THUNDER BAY HYDRO

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September 5, 2008

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
26th Floor - 2300 Yonge Street
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Thunder Bay Hydro Electricity Distribution Inc. - 2009 Cost of Service Application
OEB File No. EB-2008-0245
ED-2002-0529

Enclosed please find Thunder Bay Hydro's 2009 Cost of Service Application. The application has been prepared following the OEB Filing Requirements for Transmission and Distribution Applications. The components of the application are contained in the two attached bound packages and include the following:

1st of 3 Bound Packages
- Exhibit 1 – Administration
- Exhibit 2 – Rate Base

2nd of 3 Bound Packages
- Exhibit 3 – Operating Revenue
- Exhibit 4 – Operating Costs
- Exhibit 5 – Cost of Capital and Rate of Return*
- Exhibit 6 – Calculation of Revenue Deficiency or Surplus
- Exhibit 7 – Cost Allocation
- Exhibit 8 – Rate Design

*In light of the OEB Decisions with respect to the 2008 Cost of Service Rate Applications, Thunder Bay Hydro is not requesting disposition of any of the Deferral and Variance Accounts and therefore has not included this in the application, hence the Exhibit numbers that follow are one off from the Filing Requirements.

Also included are two (2) CD Discs containing supporting data relative to our Application (Thunder Bay Hydro Electrical Distribution System and Thunder Bay Hydro, LRAM/SSM Program Data).

An electronic copy of our complete application will be submitted through the OEB e-Filing Services and three hard copies are being sent by courier.

If you require any further information, please contact the undersigned at (807) 343-1118.

Yours truly,

Cindy Speziale

Cindy Speziale, CA
Vice President, Finance

CS/dt

Enclosures.

THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.

APPLICATION FOR APPROVAL OF ELECTRICITY DISTRIBUTION RATES

EFFECTIVE MAY 1, 2009

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DEFINED TERMS

'Historical Year' – 2007

'Bridge Year' – 2008; 2008 Estimate – based on actuals to May 31, 2008 (prepared using March 31, 2008 and reviewed using May 31, 2008) and estimated to December 31, 2008

'Test Year' – 2009

'Capital Expenditure' – the amount spent on a capital project/program in a given year

'Group or Groupings' – refers to the groups of Accounts prescribed in the 2006 Electricity Distribution Rate Handbook

The following terms are defined here and used throughout the document:

'Board Filing Requirements' – the Ontario Energy Board Filing Requirements for Transmission and Distribution Applications, November 14, 2006, as set out in Chapter 2

'EDR' – Electricity Distribution Rates

'Thunder Bay Hydro' – Thunder Bay Hydro Electricity Distribution Inc.

'LDC' –Local Distribution Company

ABBREVIATIONS

Accounting Procedures Handbook (APH)

Advanced Metering Infrastructure (AMI)

Affiliate Relationships Code for Electricity Transmitters and Distributors (ARC)

Allowance for Funds Used During Construction (AFUDC)

Asset Management Program (AMP)

Asset Management Strategy (AMS)

Asset Risk Assessment (ARA)

Association of Electrical Utilities Safety Professionals (AEUSP)

Canadian Institute of Chartered Accountants (CICA)

Canadian Standards Association (CSA)

Canadian Society of Safety Engineering (CSSE)

Capital Cost Allowance (CCA)

Chief Executive Officer (CEO)

Conservation and Demand Management (CDM)

Construction-Work-in-Progress (CIP)

Cumulative Eligible Capital (CEC)

Customer Average Interruption Duration Index (CAIDI)

Customer Information System (CIS)

Distribution System Code (DSC)

Electrical & Utilities Safety Association (E&USA) (ESA)

Electricity Distributors Association (EDA)

Electricity Distribution Rate Handbook (EDRH)

Electronic Business Transaction (EBT)

Eligible Capital Expenditure (ECE)

Employee Assistance Program (EAP)

Enterprise Resource Planning (EFP)

Full Time Equivalent (FTE)

General Accepted Accounting Principles (GAAP)

Geographic Information System (GIS)

Government Management and Budgetary Accounting (GMBA)

Software Vendor (HTE)

Incentive Regulation Mechanism (IRM)

Independent Electricity System Operator (the IESO)

Industrial Accident Prevention Association (IAPA)

Information Systems Department (ISD)

Integrated Power System Plan (IPSP)

International Brotherhood of Electrical Workers (IBEW)

International Organization for Standardization (ISO)

Key Performance Indicators (KPIs)

Kilowatt (kW)

Kilowatt hours (kWhs)

Large Corporation Tax (LCT)

Local Area Network (LAN)

Long Term Disability (LTD)

Lost Revenue Adjustment Mechanism (LRAM)

Market Adjusted Rate of Return (MARR)

Market Base Rate of Return (MBRR)

Meter Data Management/Repository (MDM/R)

Ministry of Labour (MOL)

Monthly Service Charge (MSC)

Municipal Electric Association Reciprocal Insurance Exchange (MEARIE)

Meter Viewer 90 (MV90)

`Net Book Value (NBV)

Net Present Value (NPV)

North American Occupational Safety and Health (NAOSH)

Occupational Health, Safety and Environment (OH&S)

Occupational Health and Safety Assessment Series (OHSAS)

Ontario Energy Board (OEB)

Ontario Municipal Employees Retirement System (OMERS)

Ontario Power Authority (OPA)

Ontario Price Credit (OPC)

Operational Data Store (ODS)

Operations and Maintenance (O&M)

Operations, Maintenance and Administration (OM&A)

Outage Management System (OMS)

Paid-up Capital (PUC)

Payments in Lieu of Taxes (PILs)

Personal Computer (PC)

Polychlorinated Biphenyls (PCBs)

Powerline Technician (PLT)

Public Service Works on Highways Act (PSWHA)

Quality Assurance (QA)

Quality Control (QC)

Regulated Price Plan (RPP)

Reliability Centered Maintenance (RCM)

Remote Terminal Unit (RTU)

Reporting and Record Keeping Requirements (RRR)

Request for Proposal (RFP)

Retail Cost Variance Account (RCVA)

Retail Settlement Variance Account (RSVA)

Return on Equity (ROE)

Second Generation Incentive Regulation Mechanism (2GIRM)

Service Agreements (SAs)

Service Quality Indicator (SQI)

Shared Savings Mechanism (SSM)

Smart Meters (SM)

Smart Meter Initiative (SMI)

Supervisory Control and Data Acquisition (SCADA)

Supply Facility Loss Factor (SFLF)

System Average Interruption Frequency Index (SAIFI)

System Average Interruption Duration Index (SAIDI)

Third Generation Incentive Regulation Mechanism (3GIRM)

TRC (Total Resource Cost)

Transformer Ownership Credit (TOC)

Undepreciated Capital Cost (UCC)

Uniform System of Accounts (USoA)

Unmetered Scattered Load (USL)

Utility Standards Forum (USF)

Validation Editing and Estimation (VEE)

Wide Area Network (WAN)

Workplace Safety & Insurance Board (WSIB)

Worksite specific, Health & safety, Operational, Legislative and Environmental (WHOLE)

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 THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION 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, 2009.

Title of Proceeding:	An application by **THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.** for an Order or Orders approving or fixing just and reasonable distribution rates and other charges, effective May 1, 2009.
Applicant's Name:	**THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.**
Applicant's Address for Service:	34 Cumberland St. N, Thunder Bay, Ontario
	Attention: Robert Mace, President
	Telephone: (807) 343-1122
	Fax: (807) 343-0230
	E-mail: rmace@tbhydro.on.ca

APPLICATION

1. Introduction

(a) The Applicant is Thunder Bay Hydro Electricity Distribution Inc. (referred to in this Application as the "Applicant" or "THUNDER BAY HYDRO."). The Applicant is a corporation incorporated pursuant to the Ontario *Business Corporations Act* with its head office in the City of Thunder Bay. The Applicant carries on the business of distributing electricity within the City of Thunder Bay and Fort William First Nation Reserve.

(b) The Applicant hereby applies to the Ontario Energy Board (the "OEB") pursuant to Section 78 of the *Ontario Energy Board Act*, *1998* for approval of its proposed distribution rates and other charges, effective May 1, 2009. A list of requested approvals is set out in Exhibit 1, Tab 1, Schedule 5 below.

(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 November 14, 2006 (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 Appendix A attached to this summary and Exhibit 8, Tab 1, Schedule 7, and the material being filed in support of this Application sets out Thunder Bay 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, 2009 in accordance with the Filing Requirements.

(b) In the event that the OEB is unable to provide a Decision and Order in this Application for implementation by the Applicant as of May 1, 2009, the Applicant requests that the OEB issue an interim Order approving the proposed distribution rates and other charges effective May 1, 2009, which may be subject to adjustment based on its final Decision and Order.

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 Streetlight class will see a significant bill impact (approximately 28% increase); however, in light of 2008 OEB Decisions, Thunder Bay Hydro has not requested implementation of mitigation measures. The Unmetered Scattered Load class will have a bill impact of approximately 18%) as a result of LRAM/SSM. The LRAM/SSM adjustment has significantly impacted the USL class since there have been extensive CDM programs associated with traffic lights. There are no impacts to any of the other customer classes or consumption level subgroups that are so significant as to warrant the deferral of any adjustments being requested by the Applicant or the implementation of any other mitigation measures;

(iv) the other service charges proposed by the Applicant are the same as those previously approved by the OEB with the exception of the temporary services charges; 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, 2009, or as soon as possible thereafter; and

(b) In the event that the OEB is unable to provide a Decision and Order in this Application for implementation by the Applicant as of May 1, 2009, the Applicant requests that the OEB issue an interim Order approving the proposed distribution rates and other charges, effective May 1, 2009, which may be subject to adjustment based on its final Decision and Order.

6. Form of Hearing Requested

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

DATED at Thunder Bay, Ontario, this 5th day of September, 2008.

All of which is respectfully submitted,

THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.

Cindy Speziale, Vice President, Finance

APPENDIX A

SCHEDULE OF PROPOSED RATES AND CHARGES

SCHEDULE OF PROPOSED RATES AND CHARGES

Effective May 1, 2009

Monthly Rates and Charges

Residential		
Service Charge	**$**	11.26
Distribution Volumetric Rate	**$/kWh**	0.0142
LRAM and SSM Rate Rider	**$kWh**	0.0005
Smart Meter Rate Rider	**$month**	1.2500
Regulatory Assets Rate Rider	**$kWh**	0.0000
Retail Transmission Rate – Network Service Rate	**$/kWh**	0.0043
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kWh**	0.0034
Wholesale Market Service Rate	**$/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	**$**	18.56
Distribution Volumetric Rate	**$/kWh**	0.0136
LRAM and SSM Rate Rider	**$kWh**	0.0000
Smart Meter Rate Rider	**$month**	1.2500
Regulatory Assets Rate Rider	**$kWh**	0.0000
Retail Transmission Rate – Network Service Rate	**$/kWh**	0.0040
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kWh**	0.0030
Wholesale Market Service Rate	**$/kWh**	0.0052
Rural Rate Protection Charge	**$/kWh**	0.0010
Standard Supply Service – Administrative Charge (if applicable)	**$**	0.25
General Service 50 to 999 kW		
Service Charge	**$**	224.18
Distribution Volumetric Rate	**$/kW**	1.2583
LRAM and SSM Rate Rider	**$kWh**	0.0021
Smart Meter Rate Rider	**$month**	1.2500
Regulatory Assets Rate Rider	**$kWh**	0.0000
Retail Transmission Rate – Network Service Rate	**$/kW**	1.6186
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kW**	1.1930
Retail Transmission Rate – Network Service Rate - Interval Metered	**$/kW**	1.7169
Retail Transmission Rate – Line and Transformation Connection Service Rate - I	**$/kW**	1.3185
Wholesale Market Service Rate	**$/kWh**	0.0052
Rural Rate Protection Charge	**$/kWh**	0.0010
Standard Supply Service – Administrative Charge (if applicable)	**$**	0.25

General Service 1,000 to 4,999 kW		
Service Charge	**$**	2,069.12
Distribution Volumetric Rate	**$/kW**	1.6615
LRAM and SSM Rate Rider	**$kW**	0.0027
Smart Meter Rate Rider	**$month**	1.2500
Regulatory Assets Rate Rider	**$kW**	0.0000
Retail Transmission Rate – Network Service Rate	**$/kW**	1.7169
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kW**	1.3185
Wholesale Market Service Rate	**$/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)	**$**	9.26
Distribution Volumetric Rate	**$/kWh**	0.0135
LRAM and SSM Rate Rider	**$/kWh**	0.0184
Regulatory Assets Rate Rider	**$kWh**	0.0000
Retail Transmission Rate – Network Service Rate	**$/kWh**	0.0040
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kWh**	0.0030
Wholesale Market Service Rate	**$/kWh**	0.0052
Rural Rate Protection Charge	**$/kWh**	0.0010
Standard Supply Service – Administrative Charge (if applicable)	**$**	0.25
Sentinel Lighting		
Service Charge (per connection)	**$**	6.66
Distribution Volumetric Rate	**$/kW**	5.3435
Regulatory Assets Rate Rider	**$kW**	0.0000
Retail Transmission Rate – Network Service Rate	**$/kW**	1.2269
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kW**	0.9415
Wholesale Market Service Rate	**$/kWh**	0.0052
Rural Rate Protection Charge	**$/kWh**	0.0010
Standard Supply Service – Administrative Charge (if applicable)	**$**	0.25
Street Lighting		
Service Charge (per connection)	**$**	1.14
Distribution Volumetric Rate	**$/kW**	6.9151
Regulatory Assets Rate Rider	**$kW**	0.0000
Retail Transmission Rate – Network Service Rate	**$/kW**	1.2206
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kW**	0.9222
Wholesale Market Service Rate	**$/kWh**	0.0052
Rural Rate Protection Charge	**$/kWh**	0.0010

Specific Service Charges

Customer Administration		
Arrears certificate	**$**	15.00
Statement of account	**$**	15.00
Easement letter	**$**	15.00
Account history	**$**	15.00
Returned cheque charge (plus bank charges)	**$**	25.00
Legal letter charge	**$**	15.00
Account set up charge/change of occupancy charge (plus credit agency co	**$**	30.00
Special meter reads	**$**	30.00
Meter dispute charge plus Measurement Canada fees (if meter found corre	**$**	30.00
Non-Payment of Account		
Late Payment - per month	**%**	1.50
Late Payment - per annum	**%**	19.56
Disconnect/Reconnect at meter - during regular hours	**$**	65.00
Disconnect/Reconnect at meter - after regular hours	**$**	185.00
Disconnect/Reconnect at pole - during regular hours	**$**	185.00
Disconnect/Reconnect at pole - after regular hours	**$**	415.00
Install/Remove load control device - during regular hours	**$**	65.00
Install/Remove load control device - after regular hours	**$**	185.00
Service call - customer-owned equipment	**$**	30.00
Service call - after regular hours	**$**	165.00
Specific Charge for Access to the Power Poles $/pole/year	**$**	22.35
Allowances		
Transformer Allowance for Ownership -per kW/kva of billing demand/month	**$/kW**	(0.60)
Primary Metering Allowance for transformer losses - applied to measured demand and energy	**%**	(1.00)

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0478
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0145
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0373
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0045

DISTRIBUTION LICENCE:

A copy of Thunder Bay Hydro's Electricity Distribution Licence ED-2002-0529, issued on October 9, 2003, revised on February 16, 2005, accompanies this Schedule as Appendix A hereto.

APPENDIX A

COPY OF THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC. DISTRIBUTION LICENCE

Ontario

Electricity Distribution Licence

ED-2002-0529

Thunder Bay Electricity Distribution Inc.

Valid Until
October 8, 2023

Mark C. Garner
Managing Director, Market Operations
Ontario Energy Board
Date of Issuance: October 9, 2003
Date of Issuance: February 16, 2005

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
26th. Floor
Toronto, ON M4P 1E4

Commission de l'Énergie de l'Ontario
C.P. 2319
2300, rue Yonge
26e étage
Toronto ON M4P 1E4

1 Definitions

In this Licence:

"**Accounting Procedures Handbook**" means the handbook, approved by the Board which specifies the accounting records, accounting principles and accounting separation standards to be followed by the Licensee;

"**Act**" means the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B;

"**Affiliate Relationships Code for Electricity Distributors and Transmitters**" means the code, approved by the Board which, among other things, establishes the standards and conditions for the interaction between electricity distributors or transmitters and their respective affiliated companies;

"**distribution services**"means services related to the distribution of electricity and the services the Board has required distributors to carry out, including the sales of electricity to consumers under section 29 of the Act, for which a charge or rate has been established in the Rate Order;

"**Distribution System Code**" means the code approved by the Board which, among other things, establishes the obligations of the distributor with respect to the services and terms of service to be offered to customers and retailers and provides minimum, technical operating standards of distribution systems;

"**Electricity Act**" means the *Electricity Act, 1998*, S.O. 1998, c. 15, Schedule A;

"**Licensee**" means: Thunder Bay Electricity Distribution Inc.;

"**Market Rules**" means the rules made under section 32 of the Electricity Act;

"**Performance Standards**" means the performance targets for the distribution and connection activities of the Licensee as established by the Board in accordance with section 83 of the Act;

"**Rate Order**" means an Order or Orders of the Board establishing rates the Licensee is permitted to charge;

"**regulation**" means a regulation made under the Act or the Electricity Act;

"**Retail Settlement Code**" means the code approved by the Board which, among other things, establishes a distributor's obligations and responsibilities associated with financial settlement among retailers and consumers and provides for tracking and facilitating consumer transfers among competitive retailers;

"**service area**" with respect to a distributor, means the area in which the distributor is authorized by its licence to distribute electricity;

"**Standard Supply Service Code**" means the code approved by the Board which, among other things, establishes the minimum conditions that a distributor must meet in carrying out its obligations to sell electricity under section 29 of the Electricity Act;

"**wholesaler**" means a person that purchases electricity or ancillary services in the IMO-administered markets or directly from a generator or, a person who sells electricity or ancillary services through the IMO-administered markets or directly to another person other than a consumer.

2 Interpretation

2.1 In this Licence words and phrases shall have the meaning ascribed to them in the Act or the Electricity Act. Words or phrases importing the singular shall include the plural and vice versa. Headings are for convenience only and shall not affect the interpretation of the licence. Any reference to a document or a provision of a document includes an amendment or supplement to, or a replacement of, that document or that provision of that document. In the computation of time under this licence where there is a reference to a number of days between two events, they shall be counted by excluding the day on which the first event happens and including the day on which the second event happens and where the time for doing an act expires on a holiday, the act may be done on the next day.

3 Authorization

3.1 The Licensee is authorized, under Part V of the Act and subject to the terms and conditions set out in this Licence:

a) to own and operate a distribution system in the service area described in Schedule 1 of this Licence;

b) to retail electricity for the purposes of fulfilling its obligation under section 29 of the Electricity Act in the manner specified in Schedule 2 of this Licence; and

c) to act as a wholesaler for the purposes of fulfilling its obligations under the Retail Settlement Code or under section 29 of the Electricity Act.

25

4 Obligation to Comply with Legislation, Regulations and Market Rules

26

4.1 The Licensee shall comply with all applicable provisions of the Act and the Electricity Act and regulations under these Acts except where the Licensee has been exempted from such compliance by regulation.

27

4.2 The Licensee shall comply with all applicable Market Rules.

28

5 Obligation to Comply with Codes

29

5.1 The Licensee shall at all times comply with the following Codes (collectively the "Codes") approved by the Board, except where the Licensee has been specifically exempted from such compliance by the Board. Any exemptions granted to the licensee are set out in Schedule 3 of this Licence. The following Codes apply to this Licence:

30

a) the Affiliate Relationships Code for Electricity Distributors and Transmitters;

31

b) the Distribution System Code;

32

c) the Retail Settlement Code; and

33

d) the Standard Supply Service Code.

34

5.2 The Licensee shall:

35

a) make a copy of the Codes available for inspection by members of the public at its head office and regional offices during normal business hours; and

36

b) provide a copy of the Codes to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

37

6 Obligation to Provide Non-discriminatory Access

38

6.1 The Licensee shall, upon the request of a consumer, generator or retailer, provide such consumer, generator or retailer with access to the Licensee's distribution system and shall convey electricity on behalf of such consumer, generator or retailer in accordance with the terms of this Licence.

39

7 Obligation to Connect

40

7.1 The Licensee shall connect a building to its distribution system if:

a) the building lies along any of the lines of the distributor's distribution system; and

b) the owner, occupant or other person in charge of the building requests the connection in writing.

7.2 The Licensee shall make an offer to connect a building to its distribution system if:

a) the building is within the Licensee's service area as described in Schedule 1; and

b) the owner, occupant or other person in charge of the building requests the connection in writing.

7.3 The terms of such connection or offer to connect shall be fair and reasonable and made in accordance with the Distribution System Code, and the Licensee's Rate Order as approved by the Board.

7.4 The Licensee shall not refuse to connect or refuse to make an offer to connect unless it is permitted to do so by the *Act* or a regulation or any Codes to which the Licensee is obligated to comply with as a condition of this Licence.

8 Obligation to Sell Electricity

8.1 The Licensee shall fulfill its obligation under section 29 of the Electricity Act to sell electricity in accordance with the requirements established in the Standard Supply Service Code, the Retail Settlement Code and the Licensee's Rate Order as approved by the Board.

9 Obligation to Maintain System Integrity

9.1 The Licensee shall maintain its distribution system in accordance with the standards established in the Distribution System Code and Market Rules, and have regard to any other recognized industry operating or planning standards adopted by the Board.

10 Market Power Mitigation Rebates

10.1 The Licensee shall comply with the pass through of Ontario Power Generation rebate conditions set out in Appendix A of this Licence.

54

11 Distribution Rates

55

11.1 The Licensee shall not charge for connection to the distribution system, the distribution of electricity or the retailing of electricity to meet its obligation under section 29 of the Electricity Act except in accordance with a Rate Order of the Board.

56

12 Separation of Business Activities

57

12.1 The Licensee shall keep financial records associated with distributing electricity separate from its financial records associated with transmitting electricity or other activities in accordance with the Accounting Procedures Handbook and as otherwise required by the Board.

58

13 Expansion of Distribution System

59

13.1 The Licensee shall not construct, expand or reinforce an electricity distribution system or make an interconnection except in accordance with the Act and Regulations, the Distribution System Code and applicable provisions of the Market Rules.

60

13.2 In order to ensure and maintain system integrity or reliable and adequate capacity and supply of electricity, the Board may order the Licensee to expand or reinforce its distribution system in accordance with Market Rules and the Distribution System Code, or in such a manner as the Board may determine.

61

14 Provision of Information to the Board

62

14.1 The Licensee shall maintain records of and provide, in the manner and form determined by the Board, such information as the Board may require from time to time.

63

14.2 Without limiting the generality of condition 14.1 the Licensee shall notify the Board of any material change in circumstances that adversely affects or is likely to adversely affect the business, operations or assets of the Licensee as soon as practicable, but in any event no more than twenty (20) days past the date upon which such change occurs.

64

15 Restrictions on Provision of Information

65

15.1 The Licensee shall not use information regarding a consumer, retailer, wholesaler or generator obtained for one purpose for any other purpose without the written consent of the consumer, retailer, wholesaler or generator.

66

15.2 The Licensee shall not disclose information regarding a consumer, retailer, wholesaler or generator to any other party without the written consent of the consumer, retailer, wholesaler or generator, except where such information is required to be disclosed:

a) to comply with any legislative or regulatory requirements, including the conditions of this Licence;

b) for billing, settlement or market operations purposes;

c) for law enforcement purposes; or

d) to a debt collection agency for the processing of past due accounts of the consumer, retailer, wholesaler or generator.

15.3 The Licensee may disclose information regarding consumers, retailers, wholesalers or generators where the information has been sufficiently aggregated such that their particular information cannot reasonably be identified.

15.4 The Licensee shall inform consumers, retailers, wholesalers and generators of the conditions under which their information may be released to a third party without their consent.

15.5 If the Licensee discloses information under this section, the Licensee shall ensure that the information provided will not be used for any other purpose except the purpose for which it was disclosed.

16 Customer Complaint and Dispute Resolution

16.1 The Licensee shall:

a) have a process for resolving disputes with customers that deals with disputes in a fair, reasonable and timely manner;

b) publish information which will make its customers aware of and help them to use its dispute resolution process;

c) make a copy of the dispute resolution process available for inspection by members of the public at each of the Licensee's premises during normal business hours;

d) give or send free of charge a copy of the process to any person who reasonably requests it; and

e) subscribe to and refer unresolved complaints to an independent third party complaints resolution service provider selected by the Board. This condition will become effective on a date to be determined by the Board. The Board will provide reasonable notice to the Licensee of the date this condition becomes effective.

81

17 Term of Licence

82

17.1 This Licence shall take effect on October 9, 2003 and expire on October 8, 2023. The term of this Licence may be extended by the Board.

83

18 Fees and Assessments

84

18.1 The Licensee shall pay all fees charged and amounts assessed by the Board.

85

19 Communication

86

19.1 The Licensee shall designate a person that will act as a primary contact with the Board on matters related to this Licence. The Licensee shall notify the Board promptly should the contact details change.

87

19.2 All official communication relating to this Licence shall be in writing.

88

19.3 All written communication is to be regarded as having been given by the sender and received by the addressee:

89

a) when delivered in person to the addressee by hand, by registered mail or by courier;

90

b) ten (10) business days after the date of posting if the communication is sent by regular mail; and

91

c) when received by facsimile transmission by the addressee, according to the sender's transmission report.

92

20 Copies of the Licence

93

20.1 The Licensee shall:

94

a) make a copy of this Licence available for inspection by members of the public at its head office and regional offices during normal business hours; and

95

b) provide a copy of the Licence to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

96

SCHEDULE 1 DEFINITION OF DISTRIBUTION SERVICE AREA

97

This Schedule specifies the area in which the Licensee is authorized to distribute and sell electricity in accordance with condition 8.1 of this Licence.

98

1. The City of Thunder Bay as of January 1, 1970.

99

2. Fort William First Nation.

100

SCHEDULE 2 PROVISION OF STANDARD SUPPLY SERVICE

101

This Schedule specifies the manner in which the Licensee is authorized to retail electricity for the purposes of fulfilling its obligation under section 29 of the Electricity Act.

102

The Licensee is authorized to retail electricity directly to consumers within its service area in accordance with condition 8.1 of this Licence, any applicable exemptions to this Licence, and at the rates set out in the Rate Orders.

103

SCHEDULE 3 LIST OF CODE EXEMPTIONS

104

This Schedule specifies any specific Code requirements from which the Licensee has been exempted.

105

The Licensee is exempt from the requirements of section 2.5.3 of the Standard Supply Service Code with respect to the price for small volume/residential consumers, subject to the Licensee offering an equal billing plan as described in its application for exemption from Fixed Reference Price, and meeting all other undertakings and material representations contained in the application and the materials filed in connection with it.

106

APPENDIX A MARKET POWER MITIGATION REBATES

107

1 Definitions and Interpretation

108

In this Licence,

109

"embedded distributor" means a distributor who is not a market participant and to whom a host distributor distributes electricity;

110

"embedded generator" means a generator who is not a market participant and whose generation facility is connected to a distribution system of a distributor, but does not include a generator who consumes more electricity than it generates;

111

"host distributor" means a distributor who is a market participant and who distributes electricity to another distributor who is not a market participant.

112

In this Licence, a reference to the payment of a rebate amount by the IMO includes interim payments made by the IMO.

113

2 Information Given to IMO

114

a Prior to the payment of a rebate amount by the IMO to a distributor, the distributor shall provide the IMO, in the form specified by the IMO and before the expiry of the period specified by the IMO, with information in respect of the volumes of electricity withdrawn by the distributor from the IMO-controlled grid during the rebate period and distributed by the distributor in the distributor's service area to:

115

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

116

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998*.

117

b Prior to the payment of a rebate amount by the IMO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the embedded distributor shall provide the host distributor, in the form specified by the IMO and before the expiry of the period specified in the Retail Settlement Code, with the volumes of electricity distributed during the rebate period by the embedded distributor's host distributor to the embedded distributor net of any electricity distributed to the embedded distributor which is attributable to embedded generation and distributed by the embedded distributor in the embedded distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998*.

c Prior to the payment of a rebate amount by the IMO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the host distributor shall provide the IMO, in the form specified by the IMO and before the expiry of the period specified by the IMO, with the information provided to the host distributor by the embedded distributor in accordance with section 2.

The IMO may issue instructions or directions providing for any information to be given under this section. The IMO shall rely on the information provided to it by distributors and there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

For the purposes of attributing electricity distributed to an embedded distributor to embedded generation, the volume of electricity distributed by a host distributor to an embedded distributor shall be deemed to consist of electricity withdrawn from the IMO-controlled grid or supplied to the host distributor by an embedded generator in the same proportion as the total volume of electricity withdrawn from the IMO-controlled grid by the distributor in the rebate period bears to the total volume of electricity supplied to the distributor by embedded generators during the rebate period.

3 Pass Through of Rebate

A distributor shall promptly pass through, with the next regular bill or settlement statement after the rebate amount is received, any rebate received from the IMO, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt, to:

a retailers who serve one or more consumers in the distributor's service area where a service transaction request as defined in the Retail Settlement Code has been implemented;

b consumers who are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

c embedded distributors to whom the distributor distributes electricity.

The amounts paid out to the recipients listed above shall be based on energy consumed and calculated in accordance with the rules set out in the Retail Settlement Code. These payments may be made by way of set off at the option of the distributor.

129 If requested in writing by OPGI, the distributor shall ensure that all rebates are identified as coming from OPGI in the following form on or with each applicable bill or settlement statement:

130 "ONTARIO POWER GENERATION INC. rebate"

131 Any rebate amount which cannot be distributed as provided above or which is returned by a retailer to the distributor in accordance with its licence shall be promptly returned to the host distributor or IMO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt.

132 Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party.

133 Pending pass-through or return to the IMO of any rebate received, the distributor shall hold the funds received in trust for the beneficiaries thereof in a segregated account.

