytic Approach Undertaken by Navigant Consulting



The final step of the basic data aggregation and testing was to statistically compare the TOU participants and the control group, as well as those who accessed their consumption profile online. For this comparison, Navigant used a paired means test. This test compares the means for two groups and assesses whether or not the means differ significantly (i.e., that the difference is consistently non-zero). A non-parametric paired means test was used since the distribution of responses was not normally distributed. This test was conducted on the paired groupings for monthly and hourly consumption as well as seasonal weekday/weekend hourly consumption. A paired means test was also used for the proportion of consumption attributable to each TOU period.

Pre-TOU Historical Billing Consumption Data

Navigant reviewed the two data sets, one for the pilot participants and one for the control group, representing historical readings for this analysis. Navigant filtered consumption readings that represented extreme outliers on both ends of the data range. The filtered data sets were tabulated using the read dates, account numbers, and usage data so that each column represented a customer's account and each row a consumption reading for that specific customer's meter.

Navigant Consulting undertook an effort to normalize the recorded usage and strip away the affects of weather from the data. For both groups, the clean data set was tabulated using the read dates, account numbers, and usage data so that each column represented a customer's account and each row a consumption reading for that specific customer's meter. In addition, given the variable read dates for the pilot participants, Navigant Consulting created a third table for with the number of days between each read date for each customer. The pilot participant tables were joined in SQL based on the read dates, and all read dates with less than 50 reading were filtered out, since they would introduce an unacceptable level of bias into the analysis. The weighted average of the daily usage within the remaining period was computed so as to describe the entire participant population. Weather data was linked to each period using the number of days in the period and the read date and converted to average daily weather observations. Using the weighted average daily usage and the average daily weather, Navigant Consulting performed multivariate regression modeling to determine a model that characterized the baseline consumption. The parameter estimates were used to compute baseline consumption and normalize against the effects of weather.

Findings

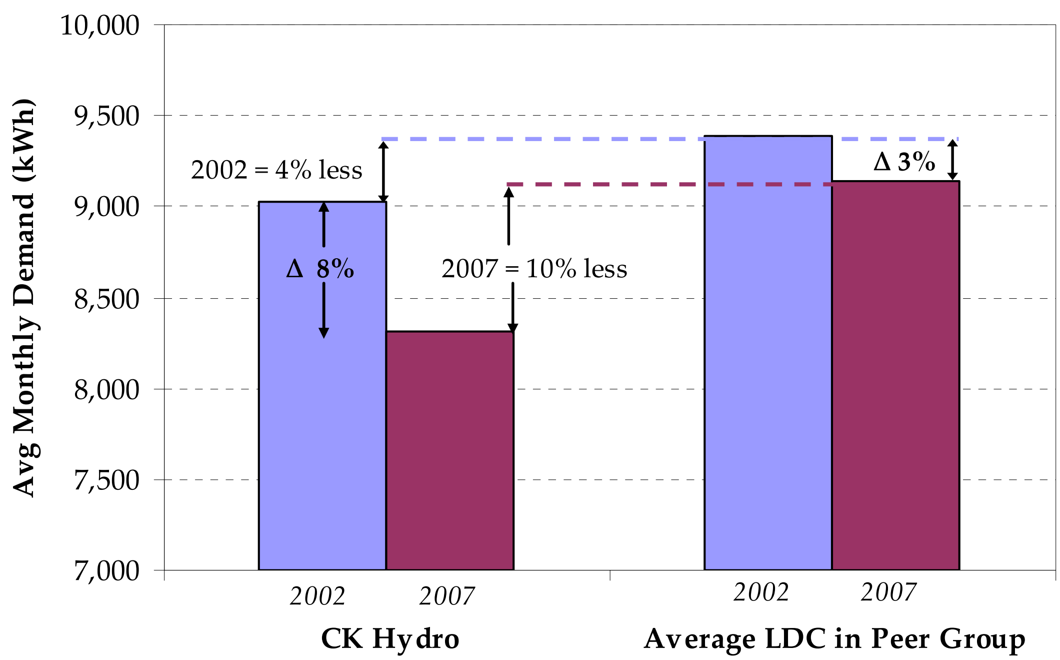
Impact of Chatham-Kent Hydro's Pre-TOU Energy Conservation Efforts

Since 2005, CK Hydro has promoted energy conservation to all of its customers through various media outlets, including radio ads, newspaper ads, bill inserts. CK Hydro also began promoting and educating their customers on time-of-use rates and smart meters long before the pilot study was introduced in their territory.

This increased awareness was confirmed by the Independent Electricity System Operator (IESO) which held a focus group in December 2007 in order to gauge customer's level of awareness of electricity pricing and smart meters. Based on their findings, the IESO reported that in Chatham, customers had received relevant communications and the level of understanding of the technology and price changes was greater than seen elsewhere.