CONTACT INFORMATION:

FOR THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.:

PRESIDENT:	Robert Mace	
	Telephone:	(807) 343-1122
	Fax:	(807) 343-0230
	E-mail:	rmace@tbhydro.on.ca

VICE PRESIDENT, FINANCE:	Cindy Speziale, CA	
	Telephone:	(807) 343-1118
	Fax:	(807) 343-1009
	E-mail:	cspeziale@tbhydro.on.ca

SPECIFIC APPROVALS REQUESTED:

In this proceeding, Thunder Bay Hydro is requesting the following approvals:

- Approval to charge rates effective May 1, 2009 to recover a revenue requirement of $19,321,728 which includes a revenue deficiency of $1,414,077, as set out in Exhibit 6, Tab 1, Schedule 1. The schedule of proposed rates is set out in Exhibit 1, Tab 1, Schedule 2, Appendix A and Exhibit 8, Tab 1, Schedule 6.

- Approval of revised Retail Transmission Rates – Network and Connection (given OEB issuance of the Ontario Uniform Transmission Rates Decision and Rate Order dated August 28, 2008) as described in Exhibit 8, Tab 1, Schedule 3;

- Approval of the proposed loss factor as set out in Exhibit 4, Tab 2, Schedule 8;

- Approval of Thunder Bay Hydro's proposed approach to cost allocation as identified in Exhibit 8; and

- Approval of the Specific Service Charges; which are unchanged from the approval in the OEB's Decision and Order in the matter of Thunder Bay Hydro's 2006 distribution rates [RP-2005-0020/EB-2005-0419/EB-2007-0580/EB-2007-0067], with the exception of the temporary service charges which we are requesting be removed from the approved rate as per our Conditions of Service, these costs are billed on a cost recovery basis.

DRAFT ISSUES LIST:

Thunder Bay Hydro would expect, based on previous regulatory experience and other hearings, that the following matters pertaining to the 2009 Test Year may constitute issues in this Application:

- The amount of Thunder Bay Hydro's proposed revenue requirement
- The reasonableness of the load forecast.
- The 2009 test year projections include a capital expenditure level of approximately $7.6 million and operating and maintenance expense increases of approximately $300,000 over 2007 actuals. In management's opinion, these increases are necessary to improve reliability and system security which has been declining given the age and condition of our assets**.**
- In accordance with the results of the cost allocation study, Thunder Bay Hydro has adjusted the percentage of revenue recovered from the various rate classes. With the requested rates, recoveries from the individual classes fall within the Board recommended ranges for the residential and GU<50 class. A move toward the recommended ranges for the remaining classes has been commenced in 2009 rates and will be continued in future rate applications.

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 2008, 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 November 22, 2007, Thunder Bay Hydro filed a self-nomination request for rebasing in 2009. Subsequently, in Board File No. EB-2006-0330, the OEB issued its list of distributors that will be rebased in 2009 – the list included Thunder Bay Hydro.

No further Procedural Orders or directions have been issued by the OEB to the date of filing this Application.

ACCOUNTING ORDERS REQUESTED:

Thunder Bay Hydro is not requesting Accounting Orders in this proceeding.

COMPLIANCE WITH UNIFORM SYSTEM OF ACCOUNTS:

Thunder Bay Hydro has followed the accounting principles and main categories of accounts as stated in the OEB's Accounting Procedures Handbook (the "APH") and the USoA in the preparation of this Application.

DISTRIBUTION SERVICE TERRITORY AND DISTRIBUTION SYSTEM:

Description of Distributor:

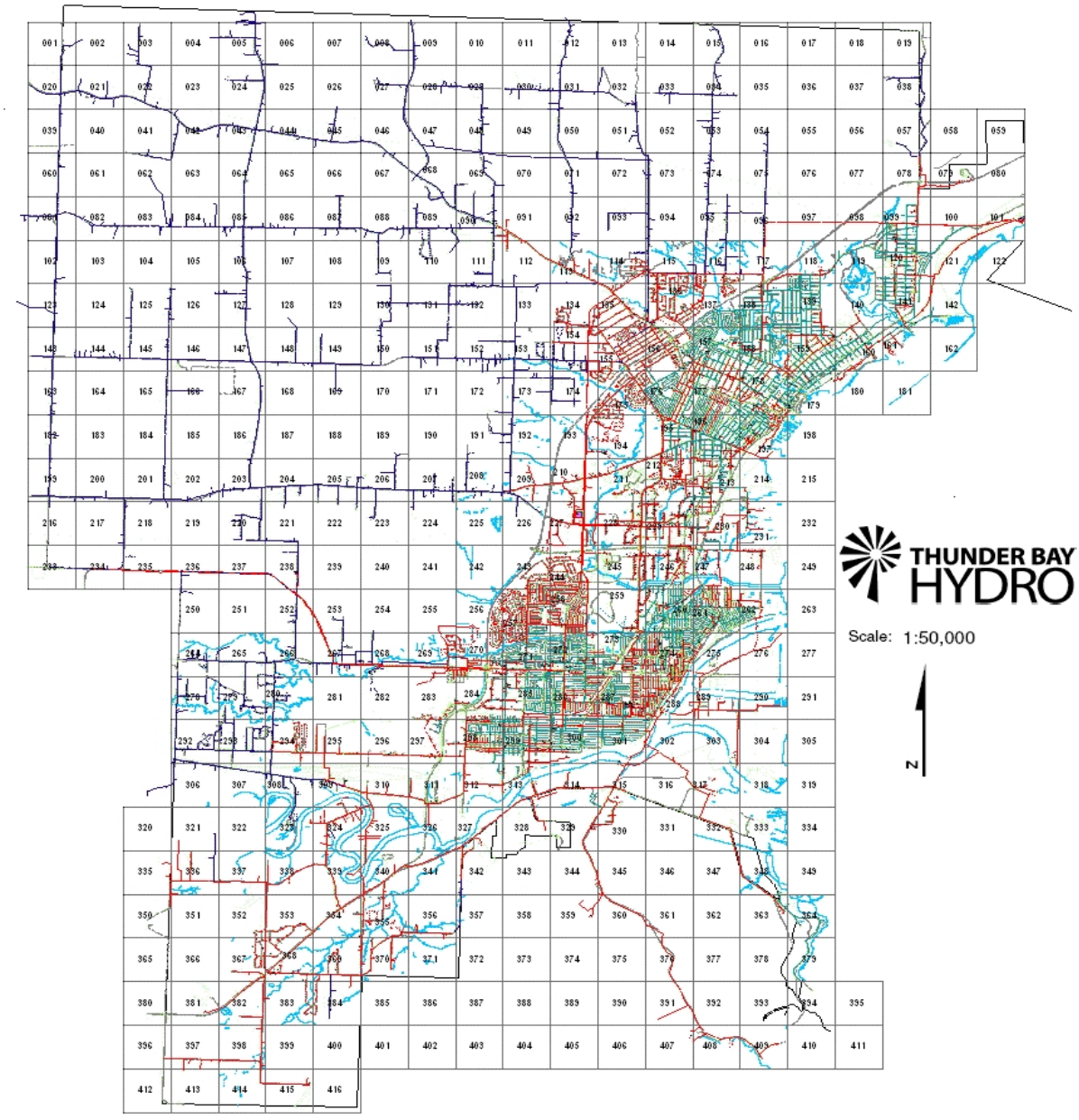
COMMUNITY SERVED:	City of Thunder Bay
TOTAL SERVICE AREA:	381 sq km
RURAL SERVICE AREA:	259 sq km
DISTRIBUTION TYPE:	Electricity distribution
SERVICE AREA POPULATION:	110,049
MUNICIPAL POPULATION:	109,140
BOUNDARIES:	Hydro One

A schematic diagram of Thunder Bay Hydro's distribution system is attached in Appendix A. The enclosed compact disc contains a map of the Thunder Bay Hydro's electricity distribution network. An image of the city should automatically appear upon insertion of the CD into the computer. Each square km of the map can be accessed by clicking on the appropriate map grid. The grid appears in an Adobe Acrobat format on D sized paper. Use the CTRL + mouse wheel up to zoom into the area under the cursor. The internet browser's 'go back' function returns to the full city map.

APPENDIX A

MAP OF DISTRIBUTION SYSTEM NETWORK

MAP OF THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC. DISTRIBUTION SYSTEM NETWORK



25kV=RED, 12kV=BLUE, & 4kV=GREEN

LIST OF NEIGHBOURING UTILITIES:

Thunder Bay Hydro is bounded by Hydro One on all service territory boundaries.

UTILITY ORGANIZATIONAL CHART:

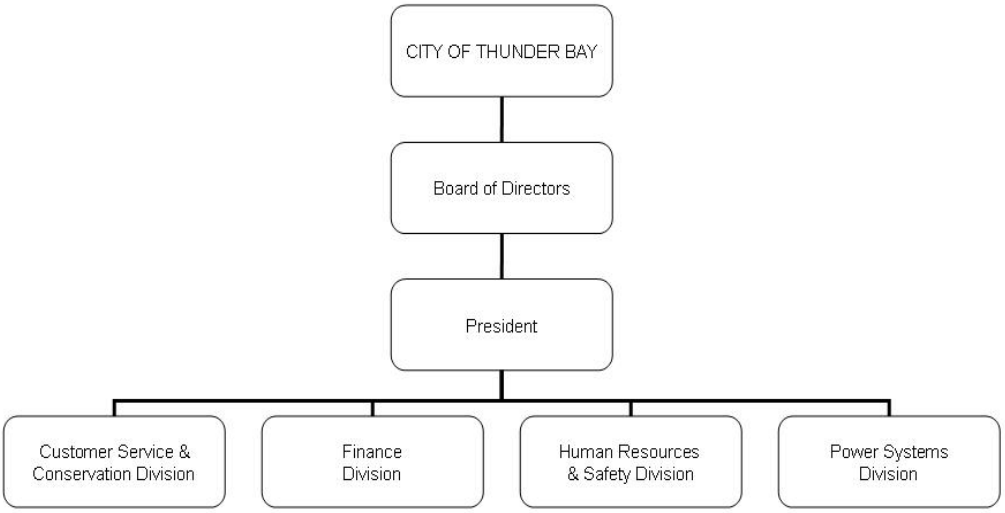
A copy of the Utility Organizational Chart accompanies this Schedule as Appendix A hereto.

APPENDIX A

COPY OF UTILITY

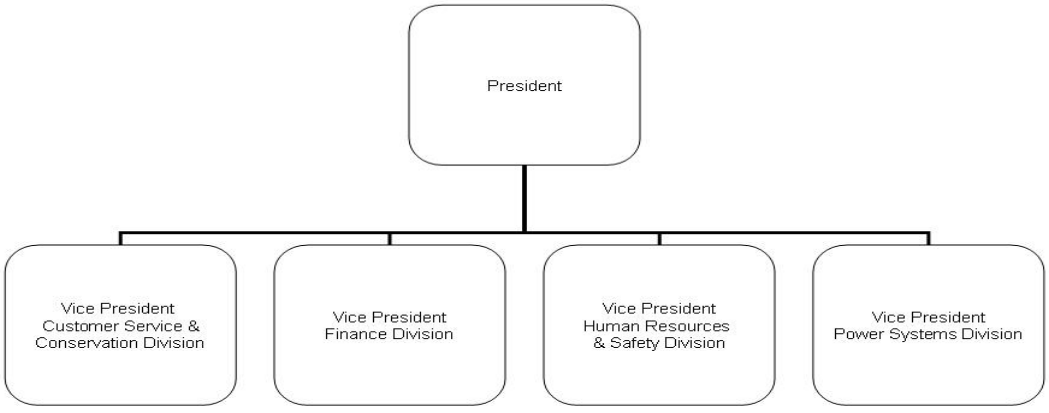
ORGANIZATIONAL CHARTS

Organization Structure

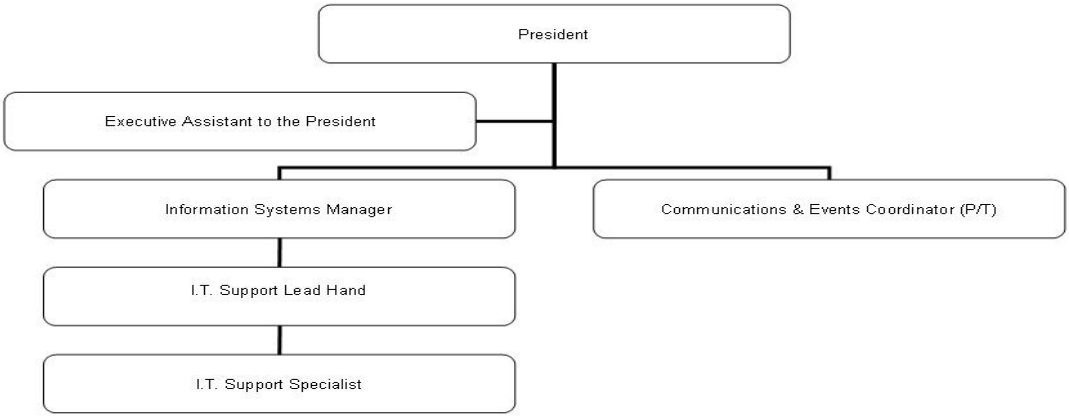


FULL-TIME COMPLEMENT = 120

Executive Team

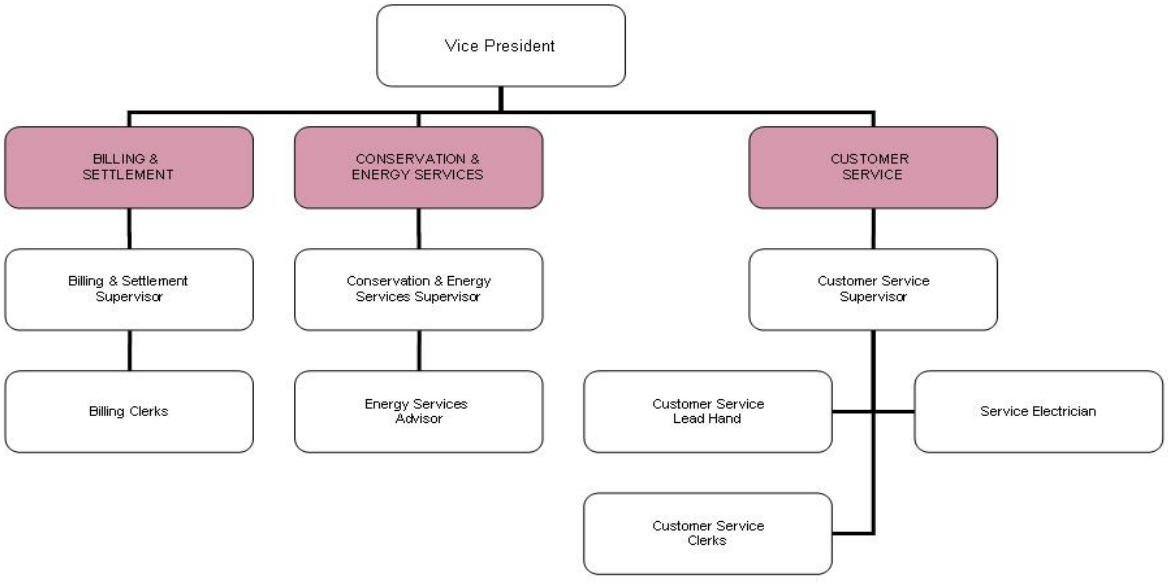


President's Office



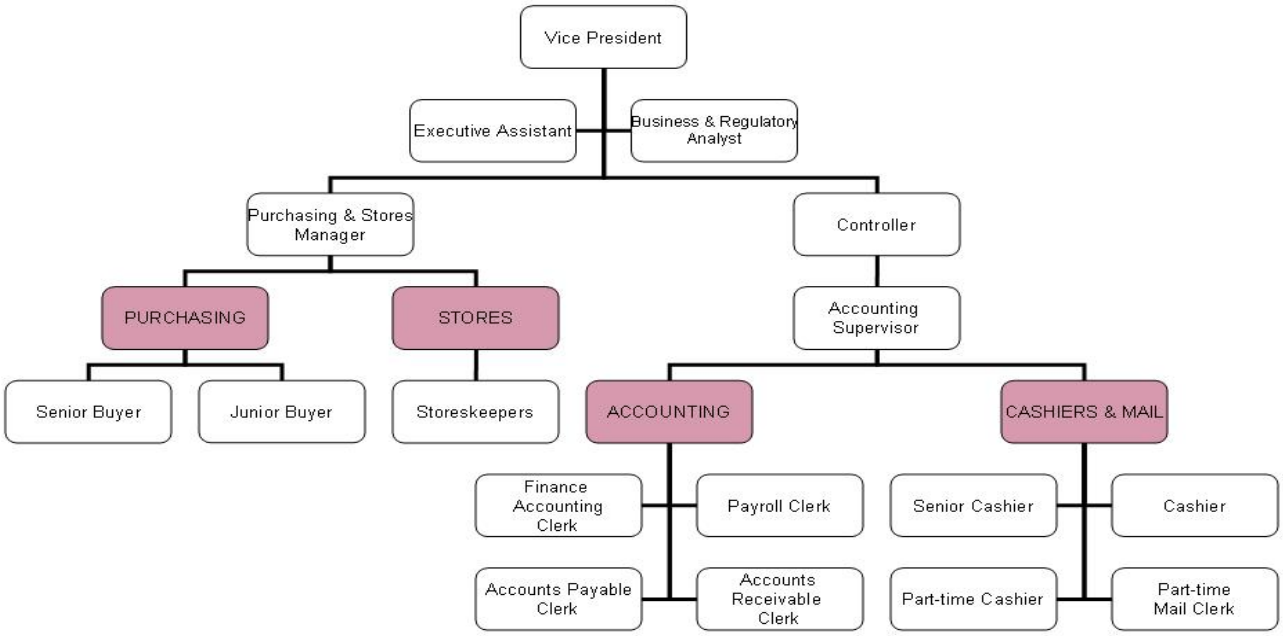
FULL-TIME COMPLEMENT = 7

Customer Service & Conservation



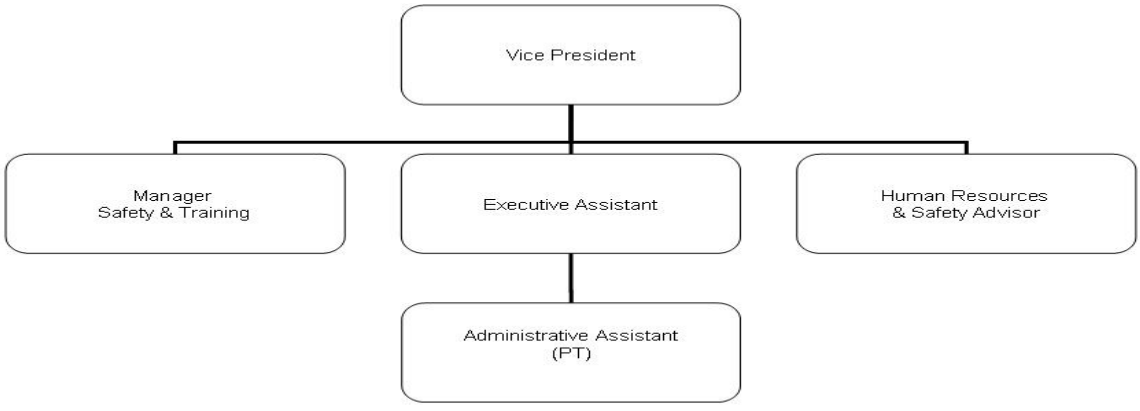
FULL-TIME COMPLEMENT = 16

Finance



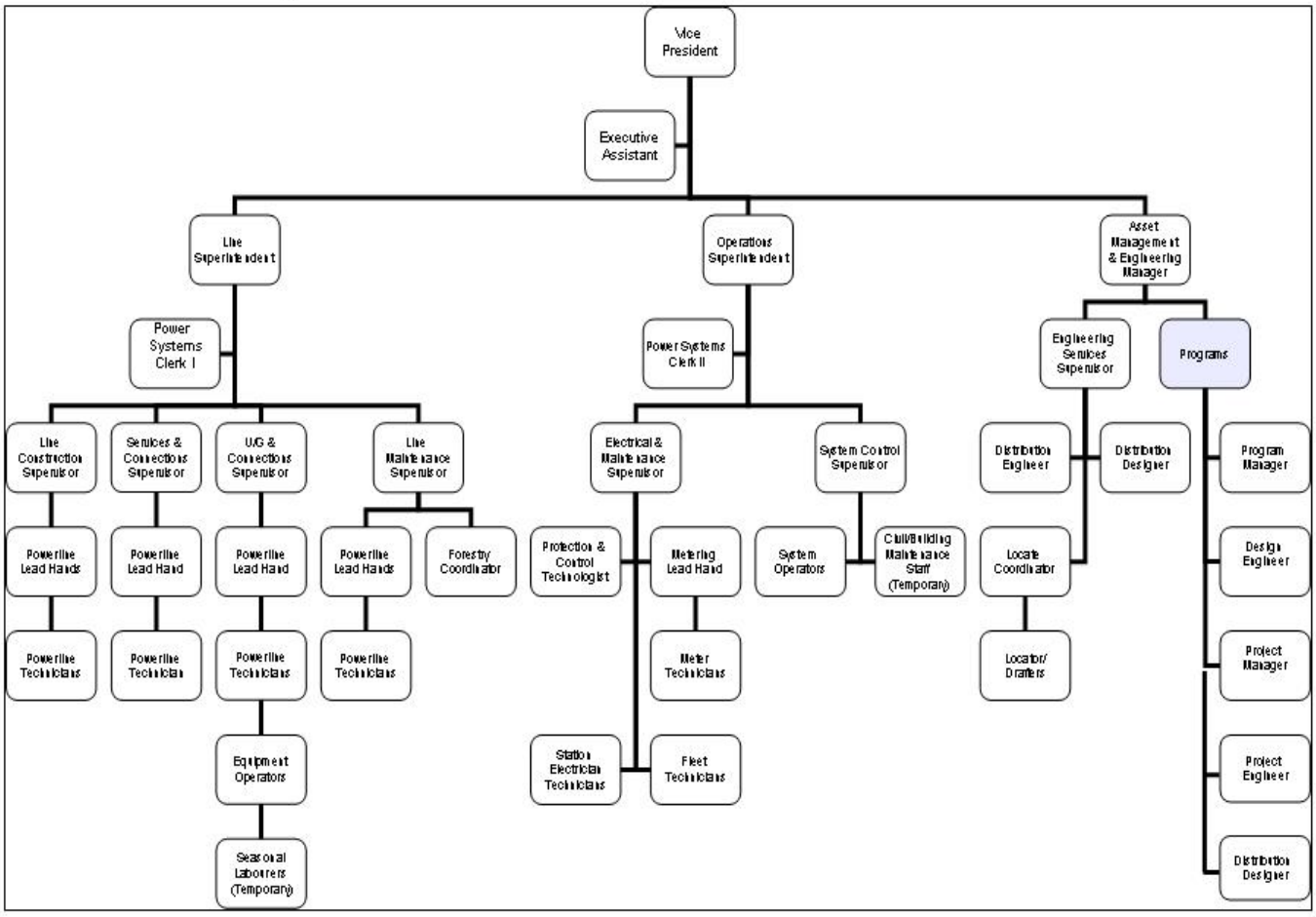
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Human Resources & Safety



FULL-TIME COMPLEMENT = 4

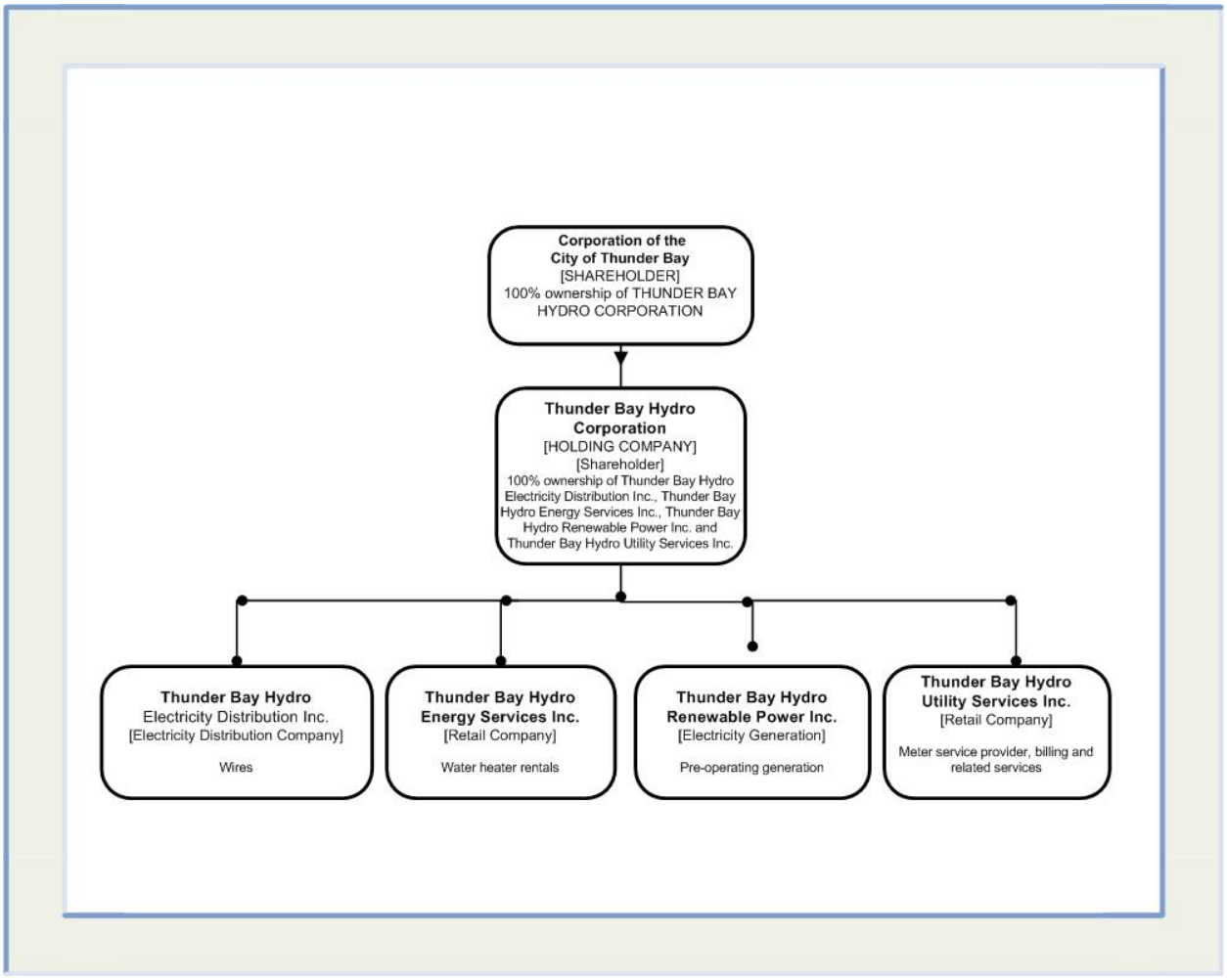
Power Systems



FULL-TIME COMPLEMENT = 70

1 **CORPORATE ENTITIES RELATIONSHIPS CHART:**

ENERGY GROUP OF COMPANIES
CORPORATE STRUCTURE



2 **Refer to Exhibit 4, Tab 2, Schedule 3 for a discussion of the companies inter-relationships.**

PLANNED CHANGES IN CORPORATE AND OPERATIONAL STRUCTURE:

No changes to Thunder Bay Hydro's corporate and operational structures are planned at the present time.

STATUS OF BOARD DIRECTIVES FROM PREVIOUS BOARD DECISIONS:

Thunder Bay Hydro has no outstanding directives from previous Board decisions.

COMPANY POLICIES AND REGULATIONS/SERVICE CHARGES:

A copy of Thunder Bay Hydro's current Conditions of Service and Service charges has been provided as Appendix A to this Schedule.

APPENDIX A

COPY OF THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC. CONDITIONS OF SERVICE AND SERVICE CHARGE

Conditions of Service

THUNDER BAY HYDRO	Thunder Bay Hydro Electricity Distribution Inc.			
Prepared By:	E. DaRosa, P.Eng.	Date:	July 13, 2007	Rev.#
Approved By:	Thunder Bay Hydro Board	Date:	August 23, 2007	
Revision Date:				

Revision Sheet

Revision	Description	Date	Initial

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SECTION 1: INTRODUCTION

The purpose of this document is to provide a means of communicating the types and level of electrical service available to Thunder Bay Hydro's electricity distribution customers. Thunder Bay Hydro's service area boundaries currently correspond to the boundaries of the City of Thunder Bay and Fort William First Nation Reserve # 52. The Ontario Energy Board, through its Distribution System Code (referred to in these Conditions of Service as the "DSC"), requires that the Conditions of Service be readily available for review by the general public. In addition, the most recent version of the document must be provided to the Ontario Energy Board (OEB), which in turn will retain it on file for the purpose of facilitating dispute resolution in the event that a dispute cannot be resolved without the Board' s intervention.

The **"Introduction"** section contains references to the Customer's and Thunder Bay Hydro's rights, the dispute resolution process and legislation that cover these Conditions of Service.

The **"Distribution Activities (General)"** section contains references to services and requirements, which span across all customer classes. This section covers such items as Rates, Billing, Hours of Work, Emergency Response, Power Quality, Available Voltage, etc.

The **"Distribution Activities (Customer Class Specific)"** section contains references to services and requirements, which are specific to individual customer classes in addition to those outlined in "Distribution Activities (General)". This section would cover such items as Metering, Service Entrance Requirements, Delineation of Ownership, Special Contracts, etc.

The **"Glossary of Terms"** contains the variety of terms that are defined in the context of this document. Where possible, the definitions in the glossary correspond to definitions in existing documents that apply to Thunder Bay Hydro, such as the Distribution System Code and the Standard Supply Service Code, and Thunder Bay Hydro' s Electricity Distributor License. The text of the Conditions of Service document is used to expand on these definitions as applicable to Thunder Bay Hydro.