In addition, based on reported electricity usage submitted by LDCs under the OEB's Reporting and Record Keeping Requirements[3] shown in Figure 8, in 2002, the average monthly consumption for CK Hydro customers was slightly (4%) below the average monthly consumption for customers group of fourteen LDCs identified in the report as CK Hydro's peer group (Mid-Size Southern Medium-High Undergrounding). By 2007, this difference in consumption widened to 10%, with CK Hydro customers reducing their average monthly consumption by 8% from 2002, as compared to a 3% decrease in consumption observed for customers in the peer group LDCs over the same period.

Figure 8: Comparison of Average Monthly Consumption for CK Hydro Customers with Customers of Peer Group LDCs



This indicates that CK Hydro customers have responded to CK Hydro's conservation education efforts. Further, it is likely that given the broad nature of CK Hydro's efforts, both TOU pilot participants and control group customers had already reduced their consumption prior to the start of the TOU pilot. If this were the case, the ability to compare conservation and load shifting effects of the pilot participants in relation to a control group who was also subject to the same education through various media outlets becomes a challenge.

3 Ontario Energy Board, Comparison of Ontario Electricity Distributors Costs (EB-2006-0268), Peer Groups per PEG Report, June 2008.

Further, Navigant Consulting believes that any pre-TOU customer response due to CK Hydro's previous conservation efforts would reduce the post-TOU conservation effect, since the TOU pilot participants appear to have implemented a number of conservation measures in advance of the TOU pilot (as have other CK Hydro customers).

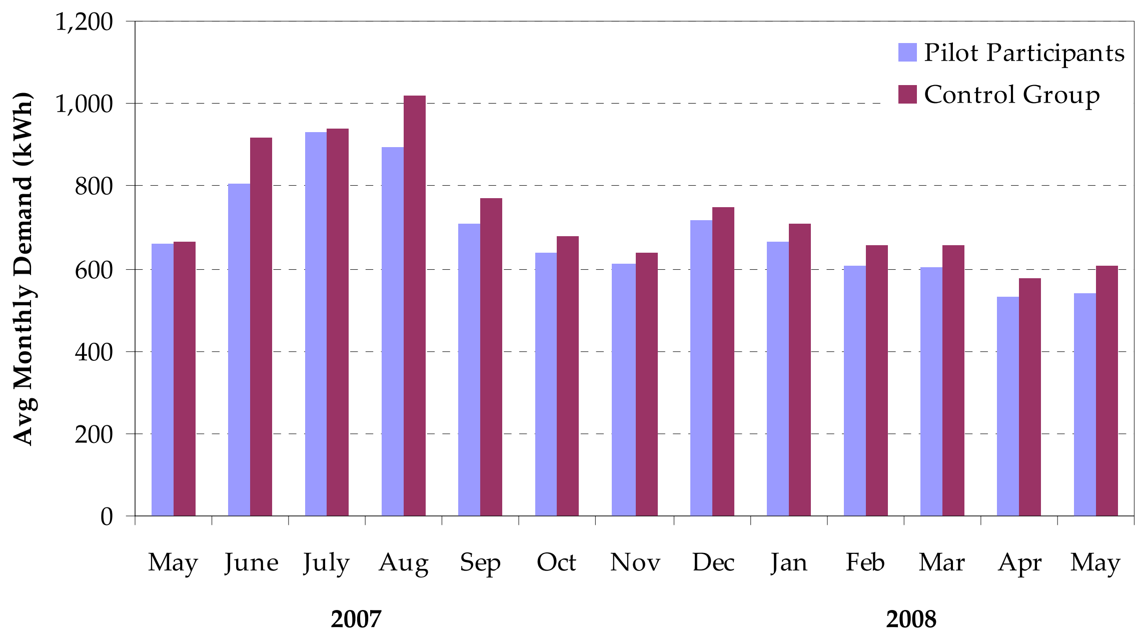
Conservation Effect

Other studies of time-of-use rates have found an overall conservation effect; not only do consumers shift their consumption from high-price to low-price periods, they also reduce their overall consumption, perhaps because of an increased awareness of their electricity use.

Figure 9 shows a comparison of the average monthly consumption from both participant group and the control group between May 2007 and May 2008. Taking the average monthly consumption for all months in the evaluation period, it was determined that on average, pilot participants consumed 52 kWh or 7% less than the control group per month.

However, the consumption for the pilot participants was also approximately 6-8% lower than the control group customers in the period preceding the pilot. Hence, there was no discernable conservation effect observed when comparing the pilot participants with the control group customers.

Figure 9: Comparison of Average Monthly Consumption for Pilot Participants and the Control Group during the Evaluation Period



Although the control group customers were chosen from a similar neighbourhood with houses of a similar vintage, there appears to be slightly higher consumption for the control group customers than the pilot participants – both before and during the pilot.

Change in Consumption – Pre TOU vs. TOU period

Navigant Consulting also developed a multivariate regression model for each of the pilot participants and the control group customers using on actual weather heating degree days and cooling degree days[4] as independent variables. Time was also added to the regression equation as an independent variable to determine whether there was a steady upward or downward trend in consumption. Finally, for the pilot participants, an additional independent variable was created to differentiate the pre-TOU and TOU period.

Based on the results of the multivariate regression model, Navigant Consulting observed a downward trend in consumption, however the heating degree days variable had no impact on this decrease in consumption and was not statistically significant in the model. A "dummy" variable used to distinguish the between pre-TOU and TOU periods was also not statistically significant in the model. A secondary model was created time excluding the heating degree days variable (using cooling degree days, time and the pre-TOU and TOU period as independent variables), and the results continued to show the downward trend in consumption with the cooling degree days and time variables showing increased significance, however the pre-TOU and TOU period "dummy" variable continued to be insignificant. Finally, a third model was created using only the cooling degree days and time as independent variables with an R-squared of 0.54. This third model also indicated that both independent variables were statistically significant.

The same methodology was applied for historical consumption data for the control group, and results indicated a similar downward trend in average consumption use, with both the cooling degree days and time being significant variables in the model. The control group regression model exhibited a R-square value of 71.5%.

This downward trend in consumption observed for both the TOU pilot participants and the control group customers is consistent with the findings from the analysis of CK Hydro average customer consumption between the period from 2002 to 2007 (as described in *Impact of Chatham-Kent Hydro's Pre-TOU Energy Conservation Efforts* on page 12).

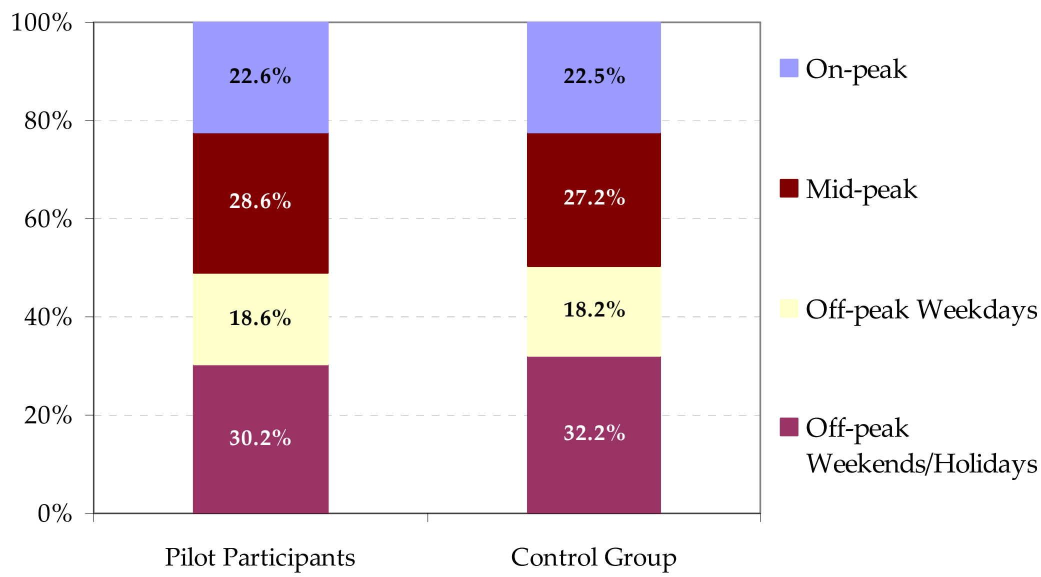
4 Average temperature data was available on an daily basis, so we compared the weather in the pre-TOU and TOU periods on a degree-day basis, with a degree-day representing the difference between the base temperature (21 °C for cooling and 15 °C for heating) and the average temperature for each day in the analysis period.

Load Shifting

The percentage of total consumption during each of the four periods (with the Off-Peak period divided into weekday and weekend Off-Peak periods) for TOU participants was compared with the breakdown for control group customers. Based on this analysis, Navigant Consulting determined that there were no statistically significant differences in the percentage of overall consumption by TOU period between the pilot participants and the control group during the evaluation period.

As illustration of the insignificant differences observed in relative percentage of total consumption between pilot participants and control group customers in the various TOU periods, Figure 10 shows the percent of total consumption determined for each of the four periods during the pilot period. Pilot participants exhibited marginally higher percentage of consumption during On-Peak (0.1% of total load) and Mid-Peak hours (1.4% of total load) relative to control group customers. Furthermore, pilot participants exhibited a 2% decrease in consumption during Off-Peak weekends (but not weekday) hours relative to control group customers. Note, however, that the differences presented in Figure 10 were determined not to be statistically significant.