1.1 Identification of Distributor and Service Area

Thunder Bay Hydro Electricity Distribution Inc., referred to herein as "Thunder Bay Hydro," is a corporation incorporated under the laws of the Province of Ontario to distribute electricity.

Thunder Bay Hydro is licensed by the Ontario Energy Board ("OEB") to supply electricity to Customers in accordance with Electricity Distribution Licence ED-2002-0529 issued to Thunder Bay Hydro on October 9, 2003, by the Ontario Energy Board ("Distribution Licence"). Additionally, there are requirements imposed on Thunder Bay Hydro by the various codes referred to in the Licence and by the *Electricity Act, 1998*, and the *Ontario Energy Board Act, 1998*.

Thunder Bay Hydro may only operate distribution facilities within the service area defined in Schedule 1 of its Distribution Licence. This service area is subject to change with the Ontario Energy Board's approval but is currently limited to the boundaries of the City of Thunder Bay as of January 1, 1970, and Fort William First Nation Reserve #52.

Nothing contained in these Conditions of Service or in any contract for the supply of electricity by Thunder Bay Hydro shall prejudice or affect any rights, privileges, or powers vested in Thunder Bay Hydro by law under any Act of the Legislature of Ontario or the Parliament of Canada, or any regulations thereunder.

1.1.1 Distribution System Overview

Thunder Bay Hydro distributes electrical power through both an overhead and underground feeder network operating at a primary voltage of 25 kV. This 25 kV primary system is a radial loop system with open points between interconnections. These feeders supply distribution transformers directly or indirectly through either a 12 kV, or 4 kV sub-distribution system. The supply of electricity by Thunder Bay Hydro to any Customer will be at the 25 kV (Urban) and 12 kV (Rural) primary voltage level where available as the 4 kV distribution system is not being expanded, and will ultimately be phased out. Connections to the 4kV system will be allowed on a case by case basis where other options are limited.

1.2 Related Codes and Governing Laws

The supply of electricity or related services by Thunder Bay Hydro to any Customer shall be subject to various laws, regulations, and Codes, including the provisions at any given point in time of:

1. *Electricity Act*, 1998
2. Ontario Energy Board Act, 1998
3. Distribution Licence ED-2002-0529
4. Affiliate Relationships Code
5. Distribution System Code
6. Retail Settlement Code
7. Standard Service Supply Code
8. Ontario Electrical Safety Code

In the event of a conflict between: (a) these Conditions of Service; and (b) the provisions of the *Electricity Act, 1998*, the *Ontario Energy Board Act, 1998* (the "Acts"), the Distribution Licence or regulatory Codes issued by the Ontario Energy Board; the provisions of the Acts, the Distribution Licence and associated regulatory Codes shall prevail in the order of priority indicated above.

When planning and designing for electricity service, Customers and their agents must refer to all applicable provincial and Canadian electrical codes, and all other applicable federal, provincial, and municipal laws, regulations, codes and by-laws to also ensure compliance with their requirements. Without limiting the foregoing, any electrical work carried out by a Customer or its agent(s) shall be conducted in accordance with the latest edition of the Ontario *Occupational Health and Safety Act* (OHSA), the Regulations for Construction Projects and the harmonized Electric Utility Safety Association (E&USA) Rulebook, traffic requirements, and Thunder Bay Hydro's Safety Policies available on request.

Any reference to a document includes all amendments to that document or that provision of the document currently in force.

1.3 Interpretation

In these Conditions of Service, unless the context otherwise requires:

- Headings, paragraph numbers and underlining are for convenience only and do not affect the interpretation of these Conditions;
- Words referring to the singular include the plural and vice versa;
- Words referring to a gender include any gender;
- The word "person" includes a firm, a body corporate, an unincorporated association, or an authority;
- Where there is a reference to a number of days between two events, they shall be counted by excluding the day on which the first event occurred and including the day on which the second event occurs; and
- Any event that is required under these Conditions to occur on or by a stipulated date, which is a holiday, may occur on or by the next business day.

1.4 Amendments and Changes

These Conditions of Service have been duly approved and authorized by Thunder Bay Hydro.

Thunder Bay Hydro may add to, revoke, alter or amend these Conditions of Service as it sees fit, and such addition, revocation, alteration or amendment shall as from the time of notification by Customer bill insert, posting on the Thunder Bay Hydro website or publication in a local newspaper, be deemed to apply from the time of such notification as if it had been included in these Conditions of Service.

The provisions of these Conditions of Service and any amendments made from time to time form part of any contract made between Thunder Bay Hydro and any connected Customer, Retailer, or Generator. These Conditions of Service supersede all previous Conditions of Service, oral or written, of Thunder Bay Hydro, as of its effective date.

In the event of changes to these Conditions of Service, Thunder Bay Hydro will issue a notice in its Customer bills and on Thunder Bay Hydro's Web site http://www.tbhydro.on.ca/. Thunder Bay Hydro may also issue a public notice in a local newspaper.

The Customer, Retailer, or Generator is responsible for contacting Thunder Bay Hydro to ensure that they have the current version of the Conditions of Service. One copy per revision of the Conditions of Service will be provided to each person that requires it. Thunder Bay Hydro may charge a reasonable fee for providing additional copies of this document.

The current version of this document is also posted on the Thunder Bay Hydro website and can be downloaded from http://www.tbhydro.on.ca/

1.5 Contact Information

1.5.1 General Enquiries

Customers may contact Thunder Bay Hydro using one of the following methods:

- **Telephone:** (807) 343-1111. Our offices are open Monday to Friday, excluding statutory holidays, from 8:30 a.m. to 5:00 p.m.
- **Fax:** (807) 343-0230
- **Web:** http://www.tbhydro.on.ca
- Customer Service Inquiries

  Email: customer_services@tbhydro.on.ca
- Connection Inquiries (Customer, Generator, Distributor)

  Email: connections@tbhydro.on.ca
- **Mail:**

  Thunder Bay Hydro
  34 Cumberland Street N.
  Thunder Bay, Ontario
  P7A 4L4

1.5.2 Emergencies and Service Interruptions

The following numbers can be contacted for emergencies:

(1) During regular hours (8:00 a.m. to 4:30 p.m., Monday to Friday): (807) 343-1111

(2) After regular hours, and on weekends and statutory holidays: (807) 343-1002

1.5.3 New Connections Contact Information

The following departments can be contacted with specific enquiries during regular hours:

(1) POWER SYSTEMS OFFICE

(a) For new residential service connections (up to 200-amps) call (807) 343-1176

(b) For new general service connections (200-amps single-phase), call (807) 343-1176

(c) For temporary services, call (807) 343-1176

(2) ENGINEERING DEPARTMENT

(a) For new general service connections or upgrades (three-phase, or single-phase over 200-amps), call (807) 343-1168

(b) For new residential services over 200-amps, call (807) 343-1168

(c) For new underground subdivision development electrical servicing, call (807) 343-1191

(d) For generation connections, call (807) 343-1036

(e) For underground cable locating, call (807) 343-1111

1.6 Customer Rights

1.6.1 Customer

Thunder Bay Hydro shall only be liable to a Customer and a Customer shall only be liable to Thunder Bay Hydro for any damages that arise directly out of the wilful misconduct or negligence:

- of Thunder Bay Hydro in providing distribution services to the Customer;
- of the Customer in being connected to Thunder Bay Hydro's distribution system; or
- of Thunder Bay Hydro or the Customer in meeting their respective obligations under these Conditions, their Licenses and any other applicable law.

Notwithstanding the above, neither Thunder Bay Hydro nor the Customer shall be liable to the other party under any circumstances whatsoever for any loss of profits or revenues, business interruption losses, loss of contract or loss of goodwill, or for any indirect, consequential, incidental or special damages, including but not limited to punitive or exemplary damages, whether any of the said liability, loss or damages arise in contract, tort or otherwise.

The Customer shall indemnify and hold harmless Thunder Bay Hydro, its directors, officers, employees and agents from any claims made by any third parties in connection with the construction and installation of electrical equipment by or on behalf of the Customer.

Customers experiencing outages or other disturbances will be advised, upon request, of the cause of the outages.

A Customer has the right to demand identification from any person representing themselves to be an authorized agent or employee of Thunder Bay Hydro.

A Customer has the right to access current meter and price data, and to interrogate the meter or to assign this right to others, in accordance with any relevant technical specifications and codes. A Consumer shall pay the reasonable cost of any software, hardware or other services required for the Consumer to obtain direct access to meter information.

A Customer has the right to receive historical consumer-specific usage, meter and payment data as defined in the Retail Settlement Code. A fee may apply.

1.6.2 Embedded Generator

Thunder Bay Hydro shall only be liable to an embedded generator and an embedded generator shall only be liable to Thunder Bay Hydro for any damages that arise directly out of the willful misconduct or negligence:

- of Thunder Bay Hydro in providing distribution services to the embedded generator;

- of the embedded generator in being connected to Thunder Bay Hydro's distribution system; or

- of Thunder Bay Hydro or embedded generator in meeting their respective obligations under these Conditions, their licences and any other applicable law.

Notwithstanding the above, neither Thunder Bay Hydro nor the embedded generator shall be liable to the other party under any circumstances whatsoever for any loss of profits or revenues, business interruption losses, loss of contract or loss of goodwill, or for any indirect, consequential, incidental or special damages, including but not limited to punitive or exemplary damages, whether any of the said liability, loss or damages arise in contract, tort or otherwise.

The embedded generator shall indemnify and hold harmless Thunder Bay Hydro, its directors, officers, employees and agents from any claims made by any third parties in connection with the construction and installation of a generator by or on behalf of the embedded generator.

1.6.3 Embedded Distributor

Thunder Bay Hydro shall only be liable to an embedded distributor and an embedded distributor shall only be liable to Thunder Bay Hydro for any damages that arise directly out of the willful misconduct or negligence:

- of Thunder Bay Hydro in providing distribution services to the embedded distributor;

- of the embedded distributor in being connected to Thunder Bay Hydro's distribution system; or

- of Thunder Bay Hydro or embedded distributor in meeting their respective obligations under these Conditions, their licences and any other applicable law.

Notwithstanding the above, neither Thunder Bay Hydro nor the embedded distributor shall be liable to the other party under any circumstances whatsoever for any loss of profits or revenues, business interruption losses, loss of contract or loss of goodwill, or for any indirect, consequential, incidental or special damages, including but not limited to punitive or exemplary damages, whether any of the said liability, loss or damages arise in contract, tort or otherwise.

The embedded distributor shall indemnify and hold harmless Thunder Bay Hydro, its directors, officers, employees and agents from any claims made by any third parties in connection with the construction and installation of a distribution system by or on behalf of the embedded distributor.

1.7 Distributor Rights

Thunder Bay Hydro shall comply with its Conditions of Service but may waive a provision of its Conditions of Service in favour of a Customer or potential Customer at Thunder Bay Hydro's sole discretion.

Thunder Bay Hydro will undertake the necessary programs to maintain and enhance its distribution plant at its expense, as part of its planned activities during normal business hours, Monday to Friday. Where a Customer requests that such planned activities occur outside normal working hours, then the Customer shall pay the incremental costs.

Thunder Bay Hydro will provide standard overhead or underground supply services to Customers. If a Customer requests special construction beyond the normal Thunder Bay Hydro standard installation in accordance with the program, the Customer shall pay any incremental costs.

1.7.1 Access to Customer Property

Thunder Bay Hydro shall have unimpeded access to the Customer's property in accordance with Section 40 of the *Electricity Act, 1998* and any successor acts thereto.

Thunder Bay Hydro shall install, maintain, and replace infrastructure that is part of its main distribution system that may be located on private property and which serve Customers that are located outside of that private property. These Thunder Bay Hydro infrastructures will require an easement.

1.7.2 Safety of Equipment

The Customer shall comply with all applicable laws, including but not limited to the Ontario Electrical Safety Code. The Customer shall ensure that equipment is properly identified and connected for metering and operation purposes. The Customer will take whatever steps necessary to correct any deficiencies, within 72 hours or a mutually agreeable time period from written notice by Thunder Bay Hydro to the Customer. If the Customer does not take such action within this time frame, Thunder Bay Hydro shall disconnect the supply of power to the Customer as described in Section 2.2 Disconnection.

The Customer shall not build, cause to be built, maintain any structure, or plant any trees, shrubs or landscaping etc., that, in the sole opinion of Thunder Bay Hydro, may affect the safety, reliability, accessibility, or efficiency of Thunder Bay Hydro's distribution facilities.

The Customer shall not access, use or interfere with the distribution facilities of Thunder Bay Hydro except in accordance with a written agreement. All connections, disconnections, or reconnections of Thunder Bay Hydro's distribution facilities (i.e. the supply side of the Customer's service entrance) must be performed by Thunder Bay Hydro employees or its appointed agents and shall be arranged in advance by the Customer or its contractor. The Customer must also grant the right to seal, secure, and/or prevent from tampering any point where a connection may be made on the supply side of the metering equipment.

In the event that Thunder Bay Hydro believes that its equipment is being interfered with, Thunder Bay Hydro will notify the Customer and permit the Customer to remove the interference (provided there is no imminent danger of safety situation being caused by the interference). In the event that: (a) the Customer does not remove the interference; or (b) the interference constitutes an imminent danger or safety situation; then Thunder Bay Hydro may disconnect the electrical service to the Customer and/or remove the interference.

1.7.3 Operating Control

The Customer shall provide a convenient and safe place, satisfactory to Thunder Bay Hydro, for installing, maintaining and operating its equipment in, on, or about the Customer's premises. Thunder Bay Hydro assumes no risk and will not be liable for damages resulting from the presence of its equipment on the Customer's premises or approaches thereto, or any acts, omissions or occurrences beyond its control, or the negligence or willful misconduct of any persons over whom Thunder Bay Hydro has no control.

The Customer shall not allow anyone other than an employee, or authorized agent of Thunder Bay Hydro, or a person lawfully entitled to do so, to repair, remove, replace, alter, inspect, or tamper with Thunder Bay Hydro facilities and equipment on the Customer's premises.

Customers will be required to pay the cost of repairs or replacement of Thunder Bay Hydro's equipment that has been damaged or lost by the direct or indirect act or omission of the Customer or its agents.

The physical location, on the Customer's premises, where Thunder Bay Hydro's responsibility for operational control of distribution equipment ends, is defined by the Distribution System Code as the "operational demarcation point".

In emergency situations, TBH may be required to operate Customer equipment.

1.7.4 Repairs of Defective Customer Electrical Equipment

The Customer will be required to repair or replace any equipment owned by the Customer that may affect the integrity or reliability of Thunder Bay Hydro's distribution system within 72 hours or a mutually agreeable time period from written notice by Thunder Bay Hydro to the Customer. If the Customer does not take such action within this time frame, Thunder Bay Hydro may disconnect the electrical service to the Customer as described in Section 2.2 Disconnection.

1.7.5 Customer's Physical Structures

The construction and maintenance of all civil works on private property owned by the Customer, including but not limited to poles, switches, meter bases, underground conduits, grounds, transformer vaults and transformer pads, will be the responsibility of the Customer.

Thunder Bay Hydro shall be notified of all civil work on private property, and where required, such work will be inspected and accepted by Thunder Bay Hydro and the Electrical Safety Authority.

It will be the Customer's responsibility to relocate physical structures on their property. Thunder Bay Hydro will make a best effort to notify the Customer to relocate the Customer's physical structures on their property impeding the repair or replacement of electrical facilities. However, in power outage situations, Thunder Bay Hydro may remove the Customer's physical structures to provide access to repair or replace facilities. In all cases, it shall be the Customer's responsibility to restore their physical structures.

Where the Customer installs physical structures impeding access or not meeting minimum clearances to electrical facilities requiring repair or replacement, Thunder Bay Hydro may decide to relocate the facilities. The Customer will be responsible to pay the incremental costs to relocate facilities.

1.7.6 Tree and Vegetation Management

To ensure public safety and the continued reliable operation of its distribution system, Thunder Bay Hydro will maintain clearance around its distribution lines on a cyclical or as-needed basis in close cooperation with the City's forestry department. The tree trimming cycle may vary depending on extent of storm damage, health of trees, and vegetation type.

Thunder Bay Hydro will coordinate and maintain tree clearance around all its distribution lines that are located on public allowance. Thunder Bay Hydro will also maintain tree clearance around Thunder Bay Hydro owned overhead lines that may be located on private property (i.e. in an easement) at no cost to the Customer. Thunder Bay Hydro will endeavour to discuss the planned re-clearing with property owners prior to work being performed in order to mitigate the impacts to the environment and the property. However, in the event of emergencies, Thunder Bay Hydro may be unable to notify the property owner prior to performing the work.

Customers are responsible for tree trimming and tree and brush removal around service lines that are located on private property when these lines are owned by the Customer. Clearances must conform to the Electrical Safety Code.

Thunder Bay Hydro will disconnect and reconnect the Customer's supply without charge once per year to permit the safe clearance of trees and vegetation. This will occur during normal business hours with ten (10) days notice.

1.7.7 Force Majeure

Other than for any amounts due and payable by the Customer to Thunder Bay Hydro or by Thunder Bay Hydro to the Customer, neither Thunder Bay Hydro nor the Customer shall be held to have committed an event of default in respect of any obligation under these Conditions of Service if prevented from performing that obligation, in whole or in part, because of a Force Majeure event.

If a Force Majeure event prevents either party from performing any of its obligations under these Conditions of Service, that party shall:

(a) Promptly notify the other party of the Force Majeure event and its assessment in good faith of the effect that the event will have on its ability to perform any of its obligations. If the immediate notice is not in writing, it shall be confirmed in writing as soon as reasonably practical;
(b) Not be entitled to suspend performance of any of its obligations under these Conditions of Service to any greater extent or for any longer time than the Force Majeure event requires it to do;
(c) Use its best efforts to mitigate the effects of Force Majeure event, remedy its inability to perform, and resume full performance of its obligations;
(d) Keep the other party continually informed of its efforts;
(e) Provided written notice to the other party when it resumes performance of any obligations affected by the Force Majeure event; and
(f) If the Force Majeure event is a strike or lockout of Thunder Bay Hydro's employees or authorized agents, Thunder Bay Hydro shall be entitled to discharge its obligations to notify Customers in writing by placing an ad in the local newspaper.

1.8 Disputes

1.8.1 Customers

Any Customer or Embedded Generator with a complaint or dispute against Thunder Bay Hydro shall submit it to Thunder Bay Hydro in writing via fax, email or regular mail. Each inquiry shall be date stamped and recorded according to the date it was received.

Thunder Bay Hydro shall investigate the cause of the complaint or dispute, and attempt in good faith to resolve the situation within ten (10) business days of receipt. If the situation is expected to exceed ten (10) business days, then the complainant will be notified of the delay and the reasons why it cannot be resolved within ten (10) business days. The resolution period will not exceed thirty (30) business days unless extenuating circumstances apply and mutual agreement is made between both parties.

Any disputes that lead to legal action against Thunder Bay Hydro shall be referred to our legal counsel. Disputes that remain unresolved shall be referred to an Ontario Energy Board approved third party complaints resolution services. As of the effective date of these Conditions of Service, the Ontario Energy Board had not yet approved a third party complaints resolution service, and was performing that function itself. Until such a complaints resolution service is appointed, any unresolved complaints shall be referred to the Ontario Energy Board.

Records will be kept of all complaints and disputes, including the complainant's name, the nature of the dispute, the resolution or escalation date, and the dispute's resolution or status.

1.8.2 Retailers

Disputes between a retailer and Thunder Bay Hydro shall be settled in accordance with Article 6 of the Retailer Service Agreement.

SECTION 2: DISTRIBUTION ACTIVITIES (GENERAL)

2.1 Requests for Service

Well in advance of installation commencement, the Customer shall make a request for electrical service. Such request must provide adequate lead time to permit acquisition of major materials and the scheduling of the appropriate work crews. If special equipment is required or equipment delivery problems occur, then longer lead times may be necessary. For service connections that require a system expansion or enhancement, Customer's may experience lead times of one year. Where system expansions are not required, Customers may experience lead times up to three months, subject to material availability. Thunder Bay Hydro will notify the Customer of any anticipated extended lead times at the time of the Estimate to Connect.

A Customer (or its authorized representative) shall apply in writing to Thunder Bay Hydro for any new or upgraded electricity services. These new service connection requests are treated by Thunder Bay Hydro as falling into one of the following two categories:

(1) Building that "Lies Along":
These are for new service connections where the property is presently serviced with lines along the Customer's property that have sufficient capacity to supply the proposed new load.

(2) Expansions and Enhancements:
These are for new service connections where the distribution system requires an expansion or enhancement to serve the proposed load. These can take the form of a line extension or a reinforcement of an existing circuit. In all cases, Thunder Bay Hydro will have the sole right to determine the need for a system expansion or enhancement.

Thunder Bay Hydro shall make every reasonable effort to respond promptly to a Customer's request for connection. Thunder Bay Hydro shall respond to a Customer's written request for a Customer connection within fifteen (15) calendar days of receipt of the written request. Thunder Bay Hydro will make an Estimate to Connect within sixty (60) calendar days of receipt of the written request, unless other necessary information is required from the Customer before the Estimate can be given. Requirements regarding the process and timing of embedded generation facility connections are set forth in Section 3.5.

Thunder Bay Hydro shall make every reasonable effort to respond promptly to another distributor's request for connection. Thunder Bay Hydro shall provide an initial consultation with another distributor regarding the connection process within thirty (30) days of receiving a written request for connection. A final Estimate to Connect the distributor to Thunder Bay Hydro's distribution system shall be made within ninety (90) days of receiving the written request for connection, unless other necessary information outside the distributor's control is required before the Estimate can be made.

In addition to any other requirements in these Conditions of Service, the provision of new electrical service is conditional upon Thunder Bay Hydro:

(a) being permitted and able to provide such supply;
(b) being able to obtain the necessary equipment, materials and labour to carry out the work;
(c) receiving the necessary easements or land rights to carry out the work;
(d) receiving all capital contribution and/or installation charge payments from the Customer; and
(e) verifying the approval of the Electrical Safety Authority.

Should Thunder Bay Hydro not be permitted to provide new electrical service to the Customer, it is under no responsibility to the Customer whatsoever and the Customer releases Thunder Bay Hydro from any liability in respect thereto.

Items that are applicable to a specific Customer class are covered in Section 3 of this Conditions of Service.

Thunder Bay Hydro, in its discretion, may require a Customer, embedded generator or distributor to enter into a Connection Agreement with Thunder Bay Hydro including terms and conditions in addition to those expressed in these Conditions of Service.

2.1.1 Building that "Lies Along"

Thunder Bay Hydro will connect any building that "lies along" its distribution system when no expansion or enhancement of facilities is required (i.e., there is sufficient capacity to supply the new load). For the purposes of these Conditions of Service, "lies along" means a Customer property or premises that is directly adjacent to or abuts the road allowance where Thunder Bay Hydro has distribution facilities.

Pursuant to the Distribution System Code, Thunder Bay Hydro has the obligation to connect (under Section 28 of the *Electricity Act*, 1998) a building or facility that "lies along" its distribution line, provided:

(a) the building can be connected to Thunder Bay Hydro's Distribution System without an Expansion or Enhancement; and
(b) the service installation meets the conditions listed in these Conditions of Service.

Connection Assets are the portion of the distribution system that is used to connect the Customer to Thunder Bay Hydro's main distribution system.

Connection Assets are generally located on or abut the Customer's property and include the following:

- Secondary underground cable
- Secondary duct banks up to the Customer's property line
- Distribution transformers
- Distribution transformer concrete pads
- Secondary terminations
- Primary terminations
- Transformer grounding

The determination of the Connection Assets will be on a case-by-case basis by Thunder Bay Hydro.

All new or upgraded underground electrical services shall be installed within ducts on private property meeting Thunder Bay Hydro Standards. For both primary and secondary services, Thunder Bay Hydro will designate the supply point. Building lots created by subdivision and/or severance are required to be serviced with underground supply.

Where Thunder Bay Hydro receives a request for service for a building that does not "lie along" its distribution system, an expansion or enhancement to Thunder Bay Hydro's existing distribution system is required. Thunder Bay Hydro will make an Estimate to Connect to the potential Customer in accordance with Section 2.1.2 below.

2.1.1.1 Connection Charges

Thunder Bay Hydro shall recover costs associated with the installation of connection assets by Customer Class via Basic Connection Credit and Variable Connection Costs collected directly from the Customer, as applicable.

The Variable Connection Costs shall be calculated as the costs associated with the installation of Connection assets above and beyond the Standard Allowance for Basic Connection as described in Appendix E of these Conditions of Service.

Thunder Bay Hydro will recover this Variable Connection Cost, which will be based on actual cost, directly from the Customer.

The Basic Connection Credit consists of:

(a) a single estimate of the Connection Cost;
(b) supply and installation of standard overhead transformation capacity for a single residential service lot;
(c) supply and installation of a single-phase residential meter;
(d) connection of the secondary service at the described demarcation points; and
(e) the supply and installation of up to 30 m of #2 triplex overhead secondary conductor for up to a 200 A service, or an equivalent credit for underground conductor.

The Basic Connection Credit shall be applied towards the total cost to connect the Customer. Customers will be responsible for customer-specific connection costs beyond the defined Basic Connection Credit. These may include:

(a) the costs of Thunder Bay Hydro supplied overhead and underground secondary cable;
(b) the costs of Thunder Bay Hydro supplied primary conductor;
(c) costs associated with the supply and installation of overhead or underground transformation; and
(d) all other costs of connecting to Thunder Bay Hydro's Distribution System.

Customers will be responsible for:

(a) the supply of tree and vegetation management on a Customer's property;
(b) any easements or property agreements as required by Thunder Bay Hydro;
(c) service upgrade charges; and
(d) the costs of any fees, permits, or other permissions required to connect the service.

2.1.2 Expansions and Enhancements

Expansion facilities are required to extend the distribution system to service a customer or group of customers which could not be otherwise supplied; for example by extending the length of the distribution system. Expansion facilities would include all upstream and capacity upgrades required to connect the Customer to Thunder Bay Hydro's distribution system.

Expansion facilities not located on the Customer's property include:

- Terminations and fusing at the connection pole;
- Overhead conductor;
- Poles;
- Switches;
- Primary underground cable;
- Primary duct banks; and
- Switchgear and concrete pads.

All expansion facilities will be subject to an economic evaluation which will determine whether the Customer will receive a credit or will be required to pay a capital contribution to Thunder Bay Hydro.

The determination of the Expansion Facilities will be determined on a case-by-case basis by Thunder Bay Hydro.

When, in order to connect a Customer, Thunder Bay Hydro must construct new distribution facilities or increase the capacity of existing distribution facilities, Thunder Bay Hydro will perform an Economic Evaluation of the expansion or enhancement project in accordance with the Distribution System Code.

The purpose of the Economic Evaluation is to determine if the future revenue from the Customer(s) will pay for the capital cost and on-going maintenance costs of the expansion or enhancement project.

The Economic Evaluation methodology that Thunder Bay Hydro shall use to calculate a Customer's capital contribution amount is set out in Appendix B of Thunder Bay Hydro's Conditions of Service. The Customer's capital contribution will not exceed that Customer's share of the difference between:

(a) the present value of the capital costs and on-going maintenance costs for the equipment; and
(b) the present value of the projected revenue for distribution services provided by those facilities (There is no projected revenue from generators and distributors).

A capital contribution from the Customer will be required in the event that the present value of the estimated capital costs exceeds the present value of the forecasted revenues and on-going maintenance costs.

The results of the Economic Evaluation will be communicated to the Customer in the Estimate to Connect.

2.1.2.1 Transfer Price for Contestable Work

The following work shall be uncontestable:

(a) the preliminary planning, design and engineering specifications of the work required for the distribution system expansion and connection (specifications shall be made in accordance with Thunder Bay Hydro's design and technical standards and specifications);

(b) work involving any existing Thunder Bay Hydro assets; and

(c) final connections to Thunder Bay Hydro's distribution system.

The transfer price for the contestable work shall be the lower of the cost to the Customer to construct the expansion facilities or the amount set out in the initial Estimate to Connect to do the contestable work less the "additional costs for alternative bid".

2.1.2.2 Final Economic Evaluation & Capital Contribution Settlement

Thunder Bay Hydro will carry out a final Economic Evaluation once the facilities are energized. The final Economic Evaluation will be based on forecasted revenues, on-going maintenance, actual costs incurred for the uncontestable work, and the transfer price to be paid to the Customer for the contestable work, where applicable.

If the required capital contribution amount resulting from the final Economic Evaluation differs from the required capital contribution amount resulting from the initial Economic Evaluation, Thunder Bay Hydro will obtain from the Customer, or credit the Customer for, any difference between the two amounts.

Thunder Bay Hydro will provide the Customer with the calculation used to determine the final capital contribution amount including all of the assumptions and inputs used to produce the final Economic Evaluation at no cost to the Customer.

2.1.2.3 Expansion Deposit

Where an expansion requires a capital contribution from the Customer, Thunder Bay Hydro may require an expansion deposit for up to 100% of the present value of the forecasted revenues.

For expansions that do not require a capital contribution from the Customer, Thunder Bay Hydro may require an expansion deposit for up to 100% of the present value of the projected capital costs and on-going maintenance costs of the expansion project.

When a Customer (regardless of its class) intends to exercise the alternative bid option, Thunder Bay Hydro may require an expansion deposit in an amount equal to 10% of the cost of the contestable work as set out in the Estimate to Connect ("warranty portion of the expansion deposit"). Thunder Bay Hydro will retain this portion of the expansion deposit for a warranty period of two (2) years and may apply such deposit to any work required to repair the expansion facilities within the two-year warranty period.

The two-year warranty period begins at the end of the Customer Connection Horizon.

The Customer Connection Horizon for a project ends:

- For residential developments, upon the earlier of the materialization of all forecasted connections or five (5) years after energization of the new facilities, and

- For commercial and industrial developments, upon the earlier of the materialization of all forecasted demands or five (5) years after energization of the new facilities.