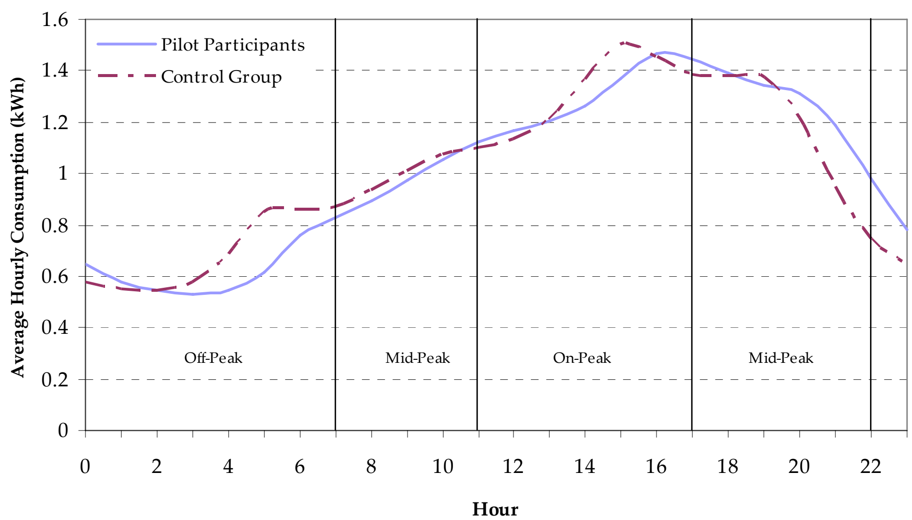
Figure 10: Comparison of Total Consumption by TOU Period for Pilot Participants and the Control Group during the Evaluation Period



The percent of total consumption during each of the TOU periods was also compared for the 34 pilot participants in the analysis dataset who signed up online to view their consumption data (web access) to the remaining TOU participant group. Navigant Consulting determined that there were no statistically significant differences between the two groups.

Figure 11 shows the average consumption for both pilot participants and control group, during the pilot period normalized to 24 kWh for a typical summer weekday for both groups. As shown, pilot participants tend to have lower consumption in the morning hours (Off-Peak and mid peak period) and slightly higher consumption in the later evening hours, in comparison to the control group. It also appears that pilot participants have marginally shifted their consumption away from the On-Peak period to later in the evening (Mid-Peak), when electricity is less expensive. This shift in the evening may be a result of shifting activities such as running the dishwasher later in the evening rather than immediately after dinner.

Figure 11: Comparison of Average Hourly Consumption for TOU Participants and the Control Group for a Summer Weekday



As show in Figure 12, pilot participant consumption tends to be lower during winter evening On-Peak hours, but slightly higher in the morning On-Peak hours suggesting that participants may be more willing and able to shift their energy consumption in the winter evening hours rather than in the winter morning hours.

Figure 12: Comparison of Average Hourly Consumption for TOU Participants and the Control Group for a Winter Weekday

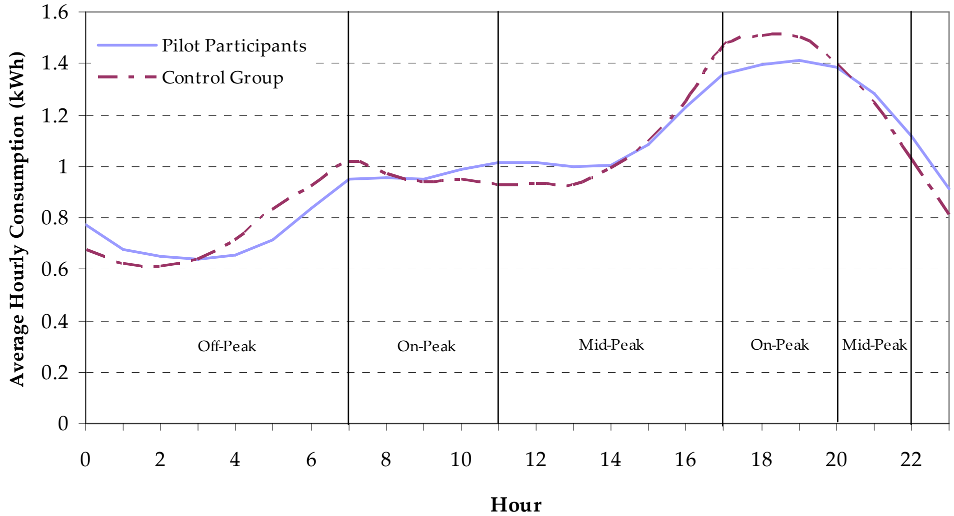


Figure 13 and Figure 14 present similar normalized average daily consumption profiles for the TOU participants who accessed their consumption data online compared with the remaining TOU participant group who did not. As shown, there were only very slight differences in the summer weekday and winter weekday consumption profiles between these subgroups of participants.