Thunder Bay Hydro shall return to the Customer the unapplied portion of the expansion deposit, if any, at the end of the two-year warranty period.

The expansion deposit must be either in the form of (i) cash or (ii) an irrevocable commercial letter of credit issued by a Schedule 1 bank as defined in the *Bank Act*, or (iii) surety bond, but the form of deposit must expressly provide for its use to cover the events for which it is held as a deposit. The expansion deposit including the portion compromising the warranty expansion deposit shall be in addition to any other charges or deposits that may be required by Thunder Bay Hydro and shall be provided prior to the commencement of any expansion work or the installation of any connection assets.

Exclusive of the warranty portion of the expansion deposit, Thunder Bay Hydro shall annually, on the anniversary date of energization, perform a true-up of the Economic Evaluation based on actual load. This annual true-up will be performed during the Customer Connection Horizon (typically a five (5) year period).

However, if after the five (5) year Customer Connection Horizon the total number of connections (for residential developments) or the actual demand (for commercial and industrial developments) contemplated by the original Estimate to Connect have not materialized, Thunder Bay Hydro shall retain any cash held as an expansion deposit, or be entitled to realize on any letter of credit or bond held as an expansion deposit and retain any cash resulting therefrom, with no obligation to return any portion of such monies to the Customer at any time.

If the Customer has provided any expansion deposit in the form of cash, any portion of the expansion deposit held as cash returned to the Customer shall include interest on the returned amount from the date of receipt of the full amount of the expansion deposit at the Prime Business Rate set by the Bank of Canada less two (2) percent.

2.1.2.4 Capital Contributions from Unforecasted Customers and Rebates to Previous Capital Contributors

Unforecasted Customers that connect to the distribution system during the Customer connection horizon will benefit from the earlier expansion and should contribute their share. In such an event, the initial contributor shall then be entitled to a rebate from the distributor as follows:

(1) For a period of up to five (5) years, the initial contributor shall be entitled to a rebate without interest, based on apportioned benefit for the remaining period.

(2) The apportioned benefit shall be determined by considering such factors as the relative load level and the relative line length (in proportion to the line length being shared by both parties).

No rebates will occur after the five (5) year Customer Connection Horizon has expired.

2.1.3 Estimates to Connect

Under the terms of the Distribution System Code, Thunder Bay Hydro is required to make an "Estimate to Connect" to any Customer that is in Thunder Bay Hydro's service territory. Thunder Bay Hydro will provide one (1) Estimate to Connect to the Customer for any plans submitted to Thunder Bay Hydro for an expansion project, at no expense to the Customer. If the Customer submits revised plans, Thunder Bay Hydro may provide a revised Estimate to Connect at the Customer's expense.

Based on the output of its economic evaluation, Thunder Bay Hydro will set out in the Estimate to Connect the following, as applicable:

(1) a description of the material and labour required to build the expansion to connect the Customer if a capital contribution is required from the Customer;

(2) a statement that the Estimate to Connect is an estimate of the costs and will be revised at the completion of the job to reflect actual costs;

(3) the amount of any "capital contribution" payable by the Customer in order to construct the expansion/enhancement facilities (including all assumptions and inputs used in the economic evaluation);

(4) a description and estimate of the connection charges that would apply to connect the Customer (and whether such charges would be included in the capital contribution or not);

(5) whether the Estimate includes work for which the Customer may select the alternative bid option for the contestable work and, if so, the process;

(6) a cost breakdown (for both the contestable and uncontestable work) into the following categories:

(a) direct labour;
(b) materials;
(c) equipment; and
(d) overheads (including administrative costs).

(7) the amount for any additional costs that will occur as a result of the alternative bid option being chosen including, but not limited to, inspection and final connection costs ("additional costs for alternative bid work"). These additional charges may include but are not limited to:
(a) costs for additional design, engineering, or installation of facilities required to complete the project;
(b) costs for inspection or approval of the work performed by the contractor hired by the Customer; and
(c) connection costs to Thunder Bay Hydro distribution system.

(8) the amount of the Basic Customer Connection Credit; and

(9) the amount of any expansion deposit.

Revision of Estimate:

Thunder Bay Hydro will revise the Economic Evaluation once the facilities are energized to take into account the actual costs of construction. If the Customer chooses the alternative bid option and transferred the facilities to Thunder Bay Hydro, the initial Estimate shall be revised once the facilities are energized to take into account the actual costs associated with the expansion or enhancement facilities, including the transfer price and related inspection costs.

If the capital contribution amount resulting from the revised Economic Evaluation differs from the capital contribution amount resulting from the initial Estimate, Thunder Bay Hydro will obtain from the Customer, or credit the Customer for, any difference between the two calculations.

2.1.3.1 Alternative Bids

If the Estimate to Connect demonstrates that:

(a) the project requires a capital contribution from the Customer; and
(b) the construction will not involve work on existing circuits;

Thunder Bay Hydro will advise the Customer that he or she has the choice to obtain alternative bids from a qualified contractor for the construction of those connection and expansion facilities that are specified in the Estimate to Connect as contestable work.

To qualify to undertake contestable work, contractors shall submit a "Construction Contractor Qualification Application" and meet the requirements posted at: http://www.tbhydro.on.ca/ no later than thirty (30) business days prior to their selection by the customer to undertake contestable work.

In addition, Thunder Bay Hydro does not make any representation or warranty regarding any contractor selected by the Customer to do any work regardless of whether the contractor has completed the requirements set by Thunder Bay Hydro or not and shall have no liability to the Customer in respect of such work.

Thunder Bay Hydro will also include in the Estimate to Connect or by separate document an estimate of any costs that will be incurred by Thunder Bay Hydro in the event that the Customer decides to pursue an alternative bid for the contestable work, including but not limited to the following:

- costs for additional design, engineering, or installation of facilities required to complete the project that were made in addition to the original Estimate to Connect;

- costs for inspection or approval of the work performed by the contractor hired by the Customer, and

- costs for making the final connection of the new facilities to the Thunder Bay Hydro distribution system.

Within sixty (60) days of receiving the Estimate to Connect, the Customer shall return a signed copy of the Estimate to Connect indicating acceptance of the Estimate, or, notify Thunder Bay Hydro of its rejection of Thunder Bay Hydro's Estimate to Connect and of its decision to pursue an alternative bid.

If the Customer decides to pursue an alternative bid, the Customer and his Qualified contractor shall only use materials that meet the same specifications as Thunder Bay Hydro approved materials (i.e. same manufacturers and same part numbers). Once the Customer has hired a Qualified contractor, the Customer must request and obtain from Thunder Bay Hydro the listing of approved materials that may be required for the alternative bid work.

The Customer shall be responsible for:

(a) selecting, hiring, and paying the Qualified contractor for the costs for the work eligible for the alternative bid;
(b) assuming full responsibility for the construction of that aspect of the Expansion project;
(c) administering the contract including the acquisition of all required permissions, permits, and property rights as required;
(d) constructing the system expansion to meet Thunder Bay Hydro's design requirements;
(e) paying an inspection fee to Thunder Bay Hydro for inspection of the construction;
(f) paying the costs of any easements or property agreements as required by Thunder Bay Hydro;
(g) transferring the ownership of the facilities built on public property or serving more than one Customer to Thunder Bay Hydro prior to connection;
(h) paying costs for any additional design and engineering; and
(i) paying all applicable Electrical Safety Authority inspection fees.

Thunder Bay Hydro shall be responsible for:

(a) providing the design specifications for the construction;
(b) inspecting and authorizing the expansion for connection; and
(c) connecting the expansion facilities to Thunder Bay Hydro's distribution system.

2.1.4 Connection Denial

2.1.4.1 Buildings

Thunder Bay Hydro is not obligated to connect a building within its service territory if the connection would result in any of the following:

(a) Contravention of existing laws of Canada or the Province of Ontario including the Ontario Electrical Safety Code;
(b) Violations of the conditions in Thunder Bay Hydro Licenses, the Customer's Connection Agreement, or Thunder Bay Hydro's Conditions of Service;
(c) Materially adverse effect on the reliability and safety of the distribution system as determined by Thunder Bay Hydro;
(d) A material decrease in the efficiency of Thunder Bay Hydro's distribution system;
(e) A materially adverse effect on the quality of distribution services received by an existing connection;
(f) Discriminatory access to distribution services;
(g) If the person requesting the connection owes Thunder Bay Hydro money for distribution services, or for non-payment of a security deposit;
(h) Public safety reasons or imposition of an unsafe work situation beyond normal risks inherent in the operation of the distribution system as determined by Thunder Bay Hydro;
(i) Where the electrical connection to Thunder Bay Hydro's distribution system does not meet Thunder Bay Hydro design requirements;
(j) Violations of the property rights of property owners or other agencies, such as railways, Ministries, or the Municipality.

In addition to the above, Thunder Bay Hydro may deny connection to any Customer for any of the following reasons:

(a) Refusal by the Customer to sign any agreements required to be executed by the Customer under these Conditions of Service;
(b) Failure to meet Thunder Bay Hydro's security deposit policy requirements as outlined in these Conditions of Service.

If Thunder Bay Hydro refuses to connect a Customer in its service area that lies along one of its distribution lines, Thunder Bay Hydro shall inform the person requesting the connection of the reasons for the denial, and where Thunder Bay Hydro is able to provide a remedy, make an Estimate to Connect. If Thunder Bay Hydro is unable to provide a remedy to resolve the issue, it is the responsibility of the Customer to do so before a connection can be made.

2.1.4.2 Subdivisions

Thunder Bay Hydro may refuse to connect a subdivision within its service territory for any of the following reasons:

(a) any of the items noted in Section 2.1.4.1 exist
(b) failure to pay the connection fees as specified in the subdivision agreement

2.1.4.3 Pole Attachments

Thunder Bay Hydro is not obligated to connect or allow access to its poles within its service territory for any of the following reasons:

(a) any of the items noted in Section 2.1.4.1 exist
(b) failure to enter into an agreement for the joint use of space on Thunder Bay Hydro poles

2.1.5 Customer Responsibilities

The location of the supply point, primary and secondary cables, transformer, and metering will be established through consultation with Thunder Bay Hydro for both new and upgraded services. Failure to comply may result in the relocation of the service at the owner's expense.

The Customer shall construct and maintain all civil infrastructure (including, but not limited to, privately owned poles, underground ducts, cable chambers, cable pull rooms, transformer room/vault/pad) on private property that is deemed required by Thunder Bay Hydro to accommodate its Connection Assets. All civil infrastructures are to be in accordance with Thunder Bay Hydro's current standards, practices, specifications and these Conditions of Service, and are subject to Thunder Bay Hydro's inspection and acceptance.

The Customer shall maintain sufficient clearances between electrical equipment and buildings and other permanent structures to meet the requirements of the Ontario Electrical Safety Code and the *Occupational Health & Safety Act* and Regulations.

The trench route must be approved by Thunder Bay Hydro and is to follow the route indicated on the underground drawing supplied by Thunder Bay Hydro. Any deviation from this route must be approved by Thunder Bay Hydro. The Customer will be responsible for Thunder Bay Hydro's costs associated with re-design and inspection or repair services due to changes or deviations initiated by the Customer or its agents.

It is the responsibility of the owner or their contractor to obtain underground cable and pipe locates from all Utilities before digging.

The Customer's service entrance and metering equipment shall meet Thunder Bay Hydro' Standards and requirements. The Customer's cables shall be brought to a point determined by Thunder Bay Hydro for connection to Thunder Bay Hydro's supply.

If the installation is not in accordance with Thunder Bay Hydro's specifications, the installation will be removed and re-installed at the Customer's expense.

It is the Customer's responsibility to maintain and repair the transformer room(s) or any other civil infrastructure that forms part or is part of the Customer's building.

Thunder Bay Hydro will provide standard overhead or underground supply services to Customers. If a Customer requests special construction beyond the normal Thunder Bay Hydro standard, the Customer shall pay the additional costs.

Where there are other services to be installed (e.g. gas, telephone, and cable) these shall be coordinated to avoid conflict with Thunder Bay Hydro's underground cables.

2.1.6 Inspections Before Connections

All Customer-owned and maintained electrical installations must be approved by the Electrical Safety Authority and must also meet Thunder Bay Hydro's design standards and requirements. Thunder Bay Hydro requires notification from the Electrical Safety Authority that the installation has passed inspection prior to energizing a Customer's supply of electricity. Services that have been disconnected for the purposes of upgrade or change, or services that have been altered subsequent to Electrical Safety Authority approval must be re-inspected and approved by the Electrical Safety Authority prior to reconnecting.

Temporary services, typically used for construction purposes and for a period of twelve months or less, must be approved by the Electrical Safety Authority and must be re-inspected at the Customer's expense should the period of use be allowed to exceed twelve (12) months.

Customer-owned substations must be inspected by both the Electrical Safety Authority and Thunder Bay Hydro.

Customer transformer vaults shall be inspected and approved by Thunder Bay Hydro prior to the installation of Thunder Bay Hydro's equipment.

All Customer-owned civil work must be inspected and approved by Thunder Bay Hydro prior to the installation of Thunder Bay Hydro equipment.

All ducts, duct banks, trenches, transformer pads, and grounding shall be inspected and approved by Thunder Bay Hydro prior to the pouring of concrete and again before backfilling. In the event of blocked ducts, the owner will be responsible for clearing or replacing the ducts, prior to cable installation. Connections made to existing concrete duct banks or cable chambers shall be done only by a contractor approved by Thunder Bay Hydro. All work done on existing Thunder Bay Hydro plant must be authorized by Thunder Bay Hydro and carried out in accordance with all applicable safety legislation and requirements.

At least two normal working days are necessary for Thunder Bay Hydro to energize a new or enlarged electrical service from the receipt of written approval by the Electrical Safety Authority provided that all Thunder Bay Hydro conditions are satisfied. A longer time interval may be required if it is necessary to arrange for power interruption to other

Customers. During extremely busy periods Thunder Bay Hydro may be required to energize the service after normal business hours due to previously scheduled commitments and limited resources.

Metering shall be completely inspected and approved by Thunder Bay Hydro prior to energization.

Where the Conditions of Service are not complied with prior to inspection and approval, the Customer is responsible for the cost of any and all damages to Thunder Bay Hydro's distribution system and any associated costs incurred by Thunder Bay Hydro in order to address the Customer's non-compliance with these Conditions of Service. The Customer's service shall be disconnected immediately until these conditions are satisfied.

2.1.7 Relocation of Plant

When requested to relocate distribution plant, Thunder Bay Hydro will exercise its rights and discharge its obligations in accordance with existing acts, by-laws and regulations including the *Public Service Works on Highways Act*, formal agreements, easements and law.

In the absence of existing agreements, Thunder Bay Hydro is not obligated to relocate the plant. However, Thunder Bay Hydro shall resolve the issue in a fair and reasonable manner. Resolution in a fair and reasonable manner will include a response to the requesting party that explains the feasibility or unfeasibility of the relocation and a fair and reasonable charge for relocation based on cost recovery principles.

Feasibility considerations may include, but may not be limited to, technical considerations and availability of alternate locations.

In the course of maintaining and enhancing Thunder Bay Hydro's distribution plant, Thunder Bay Hydro may need to relocate distribution plant that is owned by Thunder Bay Hydro. Where a Customer requests that such maintenance or construction activities be done outside Thunder Bay Hydro's normal working hours, the Customer shall pay for any incremental costs incurred by Thunder Bay Hydro as a result thereof.

2.1.8 Easements

The Customer shall, at no cost to Thunder Bay Hydro, grant where required an easement to permit installation and maintenance of service. The width and extent of this easement shall be determined by Thunder Bay Hydro. The easement must be granted prior to energization of the service.

To maintain the reliability, integrity and efficiency of the distribution system, Thunder Bay Hydro has the right to have supply facilities on private property and to have easements registered against title to the property.

Easements are required where Thunder Bay Hydro facilities are to be located on private property, or crosses over the property of a third party to serve property other than property where the facilities are located and/or where Thunder Bay Hydro deems it necessary.

The Customer will prepare at its own cost, any required reference plan and associated easement documents to the satisfaction of Thunder Bay Hydro prior to its registration and registering of the easement plan. Four (4) copies of the deposited reference plan must be supplied to Thunder Bay Hydro prior to the preparation of the easement documents. Details will be provided upon application for service. The Customer is responsible for registering both the reference plan and the easement documents.

2.1.9 Contracts

2.1.9.1 Contract for New or Modified Electricity Service

Thunder Bay Hydro shall only connect a Customer for a new or modified supply of electricity upon receipt by Thunder Bay Hydro of the following:

- a completed and signed application for service (see Appendix C for Terms and Conditions);
- payment to Thunder Bay Hydro of any applicable connection charge (see Appendix E);
- payment of any security deposit as outlined in Section 2.4.3; and
- an inspection and approval by the Electrical Safety Authority of the electrical equipment for the new or upgraded service

Thunder Bay Hydro may also require the Customer to enter into a Connection Agreement acceptable to Thunder Bay Hydro as noted in Section 2.1.9.4 in these Conditions of Service.

Customers, who require a MIST (interval) metering installation, must sign an Interval Metering Agreement.

2.1.9.2 Implied Contract

In all cases, notwithstanding the absence of a formal contract, Thunder Bay Hydro has an implied contract with any Customer or consumer that is connected to Thunder Bay Hydro's distribution system and receives distribution services. The terms of the implied contract are embedded in Thunder Bay Hydro's Conditions of Service, the OEB Rate Handbook, Thunder Bay Hydro's rate schedules, the Distribution System Code, Thunder Bay Hydro's Distribution License, the Standard Supply Service (SSS) Code, and the Retail Settlement Code, all as amended from time to time.

The acceptance of supply of electricity or related services from Thunder Bay Hydro constitutes a binding contract with Thunder Bay Hydro, which includes these Conditions and all terms thereunder. Any person accepting the supply of electricity or related services shall be liable for payment for same, and such implied contract shall be binding upon the heirs, administrators, executors, successors or assigns.

2.1.9.3 Non-Standard Contracts

Non-standard contracts that are customized in accordance with the service requested by the Customer normally include, but are not necessarily limited to, the following examples:

- Construction sites
- Mobile facilities
- Operating and maintenance
- Non-permanent structures
- Special occasions, etc.
- Generation

The requirement for Non-Standard Contracts will be determined by Thunder Bay Hydro on a case by case basis.

2.1.9.4 Connection Agreements

Thunder Bay Hydro may require a Customer to enter into a Connection Agreement in a form that is both consistent with the Distribution System Code and acceptable to Thunder Bay Hydro. The type of Connection Agreement will vary, depending upon the nature of the Customer, as follows:

- Micro-Embedded Generator Connection Agreement: Thunder Bay Hydro utilizes the connection agreement for micro-embedded generators set out in Appendix E of the Distribution System Code. In the event that a micro-embedded generator connected to Thunder Bay Hydro has not signed such a connection agreement, the micro-embedded generator Customer shall be deemed to have accepted and agreed to be bound by all of the terms in the Micro-Embedded Generator Connection Agreement in Appendix E of the Distribution System Code.

- Small and Mid-Sized Embedded Generator Connection Agreement: Thunder Bay Hydro utilizes the form of connection agreement for small and medium-sized generators set out in Appendix E of the Distribution System Code. In the event that a small or medium-sized embedded generator connected to Thunder Bay Hydro has not signed such a connection agreement, the small or medium-sized generator Customer shall be deemed to have accepted and agreed to be bound by all of the terms in the Form of Connection Agreement For Small or Medium-Sized Generators in Appendix E of the Distribution System Code.

- Large Embedded Generator Connection Agreement: Thunder Bay Hydro will enter into a customer-specific connection agreement with large embedded generators. Some of the information contained in such a connection agreement can be found in Appendix E of the Distribution System Code.

- Connection Agreement with Another Distributor: Thunder Bay Hydro will enter into a customer-specific connection agreement with other distributors.

- Connection Agreement with all other Customers: For Customers who are not embedded generators or other distributors, Thunder Bay Hydro may enter into a Connection Agreement. In the event that the Customer has not entered into a Connection Agreement with Thunder Bay Hydro, the Customer will be deemed to

have accepted and agreed to be bound by the Terms of Agreement for Electrical Service set out at Appendix C to these Conditions of Service.

2.1.10 Temporary Service

A temporary service is a metered service provided to facilitate various applications; including but not limited to uses such as construction projects, outdoor shows, gatherings, and special events. Temporary services may be provided for a period of less than 12 months. Temporary services may be renewed thereafter at the discretion of Thunder Bay Hydro. If an extension is required then the equipment for such temporary service must be re-inspected prior to the extension. At the discretion of Thunder Bay Hydro, one or more temporary services may be provided for a site.

Temporary services can be supplied overhead or underground. The location of the Service Entrance point and metering details will be established through consultation with Thunder Bay Hydro. Failure to comply may result in modifications at the owner's expense.

All installations that are built by the Customer will be built in accordance with the Electrical Safety Code and approved by the ESA.

Subject to the requirements of Thunder Bay Hydro, supply will be connected after receipt of an "Authorization to Connect" from the ESA, a signed contract and a deposit as outlined in Section 2.4.3 from the Customer.

In the case of temporary overhead services, the Customer shall leave 760 mm of cable at the masthead for connection purposes.

In the case of temporary underground services, the Customer's cable shall extend to Thunder Bay Hydro's point of supply.

The Customer will be responsible for all associated costs for the installation and removal of equipment required for a temporary service to Thunder Bay Hydro's point of supply. The Customer will pay for the temporary installation and removal based on Thunder Bay Hydro's estimated costs of such installation and removal prior to the commencement of any work being initiated by Thunder Bay Hydro.

There will be a minimum charge to all temporary services. This charge is based on 30 m of conductor and connection to the electrical distribution system.

Connection assets above and beyond the above standard allowance will be recovered based on actual costs. Where the Customer has paid Thunder Bay for the temporary installation and removal on the basis of an estimate of such costs, and the actual costs are higher than the estimate, the Customer shall pay Thunder Bay Hydro the balance of its actual costs for the installation and removal failing which, Thunder Bay Hydro will apply any outstanding amount against the Customer's temporary deposit.

The cost of any transformation may be charged to the Customer as part of the actual costs prior to energization. As appropriate, upon removal, the Customer will be credited

the cost of the transformer, as long as it is in working order. The Customer is responsible for the transformer, if any damage whatsoever occurs. The Customer will retain ownership of the transformer and the cost will not be credited to the Variable Connection Charge.

All construction that occurs on private property will be the responsibility of the Customer.

Any modifications or changes to the above will be at the discretion of Thunder Bay Hydro.

2.1.10.1 Metering

The owner will make provisions acceptable to Thunder Bay Hydro for revenue metering equipment. The provisions for metering could be one or a combination of the following, as established by Thunder Bay Hydro:

- approved meter sockets as indicated in Appendix F;
- a lockable enclosure as outlined in Appendix F; or
- for all three-phase outdoor services, the meter must be installed in a weatherproof, lockable enclosure.

Where meter bases are required, they must be approved by Thunder Bay Hydro and shall be securely mounted on minimum 152 mm diameter poles (or alternative if approved by Thunder Bay Hydro) so that the midpoint of the meter is 1.73 m (± 100 mm) from finished grade.

The metering equipment location will be agreed upon through consultation with Thunder Bay Hydro. The location allocated for Thunder Bay Hydro metering equipment shall be directly accessible to Thunder Bay Hydro staff, and shall be subject to satisfactory environmental conditions, some of which are:

- safe and adequate working space with not less than 1.2 m in front of the metering equipment;
- protection against the adverse effects of moving machinery, vibration, dust, moisture or fumes.

Prior to energization, Thunder Bay Hydro will require notification of approval by the Electrical Safety Authority. The Service Entrance and metering provision shall be inspected and accepted by Thunder Bay Hydro prior to energization.

2.1.11 Subdivisions

Developers of Subdivisions are required to enter into a Subdivision Agreement with the City of Thunder Bay and a Subdivision Connection Agreement with Thunder Bay Hydro available upon request.

In case of conflict between the Subdivision Connection Agreement and the terms herein, the Subdivision Connection Agreement shall be binding. All design work, including service locations and trench routes, must be approved by Thunder Bay Hydro.

Residential Subdivision developments shall be treated as a system expansion for the Expansion Facilities as defined in these Conditions and shall be subject to Section 2.1.2 Expansions and Enhancements. Connection Assets installed to service each individual lot connection shall individually be subject to Section 2.1.1. Each individual lot connection qualifies for the Basic Connection Credit which will be apportioned to the Developer and/or Customer according to the proportion of total connection charges assumed by each party.

All of the electrical service must be constructed to Thunder Bay Hydro's standards and in compliance with the Ontario Electrical Safety Code, applicable laws, regulations and codes.

2.2 Disconnection

Thunder Bay Hydro shall not be liable for any damages or claims as a result of disconnection of service.

Thunder Bay Hydro reserves the right to disconnect the supply of electricity to a Customer for causes including, but not limited to, the following:

- Failure to pay Thunder Bay Hydro any amounts due and payable for the distribution of electricity or for the supply of electricity under Section 29 of the *Electricity Act*;
- Non-payment of security deposit requirements in accordance with Thunder Bay Hydro's security deposit policy;
- Contravention of the laws of Canada or the Province of Ontario, including the Ontario Electrical Safety Code.
- Adverse effects on the reliability and safety of Thunder Bay Hydro's distribution system;
- Imposition of an unsafe worker situation beyond normal risks inherent in the operation of Thunder Bay Hydro's distribution system;
- A material decrease in the efficiency of Thunder Bay Hydro's distribution system;
- Electrical disturbance propagation caused by the Occupant's equipment that is not corrected in a timely fashion;
- A materially adverse effect on the quality of distribution services received by an existing connection;
- Discriminatory access to distribution services;
- Inability of Thunder Bay Hydro to perform planned inspections and maintenance or access to the meter;

- Failure of the Customer to comply with a directive that Thunder Bay Hydro has made for the purposes of meeting its Distribution License obligations;
- Failure of the Customer to comply with any requirement in these Conditions of Service or a term of any agreement made between the Customer and Thunder Bay Hydro including, but not limited to, a Connection Agreement;
- In compliance with a court order;
- By order of the Electrical Safety Authority;
- By order of the IESO; or
- Any other conditions identified in this Conditions of Service document.

In all circumstances where allowable by law, an attempt shall be made to notify the Customer in advance of the disconnection.

Thunder Bay Hydro may disconnect the supply of electricity without notice in accordance with a court order, or for emergency, safety or system reliability reasons or to inspect, maintain, repair, alter, remove, replace, or disconnect wires or other facilities used to distribute electricity.

Further, notwithstanding Section 2.1.9.2 (Implied Contract), Thunder Bay Hydro shall be entitled to disconnect the supply of electricity to a building or property where the building or property has been using power for unlawful purposes, including energy diversion and theft of power. The supply of electricity to the building or property may not be reconnected until Thunder Bay Hydro receives full payment for all reasonable costs and losses incurred by Thunder Bay Hydro arising from the unauthorized energy use (including inspection costs, repair costs, commodity costs, etc.).

Under any of the following circumstances, Thunder Bay Hydro requires the Customer to obtain the approval of the Electrical Safety Authority prior to Thunder Bay Hydro reconnecting the service:

- where Thunder Bay Hydro has reason to believe that the wiring may have been damaged or altered;
- where service was disconnected for modification of Customer wiring;
- where the service has been disconnected for a period of six months or longer;
- where the service was disconnected as a result of an adverse effect on the reliability and system of Thunder Bay Hydro's distribution system; or
- where it is a requirement of the Ontario Electrical Safety Code

2.2.1 Disconnection for Non-Payment of Overdue Accounts

Regular hydro bills, including any applicable security deposits, are due sixteen (16) days after the billing date. If the Customer does not pay by the due date, a past due reminder

will be sent out four (4) days after the due date. If the bill remains unpaid, as a courtesy, a second past due notice may be sent out advising the Customer of a pending disconnection. Thunder Bay Hydro may also attempt to contact the Customer via phone, mail, and/or hand delivered notice to facilitate payment arrangements.

Once attempted contact with the Customer has failed, and/or satisfactory payment arrangements have not been made, Thunder Bay Hydro will send a notice of disconnection of service and will arrange for disconnection of electricity supply only as a last resort. During winter months, a current limiting device may be used in place of a straight disconnection, providing the Customer with enough power to heat their residence. The day prior to the scheduled disconnection, Thunder Bay Hydro will once again make a good faith effort to contact the Customer by phone, mail and/or hand delivered notice for payment arrangements.

Thunder Bay Hydro shall not be liable for any injury, loss or damage to persons or property accruing or resulting from the failure of supply of electricity due to nonpayment of account.

Thunder Bay Hydro may recover from the disconnected Customer the reasonable costs associated with disconnection. Further, discontinuance of service does not relieve the Customer of the liability for arrears. Reconnection of the account shall be completed only after the Customer has made satisfactory payment arrangements. All such reconnections shall be subject to a reconnection charge by Thunder Bay Hydro (see Appendix E).

Disconnections and/or the use of limiting devices shall be subject to updated legislation. Also, as per Sections 4.2.1.1 and 4.2.1.2 of the Distribution Settlement Code, a copy of the "Fire Safety Notice" of the Office of the Fire Marshall will be delivered prior to, or at the time of disconnection for nonpayment.

2.3 Conveyance of Electricity

2.3.1 Limitations on the Guaranty of Supply

Thunder Bay Hydro agrees to use reasonable diligence to provide a regular and uninterrupted supply of electricity but does not guarantee constant supply or the maintenance of invariable frequency or voltage and will not be liable for damages occasioned by the failure to provide such services to the Customer.

It may be necessary to interrupt a Customer's supply to maintain or improve the Thunder Bay Hydro distribution system, or to provide new or upgraded services to other Customers. Whenever practical and cost effective, as determined by Thunder Bay Hydro, arrangements suitable to the Customer and Thunder Bay Hydro will be made to minimize any inconvenience. Customers should expect to have one planned power outage per year for Thunder Bay Hydro to perform system maintenance and/or enhancements. It is Thunder Bay Hydro's policy to attempt to limit planned outages to its Customers to one per year. Customers may experience unplanned outages over and above any planned outages.

Except in cases of extreme emergency involving danger to life and limb or impending severe equipment damage, or due to practical considerations, Thunder Bay Hydro will endeavor to provide the Customer with reasonable advance notice of power interruptions.

Customers requiring a higher degree of security, than that of normal electrical supply, are responsible to provide their own back-up or standby facilities as well as any special protective devices required at their premises to minimize the effects of momentary power interruptions.

Customers requiring a three-phase service should install protective apparatus to avoid damage to their equipment, which may be caused by the interruption of one phase, or non-simultaneous switching of phases of Thunder Bay Hydro's electricity supply.

Thunder Bay Hydro or its agents shall have rights to access a property to operate and/or maintain its facilities in accordance with section 40 of the *Electricity Act, 1998* and any successor acts thereto.

Thunder Bay Hydro will use reasonable efforts to exercise this power of entry during normal business hours. The Thunder Bay Hydro employee or authorized agents exercising this power of entry will identify themselves with proper identification upon request.

During an emergency, Thunder Bay Hydro may interrupt electrical supply to its Customers in response to a shortage of supply of electricity, to affect repairs on its distribution system, to perform other operations as deemed necessary by Thunder Bay Hydro, or while repairs are being made to Customer owned equipment.

To assist with distribution system outages or emergency response, Thunder Bay Hydro may require a Customer to provide Thunder Bay Hydro with emergency access to Customer-owned distribution equipment or Thunder Bay Hydro-owned equipment on Customer's property.

2.3.2 Power Quality

Upon request for an appointment, Thunder Bay Hydro will provide no charge voltage checks at a Customer secondary service entrance only. Other voltage checks beyond the service entrance point will be the responsibility of the Customer, except for Thunder Bay Hydro owned equipment.

2.3.2.1 Power Quality Investigations

Thunder Bay Hydro will respond to Customer power quality concerns and investigate the condition of supply at the service entrance. There is no fee for such initial investigation during business hours. Upon completion of the initial investigation, Thunder Bay Hydro shall report the results to the Customer.

If the cause is deemed to be the result of the Customer's service, the Customer will be responsible to rectify the condition. Thunder Bay Hydro will provide an option to the Customer to proceed with the investigation and correction of the service condition at the expense of the Customer. Further, if the power quality problem is found to be caused by

the Customer making the complaint, Thunder Bay Hydro may seek reimbursement for the initial investigation of the complaint.

If the cause of the power quality problem is deemed to be Thunder Bay Hydro's power supply, Thunder Bay Hydro will proceed to rectify the condition at its expense.

To determine the parameters of adequate power quality and whether the Customer's concerns are reasonable for local distribution systems, Thunder Bay Hydro will use appropriate industry standards (such as IEC, IEEE, CAN3-C235-87) and established good utility practice guidelines.

2.3.2.2 Power Quality Customer Obligations

It is the responsibility of the Customer to ensure that electrical service usage does not cause disturbance on the distribution system.

Specifically:

(1) Large non-linear loads must be equipped with proper corrective measures, such as filtering and/or grounding techniques. Power electronics equipment installed must comply with IEEE Standard 519-1992. The limit on individual harmonic distortion is 3%, while the limit on total harmonic distortion is 5%.

(2) Motor starting current shall not exceed their associated supply circuit limitations or cause voltage levels at the supply point to go outside the acceptable limits in Section 2.3.5. Reduced voltage starting may be required if satisfactory transformer fusing cannot be obtained due to excessive starting current or a relatively long starting cycle. It should be noted that objectionable voltage flicker on the Customer's secondary system may be experienced if the motor(s) are supplied from a transformer bank which also supplies lighting or other sensitive equipment in the building.

(3) Three-phase Customers shall ensure their load is balanced between the three phases within 15% of each phase, unless specific unbalancing is approved by Thunder Bay Hydro.

(4) With respect to older services with ground fault detection for three-phase, 3-wire delta services: ground fault detection (phase indication lights) is required on the load-side of the revenue metering for each individual service, and if more than one individual meter is required off a splitter trough, then ground fault detection (phase indication lights) is required on the load-side of each revenue meter. In case of bulk metering, ground fault detection would be required on the load-side of the bulk metering.

Customers are obligated to assist Thunder Bay Hydro with power quality investigations by providing the required equipment information, relevant data and necessary access for the installation of monitoring equipment.

The Customer shall assist in the investigation and resolution of power quality problems by:

a) Maintaining and providing Thunder Bay Hydro with a detailed log of exact times and dates of poor power quality;
b) Ensuring corrective measures such as filters and/or grounding are installed for non-linear loads connected to the distribution system;
c) Assisting Thunder Bay Hydro in determining whether the Customer's equipment may be a source of undesirable system disturbances; and
d) Ceasing operation of equipment deemed to be the cause of system disturbances until satisfactory remedial action has been taken.

If Thunder Bay Hydro determines the Customer's equipment to be the source of unacceptable power quality on Thunder Bay Hydro's distribution system, the Customer will be required to cease operation of the equipment until the problem is rectified at the sole expense of the Customer. If the Customer does not comply with the efforts of Thunder Bay Hydro to remedy the situation within a reasonable time, Thunder Bay Hydro may disconnect the Customer in accordance with the disconnection provisions of these Conditions of Service.

Any Customer condition that adversely affects the Thunder Bay Hydro distribution system must be corrected immediately by the Customer, at the Customer's sole expense, if directed to do so by Thunder Bay Hydro. Such adverse affects include, but are not limited to, direct hazards to the public, or adversely affecting the reliability of the Thunder Bay Hydro distribution system.

2.3.2.3 Notifications for Power Interruptions

Although it is Thunder Bay Hydro's policy to minimize inconvenience to Customers, it is necessary to occasionally interrupt a Customer's supply of electricity to allow work on Thunder Bay Hydro's electrical system. All customers should expect one outage per year for maintenance or system enhancement. Thunder Bay Hydro will endeavor to provide Customers with reasonable notice of planned power interruptions; however, interruption times may change due to inclement weather or other unforeseen circumstances. Thunder Bay Hydro shall not be liable in any manner to such Customers for failure to provide such notice of planned power interruptions or for any change to the schedule for planned power interruptions.

During an emergency, Thunder Bay Hydro may interrupt supply of electricity to a property without notice in response to a shortage of supply of electricity or to effect repairs on Thunder Bay Hydro's distribution system or while repairs are being made to Customer-owned equipment, or to conduct work of an emergency nature involving the possibility of injury to persons or damage to property or equipment.

2.3.2.4 Emergency Trouble Calls

Thunder Bay Hydro will exercise reasonable diligence and care to deliver a continuous supply of electricity to the Customer. However, Thunder Bay Hydro cannot guarantee a supply that is free from interruption.

When power is interrupted or otherwise adversely affected, the Customer should first confirm that the problem is not due to open fuses, breakers, or disconnect devices on their equipment. If there is a partial power failure, the Customer should obtain the services of an electrical contractor to carry out the necessary repairs. If upon

investigation, it appears that Thunder Bay Hydro's main source of supply has failed, the Customer should report these conditions at once to Thunder Bay Hydro's Trouble Call Line at (807) 343-1002 or the general number at (807) 343-1111.

Thunder Bay Hydro operates a System Control Centre 24 hours a day to provide emergency services to Customers. Thunder Bay Hydro will initiate restoration efforts as expediently as practicable.

2.3.3 Electrical Disturbances

Thunder Bay Hydro shall not be held liable for the failure to maintain supply voltages within standard levels due to Force Majeure as defined in the Glossary of these Conditions.

Voltage fluctuations and other disturbances can cause flickering of lights and other serious difficulties for Customers connected to Thunder Bay Hydro's distribution system. It is the Customer's responsibility to ensure that their equipment does not cause undesirable system disturbances, which may be reflected back to Thunder Bay Hydro's circuits, such as harmonic distortions, and spikes that might interfere with or adversely affect the operation of adjacent Customer equipment. Equipment that may cause these disturbances includes large motors, welders, and variable speed drives, electronic power converters, etc. The Customer must notify Thunder Bay Hydro in advance of installation of such equipment to ascertain if the installation of such equipment is permissible and to what extent additional facilities may be required to prevent disturbance to the Thunder Bay Hydro distribution system.

Customers who may require an uninterrupted source of power supply or a supply completely free from fluctuation and disturbance must provide their own power conditioning equipment for these purposes.

2.3.4 Standard Voltage Offerings

2.3.4.1 Primary Voltage

The primary voltage to be used will be determined by Thunder Bay Hydro for both Thunder Bay Hydro-owned and Customer-owned transformation. Depending on the voltage of the building that "lies along", the supplied primary voltage will be at 25/14.4 kV grounded wye, three-phase, 4-wire system for urban and 12/7.2 kV grounded wye, three-phase, 4-wire system in the rural. Where 4.16/2.4kV grounded wye, three-phase, 4-wire exists, connections to the 4kV system will be allowed on a case by case basis where other options are limited since the use of the 4kV system is not being expanded, and will ultimately be phased out.

2.3.4.2 Supply Voltage

Depending on the type of distribution plant that "lies along," the supplied secondary voltage shall be:

(a) 120/240 V , single-phase, 3-wire;
(b) 120/208Y V , three-phase, 4-wire; or

(c) 347/600Y V , three-phase, 4-wire

The following primary services may be made available:

(a) 14,400/24,940 Y V;
(b) 7200/12,470 Y V; or
(c) 2400/4,160 Y V (determined on a case by case basis).

Although Thunder Bay Hydro can provide the above voltages, they are not always available from the portion of the distribution system that the building "lies along". The Customer must check with Thunder Bay Hydro to find out whether or not a particular voltage is available at any particular site. It may be necessary to expand or enhance the distribution system in order to provide the requested voltage. If an expansion or enhancement is required, the Customer may be required to provide a capital contribution in accordance with Section 2.1.2.

2.3.5 Voltage Guidelines

The following Extreme Operating Conditions are the conditions under which Thunder Bay Hydro will contract to supply electrical energy. Thunder Bay Hydro attempts to maintain service voltage at the service entrance of the Customer within the guidelines of CSA Standard CAN3-C235-87 (or latest edition), which allows variations from nominal voltage as shown in the chart below:

Voltage Variation Limits
Applicable at Service Entrances

Nominal System Voltages	Extreme Operating Conditions	Normal Operating Conditions		
Single-Phase				
120/240	106/212	110/220	125/250	127/254
240	212	221	250	254
600 (*)	530	550	625	635
Three-Phase (4 Conductor)				
120/208Y	110/190	112/194	125/216	127/220
240/416Y (*)	220/380	224/388	250/432	254/440
347/600Y	306/530	318/550	360/625	367/635

(*) no longer a standard voltage offered by Thunder Bay Hydro.

Thunder Bay Hydro shall practice reasonable diligence in maintaining voltage levels, but is not responsible for variations in voltage from external forces such as operating contingencies, exceptionally high loads and low voltage supply from the transmitter. Thunder Bay Hydro shall not be liable for any failure or delay in performing its obligations under these conditions due to a "Force Majeure" event.

When voltages lie outside the acceptable limits for Normal Operating Conditions, but within the indicated limits for Extreme Operating Conditions, improvement or corrective action will be taken on a planned and programmed basis, but not necessarily on an emergency basis. When voltages lie outside the acceptable limits for Extreme Operating Conditions, improvement or corrective action should be taken on a priority basis.

Upon request for an appointment, Thunder Bay Hydro will provide voltage checks at no charge, at a Customer secondary service entrance only. Other voltage checks beyond the service entrance point will be the responsibility of the Customer, except for Thunder Bay Hydro equipment.

2.3.6 Emergency Back-up Generation Facilities

Customers with portable or permanently connected backup generation facility (including an embedded generation facility that is used exclusively for load displacement purposes) shall comply with all applicable criteria of the Ontario Electrical Safety Code. Customers with permanently connected emergency generation equipment must notify Thunder Bay Hydro.

In particular, the Customer must ensure that their backup generation facility does not parallel with Thunder Bay Hydro's system without a proper interface protection and a Generator Connection Agreement, as required by Thunder Bay Hydro, and does not adversely affect Thunder Bay Hydro's distribution system. Where a Customer's portable or permanently connected generator causes damage to Thunder Bay Hydro's electrical distribution system, the Customer is responsible for the cost of all repairs to the electrical distribution system as a result of their connection.

2.3.7 Metering

Thunder Bay Hydro will supply, install, own, and maintain all meters, instrument transformers, ancillary devices, and secondary wiring required for revenue metering.

Any generator connected to the Thunder Bay Hydro distribution system that sells energy through the Thunder Bay Hydro distribution system shall install a meter in accordance with the Ontario Energy Board and Ontario Power Authority requirements. The Customer shall obtain a written approval from Thunder Bay Hydro with respect to technical details of the metering installation.

Where practical, metering for an embedded generation facility shall be installed at the point of supply. If it is not practical to install the meter at the point of supply, Thunder Bay Hydro will apply loss factors to the generation output in accordance with the loss factors applied for retail settlements and billing.

Where an embedded generation facility metering installation does not conform to Measurement Canada standards or the Customer cannot confirm accuracy class of its instrument transformers, the Customer shall have the metering installation, including instrument transformers, tested, and provide satisfactory test results to Thunder Bay Hydro. Thunder Bay Hydro will apply a Measurement Canada correction factor to meter readings until such time as standards conformance is achieved.

Metered market participants in the Independent Electricity System Operator ("IESO") administered wholesale market must meet or exceed all IESO metering requirements. All Embedded Generation Facilities of 10MW or larger must meet or exceed all IESO metering requirements.

Thunder Bay Hydro will typically install metering equipment at the Customer supply voltage. The Customer must provide a convenient and safe location satisfactory to Thunder Bay Hydro, reserved solely for metering equipment, with direct outside access acceptable to Thunder Bay Hydro with a locking mechanism in conformity with Section 3.3.7 and the Electrical Safety Authority, for the installation of Thunder Bay Hydro revenue metering equipment, meters, wires and ancillary equipment, free of charge or rent. Customers will allow only a properly identified employee or authorized agent of Thunder Bay Hydro to read, remove, inspect, connect, replace, adjust, or repair Thunder Bay Hydro metering, service entrance equipment, communications equipment, or other plant located on the Customer's premises.

The Customer will allow Thunder Bay Hydro employees and agents free and unrestricted access, at all reasonable hours, to Thunder Bay Hydro meters, wires and other equipment. Where safety or reliability of the electrical distribution system is at risk, free and unrestricted access will be required at all times.

The Customer will be responsible for the care and safekeeping of Thunder Bay Hydro meters, wires and ancillary equipment on the Customer's premises. If any Thunder Bay Hydro equipment installed on Customer premises is damaged, destroyed, or lost other than by ordinary wear and tear, tempest or lightning, the Customer will be liable to pay to Thunder Bay Hydro the value of such equipment, or at the option of Thunder Bay Hydro, the cost of repairing the same.

The location allocated by the owner for Thunder Bay Hydro metering shall provide direct access for Thunder Bay Hydro staff and shall be subject to satisfactory environmental conditions, some of which are:

- maintain a safe and adequate working space in front of equipment, not less than 1.2 m (48") and a minimum ceiling height of 2.1 m (84"); and
- maintain an unobstructed working space in front of equipment, free from, or protected against, the adverse effects of moving machinery, vibration, dust, moisture or fumes.

Where Thunder Bay Hydro deems self-contained meters to be in a hazardous location, the Customer shall provide a meter cabinet or protective housing in accordance with these Conditions of Service.

Any compartments, cabinets, boxes, sockets, or other work-space provided for the installation of Thunder Bay Hydro's metering equipment shall be for the exclusive use of Thunder Bay Hydro. No equipment, other than that provided and installed by Thunder Bay Hydro, may be installed in any part of the Thunder Bay Hydro metering workspace.

Each unit in all new multi-unit sites including apartment buildings, condominiums and malls shall be individually metered. Developers will contact Thunder Bay Hydro for details of metering requirements for multi-unit sites prior to submission of drawings to

Thunder Bay Hydro. Each unit in all new multi-unit sites shall be metered in accordance with Section 3.3.6.

Residential type townhouses will be individually metered.

Bulk metered buildings may be converted to individually metered interval metered units at the Customer's cost.

2.3.7.1 Main Switch and Meter Mounting Devices

The Customer's main switch immediately preceding the meter shall be installed so that the top of the switch is 1.83 m or less from the finished floor and shall permit the sealing and padlocking of:

a) the handle in the "open" position; and

b) the cover or door in the closed position.

Meter mounting devices for use on Commercial/Industrial accounts shall be installed on the load-side of the Customer's main switch and located indoors.

When the Customer is required to supply and install a Thunder Bay Hydro approved meter socket for the use of Thunder Bay Hydro's self-contained socket meters, the main switch ratings and supply voltages listed in Appendix F appended to these Conditions of Service apply.

When the Customer is required to supply and install a meter cabinet to contain Thunder Bay Hydro's metering equipment, the main switch ratings and supply voltages listed in Appendix F appended to these Conditions apply.

Meter centers installed for individual metering applications must meet the requirements specified in Appendix F appended to these Conditions.

The Customer shall permanently and legibly identify each metered service with respect to its specific address, including unit or apartment number. The identification shall be applied to all service switches, circuit breakers, meter cabinets, and meter mounting devices. Thunder Bay Hydro shall not be liable for any loss or damage resulting from the incorrect identification of services or equipment.

2.3.7.2 Service Main Limitations

The metering provision and arrangement for service mains in excess of either 600 A or 600 V shall be submitted to Thunder Bay Hydro for approval before building construction begins. Additional standards and requirements for services metered above 600 V can be made available upon request.

2.3.7.3 Special Enclosures

Specially constructed meter entrance enclosures may be permitted for outdoor use upon Thunder Bay Hydro's approval of a written application for use.

2.3.7.4 Meter Loops

The Customer shall provide meter loops having a length of 610 mm in addition to the length between line and load entry points. Line and load entry points shall be approved by Thunder Bay Hydro prior to installation. Where more than two conductors per phase are used, the connectors shall be provided by the Customer. Mineral insulated, solid, or hard drawn wire conductors are not acceptable for meter loops.

Any variation from the above must first be checked and approved by Thunder Bay Hydro prior to installation.

2.3.7.5 Barriers

Barriers are required in each section of switchgear or service entrance equipment between metered and un-metered conductors and/or between sections reserved for Thunder Bay Hydro use and sections for Customer use.

2.3.7.6 Doors

Side-hinged doors shall be installed over all live electrical equipment where Thunder Bay Hydro personnel may be required to work (i.e. line splitters, unmetered sections of switchgear, breakers, switches, metering compartments, meter cabinets and enclosures). These hinged doors shall have provision for sealing and padlocking. Where bolts are used, they shall be of the captive knurled type. All outer-hinged doors shall open no less than 135°. All inner hinged doors shall open to a full 90°.

2.3.7.7 Auxiliary Connections

All connections to circuits such as fire alarms, exit lights and Customer instrumentation shall be made to the load-side of Thunder Bay Hydro's metering.

No Customer equipment shall be connected to any part of the Thunder Bay Hydro metering circuit.

2.3.7.8 Working Space

Clear working space shall be maintained in front of all equipment and from all side panels in accordance with the Ontario Electrical Safety Code.

2.3.7.9 Instrument Transformer Compartments

Where instrument transformers are incorporated in low voltage switchgear, the chamber size and number of instrument transformers shall be as shown in Appendix F of these Conditions. A separate **meter base** must be supplied and installed by the Customer, located to the satisfaction of Thunder Bay Hydro and as close as possible to the instrument transformer compartment. See Thunder Bay Hydro Engineering for specific metering requirements.

The meter base and compartment will be located in the same electrical room and connected by an empty 30 mm conduit. The length of this conduit shall not exceed 20 m, and shall include a maximum of three 90° bends. The conduit will be provided for the exclusive use of Thunder Bay Hydro. Fittings with removable covers are permitted only if designed to be sealed.

The meter base shall be grounded by a minimum #6 copper grounding conductor, not installed in the above conduit. The Customer shall install a strong nylon or poly-rope pull line in the conduit, with an excess of 1500 mm loop left at each end.

The final layout and arrangements of components must be approved by Thunder Bay Hydro prior to fabrication of equipment.

Where two or more circuits are totalized, or where remote totalizing is involved, or where instrument transformers are incorporated in high voltage switchgear (greater than 750 V); Thunder Bay Hydro will issue specific metering requirements.

2.3.7.10 Interval Metering

Interval meters will be installed for all new or upgraded services where the peak demand is forecast to be 500 kW or greater. Prior to the installation of an interval meter, the Customer must provide a 30mm conduit from its telephone room to the meter cabinet. The Customer will arrange for the installation of a telephone line, terminated in the meter cabinet for the exclusive use of Thunder Bay Hydro to retrieve interval meter data. The Customer will be responsible for the installation and ongoing monthly costs of operating the phone line. The phone line will be direct dial, voice quality, active 24 hours per day, and activated prior to meter installation.

Other Customers wishing to participate in the spot market pass-through pricing or that request interval metering shall compensate Thunder Bay Hydro for all incremental costs associated with that meter, including the capital cost of the interval meter, installation costs associated with the interval meter, ongoing maintenance (including allowance for meter failure), verification and re-verification of the meter, installation and ongoing provision of communication line or communication link with the Customer's meter, and cost of metering made redundant by the Customer requesting interval metering.

2.3.7.11 Meter Reading

The Customer must provide or arrange free, safe and unobstructed access during regular business hours to any authorized representative of Thunder Bay Hydro for the purpose of meter reading, meter changing, or meter inspection. Where the Customer's premises are closed during Thunder Bay Hydro's normal business hours, the Customer must, on reasonable notice, arrange such access at a mutually convenient time.

Where Thunder Bay Hydro is unable to obtain a meter reading, the Customer's bill shall be estimated based on the consumption from the same period of the previous year.

2.3.7.12 Final Meter Reading

When a service is no longer required, the Customer shall provide five (5) working days notice of the date the service is to be discontinued so that Thunder Bay Hydro can obtain a final meter reading as close as possible to the final reading date. The Customer shall provide access to Thunder Bay Hydro or its agents for this purpose. If a final meter reading is not obtained, the Customer shall pay a sum based on an estimated demand and/or energy for electricity used since the last meter reading, as determined by Thunder Bay Hydro.

2.3.7.13 Inaccurate Energy Registration

Metering electricity usage for the purpose of billing is governed by the federal *Electricity and Gas Inspection Act* and associated regulations, under the jurisdiction of Measurement Canada, Industry Canada. Thunder Bay Hydro's revenue meters are required to comply with the accuracy specifications established by the regulations under the above Act.

In the event of incorrect electricity usage registration, Thunder Bay Hydro will determine the correction factors based on the specific cause of the metering error and the Customer's electricity usage history. The Customer shall pay, for all the electricity supplied, a reasonable sum based on the reading of any meter formerly or subsequently installed on the premises by Thunder Bay Hydro, due regard being given to any change in the characteristics of the installation and/or the demand. If Measurement Canada, Industry Canada determines that the Customer was overcharged, Thunder Bay Hydro will reimburse the Customer for the amount incorrectly billed.

If the incorrect measurement is due to reasons other than the accuracy of the meter, such as incorrect meter connection, incorrect connection of auxiliary metering equipment, or incorrect meter multiplier used in the bill calculation, the billing correction will apply for the duration of the error. Thunder Bay Hydro will correct the bills for that period in accordance with the regulations under the *Electricity and Gas Inspection Act.*

2.3.7.14 Meter Dispute Resolution

Metering inaccuracy is an extremely rare occurrence. Most billing inquiries can be resolved between the Customer and Thunder Bay Hydro without resorting to the meter dispute test.

Either Thunder Bay Hydro or the Customer may request the service of Measurement Canada to resolve a dispute. If the Customer initiates the dispute, Thunder Bay Hydro will charge the Customer a meter dispute fee if the meter is found to be accurate and Measurement Canada rules in favor of the utility. Further, the disputed meter will be re-installed at the Customer's service location.

2.4 Tariffs and Charges

2.4.1 Service Connection

Charges for distribution services are made as set out in Thunder Bay Hydro's Tariff of Rates and Charges ("Rate Schedule"), available upon request from Thunder Bay Hydro or as posted on its website at http://www.tbhydro.on.ca. Notice of rate revisions will be published in major local newspapers or via bill inserts or otherwise directed by the OEB.

2.4.1.1 Customers Switching to Retailers

There are no physical service connection differences between Standard Supply Service (SSS) customers and third party retailer customers. The supply of electricity to both types of customers is delivered through the distribution system of Thunder Bay Hydro with the same distribution requirements. Therefore, all service connection requirements applicable to the SSS customers are applicable to a third party retailers' Customers.

2.4.1.2 Supply Deposits and Agreements

Where an owner proposes the development of premises that require Thunder Bay Hydro to place orders for equipment for a specific project and before actual construction begins, the owner is required to sign the Estimate to Connect and furnish a suitable deposit before such equipment is ordered by Thunder Bay Hydro.

2.4.2 Energy Supply

Customers may purchase their supply of electricity under contract from an electricity retailer or from Thunder Bay Hydro under SSS. Thunder Bay Hydro will supply and deliver electricity to all connected Customers according to its current Rate Schedule.

2.4.2.1 Standard Supply Service (SSS)

Thunder Bay Hydro's existing SSS Customers are Customers until Thunder Bay Hydro is informed by the Customer or the authorized retailer of the Customer of their switch to a competitive electricity supplier. The Service Transfer Request ("STR") must be made by the Customer or the Customer's authorized retailer.

For SSS Customers the price electricity is charged to consumers on a pass-through basis. Customers will pay a price based on the weighted average hourly spot market price of electricity. This price may be subject to such rebates or adjustments as may be required by law.

2.4.2.2 Retailer Supply

Customers transferring from SSS to a retailer shall comply with the STR requirements as outlined in Sections 10.5 through 10.5.6 of the Retail Settlement Code. All requests shall be submitted as an electronic file and transmitted through EBT Express. STR shall contain information as set out in Section 10.3 of the Retail Settlement Code.

If the information is incomplete, Thunder Bay Hydro shall notify the retailer or Customer about the specific deficiencies and await a reply before proceeding to process the transfer.

2.4.2.3 Wheeling of Energy

All Customers considering delivery of electricity through the Thunder Bay Hydro distribution system are required to contact Thunder Bay Hydro for technical requirements and applicable tariffs.

2.4.3 Security Deposits

All Customers must meet Thunder Bay Hydro's Security Deposit Policy as outlined in Appendix A of these Conditions of Service. Thunder Bay Hydro reserves the right to amend the policy from time to time.

2.4.4 Billing

In preparing an energy billing for standard supply service, Thunder Bay Hydro includes in its billing a number of charges mandated by third parties, such as:

- The Independent Electricity System Operator (IESO)
  - Under standard supply service - the price of the electrical energy commodity
- Hydro One
  - Transmission connection charge
  - Transmission network charges
- The Provincial Government
  - Debt retirement charge
  - Wholesale market service charge
  - Rural rate assistance
- Retailers
  - If you purchase your electricity from a retailer, but you receive your bills from Thunder Bay Hydro (i.e., distributor consolidated billing) the price of the electrical energy commodity will be the price supplied to us by your retailer.

The rates charged for the above services, with the exception of the market price for electricity as invoiced by the IESO, or retailer charges for the electrical energy commodity under distributor consolidated billing, are approved by the Ontario Energy Board. The retailer charges for the electrical energy commodity are based on agreements signed by the customer with their retailer.

Thunder Bay Hydro facilitates the operation of the electrical energy market by billing and collecting these amounts on behalf of these third parties. These may change from time to time.

Some Customers that sign agreements with electricity retailers may receive their invoice from their retailer. These charges will also appear on the retailer invoice (in addition to Thunder Bay Hydro's distribution charges).

2.4.4.1 Establishment of Billing Services

Prior to the establishment of billing services, a customer must provide to Thunder Bay Hydro the following:

a) two items of identification, with one containing a photograph;
b) a security billing deposit; and
c) a signed service agreement.

Failure to meet these requirements will delay the establishment of the supply of electrical energy.

2.4.4.2 Establishment of Rate Class

The establishment of a rate class appropriate to a customer is dependent on the nature of electrical service being supplied to the customer's building.

See Sections 3.1, 3.2, 3.3 and 3.4 and the tariff sheet for further details.

2.4.4.3 Billing Frequency

Thunder Bay Hydro may, at its option, render bills to its Customers on either a monthly, bi-monthly, quarterly or annual basis or such other periodic basis as may be determined from time to time.

2.4.4.4 Prorating Bills and Service Charges

Service and demand charges will be prorated for initial and final bills only. Charges will be based on a straight ratio calculation of the number of days of service to a standard 30-day month.

2.4.4.5 Estimating Bills

Reasonable attempts will be made to obtain a meter reading for all regular electricity bills, based on access to the meter (see Section 2.3.7.11 Meter Reading). If Thunder Bay Hydro has been unsuccessful in obtaining a meter reading, either through its authorized agents or via phone-in or mail-in Customer readings, the reading will be estimated. Estimates are done based on historical consumption information for the account, where possible. If there is not enough historical information on the account to provide an estimate, then historical information on the previous occupant of the location may be used instead. Demand readings will be estimated in a similar fashion when required.

2.4.4.6 Account Setup Charge

A setup charge shall be applied to all new accounts, regardless of the Customer's account history with Thunder Bay Hydro. The charge shall be at a rate approved by the Ontario Energy Board.

2.4.4.7 Arrears Certificate / Lawyer's Letter

When a property is purchased, the buyer's lawyer will typically request a form letter be filled out by Thunder Bay Hydro, which lists any equipment rentals, or outstanding arrears that are linked to the property. Thunder Bay Hydro shall levy a charge for each service address requested.

2.4.4.8 Transformer Ownership Credit

A credit will be provided for all Customers owning their own distribution transformer. The credit will be at a rate approved by the Ontario Energy Board.