Figure 13: Comparison of Average Hourly Consumption for TOU participants who Accessed their Consumption Online and the Remaining TOU Participants for a Summer Weekday

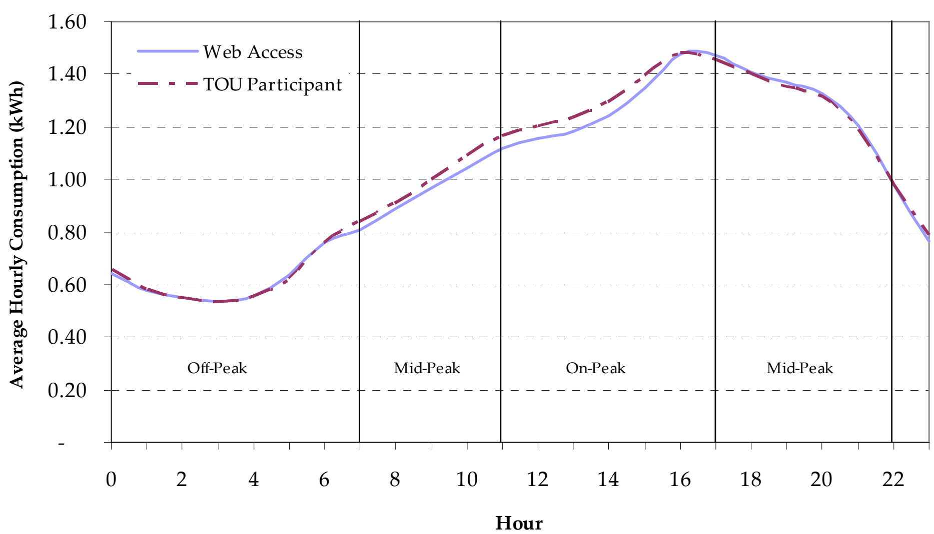
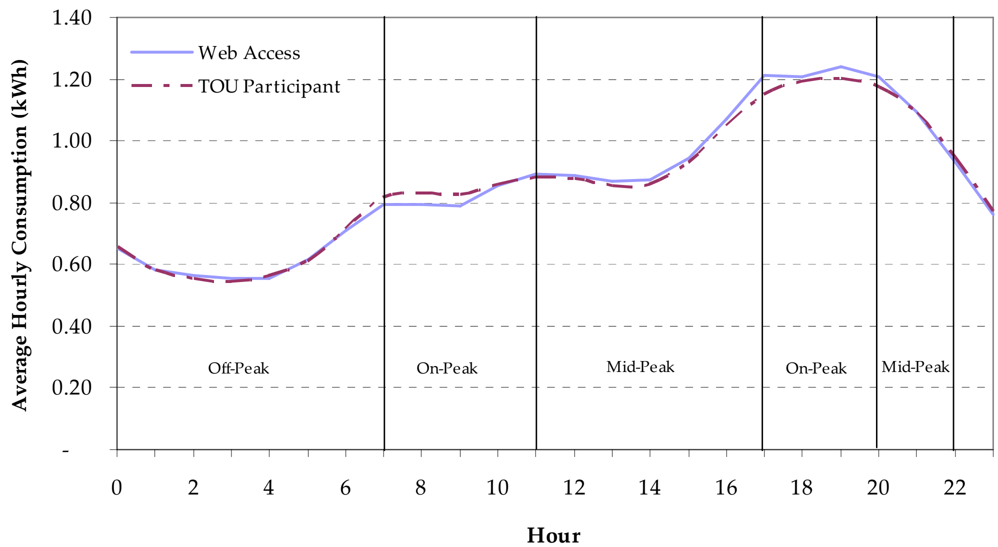


Figure 14: Comparison of Average Hourly Consumption for TOU participants who Accessed their Consumption Online and the Remaining TOU Participants for a Winter Weekday



Estimated Commodity Cost Impacts

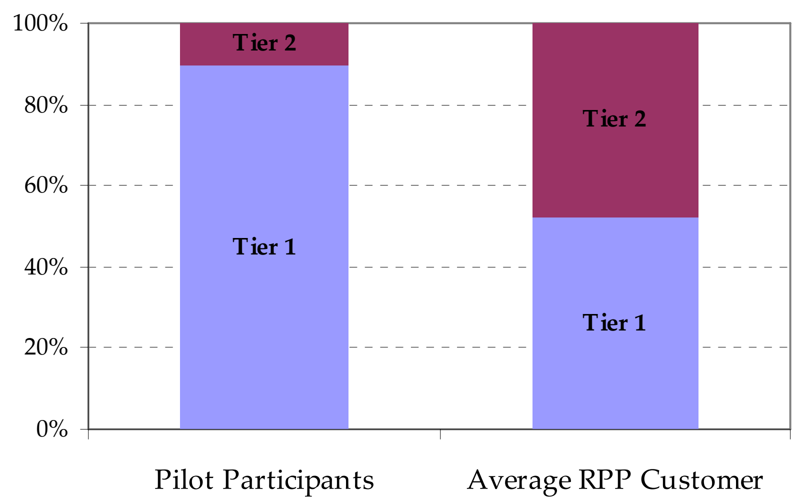
One of the factors that is most important to consumers is how TOU pricing will affect their monthly bills relative to what they would have paid had they remained on the two-tiered RPP prices.