2.4.4.9 Primary Meter Discount

Commercial Customers that are metered on the primary side of the transformer shall receive a discount to adjust for the transformer losses. The discount will be at a rate approved by the Ontario Energy Board.

2.4.4.10 Power Factor Adjustment

A Customer with measured demand will be billed for distribution services based on the measured kilowatts or 90% of the measured kilovolt-amperes, whichever is greater.

Any dispute under this part shall be resolved in accordance with Section 1.8 of these Conditions of Service.

2.4.5 Payments and Late Payment Charges

2.4.5.1 Payments

Unless otherwise agreed to between the Customer and Thunder Bay Hydro, all bills shall be payable, in full, on or before the due date clearly shown on the bill. Payments may be made in the following ways:

- At our office – deposit box inside or night deposit box outside*;
- At any of several authorized Depots located throughout the city;
- By mail – do not send cash*;
- With a bank debit card at an automated Kiosk at our office; or
- ATM Machine/ PC/Telephone banking through the Customer's bank, Trust Company or Credit Union.

** Cash, personal/certified cheques, and money orders are acceptable forms of payment, unless otherwise noted.*

2.4.5.2 Payment Plans

Thunder Bay Hydro shall offer the following payment plans to its Customers. Some restrictions may apply.

- Budget Billing – A monthly payment amount will be determined for the Customer's account based on historical consumption and bill amounts. This amount will be billed to the Customer each month. The Customer's account shall be reconciled annually, at which time, any residual amounts owing to Thunder Bay Hydro shall be paid in full or any residual amounts owing to the Customer will be applied to the Customer's next billing(s). Written notification of the outstanding balance shall be provided to the Customer in advance. If a change is required to the monthly payment amount based on large discrepancies in the actual energy charges, the Customer will be notified, in writing, in advance of the payment change. This plan is available to all Customers upon request, *except those enrolled with a retailer.* If payments are not maintained or remain outstanding, the Customer shall be automatically removed from the plan; standard billing and collection timelines shall then apply.

- Pre-authorized Payment – A pre-authorized bank debit of the net-billed amount shall be withdrawn from the Customer's bank account on the due date of the bill according to the billing cycle. This plan is available to all Customers upon request, *except those enrolled with a retailer under the retailer-consolidated billing option.*

- Customers may request to opt out of a payment plan at any time, at which point standard billing and collection timelines shall apply.

2.4.5.3 Late Payment Charges

All bills, including final bills, are due and payable sixteen (16) days from the date of mailing. A late payment charge (interest on past due accounts) shall be applied to all accounts not paid by the due date. If the Customer makes a partial payment on or before the due date, the late payment charge will be calculated based only on the outstanding amount of the bill.

2.4.5.4 Returned Cheque Charge

A charge shall be applied to the Customer's account for any payment that cannot be processed.

2.4.5.5 Collection of Account Charge

A collections charge shall be applied to a Customer's account when an authorized agent of Thunder Bay Hydro is sent to the Customer's premises for purposes of collecting arrears amounts.

2.4.5.6 Disconnection and Reconnection Charges

Ultimately, non-payment can lead to disconnection, and a reconnection will not be made until payment of arrears is made (including payment of a disconnection change). Thunder Bay Hydro's disconnection policy is explained in section 2.2 of these Conditions of Service. Following a service disconnect for non-payment, a reconnection charge shall be applied to a Customer's account when service is reconnected/restored. Thunder Bay Hydro's OEB-approved reconnection charges are set out in Appendix E.

Only one (1) reconnection charge or collection charge shall be applied in the same billing period following service disconnect for non-payment.

2.5 Customer Information

Thunder Bay Hydro shall process and handle requests for Customer information in accordance with the requirements of Chapter 11 of the Retail Settlement Code.

Thunder Bay Hydro shall not disclose specific information about a Customer unless the release of information had been authorized by that particular Customer or unless necessary for compliance with Market Rules or any Board approved Code or Standard.

Customers have the obligation to provide Thunder Bay Hydro with information that is true, complete and correct.

2.5.1 Billing Information

Thunder Bay Hydro shall address customer inquiries concerning distribution service, meter accuracy and bill calculation errors. Thunder Bay Hydro will refer all inquiries pertaining to retailer pricing or contract terms to the relevant retailer. Inquiries as to usage, including how usage might be modified, may be addressed by either Thunder Bay Hydro, for Standard Supply Service (SSS) Customers, or referred to the Customer's retailer.

2.5.2 Historical Information to Designated Parties

Customers have the right upon request to have historical usage information, information about their meter configuration and payment information sent to their service address or to any designated retailer or third party.

Upon written request by the Customer, Thunder Bay Hydro will provide to the Customer or one or more retailers, usage data, meter data and payment information. Thunder Bay Hydro shall provide data for no less than one calendar year's worth of information, unless the Customer has been connected to Thunder Bay Hydro's distribution system for less than one year. Thunder Bay Hydro will honour requests once a year for historical data to Retailers and Customers, if not delivered electronically through the EBT system. Thunder Bay Hydro, at its discretion, may charge a fee for any additional requests based on actual costs incurred. A request is considered delivery of data to a single address.

2.5.3 Historical Information to Third Parties

A third party who is not a retailer may request historical usage information with the written and signed authorization of the Customer to provide their historical usage information.

Thunder Bay Hydro will provide information appropriate for operational purposes that has been aggregated sufficiently, such that an individual's Customer information cannot reasonably be identified, at no charge to another distributor, a transmitter, the IESO or the OEB. Thunder Bay Hydro may charge a fee that has been approved by the OEB for all other requests for aggregated information.

At the request of a Customer, Thunder Bay Hydro will provide a list of retailers who have Service Agreements in effect within its distribution service area. The list will inform the Customer that an alternative retailer does not have to be chosen in order to ensure that the Customer receives electricity and the terms of service that are available under SSS.

SECTION 3: DISTRIBUTION ACTIVITIES (CUSTOMER CLASS SPECIFIC)

3.1 Residential

3.1.1 Definition of Class

This section refers to the supply of electrical energy to detached and semi-detached residential buildings as defined in the local zoning by-laws.

Where electricity is provided to a combined residential and business building, and the service does not provide for separate metering, the classification shall be at the discretion of Thunder Bay Hydro and shall be based on such considerations as the estimated predominant consumption.

Services to residential buildings other than detached or semi-detached will be treated the same as General Service Class Customers and will be subject to the provisions of either Section 3.2 or 3.3 of these Conditions of Service, as applicable.

For the purposes of connections under these Conditions of Service, subdivision developments, multi-units or townhouse-type developments are not considered as Residential. They will be treated as General Service Class developments and subject to the provisions of Section 3.3 of these Conditions of Service.

3.1.2 General Information

All new lots created by severance or subdivision shall be supplied by underground secondary service where it enters the Customer's property in accordance with the City of Thunder Bay's requirements.

There shall be only one service to a building except for semi-detached buildings. For semi-detached buildings with required fire separation, there may be two services.

In circumstances where multiple services are installed to a single dwelling and one service is to be upgraded, the upgraded service will replace all existing services.

Residential services will include all services up to and including 400 A, 120/240 V single-phase 3-wire. Residential Customers requiring an electrical service greater than 400 A single-phase 120/240 V shall be treated the same as General Service in Section 3.2 or 3.3 as applicable.

3.1.3 Information Requirements for Service

At the time the request is made for service, the Customer shall submit the following:

- Address (complete municipal address);
- Name, address, telephone number, fax number and e-mail address of the Owner;
- Previous address of the Owner;

- Name, address, telephone number, fax number and e-mail address of the person to contact regarding the technical aspects of the service;
- Required in service date;
- Proposed service entrance capacity and voltage rating of the service entrance equipment;
- Survey plan and site plan indicating the proposed location of the service entrance equipment with respect to rights-of-way and lot lines; and
- All information required for setting up a billing account.

3.1.4 Point of Demarcation

The Demarcation and Ownership Points are as follows:

- for Overhead Secondary at the property line (not requiring transformation facilities on private property), it is the top of the Customer's service mast or the line-side of the meter base where the service transitions to underground;

- for Overhead Primary at the property line (requiring transformation facilities on private property), the Demarcation is at the service mast or the line-side of the meter base for underground secondaries. On private property, Thunder Bay Hydro shall not own the poles, hardware and primary conductors up to and including the transformation pole as these are not part of the components of the Basic Minimum Service.;

- for Secondary Underground at the property line (not requiring transformation facilities on private property), it is the line-side of the meter base.

- for dedicated Primary Underground (not part of Thunder Bay Hydro's main distribution system) onto Customer's property the Demarcation is at the line-side of the meter base. On private property, Thunder Bay Hydro shall not own the dedicated primary underground cable up to the transformer as this is not a component of the Basic Minimum Service.;

In all cases on private property, the Customer shall own and maintain any poles from the first point of attachment and all ducts as these are not part of the components of the Basic Minimum Service.

In all cases, Thunder Bay Hydro owns the revenue meter.

The Operational Demarcation Point for a residential service is at the meter base. Thus Thunder Bay Hydro has operational control of all equipment whether owned by Thunder Bay Hydro or not up to and including the meter.

3.1.5 Metering

Meters for new or upgraded residential services will be mounted outdoors on a meter socket approved by Thunder Bay Hydro. Where revenue metering is located inside a residence, it will be relocated by the owner to the exterior of the building at the time of upgrading.

Each dwelling of a semi-detached or duplex arrangement shall be separately metered.

A meter socket base must be installed outside on the line-side of the main disconnect on all single phase services up to and including 400 A. All 400 A services are to have a 400 A self-shorting residential outdoor meter base with 400/200:5 current transformer accommodation. The meter and current transformers will be supplied by Thunder Bay Hydro.

a) Meter sockets of an approved manufacturer shall be provided. The Customer should contact Thunder Bay Hydro to confirm details.

b) Clear unobstructed access must be maintained to and in front of the meter location.

c) The approved meter base shall be mounted directly below the service mast such that the midpoint of the meter is 1.73 m (± 100 mm) above finished grade within 1 m of the face of the building (in front of any existing or proposed fence), unless otherwise approved by Thunder Bay Hydro.

3.1.6 Overhead Services for Residential Service

3.1.6.1 Minimum Requirements

In addition to the requirements of the Ontario Electrical Safety Code, the following conditions shall apply:

(i) A clevis type insulator is to be supplied and installed by the Customer.

(ii) This point of attachment device must be located:

(a) Not less than 4.5 m (15 feet) nor greater than 5.5 m (18 feet) above grade (to facilitate proper ladder handling techniques).

(b) Between 150 mm and 300 mm (6-12 inches) below the service head.

(c) Within 914 mm (3 feet) of the face of the building.

(iii) Clearance must be provided between utility conductors and finished grade of at least 6 m (19 feet) over traveled portions of the road allowance and 4.5 m (15 feet) over all other areas. A minimum horizontal clearance of 1.0 m (39 inches) must be provided from utility conductors and any second storey windows.

(iv) A 4-jaw meter socket of an approved manufacturer shall be provided. Certain areas will require a 5-jaw socket as determined by Thunder Bay Hydro. The Customer should contact Thunder Bay Hydro to confirm details.

3.1.6.2 Services Over Swimming Pools

Although the Ontario Electrical Safety Code allows electrical conductors to be located at adequate height, Thunder Bay Hydro will **not** allow new electrical conductors to be located above swimming pools.

Where a swimming pool is to be installed it will be necessary to relocate, at the property owner's expense, any electrical conductors located directly over the proposed pool location.

Where overhead service conductors are in place over an existing swimming pool, Thunder Bay Hydro will provide up to 30 m of overhead service conductors, at no charge, to allow rerouting of the service. The property owner will pay any other costs.

3.2 General Service (Under 50 kW)

3.2.1 Definition of Class

All non-Residential Customers with an average peak demand under 50 kW over the preceding twelve months are to be classified as General Service (Under 50 kW). For new Customers without prior billing history, the peak demand will be based on 90% of the proposed capacity or installed transformation.

For three-phase services, the Customer shall maintain a balanced three-phase load. Where single-phase step down transformers are employed by the Customer on their premises, they shall not exceed 25% of total connected transformation capacity.

Apartment buildings or multi-unit complexes are treated as General Service in Section 3.3 or 3.4 as applicable.

3.2.2 General Information

See Section 2.3.4.2 for standard voltages available from Thunder Bay Hydro. The Customer shall obtain the prior approval from Thunder Bay Hydro for the use of any specific voltage at any specific location.

Where practical there shall be only one Point of Entry to each land parcel. In all cases, there shall be only one service to a building.

In circumstances where multiple services are installed to a General Service Customer's building and one service is to be upgraded, the upgraded service will replace all existing services.

It is the Customer's responsibility to ensure that all transformers, poles and conductors located on private property are kept clear of any obstructions in order to facilitate regular and emergency maintenance. Obstructions may include vegetation, structures and landscaping. Removal of any obstruction by Thunder Bay Hydro will be at the expense of the Customer.

3.2.3 Information Requirements for Service

At the time the request is made for service, the Customer shall submit the following:

- Address (complete municipal address);
- Name, address, telephone number, fax number and e-mail address of the Owner;
- Name, address, telephone number, fax number and e-mail address of the person to contact regarding the technical aspects of the service;
- Required in-service date;
- proposed service entrance equipment's rated capacity (amperes) and voltage rating and metering requirements;
- Proposed total load details in kVA and/or kW (winter and summer);
- Locations of other services, gas, telephone, water and cable TV;

- Details respecting heating equipment, air conditioners, motor starting current limitation and any appliances which demand a high consumption of electrical energy;
- Survey plan and electrical site plan drawn to scale, showing the following:
    a) indicating the proposed location of the service entrance equipment with respect to public rights-of-way and lot lines;
    b) location of metering equipment; and
    c) indication of how Thunder Bay Hydro will gain direct outside access to the meter(s);
- Schematic drawing of the main secondary distribution system, showing the following:
    a) voltage;
    b) size, number, and material of the service entrance conductors;
    c) main disconnect switch, including size in amperes;
    d) metering equipment; and
    e) disconnect switches for each metered sub-feed;
- Number and size of services to individual units;
- Plan to scale, showing the electrical room and provision for metering;
- Grading and site plan showing building(s) in relation to existing and proposed property lines, other buildings, streets and driveways, and the location of other sources, gas, telephone and water;
- All information required to set up a billing account; and
- Electrical, architectural and/or mechanical drawings as required by Thunder Bay Hydro.

3.2.4 Point of Demarcation

The Demarcation Points are as follows:

- for Overhead Secondary at the property line (not requiring transformation facilities on private property), it is the top of the Customer's service mast or the line-side of the meter base/junction box where the service transitions to underground;

- for Overhead Primary at the property line (requiring transformation facilities on private property), it is the first point of attachment on private property. Thunder Bay Hydro will supply at a cost to the Customer and assume ownership and maintenance of the transformer;

- for Secondary Underground service (not requiring transformation facilities on private property), it is the line-side of the exterior mounted meter base or junction box; or

- for Primary Underground services onto Customer's property it is to the secondary terminals of the transformer. Thunder Bay Hydro will supply at a cost to the Customer and assume ownership and maintenance of the transformer.

In all cases on private property, the Customer shall own and maintain any poles from the first point of attachment and all ducts as these are not part of the components of the Basic Minimum Service.

In all cases, Thunder Bay Hydro owns the revenue meter.

The Operational Demarcation Point is, for both overhead and underground services, at the exterior mounted meter base or junction box, whichever comes first.

3.2.5 Location of Service Equipment

The location of the supply point, primary and secondary cables, transformer, and metering will be established through consultation with Thunder Bay Hydro for both new and upgraded services. Failure to comply may result in the relocation of the service at the owner's expense.

3.2.6 Metering

The Customer shall provide the following equipment in order to accommodate Thunder Bay Hydro's meter installation:

a) If the service is 120/240 V, 200 A, a single-phase 4-jaw outdoor meter socket; or

b) If the service is 120/240 V, 400 A, single-phase, a 4-jaw outdoor meter socket; or

c) If the service is 120/208 V, 200 A, three-phase, a 7-jaw indoor meter socket connected on the load-side of the main disconnecting device; or

d) If the service is 347/600 V, 100 A, three-phase, a 7-jaw indoor meter socket with an insulated neutral, and connected on the load-side of the main disconnecting device.

See Section 2.3.7 and Appendix F of these Conditions of Service for requirements.

3.2.7 Electrical Room Requirements (As Applicable)

The owner is required to supply and maintain an electrical room of sufficient size to accommodate the service entrance and meter requirements of the tenants and provide clear working space in accordance with the Ontario Electrical Safety Code.

Access doors, panels, slabs, and vents shall be kept free from obstructing objects. The Customer will provide unimpeded and safe access to Thunder Bay Hydro at all times for the purpose of installing, removing, maintaining, operating or changing transformers and associated equipment.

The electrical room must be located to provide safe direct access from the outside so that it is readily accessible to Thunder Bay Hydro's employees and agents at all hours to permit meter reading and to maintain electric supply. This room must be locked. The owner shall install a padbolt with mortise strike. Thunder Bay Hydro shall provide a secure arrangement so that Thunder Bay Hydro's padlock can be installed as well as the Customer's lock.

The electrical room shall not be used for storage or contain equipment foreign to the electrical installation within the area designated as safe working space. All stairways leading to electrical rooms above or below grade shall have a handrail on at least one side as per the Ontario Building Code and shall be located indoors.

Outside doors providing access to electrical rooms must have at least 150 mm clearance between final grade and the bottom of the door.

Electrical rooms 'on' or 'below' grade must have a drain including a "P" trap complete with a non-mechanical priming device and a backwater valve connected to the sanitary sewer. The electrical room floor must slope 6 mm/300 mm or 2% towards the drain.

The electrical room shall have a minimum ceiling height of 2.2 m clear, be provided with adequate lighting at the working level, in accordance with Illuminating Engineering Society (I.E.S.) Standards, and a 120 V convenience outlet. The lights and convenience outlet noted above and any required vault circuit shall be supplied from a panel located and clearly identified in the electrical room.

The owner shall identify each Customer's metered service by address and/or unit number in a permanent and legible manner. The identification shall apply to all main switches, breakers and to all meter cabinets or meter mounting devices that are not immediately adjacent to the switch or breaker. The electrical room shall be visibly identified from the outside.

3.3 General Service (50 to 1000 kW)

3.3.1 Definition of Class

All non-residential Customers with an average peak demand between 50 kW and 1000 kW over the preceding twelve months are to be classified as General Service (50 kW to 1000 kW) Customers. For new Customers without prior billing history, the peak demand will be based on 90% of the proposed capacity or installed transformation.

The maximum allowed single phase service is 120/240 V, 400 A. For three-phase services, the Customer shall maintain a balanced three-phase load. Where single-phase step down transformers are employed by the Customer on their premises, they shall not exceed 25% of total connected transformation capacity.

3.3.2 General

See Section 2.3.4.2 for standard voltages available from Thunder Bay Hydro. The Customer shall obtain the prior approval from Thunder Bay Hydro for the use of any specific voltage at any specific location.

Where practical there shall be only one Point of Entry to each land parcel. In all cases, there shall be only one service to a building.

In circumstances where multiple services are installed to a General Service Customer's building and one service is to be upgraded, the upgraded service will replace all existing services.

It is the Customer's responsibility to ensure that all transformers, poles and conductors located on private property are kept clear of any obstructions in order to facilitate regular and emergency maintenance. Obstructions may include vegetation, structures and landscaping. Removal of any obstruction by Thunder Bay Hydro will be at the expense of the Customer.

3.3.3 Information Requirements for Service

At the time the request is made for service, the Customer shall submit the following:

- Address (complete municipal address);
- Name, address, telephone number, fax number and e-mail address of the Owner;
- Name, address, telephone number, fax number and e-mail address of the person to contact regarding the technical aspects of the service;
- Required in-service date;
- proposed service entrance equipment's rated capacity (amperes) and voltage rating and metering requirements;
- Proposed total load details in kVA and/or kW (winter and summer);
- Locations of other services, gas, telephone, water and cable TV;
- Details respecting heating equipment, air conditioners, motor starting current limitation and any appliances which demand a high consumption of electrical energy;

- Survey plan and electrical site plan drawn to scale, showing the following:
    a) indicating the proposed location of the service entrance equipment with respect to public rights-of-way and lot lines;
    b) location of metering equipment; and
    c) indication of how Thunder Bay Hydro will gain direct outside access to the meter(s);
- Schematic drawing of the main secondary distribution system, showing the following:
    a) voltage;
    b) size, number, and material of the service entrance conductors;
    c) main disconnect switch, including size in amperes;
    d) metering equipment; and
    e) disconnect switches for each metered sub-feed;
- Number and size of services to individual units;
- Plan to scale, showing the electrical room and provision for metering;
- Grading and site plan showing building(s) in relation to existing and proposed property lines, other buildings, streets and driveways, and the location of other sources, gas, telephone and water;
- All information required to set up a billing account; and
- Electrical, architectural and/or mechanical drawings as required by Thunder Bay Hydro.

Where project drawings are required for Thunder Bay Hydro's approval, for items under Thunder Bay Hydro's jurisdiction, the Customer or its authorized representative must ensure that proposal drawings are fully in compliance with Thunder Bay Hydro's standards. Approval of project drawings by Thunder Bay Hydro shall not relieve the Customer of its responsibility in respect of full compliance with Thunder Bay Hydro's standards. In all cases, one copy of all relevant drawings must be submitted to Thunder Bay Hydro. Where the Customer requires an approved copy to be returned, two copies of all plans must be submitted.

Prior to the preparation of a design for a service, the Customer will provide the following information to Thunder Bay Hydro including the approximate date that the Customer requires the electrical service and the due date that Thunder Bay Hydro's civil construction drawings are required to co-ordinate with site construction:

3.3.3.1 Site & Grading Plans

Indicate the lot number, plan numbers and, when available, the street number. The site plan shall show the location of the Building on the property relative to the property lines, any driveways and parking areas and the distance to the nearest intersection. All elevations shall be shown for all structures and proposed installations.

3.3.3.2 Mechanical Servicing Plan

Show the location on the property of all services proposed and/or existing such as water, gas, storm and sanitary sewers, telephone, etc.

3.3.3.3 Floor Plan

Show the service location, other services location, driveway, parking and indicate the total gross floor area of the building.

3.3.3.4 Duct Bank Location

Show the preferred routing of the underground duct bank on the property. This is subject to approval by Thunder Bay Hydro.

3.3.3.5 Transformer Location

Indicate the preferred location on the property for the high voltage transformation. This is subject to approval by Thunder Bay Hydro. Transformation will be vault, pad, submersible type or pole-mounted depending on the project load requirements.

3.3.3.6 Electrical Meter Room

Indicate preferred location in the building of the meter room and the main switchboard.

3.3.3.7 Single Line Diagram

Show the main service entrance switch capacity, the required supply voltage, and the number and capacity of all sub-services showing provision for metering facilities, as well as the connected load breakdown for lighting, heating, ventilation, air conditioning, etc. Also, indicate the estimated initial kilowatt demand and ultimate maximum demands. Provide protection equipment information where coordination is required between Thunder Bay Hydro and Customer owned equipment. Fusing will be determined later by Thunder Bay Hydro to co-ordinate with the transformer size selected.

3.3.3.8 Switchgear

Submit three copies of any service entrance switchgear to be installed for Thunder Bay Hydro's approval, including interlocking arrangement if required.

3.3.3.9 Substation Information

Where a Customer-owned substation is to be provided, the owner will be required to provide the following in addition to the site information outlined above.

- All details of the transformer, including kVA capacity, short circuit rating (in accordance with 3.3.5.1), primary and secondary voltages, impedance and cooling details.
- A site plan of the transformer station showing the equipment layout, proposed primary connections, grounding and fence details, where applicable.
- A coordination study for protection review.

3.3.4 Point of Demarcation

The Demarcation Points are as follows:

- for Overhead Secondary at the property line of 347/600 V (allowed up to 300 kVA) or 120/208 V (allowed up to 112.5 kVA), not requiring transformation facilities on private property, it is the top of the Customer's service mast or the line-side of the meter base/junction box where the service transitions to underground;

- for Overhead Primary at the property line requiring transformation facilities on private property it is the first point of attachment on private property. Thunder Bay Hydro will supply at a cost to the Customer and assume ownership and maintenance of transformers up to 1000 kVA;

- for Secondary Underground at the property line (allowed up to 300 kVA), it is the line-side of the exterior mounted meter base or junction box; or

- for Primary Underground onto Customer's property it is to the secondary terminals of the transformer. Thunder Bay Hydro will supply at a cost to the Customer and assume ownership and maintenance of transformers up to 1000 kVA.

In all cases on private property, the Customer shall own and maintain any poles from the first point of attachment and all ducts.

In all cases, Thunder Bay Hydro owns the revenue meter.

3.3.5 Location of Service and Equipment

See Section 3.2.5

3.3.6 Metering

The Customer shall provide the following equipment in order to accommodate Thunder Bay Hydro's meter installation:

a) for self-contained metering up to 200 A – a self-contained meter installation at low voltage where the rating of the Customer's main disconnecting device does not exceed 200 A shall be provided with:

- 120/240 V, 200 A, single-phase 4-jaw outdoor meter socket connected on the load-side of the main disconnecting device; or

- 120/208 V, 200 A, three-phase 7-jaw indoor meter socket connected on the load-side of the main disconnecting device; or

- 347/600 V, 200 A, three-phase 7-jaw indoor meter socket with an insulated neutral jaw, and connected on the load-side of the disconnecting device;

b) for 120/240 V, 400 A – a single-phase transformer-type meter installation at 120/240 V where the rating of the Customer's main disconnecting device ranges from greater than 200 A up to 400 A shall be provided with:

- a 400 A self-shorting outdoor meter base with 400/200:5 A current transformer accommodations. Thunder Bay Hydro will supply the meter and current transformers at the Customer's expense;

c) for three-phase less than 500 kW – a three-phase transformer-type meter installation that is not equipped with interval meters and where the monthly average peak demand during a calendar year is forecast by Thunder Bay Hydro, not to exceed 500 kW shall be provided with:

- meter base to be located in electrical room as per Section 3.3.7 of these Conditions of Service;
- meter base and instrument transformer compartment specifications to be in accordance with Appendix F of these Conditions of Service;
- switchgear utility compartment in accordance with Appendix F of these Conditions of Service;
- 25 mm conduit from the instrument transformer enclosure to the meter enclosure;

d) for three-phase greater than 500 kW – a transformer-type meter installation for a secondary service where the monthly peak demand during a calendar year is forecast by Thunder Bay Hydro to exceed 500 kW is required to have an interval meter and shall provide:

- meter base to be located in electrical room as per Section 3.3.7 of these Conditions of Service;
- meter base and instrument transformer compartment specifications to be in accordance with Appendix F of these Conditions of Service;
- switchgear utility compartment in accordance with Appendix F of these Conditions of Service.
- 31 mm conduit from the instrument transformer enclosure to the meter enclosure;
- provisions for interval metering will be made as per Section 2.3.7.10
- a voice grade direct access telephone line that is active 24-hours every day, and protected by a 13 mm conduit from the telephone entrance into the meter enclosure.

In addition, see Section 2.3.7 and Appendix F, of these Conditions of Service for requirements.

3.3.7 Electrical Room Requirements

Where the size of the Customer's electrical service warrants, the Customer will be required to provide facilities on its property and an easement as required (i.e. on the premises to be served), acceptable to Thunder Bay Hydro, to house the necessary transformer(s) and/or switching equipment. Thunder Bay Hydro will provide planning details upon application for service.

The owner is required to supply and maintain an electrical room of sufficient size to accommodate the service entrance and meter requirements of the tenants and provide clear working space in accordance with the Ontario Electrical Safety Code.

In order to allow for an increase in load, the owner shall provide spare wall space so that at least 30% of the Customers supplied through meter sockets can accommodate meter cabinets at a later date.

The electrical room must be separate from, but adjacent to, the transformer pad / vault. It must be located to provide safe access from the outside or main hallway, and not from an adjoining room, so that it is readily accessible to Thunder Bay Hydro's employees and agents at all hours to permit meter reading and to maintain electric supply. This room must be locked. The owner shall install a pad bolt with mortise strike. Thunder Bay Hydro shall provide a secure arrangement so that Thunder Bay Hydro's padlock can be installed as well as the Customer's lock.

The electrical room shall not be used for storage or contain equipment foreign to the electrical installation within the area designated as safe working space. All stairways leading to electrical rooms above or below grade shall have a handrail on at least one side as per the Ontario Building Code and shall be located indoors.

Outside doors providing access to electrical rooms must have at least 150 mm clearance between final grade and the bottom of the door. Electrical rooms 'on' or 'below' grade must have a drain including a "P" trap complete with a non-mechanical priming device and a backwater valve connected to the sanitary sewer. The electrical room floor must slope 6 mm/300 mm or 2% towards the drain.

The electrical room shall have a minimum ceiling height of 2.2 m clear, be provided with adequate lighting at the working level, in accordance with Illuminating Engineering Society (I.E.S.) standards, and a 120 V convenience outlet. The lights and convenience outlet noted above and any required vault circuit shall be supplied from a panel located and clearly identified in the electrical room.

The owner shall identify each Customer's metered service by address and/or unit number in a permanent and legible manner. The identification shall apply to all main switches, breakers and to all meter cabinets or meter mounting devices that are not immediately adjacent to the switch or breaker. The electrical room shall be visibly identified from the outside.

3.3.8 Transformation – Utility Owned

Thunder Bay Hydro will supply at a cost to the Customer and assume ownership of transformation up to 1000 kVA. The Customer may own their own transformation assuming all maintenance and replacement costs, as well as receiving a transformation credit allowance. Unless noted otherwise, transformation will be on the Customer's property, and on foundations or transformer rooms supplied by the Customer. Thunder Bay Hydro will determine the size of the transformer that it will supply.

When the transformation is supplied by Thunder Bay Hydro, it must be accessible by a roadway/parking lot capable of carrying heavy trucks. This roadway/parking lot is to facilitate the installation, repair or replacement of the transformer by Thunder Bay Hydro personnel. An access roadway, when required, will be installed and maintained by the Customer.

Depending upon location, Thunder Bay Hydro may require concrete filled steel bollards (bumper posts) in accordance with Thunder Bay Hydro specifications.

3.3.9 Technical Considerations

3.3.9.1 Short Circuit Ratings

- 14400/25940 V Supply: The Customer's protective equipment shall have a minimum three phase, short circuit rating of 750 MVA symmetrical. The asymmetrical current is 27000 A (1.6 factor used).

- 7200/12470 V Supply: The Customer's protective equipment shall have a minimum three phase, short circuit rating of 75 MVA symmetrical. The asymmetrical current is 4500 A (1.6 factor used.)

- 2400/4160 V Supply: The Customer's protective equipment shall have a minimum three phase, short circuit rating of 100 MVA symmetrical. The asymmetrical current is 16400 A (1.6 factor used.)

- 600/347 V Supply: Available short circuit current may be obtained upon request to Thunder Bay Hydro.

- 208/120 V Supply: Available short circuit current may be obtained upon request to Thunder Bay Hydro.

3.3.9.2 Primary Fusing

All equipment connected to the Thunder Bay Hydro's distribution system shall satisfy the short circuit ratings specified in Section 3.3.9.1. The Customer and/or the Customer's consultant shall specify the fuse link rating and demonstrate coordination with Thunder Bay Hydro's upstream protection including station breakers and/or distribution fuses. The Customer shall submit a coordination study to Thunder Bay Hydro for verification to ensure coordination with upstream protection including station breakers and/or

distribution fuses. The Customer shall maintain an adequate supply of spare fuses to ensure availability for replacement in the event of a fuse blowing.

3.3.9.3 Basic Impulse Level (B.I.L.)

The Customer's apparatus shall have a minimum Basic Impulse Level in accordance with the following Supply Voltages:

a) 2400/4160 - 60 kV B.I.L.
b) 7200/12470 - 95 kV B.I.L
c) 14400/25940 - Grounded Wye primary 125 kV B.I.L.

3.4 General Service (Above 1000 to 5000 kW) and Large Users (Above 5000 kW)

3.4.1 Definition of Class

All non-Residential Customers with an average peak demand above 1000 to 5000 kW over the preceding twelve months are to be classified as General Service (Above 1000 to 5000 kW). For new Customers without prior billing history, the peak demand will be based on 90% of the proposed capacity or installed transformation.

All non-Residential Customers with an average peak demand above 5000 kW over the preceding twelve months are to be classified as General Service (Above 5000 kW). For new Customers without prior billing history, the peak demand will be based on 90% of the proposed capacity or installed transformation.

3.4.2 General

See Section 2.3.4.2 for standard voltages available from Thunder Bay Hydro. The Customer shall obtain the prior approval from Thunder Bay Hydro for the use of any specific voltage at any specific location.

Where practical there shall be only one Point of Entry to each land parcel. In all cases, there shall be only one service to a building.

In circumstances where multiple services are installed to a General Service Customer's building and one service is to be upgraded, the upgraded service will replace all existing services.

It is the Customer's responsibility to ensure that all transformers, poles and conductors located on private property are kept clear of any obstructions in order to facilitate regular and emergency maintenance. Obstructions may include vegetation, structures and landscaping. Removal of any obstruction by Thunder Bay Hydro will be at the expense of the Customer.

3.4.3 Information Requirements for Service

For details see Section 3.3.3.

3.4.4 Point of Demarcation

The Operational and Ownership Demarcation Point for a General Service Customer, in this section, is as follows:

- for Overhead Primary requiring transformation facilities on private property it is the first point of attachment, which shall be the line-side of the Customer's primary load break switch on private property,
- for Primary Underground it is the line-side of the Customer's padmount primary load break switch located just inside the Customer's property.

In all cases on private property, the Customer shall own and maintain any poles from the first point of attachment and all ducts.

In all cases, Thunder Bay Hydro owns the revenue meter.

3.4.5 Location of Service and Equipment

For details see Section 3.2.5.

3.4.6 Metering

The Customer shall provide the following equipment in order to accommodate Thunder Bay Hydro's meter installation:

- provision for instrument transformers as per Appendix F of these Conditions of Service;
- meter cabinet, weatherproof if located in an outside installation, as per Appendix F of these Conditions of Service;
- 31 mm conduit from the instrument transformers to the meter enclosure;
- a voice grade direct access telephone line that is active 24 hours every day and protected by a 13 mm conduit from the telephone entrance equipment to the meter enclosure as per Section 2.3.7.10
- 120 V, 15 A fused auxiliary power supply to be supplied to the inside of the metering cabinet with one (1) GFI duplex receptacle;
- in addition, service registration as a wholesale meter point must meet IESO requirements;
- in addition, see Section 2.3.7 and Appendix F of these Conditions of Service for requirements.

3.4.7 Electrical Requirements

Where a primary service is provided to a Customer-owned substation, the Customer shall install and maintain such equipment in accordance with all applicable laws, codes, regulations, and Thunder Bay Hydro's requirements for high voltage installations. Thunder Bay Hydro will provide system requirement details upon application for service.

Customer-owned substations include transformers and switchgear located in a suitable room or enclosure, owned and maintained by the Customer, and supplied at primary voltage: i.e. the Supply Voltage is greater than 750 V.

All high voltage distribution services are three-phase, 4-wire. The Customer is required to bring out a neutral conductor for connection to the Thunder Bay Hydro's distribution system neutral. If not required for Customer's use, this neutral shall be terminated to the

Customer's station ground system. Thunder Bay Hydro will provide Customer interface details and requirements for high voltage supplies.

It is recommended that Customers' transformers have voltage taps in their primary windings as shown below:

Transformer Primary Voltage	Recommended Primary Voltage Taps				
	+5%	+2.5%	0%	-2.5%	-5%
24,940/14,440 V Grd Y	26,187 V	25,564 V	24,940 V	24,317 V	23,693 V
12,470/7,200 V Grd Y	13,094 V	12,782 V	12,470 V	12,158 V	11,847 V
4,160/2,400 V Grd Y	4,368 V	4,264 V	4,160 V	4,056 V	3,952 V

Transformers other than listed may be suitable but shall not be connected without the specific written approval of Thunder Bay Hydro.

Customer-owned substations, prior to energization, must be inspected by both the Electrical Safety Authority and Thunder Bay Hydro. The owner will provide a pre-service inspection report to Thunder Bay Hydro. A Qualified Contractor will prepare the certified report to Thunder Bay Hydro.

The Customer shall inspect their own respective substations in accordance with the Distribution System Code. The minimum inspection cycles for Customer specific substations are one year for open substations and three years for enclosed substations. To facilitate and encourage the maintenance of this equipment, Thunder Bay Hydro will provide one power interruption annually, at no charge, in lieu of or coincident to interruptions arranged for the installation, maintenance, and testing of vault fire alarm detectors. This no-charge service will be scheduled during Thunder Bay Hydro's normal business hours, Monday to Friday, but the time cannot necessarily be guaranteed. Thunder Bay Hydro may charge Customers for power interruption requests arranged at times other than as outlined above.

3.4.8 Transformation

A General Service (Above 1000 – 5000 kW) and (Above 5000 kW) Customer shall provide, own and be responsible for transformation facilities from high voltage to low voltage at the Customer's premises and, as such, shall construct, maintain and operate said transformation facilities in accordance with the requirements of the Ontario Electrical Safety Code.

Customer-owned transformers connected to Thunder Bay Hydro's distribution system shall be built in accordance with CAN/CSA Standard C802, Maximum Losses for Distribution, Power and Dry Type Transformers. Impedances that exceed the values specified in the standard are not acceptable. For transformers larger than 3000 kVA, total losses that exceed 0.8% of the kVA rating of the transformer are not acceptable.

3.4.9 Technical Information and Considerations

The same information and considerations apply as for other General Service Customers. Refer to Subsection 3.3.3 and 3.3.9 for applicable requirements.

3.5 Embedded Generation

The Generator Classifications set forth in the Distribution System Code are outlined in the table below:

Generator Classification	Rating
Micro	≤ 10 kW, for customer's own use
Small	(a) ≤ 500 kW connected on distribution system voltage < 15 kV (b) ≤1 MW connected on distribution system voltage ≥15 kV
Mid-Sized	(a) > 500 kW but ≤ 10 MW connected on distribution system voltage < 15 kV (b) > 1 MW but ≤ 10 MW connected on distribution system voltage ≥15 kV
Large	> 10 MW

Section 3.5 does not apply to the connection or operation of an emergency backup generation facility or an embedded generation facility that is used exclusively for load displacement purposes. Refer to Subsection 2.3.6 for applicable requirements.

3.5.1 Connection Agreement

Thunder Bay Hydro shall enter into a Connection Agreement with all existing Customers who have an embedded generation facility connected to the Thunder Bay Hydro distribution system and also with all new Customers prior to connecting a new generation facility. For micro, small, mid-sized, and large embedded generation facilities, the Connection Agreement shall be in the form set out in Appendix E of the Distribution System Code.

3.5.2 Connection Process

Thunder Bay Hydro has created an "Embedded Generation Connection Overview", which is available upon request and contains the following information:

(a) the process for having a generation facility connected to the Thunder Bay Hydro distribution system, including any form necessary for the application;

(b) information regarding any approvals from the ESA, the IESO, OEB, OPA, or a transmitter that are required before Thunder Bay Hydro will connect a generation facility to its distribution system;

(c) the technical requirements for being connected to the Thunder Bay Hydro distribution system including the metering requirements; and

(d) the standard contractual terms and conditions for being connected to the Thunder Bay Hydro distribution system.

Subject to all applicable laws, Thunder Bay Hydro will make all reasonable efforts in accordance with the provisions of Section 3.5 to promptly connect to its distribution system a generation facility, which is the subject of an application for connection.

3.5.3 Connection of Micro-Generation Facilities

A person who wishes to connect a micro-embedded generation facility to the Thunder Bay Hydro distribution system shall submit an application to Thunder Bay Hydro providing the following information:

(a) the name-plate rated capacity of each unit of the proposed generation facility and the total name-plate rated capacity of the proposed generation facility at the connection point;

(b) the fuel type of the proposed generation facility;

(c) the type of technology to be used; and

(d) the location of the proposed generation facility including address and account number where available.

Where the proposed micro-embedded generation facility is located at an existing Customer connection, Thunder Bay Hydro shall, within fifteen (15) days of receiving the application, provide an Estimate to Connect or provide reasons for refusing to connect the proposed generation facility. Thunder Bay Hydro shall give the applicant at least thirty (30) days to accept the Estimate to Connect and shall not revoke the Estimate to Connect until this time period has expired. Thunder Bay Hydro will not charge the Customer for the preparation of the Estimate to Connect.

Thunder Bay Hydro shall make any necessary metering changes and connect the applicant's micro-embedded generation facility to its distribution system within five (5) days of the applicant completing the following:

(a) Provide Thunder Bay Hydro with a copy of the authorization to connect from the ESA;

(b) enter into a Connection Agreement with Thunder Bay Hydro; and

(c) pay Thunder Bay Hydro for the costs of any necessary metering changes.

3.5.4 Connection of Other Generation Facilities

This subsection applies to the connection to the Thunder Bay Hydro distribution system of an embedded generation facility, which is not a micro-embedded generation facility.

After a person who is considering applying for the connection of a generation facility to the Thunder Bay Hydro distribution system has requested a preliminary meeting with Thunder Bay Hydro and has provided the required initial set of information, Thunder Bay Hydro shall provide a time when its relevant employees are available to meet with the

person within fifteen (15) days of the person requesting the meeting. For the purposes of this section, the following is the required "initial set of information":

(a) the nameplate rated capacity of each unit of the proposed generation facility and the total nameplate rated capacity of the generation facility at the connection point;

(b) the fuel type of the proposed generation facility;

(c) the type of technology to be used; and

(d) the location of the proposed generation facility including address and account number with the distributor where available.

At the preliminary meeting, Thunder Bay Hydro shall discuss the basic feasibility of the proposed connection including discussing the location of its existing distribution facilities in relation to the proposed generation facility and providing an estimate of the time and costs necessary to complete the connection. Thunder Bay Hydro will not charge for its preparation for and attendance at the preliminary meeting.

A person who wishes to apply for the connection of a generation facility to the Thunder Bay Hydro distribution system shall submit an application, pay their impact assessment costs (applicable to mid-sized and large generation facilities or small generation facilities where requested by Thunder Bay Hydro) and provide the following information:

(a) any of the "initial set of information" which has not yet been provided to Thunder Bay Hydro;

(b) a single line diagram of the proposed connection; and

(c) a preliminary design of the proposed interface protection.

For a **small** embedded generation facility, where Thunder Bay Hydro believes that a system directly connected to its distribution system may be impacted by the proposed small embedded generation facility, Thunder Bay Hydro will advise the Customer of the costs to conduct any required impact assessment.

Thunder Bay Hydro shall provide the Customer with its results of its impact assessment of the proposed generation facility, a detailed cost estimate of the proposed connection, and an Estimate to Connect within:

(a) 60 days of the receipt of the application where no distribution system reinforcement or expansion is required; and

(b) 90 days of the receipt of the application where a distribution system reinforcement or expansion is required.

For a **mid-sized** embedded generation facility, Thunder Bay Hydro shall provide the Customer with its impact assessment of the proposed generation facility within sixty (60) days of the receipt of the application.

For a **large** embedded generation facility, Thunder Bay Hydro shall provide the Customer with its impact assessment of the proposed generation facility within ninety (90) days of the receipt of the application.

The impact assessment shall set out the impact of the proposed generation facility on the Thunder Bay Hydro distribution system and any of its customers including:

(a) any voltage impacts, impacts on current loading settings and impacts on fault currents;

(b) the connection feasibility;

(c) the need for any line or equipment upgrades;

(d) the need for transmission system protection modifications; and

(e) any metering requirements.

The Customer shall submit any material revisions to the design, planned equipment or plans for the proposed generation facility and connection with Thunder Bay Hydro. Thunder Bay Hydro shall then prepare a new impact assessment within the relevant time period as set out above.

In the case of an application for the connection of a mid-sized or large embedded generation facility, after receiving from Thunder Bay Hydro the impact assessment the applicant shall pay to Thunder Bay Hydro for the cost of preparing a detailed cost estimate of the proposed connection and enter into an agreement with Thunder Bay Hydro on the scope of the project. Thunder Bay Hydro shall then provide the applicant with a detailed cost estimate and an Estimate to Connect by the later of ninety (90) days after the receipt of payment from the applicant and thirty (30) days after the receipt of comments from a transmitter or other distributor that may have been advised under the following clause.

Within ten (10) days of receiving payment from the applicant for preparing a detailed cost estimate, Thunder Bay Hydro shall advise any transmitter or distributor whose transmission or distribution system is directly connected to the Thunder Bay Hydro distribution system that it is preparing a detailed cost estimate for a proposed large or mid-sized embedded generation facility. Thunder Bay Hydro will use its discretion in advising impacted transmitter or distributor when the detailed cost estimate involves a proposed small embedded generation facility.

After the applicant has entered into a Connection Cost Agreement with Thunder Bay Hydro and has provided the detailed engineering drawings with respect to the proposal, Thunder Bay Hydro shall conduct a design review to determine if the detailed engineering plans are acceptable.

Thunder Bay Hydro has the right to witness the commissioning and testing of the connection of the generation facility to its distribution system. After the applicant has

(a) informed Thunder Bay Hydro that it has received all necessary approvals;

(b) provided Thunder Bay Hydro with a copy of the Certificate of Inspection from the ESA; and

(c) entered into the appropriate Connection Agreement;

and Thunder Bay Hydro has received the Authorization to Connect from ESA it shall act to connect the generation facility to its distribution system in accordance with this Conditions.

Subject to any delays in commissioning and testing of the generation facility, which may be beyond the control of Thunder Bay Hydro, Thunder Bay Hydro shall connect a proposed small embedded generation facility within:

(a) 60 days of the applicant taking the steps set out above, where no distribution system reinforcement or expansion is required; and

(b) 180 days of the applicant taking the steps set out above, where a distribution system reinforcement or expansion is required.

Information on the process for connecting a generation facility to a distribution system is set out in Appendix F.1 of the Distribution System Code.

3.5.5 Technical Requirements

The Customer shall ensure that the connection of its generation facility to the distribution system does not materially adversely affect the safety, reliability and efficiency of the Thunder Bay Hydro distribution system. New or significantly modified generation facilities shall meet the technical requirements specified in Appendix F.2 of the Distribution System Code. In addition, the Customer shall also comply with the detailed requirements outlined in "Thunder Bay Hydro Parallel Generation Requirements". A copy of this document will be provided by contacting the Engineering Department.

The Customer with an embedded generation facility connected to the Thunder Bay Hydro distribution system (other than a micro-embedded generation facility) shall reimburse Thunder Bay Hydro for any damage to the distribution system or increased operating costs that may result from the connection of a generation facility.

A Customer with a generation facility connected to the Thunder Bay Hydro distribution system shall include in the Connection Agreement and upon request by Thunder Bay Hydro provide satisfactory evidence of a regular, scheduled maintenance plan that ensures that the generator's connection devices, protection systems and control systems are maintained in good working conditions.

All equipment that is connected, operated, procured or ordered before May 1, 2002 is deemed to be in compliance with the technical requirements of the Distribution System Code.

Thunder Bay Hydro may determine that equipment that was deemed to be in compliance with the technical requirements of the Distribution System Code as noted in the immediately preceding paragraph is not in **actual** compliance with the technical requirements due to any of the following conditions:

(a) a material deterioration of the reliability of the distribution system resulting from the performance of the generator's equipment; or

(b) a material negative impact on the quality of power of an existing or a new customer resulting from the performance of the generator's equipment; or

(c) a material increase in generator capacity at the site where the equipment deemed compliant is located.

In such a case, Thunder Bay Hydro will provide the Customer with the process for requiring such equipment to be brought into actual compliance. The Customer shall then bring its equipment into actual compliance with the technical requirements and within a reasonable time period specified by Thunder Bay Hydro.

When a Customer with an embedded generation facility is connected to the Thunder Bay Hydro distribution system, the Customer shall provide an interface protection that is capable of automatically isolating the generation facility from the Thunder Bay Hydro distribution system under the following situations:

(a) internal faults within the generator

(b) external faults in the Thunder Bay Hydro distribution system

(c) certain abnormal system conditions, such as over/under voltage, over/under frequency.

The Customers shall disconnect the embedded generation facility from the Thunder Bay Hydro distribution system when:

(a) a remote trip or transfer trip is included in the interface protection, and

(b) the Customer effects changes in the normal feeder arrangements other than those agreed upon in the operating agreement between Thunder Bay Hydro and the Customer.

3.5.6 Net Metering Program for an Embedded Generation Facility

As a way to encourage conservation, Thunder Bay Hydro has established a Net Metering Policy for eligible customers wishing to participate in the Net Metering program. Eligible customers with specific generation facilities may reduce their net energy costs by exporting surplus generated energy back onto the Thunder Bay Hydro distribution system for credit against the energy the Customer consumes from the distribution system.

Participation in the Net Metering Program is available to all Thunder Bay Hydro Customers with a generator that meet all of the following conditions:

1. The electricity is generated primarily for the customer's own use;

2. The electricity generated is conveyed to the customer's own consumption point without reliance on the Thunder Bay Hydro distribution system;

3. The maximum cumulative output capacity of the generator does not exceed 500 kW; and

4. The electricity is solely generated from a renewable energy source (such as wind, drop in water elevation, solar radiation, agricultural bio-mass, or any combination thereof).

In order to participate in the Net Metering program, the customer will be required to meet all the parallel generation requirements for Connecting Micro Generation Facilities (10 kW or less) or Other Generation Facilities (greater than 10 kW and less than 500 kW), as applicable to the generator size, as found in Section 3.5 of these Conditions of Service.

The customer must have a bi-directional revenue meter that records energy flow in both directions.

In accordance with the Net Metering Regulation, Thunder Bay Hydro has established a Net Metering Program regarding the netting of surplus generated energy with energy consumed from the Thunder Bay Hydro supply. This program, as amended from time to time, is posted on the Thunder Bay Hydro website (www.tbhydro.on.ca).

3.5.7 Ontario Power Authority (OPA) Standard Offer Program for an Embedded Generation Facility

In conjunction with the OPA Standard Offer Program (SOP), Thunder Bay Hydro has established its policy to encourage and promote greater use of renewable energy sources such as wind, solar, photovoltaic (PV), renewable biomass, biogas, bio-fuel, landfill gas, or drop in water elevation for generating electricity.

Renewable energy electricity generation projects with a capacity of 10 MW or less that meets the program's requirements may be connected to Thunder Bay Hydro distribution system in order to export electricity.

In most circumstances, generating facilities participating in the Standard Offer Program will connect directly to the Thunder Bay Hydro distribution system at a voltage of 25 kV or less. Output from the generating facility shall be metered as follows:

(a) for generators of 10 kW or less and connected to the line-side of the load meter, a bi-directional kWh meter must be installed to measure energy consumed and energy exported; and

(b) for all other generators, an interval meter must be installed.

The generator will be solely responsible for any costs associated with the connection to the Thunder Bay Hydro distribution system and any required metering installation.

Thunder Bay Hydro's guide for connecting embedded generation is posted, as amended from time to time, on the Thunder Bay Hydro website (www.tbhydro.on.ca).

3.6 Embedded Market Participant

Chapter 2, Section 1.2.1 of the IESO Market Rules states: "No persons shall participate in the IESO administered markets or cause or permit electricity to be conveyed into, through or out of IESO controlled grid unless that person has been authorized by the IESO to do so".

All embedded market participants, within the service area of Thunder Bay Hydro are required to inform Thunder Bay Hydro that they have been authorized by the IESO at least thirty (30) days prior to their participation in the Ontario electricity market. All embedded market participants are responsible for all Thunder Bay Hydro charges as approved by the Ontario Energy Board.

An embedded market participant shall enter into a Connection Agreement in a form acceptable to Thunder Bay Hydro. Until such time as the embedded market participant executes such a Connection Agreement with Thunder Bay Hydro, the embedded market participant shall be deemed to have accepted and agreed to be bound by these Conditions of Service, and the terms of any operating schedule delivered to it from time to time by Thunder Bay Hydro.

3.7 Embedded Distributor

All embedded distributors within the service area of Thunder Bay Hydro are required to inform Thunder Bay Hydro of their status in writing, thirty (30) days prior to the supply of energy from Thunder Bay Hydro. The terms and conditions applicable to the connection of an embedded distributor shall be included in the Connection Agreement with Thunder Bay Hydro.

An embedded distributor shall enter into a Connection Agreement in a form acceptable to Thunder Bay Hydro, the contents and the format of which will be at Thunder Bay Hydro's discretion and be in conformity with the requirements of the Distribution System Code. Until such time as the embedded distributor executes such a Connection Agreement with Thunder Bay Hydro, the embedded distributor shall be deemed to have accepted and agreed to be bound by all of the terms in these Conditions of Service that apply to such embedded distributor.

The following terms and conditions apply to the connection of an embedded distributor:

- Thunder Bay Hydro shall make every reasonable effort to respond to another distributor's request for connection.
- Thunder Bay Hydro shall provide an initial consultation with another distributor regarding the connection process within thirty (30) days of receiving a written request for connection.
- A final Estimate to Connect the distributor to Thunder Bay Hydro's distribution system shall be made within ninety (90) days of receiving the written request for

connection, unless the necessary information outside of Thunder Bay Hydro's control is required before an Estimate can be made.

3.7.1 Connection Request

An embedded distributor shall submit its request to Thunder Bay Hydro, summarizing in writing the required initial and ultimate load requirements, the required in service date and any other specific requirements.

Thunder Bay Hydro will carry out an initial consultation and determine the scope and estimated cost of preparing a System Impact Study. Thunder Bay Hydro will respond within thirty (30) days of receiving the embedded distributor's request.

3.7.2 System Impact Study

Upon receipt of a purchase order or equivalent from the embedded distributor, Thunder Bay Hydro, in cooperation with the applicant, will study in detail all options and recommend the preferred option. The results of the study will be documented in a system impact report. This report will provide the embedded distributor with preliminary information regarding the work required to provide the requested supply, the estimated capital contribution and the expected lead time.

Thunder Bay Hydro will complete the system impact study within sixty (60) days of receiving the embedded distributor's purchase order to proceed. If, despite Thunder Bay Hydro's best efforts, the sixty (60) day target cannot be met, Thunder Bay Hydro will notify the embedded distributor in writing and provide a new target completion date. The embedded distributor will review the system impact study and decide whether or not to proceed. To proceed the embedded distributor submits a connection application, provides all necessary information and a letter of credit with a related purchase order for the preparation of detailed engineering specifications. The embedded distributor will submit a connection application to Thunder Bay Hydro within thirty (30) days of receiving the system impact study report, failing which Thunder Bay Hydro may require that a new preliminary review and system impact study be performed at the embedded distributor's cost.

3.7.3 Costs

Once the request for connection has been approved, and upon receipt of a purchase order or equivalent from the embedded distributor, Thunder Bay Hydro shall prepare detailed engineering specifications for required system enhancements, obtain cost estimates for the specified work, and determine cost-sharing arrangements.

Within ninety (90) days of receiving the connection application and the accompanying material set out in section 3.7.2 above, Thunder Bay Hydro will provide the Customer, in writing, a Project Description and Letter of Intent that include:

1. a description of the work to be performed by Thunder Bay Hydro;

2. a summary of the work to be performed by the Customer;

3. Thunder Bay Hydro's capital investment in the project; and

4. the Customer's financial contribution to the project.

If, despite Thunder Bay Hydro's best efforts, the ninety (90) day target cannot be met, Thunder Bay Hydro will notify the embedded distributor in writing and provide a new target completion date.

3.7.4 Contact Information

The contact information will be reviewed annually. Each Party will notify each other by November 1 of each year to confirm or update such information. If either party proposes to make a change affecting the embedded connection point, then notice of such change will be given in writing. Such notice will be given a minimum of thirty (30) days prior to any planned implementation of the change. Any change will require the approval of both Parties.

The Customer acknowledges and agrees that Thunder Bay Hydro may provide any information provided by the Customer under the terms of the Standard embedded distributor Agreement to Thunder Bay Hydro's representatives, provided that Thunder Bay Hydro:

- provides such information to only those of Thunder Bay Hydro's representatives who need to know the information; and
- has directed such representatives to use the information in accordance with the terms hereof.

3.7.5 Energy Supply

As the Host Distributor, Thunder Bay Hydro reserves the right to limit the amount of energy that it agrees to supply the embedded distributor at each embedded connection/delivery point, and this amount shall be agreed upon by both Parties. The embedded distributor shall notify and include Thunder Bay Hydro in any discussion, planning and interconnection design of any proposed embedded generation facility that the embedded distributor proposes to connect to its distribution system.

3.7.6 Billing

Thunder Bay Hydro shall bill the embedded distributor on a regular billing cycle for the provision of distribution services by Thunder Bay Hydro, and for all other applicable charges approved or authorized by the Ontario Energy Board, pursuant to Thunder Bay Hydro's rate orders or any codes issued by the Ontario Energy Board.

Thunder Bay Hydro shall settle non-competitive electricity services based on the rates approved by the Ontario Energy Board and by the requirements of the Retail Settlement Code. Thunder Bay Hydro shall adjust the embedded distributor's usage by the applicable total loss factor for purposes of determining the embedded distributor's non-competitive electricity costs.

If the embedded distributor is not a wholesale market participant, then Thunder Bay Hydro shall provide revenue metering for the settlement and monthly billing of the embedded distributor. If the embedded distributor is or becomes a wholesale market participant distributor, then the IESO shall settle the Customer's monthly energy bill.

If the embedded distributor is, or becomes, a wholesale market participant distributor registered with the IESO, the embedded distributor will be responsible for the wholesale metering installation(s) metering data as per the IESO Market Rules.

3.7.7 Ownership

All Thunder Bay Hydro-owned equipment, including the revenue metering equipment and instrument transformers, shall continue to be vested in Thunder Bay Hydro, unless the Parties have specified otherwise in the embedded distributor agreement.

All Customer equipment and facilities shall continue to be vested in the Customer, unless the Parties have specified otherwise in the embedded distributor agreement.

3.7.8 Assignment of Responsibility

The electrical distribution systems shall be under the operating control of a controlling authority at all times.

The responsibility for regular maintenance of equipment rests with the owner. Thunder Bay Hydro and the embedded distributor shall ensure that only qualified persons perform the operation and maintenance of their respective electrical distribution systems.

Each Party shall be responsible for maintenance, protection and power quality of each Party's portion of the shared distribution feeder that each Party owns. Each Party shall ensure that its portion of the feeder has proper fault protection and voltage within proper limits.

Thunder Bay Hydro and the Customer shall maintain their respective equipment in efficient condition with proper devices, according to electrical distribution utility standards. If, in the opinion of Thunder Bay Hydro or the Customer, maintenance is not properly performed, the identifying Party will notify the other in writing.

3.7.9 Normal Operations

Controlling authorities will inform each other at least seven (7) calendar days in advance of any planned work which would have an effect on the other Party's electrical distribution system.

Applications for work involving load interruptions shall be initiated at least ten (10) calendar days in advance, to permit proper notification of other customers who would be interrupted.

Each controlling authority is responsible for establishing the appropriate conditions for, and the co-ordination of, switching on the equipment under its control.

The controlling authority for the equipment under its control shall issue work protection on the equipment when work is done on that equipment. Each controlling authority is responsible for establishing, in accordance with industry standards, a safe work environment for their forces while carrying out planned or emergency maintenance. Each Party is responsible for providing isolation at devices under their operating control to assist the other Party.

3.7.10 Communication

Communications between controlling authorities must be readily available to deal with routine and unforeseen system conditions. Each party must identify the controlling authority for communications.