The commodity cost impact was calculated for each participant by taking their electricity consumption for each month during the full TOU period and estimating their commodity charge (excluding distribution charges and other regulated charges) under both pricing plans: what they paid under TOU prices and what they would have paid had they remained on the tiered RPP prices. For the TOU price estimates, the monthly distribution of On-Peak, Mid-Peak and Off-Peak usage was taken for each participant based on their usage patterns during the TOU period. Note that commodity costs under TOU and tier prices were calculated based on consumption during the analyzed period (May 2007 through May 2008).

The estimated bill impacts presented below are related to the way in which the tier and time-of-use prices are set under the Regulated Price Plan. Both are set so that the *average* price paid by the *average* RPP customer will be the same. Pilot participant have consumption patterns that do not exactly match those of the average RPP customer. In particular:

- A significantly higher percentage of the participants' consumption falls under the threshold: 90%, compared to just over 50% for the average RPP customer. This difference is illustrated in Figure 15. As a result, the average commodity charge paid by study participants under tiered RPP prices would be lower than the average RPP price.

Figure 15: Average Monthly Consumption by Tier – Pilot Participants and Average RPP Customer



- The study participants' percentage of overall consumption during the On-Peak period is slightly less than for the average RPP customer (23% vs. 26% for the average RPP customer) and approximately the same in the Off-Peak period (49% vs. 50%). As a result, the average price paid by study participants under TOU prices would be slightly lower than the average RPP price.

While study participants will on average pay less than the average RPP prices under either set of prices, the difference is slightly greater under tier prices, meaning that the average price paid would be slightly lower under tiered prices.

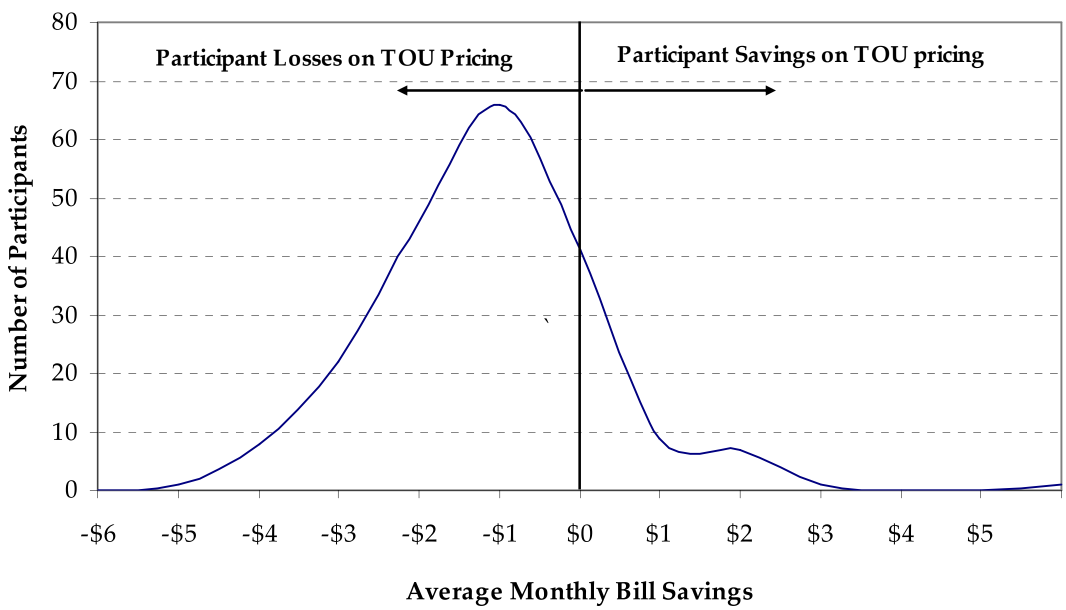
Table 6 shows the commodity cost impacts for the pilot participants on TOU rates in comparison to what they would have paid had they remained on two-tiered pricing over the TOU period. TOU prices resulted in slightly higher commodity costs for pilot participants over the 13 month period analyzed relative to the two-tiered prices. Commodity cost impacts ranged from a savings (commodity cost reduction) of 12% to an increase of 15%. Note that this is based only on the commodity portion of the bill, which accounts for approximately half of a typical residential customer's bill and *does not* reflect any changes in overall consumption in the TOU period relative to the pre-TOU period.

Table 6: Average Commodity Cost Savings under TOU Prices by Group

	Average Participant
Average Saving (%)	**-5.0%**
Largest Saving (%)	**12.1%**
Largest Increase (%)	**15.1%**
% of Participants Saving on TOU	**9%**

Just under 10% of study participants experienced lower commodity costs under TOU prices compared to tier prices, while 90% paid slightly more. Under tier prices, customers who consume less in a given month will tend to have a lower average price than customers who consume more, because more (or all) of their consumption will fall under the lower Tier 1 price. Prices will also vary under TOU prices, depending on the mix of On-Peak, Mid-Peak and Off-Peak consumption, but this variation is not necessarily related to a customer's total consumption. Thus, when comparing bills under TOU versus tier prices, it appears that customers who consume less are more likely to see a slight increase in their average price given the tiered pricing structure they are exposed to pre-TOU. As Figure 16 shows, the impact of the switch from tier to TOU prices was small for most study participants, though a few, presumably those with atypical consumption patterns, saw larger increases or decreases. The median average monthly change over the TOU period was determined to be a $1.68 increase for the pilot participants.

Figure 16: Distribution of Average Monthly Commodity Cost Savings for Pilot Participants



As noted, it is important to keep in mind that these results essentially reflect the difference in commodity costs based on either tiered or time-of-use pricing given participant's consumption levels and consumption patterns in the TOU period.

While most RPP customers are single family households, like the study participants, RPP customers also include small businesses as well as public buildings such as municipalities, universities, schools and hospitals (the "MUSH" sector). MUSH customers in particular are likely to be larger than single-family households, and to use more electricity during On-Peak and Mid-Peak periods. It is expected that as of May 1, 2009, MUSH consumers will no longer be eligible for RPP prices (unless their annual usage is less than 250,000 kWh per year). This will change the allocation of consumption between Tier 1 and Tier 2, and between on-, mid- and Off-Peak, as used in setting RPP prices. The effect of this change on the commodity costs of customers like the study participants under either tiered or time-of-use pricing are not known at this time.

CONCLUSIONS

Based on Navigant Consulting's analysis of the consumption patterns of the participants in CK Hydro's TOU pricing pilot and those of control group customers in a similar subdivision, the following conclusions can be drawn. Note that the TOU response observed reflects short-term behaviour changes only and it is expected that the response will increase over time.

1. CK Hydro average residential customer consumption decreased by 8% from 2002 to 2007, compared with a decline of only 3% for residential customers in fourteen similar Ontario LDCs. In 2007, CK Hydro's average residential customer consumption was 10% less than for residential customers in similar LDCs. This observation was confirmed through Navigant Consulting's regression analysis, with a statistically significant downward trend in consumption among CK Hydro customers. Navigant Consulting attributes this effect to CK Hydro's aggressive conservation education efforts. Further, this effect appears to have dampened the conservation effect typically seen among customers switching to TOU rates. In effect, the CK Hydro customers had already reduced their consumption prior to the implementation of the TOU pilot, whereas TOU pilot participants elsewhere who had not been exposed to a similar level of conservation education pre-TOU would have more conservation opportunities available to them post-TOU (and would generally be expected to have greater conservation awareness post-TOU).

2. There was no discernable conservation effect observed when comparing the pilot participants' consumption in the pre-TOU and TOU period and with the control group customers' consumption in the same periods, likely due to the earlier conservation efforts of these and other CK Hydro customers.

3. There were no statistically significant differences in the percentage of overall consumption by TOU period between the pilot participants and the control group during the pilot period.

4. Given their level of monthly consumption and consumption patterns, pilot participants would pay less than the average RPP prices under either TOU prices or tiered prices, but the difference is slightly greater under tier prices. As a result, pilot participants paid, on average, just under $2 per month more under TOU prices than they would have paid under tiered prices.

It is important to keep in mind that all forms of "flat" (or non-time varying) electricity pricing such as the tiered RPP prices inherently result in cross-subsidies between consumers with different consumption patterns, as the actual cost of power changes on an hourly basis. Two consumers could have identical overall consumption levels, but if one uses most of their electricity during the Off-Peak period and the other uses most during On- and Mid-

Peak periods, the cost to supply the latter consumer will be much higher. The time-of-use prices better reflect the true cost of power and significantly reduce such cross-subsidies.

In addition, the impact of time-of-use prices on the average commodity charges experienced by customers is also dependent on the relative percentage of their consumption in each of the two tiers under the RPP tiered pricing structure. Consumers, such as many in this pilot project, with most of their monthly consumption below the tier threshold pay somewhat less under tiered pricing than the average actual cost of electricity.

LOST REVENUE ADJUSTMENT MECHANISM:

The purpose of an LRAM adjustment is to account for the variance between forecasted volumes used to set class rates and actual volumes resulting from CDM programs. The LRAM recovery has been calculated as the approved savings per measure multiplied by the number of measures implemented for the particular programs targeted at each rate class for a total of $569,637.

The reduction in distribution revenue is calculated on the forgone volumes resulting from CDM activities by class and at the variable distribution rates applicable to the years 2005 to 2009.

Chatham-Kent Hydro is not requesting the recovery of carrying costs on the forgone distribution revenue in this Application. The recovery of the LRAM will be from the residential, GS< 50 kW and Street Light classes as these classes have benefited from the CDM programs. There will not be any recovery from the GS >50kW, Intermediate, Standby, Sentinel Lighting and Unmetered Scattered Load classes, as they are unaffected. Table 10-2 on the following page summarizes the forgone revenue by customer class:

Table 10-2
LRAM Summary

Forgone Revenue by Class and Program

Class

Program	Total Revenue
Residential	
Third Tranche	
Smart Meters	$ 347,010

Street Lighting	
Third Tranche	
Street Lights	$ 4,137

Residential	
OPA Conservation Programs	$ 204,897

General Service (<50 kW Demand)	
OPA Conservation Programs	$ 2,764

General Service(>50 KW Demand)	
OPA Conservation Programs	$ 10,830

SHARED SAVINGS MECHANISM:

SSM amounts are calculated based on the results of the TRC test, defined as a test that "*measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participant's and the LDC's costs.*"

In measuring the effectiveness of a program the TRC test examines the benefits of a program, which is typically the avoided resource costs such as electricity, with program costs which includes both the LDC's costs and the participant's costs, over the life of the program. The stream of future net benefits is net present valued ("NPV") to a single number and must be greater than zero to be cost effective.

The TRC test also provides for free ridership such that a program with a high degree of free ridership is therefore less cost effective for the LDC to pursue as the program costs will exceed the program benefits.

The amount of the SSM incentive is based on 5% of the NPV of the net benefits of Chatham-Kent Hydro CDM programs.

Chatham-Kent Hydro has calculated the SSM amount in accordance with the methodology set out in the TRC Guide. In accordance with the Guidelines for applying for the SSM incentive, Chatham-Kent Hydro is only making application for customer-focused initiatives (no "utility side" programs) that reduce the demand for electricity.

As noted above, Chatham-Kent Hydro has calculated the SSM recovery as 5% of the NPV of the net benefits for each program, in accordance with the TRC Guide. The total SSM calculated in this Application amounts to $204,557 (Table 10-3). Chatham-Kent Hydro is filing for recovery of this amount without gross up for PILs in accordance with the Toronto Hydro Decision.

As with the LRAM adjustment, Chatham-Kent Hydro proposes that the SSM amount arising from CDM activities in each rate class be allocated to that class, and that the SSM be recovered through a variable distribution rate rider applicable to that class. Also consistent with the LRAM rate rider, Chatham-Kent Hydro proposes to implement the variable distribution rate rider over 3 years, however, to delay the implementation to May 1, 2011. Therefore the rider will be in place from May 1, 2011 to April 30, 2014, to mitigate potential customer impacts.

Table 10-3
SSM Summary

SSM Amounts by Class and Program

Class Program	Admin Costs $	Total Costs $	Total Benefits $	Net Benefits $ NPV	Benefits/Cost Ratio	SSM Amount $
2006						
Residential **Third Tranche** Smart Meters	$357,780	$5,961,601	$9,586,925	$3,625,324	$1.61	$181,266
Street Lights **Third Tranche** Street Lights	$21,204	$201,204	$667,029	$465,825	$3.32	$23,291
TOTALS	$378,984	$6,162,805	$10,253,954	$4,091,149	$4.92	$204,557

RELIEF REQUESTED:

Chatham-Kent Hydro proposes that the LRAM and SSM rate riders be combined into, and recovered through a single distribution rate rider as provided in Table 10-2 of the preceding Schedule 2, and that the total LRAM and SSM rate rider be implemented effective May 1, 2011 for a period of 3 years beginning May 1, 2011 and ending April 30, 2014.

Chatham-Kent Hydro notes that at page 11 of the Toronto Hydro Decision, the OEB states "The Board believes that for future claims relating to third tranche and 2006 incremental spending, the Board and stakeholders could be assisted by an independent third party review of program results, and claim amounts." Chatham-Kent Hydro's evidence is supported by the report from EnerSpectrum Group.

Chatham-Kent Hydro submits that its claim for LRAM and SSM in the amount of $774,194 represents only 4.9% of its distribution revenue requirement and therefore has minimal impact on distribution rates, and that any such impact has been mitigated by recovering the LRAM/SSM over 3 rate years and delaying the start of implementing the rate rider until May 1, 2011. This can be seen in the discussion of bill impacts in Schedule 6. In light of the foregoing, Chatham-Kent Hydro requests approval of its proposed LRAM and SSM without being subject to a further review.

BILL IMPACT:

Chatham-Kent Hydro proposes that the LRAM and SSM amounts be recovered over 3 years through rate riders effective May 1, 2011 until April 30, 2014. Table 10-4 below provides a summary of the impacts of the proposed LRAM and SSM adjustments on the variable distribution rate, the percent change in distribution cost, and the percent change in total bill, for the average customer in each affected rate class.

Table 10-4
LRAM & SSM Rate Impacts by Class

Consumption per Month	% Change Variable Rates	% Change Distribution Cost	% Change Total Bill
Residential			
800 kWh	13.9%	9.2%	1.1%
General Service < 50 kW			
2,000 kWh	0.5%	1.7%	0.05%

Chatham-Kent Hydro submits that the recovery of the LRAM and SSM adjustments over 3 years and delaying the implementation to May 1, 2011 satisfactorily mitigates the rate impact to customers, and that further mitigation is not required.