The controlling authority of each Party agrees to communicate for the following reasons:

For normal operating communications with regard to outage planning, work protection and switching, etc.:

- provide each other with information relative to prearranged outages, power interruptions or system problems which materially affect the supply of power to each others distribution system;
- provide each other with information relative to feeder trips or re-closure operations caused by equipment under each Parties ownership or control;
- following a lock-out, Thunder Bay Hydro's Controlling Authority will not authorize the Hydro One Controlling Authority to re-energize a feeder owned by Thunder Bay Hydro to which the embedded distributor is connected until contact has been made with the embedded distributor's Controlling Authority;
- when a permanent fault occurs on a feeder which supplies Thunder Bay Hydro and an embedded distributor load, the Thunder Bay Hydro Controlling Authority will notify the embedded distributor's Controlling Authority during regular working hours, and the embedded distributor's designated person on call for after hours permanent faults. Once communication is established and the location of the fault is not known, Thunder Bay Hydro and/or embedded distributor staff will be dispatched to patrol their systems, and may assist each other in sectionalizing the faulted feeder.

If Thunder Bay Hydro and the embedded distributor each own portions of, and share, a common feeder, both Parties agree to provide each other with the following information:

- Thunder Bay Hydro shall provide the embedded distributor with fault current information and protection settings of upstream protective devices;
- the embedded distributor shall provide Thunder Bay Hydro with load forecasting information;
- Thunder Bay Hydro and the embedded distributor agree to maintain phase balance within generally acceptable industry standards;

• Thunder Bay Hydro and the embedded distributor agree to adhere to generally acceptable standards pertaining to power quality and voltage levels on the section of feeder each Party owns; and

• Thunder Bay Hydro and the embedded distributor agree to provide each other, on request, with maintenance schedules and records on the section of feeder each party owns.

3.7.11 Emergency Operations

Each Party will co-operate fully in cases of emergency in order to facilitate restoration of the system back to normal, and to permit the commencement of possible repairs.

On the request of one Party's Controlling Authority, the other Party's Controlling Authority, staff or agents, will provide the required timely isolation of equipment as required for emergency switching, or to establish a "Condition Guarantee".

3.7.12 Metering and Fault Protection

Thunder Bay Hydro agrees to deliver electricity to the embedded distributor's distribution system through an interval meter for settlement purposes.

If the embedded distributor is, or becomes, a wholesale market participant distributor registered with the IESO, the Customer will be responsible for the wholesale metering installation(s) metering data as per the IESO Market Rules. Thunder Bay Hydro shall have read-only access to such wholesale metering installations.

The Parties shall act at all times in accordance with the Distribution System Code, for situations where Thunder Bay Hydro or the embedded distributor provides distribution services through a load transfer.

Thunder Bay Hydro and the embedded distributor shall each manage its own portion of a supply feeder, and ensure that its portion of the feeder has proper fault protection and voltage within proper limits in accordance with industry standards.

The owner of the feeder breaker would be responsible for maintaining appropriate relay settings for overall feeder protection, and both Thunder Bay Hydro and the embedded distributor would be responsible to provide the required information to accomplish this.

3.7.13 Security

The amount of security that the embedded distributor will have to provide to Thunder Bay Hydro shall be an amount equal to 2.0 times Thunder Bay Hydro's estimate of the embedded distributor's average monthly bill, or an average one-month billing if enrolled in the pre-authorized payment plan, for all supply points listed in the standard agreement.

The security to be provided by the embedded distributor shall be any one or a combination of the following types of security: irrevocable standby letter of credit or cash deposit. If the embedded distributor provides an irrevocable standby letter of credit as

security, the embedded distributor and Thunder Bay Hydro agree that the irrevocable standby letter of credit will be automatically renewed unless the embedded distributor provides notification in writing ninety (90) days prior to the termination date.

Interest on cash Security Deposits will be calculated in accordance with Section 2.4.3 of these Conditions of Service.

3.7.14 Liability

Thunder Bay Hydro shall only be liable to the embedded distributor, and the embedded distributor shall only be liable to Thunder Bay Hydro, for any damages which arise directly out of the willful misconduct or negligence:

- of Thunder Bay Hydro in providing distribution services to the embedded distributor;

- of the embedded distributor in being connected to Thunder Bay Hydro's distribution system; or

- of Thunder Bay Hydro or the embedded distributor in meeting their respective obligations under the Distribution System Code, their licences, and any other applicable law.

The embedded distributor agrees to take out liability insurance in the amount of $5,000,000, or from time to time such other amount as may be determined by Thunder Bay Hydro in its sole discretion, to which the City of Thunder Bay and Thunder Bay Hydro are added as additional named insured, and to provide proof of such insurance.

Despite the above, neither Thunder Bay Hydro nor the embedded distributor shall be liable under any circumstances whatsoever for any loss of goodwill or for any indirect, consequential, incidental or special damages, including but not limited to punitive or exemplary damages, whether any of the said liability, loss or damages arise in contract, tort or otherwise notwithstanding the embedded distributor's financial contribution as per Section 3.7.3. of these Conditions of Service.

3.7.15 Force Majeure

Subject to the items below, neither Party shall be held to have committed an event of default in respect of any obligation under the embedded distributor agreement if prevented from performing that obligation, in whole or in part, because of a force majeure event.

If a force majeure event prevents a Party from performing any of its obligations under the Distribution System Code and the embedded distributor agreement, that Party shall:

- promptly notify the other Party of the force majeure event and its assessment, in good faith, of the effect that the event will have on its ability to perform any of its obligations. If the immediate notice is not in writing, it shall be confirmed in writing as soon as reasonably practicable;

• not be entitled to suspend performance of any of its obligations under the embedded distributor Agreement to any greater extent, or for any longer time, than the force majeure event requires it to do;

• use its best efforts to mitigate the effects of the force majeure event, remedy its inability to perform, and resume full performance of its obligations;

• keep the other Party continually informed of its efforts; and

• provide written notice to the other Party when it resumes performance of any obligations affected by the force majeure event.

Notwithstanding any of the foregoing, settlement of any strike, lockout or labour dispute constituting a force majeure event shall be within the sole discretion of the Party to the embedded distributor agreement involved in the strike, lockout or labour dispute. The requirement that a Party must use its best efforts to remedy the cause of the force majeure event, mitigate its effects, and resume full performance under the embedded distributor Agreement and the Distribution System Code shall not apply to strikes, lockouts or labour disputes.

3.8 Unmetered Connections

3.8.1 Street Lighting

Unless agreed to by both Parties, roadway lighting such as in the City of Thunder Bay and on Fort William First Nation land shall be controlled by photo cells. The daily consumption for these Customers shall be based on the calculated connected loads times the required night time or lighting times established in the approved OEB street lighting load shape template.

Attachment of street lighting equipment to Thunder Bay Hydro's electrical distribution system and the electrical supply to street lighting equipment is subject to approval by Thunder Bay Hydro. Street lighting plant, facilities, or equipment owned by the Customer are subject to the ESA requirements.

Actual costs related to the connection of street lighting will be recovered from the Customer.

3.8.2 Traffic Signals and Pedestrian X-Walk Signals/Beacons

Traffic signals and pedestrian X-walk signals/beacons shall have a rate structure equal to General Service (< 50 kW) Class Customers, as approved by the OEB. The service will be unmetered. Energy consumption will be based on connected wattage information submitted by the Customer and calculated as per hours of use. It is the responsibility of the Customer to report to Thunder Bay Hydro in writing a change of consumption to the installation.

Each traffic signal and pedestrian X-walk signal/beacon location is reviewed individually and is connected to Thunder Bay Hydro's low voltage distribution system. Electrical

Safety Authority (ESA) "Authorization to Connect" is required prior to connecting the service.

Service conductors will be supplied by the Customer.

Thunder Bay Hydro will advise the Customer of the service connection point.

Where transformation does not exist, it will be provided as part of the Variable Connection Charge. A capital contribution will be required.

The Ownership Demarcation point is as follows:

- for overhead - the top of the Customer's service standpipe/mast;
- for underground – the line-side of the fuse in the first handwell, tap box, junction box, transformer (as applicable) beyond Thunder Bay Hydro's plant.

Connection assets will be recovered through a Variable Connection Charge, based on actual costs.

Re-design and inspection services are the expense of the Customer. The Customer is responsible for maintaining and repairing its equipment and/or facilities.

3.8.3 Bus Shelters, Telephone Booths, Signs (< 5kW) and Miscellaneous Unmetered Loads (< 5kW)

This section pertains to the supply of electrical energy for bus shelters, telephone booths, cable TV amplifiers and similar small unmetered loads.

The above service types shall have a rate structure as General Service (Under 50 kW) Class Customers and have the same terms and conditions as outlined in Section 3.8.2 above titled "Traffic Signals and Pedestrian X-Walk Signals/Beacons".

An "Authorization to Connect" from the ESA is required prior to connecting the service.

3.8.4 Decorative Lighting and Tree Lighting Services

a) Decorative or Tree Lighting, if connected to the City of Thunder Bay system will be treated as a Street Lighting Class of service. Please refer to Section 3.8.1 of these Conditions of Service for applicable Terms and Conditions and rate structure.

b) Decorative or Tree Lighting connected to Thunder Bay Hydro's distribution system shall have a rate structure as General Service (Under 50 kW) Class Customers. Refer to the Schedule of Rates.

i. **For unmetered service installations**, refer to Section 3.8.2 titled Traffic Signals and Pedestrian X-Walk Signals/Beacons for applicable Terms and Conditions.

ii. **For metered service installations**, refer to 3.2 General Service (Under 50 kW) for applicable Terms and Conditions.

Re-design and inspection services are at the expense of the Customer. The Customer is responsible for maintaining and repairing its equipment and/or facilities.

An ESA "Authorization to Connect" is required prior to connecting the service.

3.8.5 Sign Boards

Sign boards must be supplied from Customer's service at the site, unless no service exists. The conditions of connection and supply of an unmetered service will be by Thunder Bay Hydro Power Systems Division.

SECTION 4: GLOSSARY OF TERMS

Sources of definitions from applicable Acts & Codes:

DSC	Distribution System Code
EA	Electricity Act, 1998, Schedule A, section 2
MR	Market Rules for the Ontario Electricity Market, Chapter 11
RSC	Retail Settlement Code
TDL	Transitional Distribution Licence, Part 1
TTL	Transitional Transmission Licence, Part 1

"Act" means the Ontario Energy Board Act, 1998, S.O. 1998, C. 15, Schedule A; (EA)

"Affiliate Relationships Code" means the code, approved by the Board and in effect at the relevant time, which among other things, establishes the standards and conditions for the interaction between electricity distributors or transmitters and their respective affiliated companies; (TDL, DSC)

"application for service" means the agreement or contract with Thunder Bay Hydro under which electrical service is requested;

"basic service" means a service that is recovered through revenue requirements and does not require a variable connection charge. Thunder Bay Hydro shall define a basic connection for each Customer to include a share of distribution transformation capacity and 31 m (100 ft.) of overhead conductor or an equivalent credit for underground services;

"billing demand" means the greater of measurement in kilowatts (kW) or 90% of kVA of the maximum rate at which electricity is consumed during a billing period.

"Board" means the Ontario Energy Board; (EA, TDL, DSC)
"Board of Directors" means the Thunder Bay Hydro Board of Directors;

"building" means a building, portion of a building, structure or facility;

"circuit breaker" means a device designed to open and close a circuit by non-automatic means and to open the circuit automatically on a predetermined overcurrent without damage to itself when properly applied within its ratings;

"connection" means the process of installing and activating connection assets in order to distribute electricity (DSC)

"Connection Agreement" means an agreement entered into between a distributor and a person connected to its distribution system that delineates the conditions of the connection and delivery of electricity to or from that connection; (DSC)

"connection assets" means that portion of the distribution system used to connect a Customer to the existing main distribution system, and consists of the assets between the point of connection on a distributor' s main distribution system and the ownership demarcation point with that Customer; (DSC)

"consumer" means a person who uses, for the person' s own consumption, electricity that the person did not generate; (EA, MR, TDL, DSC)

"contestable" means any construction activities not connected to Thunder Bay Hydro existing distribution assets. This is to be defined specifically on each Estimate to Connect;

"Customer" means a person that has contracted for or intends to contract for connection of a building or an embedded generation facility. This includes developers of residential or commercial sub-divisions; (DSC)

"demand" means the average value of power measured over a specified interval of time, usually expressed kilowatts (kW). Typical demand intervals are 15, 30 and 60 minutes;

"demand meter" means a meter that measures a consumer' s peak usage during a specified period of time; (DSC)

"device" means any operating or non-operating mechanical connection or attachment;

"disconnection" means a deactivation of connection assets that results in cessation of distribution services to a consumer; (DSC)

"distribute", with respect to electricity, means to convey electricity at voltages of 50 kilovolts or less; (EA, MR, TDL, DSC)

"distribution losses" means energy losses that result from the interaction of intrinsic characteristics of the distribution network such as electrical resistance with network voltages and current flows; (DSC)

"distribution services" means services related to the distribution of electricity and the services the Board has required distributors to carry out, for which a charge or rate has been approved by the Board under section 78 of the Act. (RSC, DSC, TDL)

"distribution system" means a system for distributing electricity, and includes any structures, equipment or other things used for that purpose. A distribution system is comprised of the main system capable of distributing electricity to many Customers and the connection assets used to connect a Customer to the main distribution system; (EA, MR, TDL, DSC)

"Distribution System Code" means the code, approved by the Board, and in effect at the relevant time, which, among other things, establishes the obligations of a distributor with respect to the services and terms of service to be offered to Customers and retailers and provides minimum technical operating standards of distribution systems; (TDL, DSC)

"distribution system loss factor" means a factor(s) by which metered loads must be multiplied. Such that when summed equal the total measured load at the supply point(s) to the distribution system; (RSC)

"distributor" means a person who owns or operates a distribution system; (EA, MR, TDL, DSC)

"duct bank" means two or more ducts that may be encased in concrete used for the purpose of containing and protecting underground electric cables;
"Electricity Act" means the Electricity Act, 1998, S.O. 1998, c.15, Schedule A; (MR, TDL, DSC)

"Energy Competition Act" means the Energy Competition Act, 1998, S.O. 1998, c. 15; (DSC)

"electrical service" means the Customer's conductors and equipment for delivery of energy from Thunder Bay Hydro'

"Electrical Safety Authority" or "ESA" means the person or body designated by the regulations as the Electrical Safety Authority; (EA)

"embedded distributor" means a distributor who is not a wholesale market participant and that is provided electricity by a host distributor; (RSC, DSC)

"Embedded Generator" or "embedded generation facility" means a generation facility which is not directly connected to the IESO-controlled grid but instead is connected to a distribution system, and has the extended meaning given to it in section 9 of the DSC; (DSC, RSC)

"embedded retail generator" means a customer that (a) is not a wholesale market participant or a net metered generator (as defined in section 6.7.1 or the DSC), (b) owns or operates an embedded generation facility, other then an emergency backup generation facility; and (c) sells out put from the embedded generation facility to the Ontario Power Authority under contract or to a distributor; (DSC, RSC)

"embedded wholesale Consumer" is a generator who is a wholesale market participant whose facility is not directly connected to the IESO-controlled grid but is connected to a distribution system; (DSC)

"embedded wholesale generator" is a generator who is a wholesale market participant and whose generation facility is connected to the distribution system (RSC);

"emergency" means any abnormal system condition that requires remedial action to prevent or limit loss of a distribution system or supply of electricity that could adversely affect the reliability of the electricity system. (DSC) In addition to the electrical context of emergency, emergency also included prevention of loss of life or property;

"emergency backup" means a generation facility that has a transfer switch that isolates it from a distribution system; (DSC)

"energy" means the product of power multiplied by time, usually expressed in kilowatt-hours (kWh);

"Energy Competition Act" means the Energy Competition Act, 1998, S.O. 1998, c. 15; (MR)

"energy diversion" means the electricity consumption unaccounted for but that can be quantified through various measures upon review of the meter mechanism, such as unbilled meter reading, tap off load(s) before the revenue meter or meter tampering;

"enhancement" means a modification to an existing distribution system that is made for purposes of improving system operating characteristics such as reliability or power quality or for relieving system capacity constraints resulting, for example, from general load growth; (DSC)

"expansion" means an addition to a distribution system in response to a request for additional Customer connections that otherwise could not be made; for example, by increasing the length of the distribution system; (DSC)

"extreme operating conditions" means extreme operating conditions as defined in the Canadian Standards Association ("CSA") Standard CAN3-C235-87 (latest edition);

"Force Majeure" means any events or causes beyond the reasonable control of Thunder Bay Hydro which prevent Thunder Bay Hydro from the ability to perform any of its obligations under these Conditions of Service including, without limitation, severe weather, flood, fire, lightning, other forces of nature, acts of animals, epidemic, quarantine restriction, war, sabotage, act of a public enemy, earthquake, insurrection, riot, civil disturbance, strike, lockout, labour dispute, restraint by court order or public authority, or action or non-action by or inability to obtain authorization or approval from any government authority, or any combination of these causes;

"general service" means any service supplied to premises other than those designated as Residential. This includes multi-unit residential establishments such as apartment buildings supplied through one service (bulk-metered);

"generate", with respect to electricity, means to produce electricity or provide ancillary services, other than ancillary services provided by a transmitter or distributor through the operation of a transmission or distribution system; (DSC, TDL)

"generation facility" means a facility for generating electricity or providing ancillary services, other than ancillary services provided by a transmitter or distributor through the operation of a transmission or distribution system, and includes any structures ,equipment or other things used for that purpose; (EA, MR, TDL, DSC)

"Generator" means a person who owns or operates a generation facility; (EA, MR, TDL, DSC)

"good utility practice" means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry in North America during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made,

could have been expected to accomplish the desired result at a reasonable cost consistent with good practices, reliability, safety and expedition. Good utility practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in North America; (MR, DSC)

"holiday" means a Saturday, Sunday, statutory holiday, or any day as defined in the Province of Ontario as a legal holiday; (DSC)

"host distributor" means the distributor who provides electricity to an embedded distributor; (RSC, DSC)

"house service" means that portion of the electrical service in a multiple occupancy facility which is common to all occupants, (i.e. parking lot lighting, sign service, corridor and walkway lighting, et cetera);

"IEC" means International Electrotechnical Commission;

"IEEE" means Institute of Electrical and Electronics Engineers;

"IESO" means the Independent Electricity System Operator established under the Electricity Act; (EA, TDL, DSC)

"IESO-Controlled Grid" means the transmission systems with respect to which, pursuant to agreements, the IESO has authority to direct operation; (EA, TDL, DSC)

"interval meter" means a meter that measures and records electricity use on an hourly or sub-hourly basis; (RSC, DSC)

"large user" means a Customer with a monthly peak demand of 5000 kW or greater, regardless the demand occurs in the peak or off-peak periods, averaged over 12 months;

"main service" refers to Thunder Bay Hydro incoming cables, bus duct, disconnecting and protective equipment for a Building or from which all other metered sub-services are taken;

"maintenance" means any inspection, testing, cleaning, torquing, adjusting, and calibrating electrical equipment, or replace support structures associated with the electrical system but no electrical betterments;

"market participant" has the meaning prescribed in the Market Rules;

"Market Rules" means the rules made under section 32 of the Electricity Act;1998 (MR, TDL, DSC, RSC)

"Measurement Canada" means the Special Operating Agency established in August 1996 by the Electricity and Gas Inspection Act, 1980-81-82-83, c. 87., and Electricity and Gas Inspection Regulations (SOR/86-131); (DSC)

"meter installation" means the meter and, if so equipped, the instrument transformers, wiring, test links, fuses, lamps, loss of potential alarms, meters, data recorders, telecommunication equipment and spin-off data facilities installed to measure power past a meter point, provide remote access to the metered data and monitor the condition of the installed equipment; (RSC, DSC)

"meter service provider" means any entity that performs metering services on behalf of a distributor or generator; (DSC)

"meter socket" means the mounting device for accommodating a socket type revenue meter;

"metering services" means installation, testing, reading and maintenance of meters; (DSC)

"MIST meter" means an interval meter from which data is obtained and validated within a designated settlement timeframe. MIST refers to "Metering Inside the Settlement Timeframe;(RSC, DSC) These must be connected to a telephone line for remote reading of the meter.

"MOST meter" means an interval meter from which data is only available outside of the designated settlement timeframe. MOST refers to "Metering Outside the Settlement Timeframe; (RSC, DSC)"

"multiple dwelling" means a Building which contains more than one self-contained dwelling unit;

'municipal street lighting" means all services supplied to street lighting equipment owned and operated for a municipal corporation;

"normal operating conditions" means the operating conditions comply with the standards set by the Canadian Standards Association ("CSA") Standard CAN3-C235-87 (latest edition);

"operational demarcation point" means the physical location at which a distributor's responsibility for operational control of distribution equipment including connection assets ends at the Customer; (DSC)

"ownership demarcation point" means the physical location at which a distributor's ownership of distribution equipment including connection assets ends at the Customer; (DSC)

"performance standards" means the performance targets for the distribution and connection activities of the distributor as established by the Board pursuant to the Act and in the Rate Handbook; (DSC)

"person" includes an individual, a corporation, sole proprietorship, partnership, unincorporated organization, unincorporated association, body corporate, and any other legal entity;

"physical distributor," with respect to a load transfer, means the distributor that provides physical delivery of electricity to a load transfer Customer, but is not responsible for connecting and billing the load transfer Customer directly; (DSC)

"point of supply," with respect to an embedded generator, means the connection point where electricity produced by the generation facility is injected into a distribution system; (DSC)

"power factor" means a variable equal to the ratio of kW and kVA demand (RSC);

"primary service" means any service which is supplied with a nominal voltage greater than 750 V;

"private property: means the property beyond the existing public street allowances;

"rate" means any rate, charge or other consideration, and includes a penalty for late payment; (TDL, DSC)

"Rate Handbook" means the document approved by the Board that outlines the regulatory mechanisms that will be applied in the setting of distributor rates; (RSC, DSC)

"reactive power" means the power component which does not product work but is necessary to allow some equipment to operate, and is measured in kilovolt Amperes Reactive (kVAR);

"real power" means the power component required to do real work, which is measured in kilowatts (kW);

"Regulations" means the regulations made under the Act or the Electricity Act; (TDL, DSC)

"residential service" means a service which is supplied to single-family dwelling units that is for domestic or household purposes, including seasonal occupancy. At Thunder Bay Hydro's discretion, residential rates may be applied to apartment buildings with 6 or less units by simple application of the residential rate or by blocking the residential rate by the number of units;

"retail", with respect to electricity means, a) to sell or offer to sell electricity to a consumer b) to act as agent or broker for a retailer with respect to the sale or offering for sale of electricity, or c) to act or offer to act as an agent or broker for a consumer with respect to the sale or offering for sale of electricity (EA, MR, TDL, DSC);

"Retail Settlement Code" means the code approved by the Board and in effect at the relevant time, which, among other things, establishes a distributor' s obligations and responsibilities associated with financial settlement among retailers and Customers and provides for tracking and facilitating Customer transfers among competitive retailers; (TDL, DSC)

"retailer" means a person who retails electricity; (EA, MR, TDL, DSC)

"secondary service" means any service which is supplied with nominal voltage less than 750 volts;

"service area," with respect to a distributor, means the area in which the distributor is authorized by its Licence to distribute electricity; (EA, TDL, DSC)

"service date" means the date that the Customer and Thunder Bay Hydro mutually agree upon the permanent energization by Thunder Bay Hydro for billing purposes;

"Standard Supply Service Code (SSS)" means the code issued by the Board and in effect at the relevant time, which, among other things, establishes the manner in which a distributor must meet in carrying out it's obligations to sell electricity under section 29 of the Electricity Act, 1998; (RSC, TDL)

"sub-service" means a separately metered service that is taken from the main Building service;

"supply point" means the Customer connection point, for both primary and secondary services, to the Thunder Bay Hydro distribution system. This might be located at a manhole, stub-up, vault, pole, or padmounted device. This electrical supply location might be located on an adjacent property from which Thunder Bay Hydro has land access rights. With respect to an embedded generator, "supply point" means the connection point where electricity produced by the generator is injected into a distribution system. In all cases, the final supply point will be designated by Thunder Bay Hydro;

"supply voltage" means the voltage measured at the Customer's main service entrance equipment (typically below 750 volts). Operating conditions are defined in the Canadian Standards Association ("CSA") Standard CAN3-C235 (latest edition);

"support structure" means any equipment that physically supports and routes the distribution system between the substation and the Customer. This would include poles, overhead platforms, towers, anchors, guy wires, lashing messengers, manholes, handholes, transformer & switch bases, and ducts;

"temporary service" means an electrical service granted temporarily for such purposes as construction, real estate sales, trailers, et cetera;

"termination pole" refers to the Thunder Bay Hydro distribution pole on which the service supply cables are terminated;

"transformer vault" means an isolated enclosure built to applicable codes to house transformers and associated electrical equipment;

"uncontestable" means the following work associated with the expansion of a distributor's existing system: (a) the preliminary planning, design and engineering specifications of the work required for the distribution system expansion and connection ; and (b) work involving existing distributor assets; (DSC)

"unmetered loads" means electricity consumption that is not metered and is billed based on estimated usage; (DSC, RSC)

"validating, estimating and editing (VEE)" means the process used to validate, estimate and edit raw metering data to produce final metering data or to replicate missing metering data for settlement purposes; (MR, DSC)

"wholesale market participant", means a person that sells or purchases electricity or ancillary services through the IESO-administered markets; (RSC, DSC)

"wholesale settlement cost" means costs for both competitive and non-competitive services billed to a distributor by the IESO or a host distributor, or provided by an embedded retail generator or by a neighboring distributor; (RSC)

SECTION 5: APPENDICES

Appendix A Security Deposit Policy

Appendix B Distribution System Code Appendix B

Appendix C Terms of Agreement for Electrical Service

Appendix D Demarcation Points and Charges and Residential Overhead & Underground Service Demarcations

Appendix E OEB-Approved Rates for Miscellaneous Charges

Appendix F Metering Requirements

APPENDIX A

Thunder Bay Hydro
Security Deposit Policy

Thunder Bay Hydro Security Deposit Policy

Effective June 2007

This policy is available to Thunder Bay Hydro customers for their inspection upon request.

1. General:

All applicants for electrical service will complete a customer information form or provide personal information (with their authorized consent) for the purpose of collecting information.

Based on this information, Thunder Bay Hydro, an electricity distributor, will request an account Security Deposit, as described in the Ontario Energy Board's Distribution System Code, from all applicants who are unable to demonstrate a good payment history.

Thunder Bay Hydro may use any risk mitigation options available under law to manage customer non-payment risk. Thunder Bay Hydro will not discriminate among customers with similar risk profiles or risk related factors except where expressly permitted under the Distribution System Code.

If Thunder Bay Hydro has requested an account Security Deposit and the Customer fails payment and/or equal installments are not maintained, a "disconnect/collect trip" may be required. This is a visit to a Customer's premises by an employee, or agent of Thunder Bay Hydro, to demand payment of an outstanding amount or to shut off, or limit, the distribution of electricity. The Customer will also be subject to service reconnection fees upon restoration of service.

Where a Customer's service is subject to disconnection, Thunder Bay Hydro may conduct a review of the Customer's payment history to determine if a Security Deposit is required, or if the amount of the existing Security Deposit is to be adjusted. Thunder Bay Hydro will require the customer to pay this additional amount at the same time as that customer's next regular bill comes due.

Where a Customer's service has been disconnected, or limited, for non-payment, and no Security Deposit is being held, Thunder Bay Hydro may request a Security Deposit from the Customer prior to restoring service or at the same time as that Customer's next regular bill comes due.

2. Exceptions:

a. The Customer has a *good payment history* of:

- **1 year** - in the case of a residential customer (RS),
- **5 years** - in the case of a non-residential customer in a <50 kW demand rate class (GU) or,
- **7 years** - in the case of a non-residential customer in any other rate class (*commercial classes other than* GU).

The Customer is deemed to have a *good payment history* unless, during the relevant time period listed above:

- the Customer has received more than one disconnection notice from a Distributor;
- more than one cheque given to a distributor, by the Customer, has been returned for insufficient funds;
- more than one pre-authorized payment to a Distributor has been returned for insufficient funds; or
- a disconnect / collect trip by a Distributor has occurred.

The time period that makes up the *good payment history* must be the most recent period of time (*as listed above*) and some of that time period must have occurred within the previous twenty-four (24) months.

If any of the events *listed above* occur due to an error by Thunder Bay Hydro, the Customer's *good payment history* will not be affected.

b. The Customer provides a letter from another Electricity Distributor, or Gas Distributor, in Canada confirming a good payment history with that Distributor for the most recent relevant time period set above where some of the time period which makes up the good payment history has occurred in the previous 24 months, or

c. the Customer, other than a customer in a >5000 kW demand rate class, provides a satisfactory credit check made at the Customer's expense from a Credit company such as Equifax, TransUnion or Dun & Bradstreet.

2. Security Deposit Amounts:

a. The maximum amount of a Security Deposit which Thunder Bay Hydro may require a Customer to pay shall be calculated, and billed for, using the following formula:

A billing cycle factor **x** the estimated bill, based on the Customer's average (or highest), load with Thunder Bay Hydro during the most recent 12 consecutive months and within the past two (2) years.

b. Where relevant usage information is not available for the Customer for 12 consecutive months within the past two (2) years, the Customer's average, or highest, monthly load shall be based on a reasonable estimate made by Thunder Bay Hydro as described in section 2.4.14 of the Distribution System Code.

Where a non-residential Customer, in a >50 kW demand rate class, provides a credit rating from a recognized rating agency, the maximum amount of a Security Deposit, which the Distributor may require from the Customer to pay, will be reduced in accordance with the following table:

Credit Rating (Using Standard and Poor's Rating Terminology)	Allowable Reduction in Security Deposit
AAA – and above	100%
AA -, AA, AA+	95%
A-, From A, A+ to below AA	85%
BBB-, From BBB, BBB+ to Below A	75%
Below BBB-	0%

c. Billing Cycle Factor

"New" TBH Customer - Residential Service (RS)

A bi-monthly billing cycle factor of **1.75** x estimated bimonthly bill - based on the Customer's average monthly load at the service location.

"New" TBH Customer - Commercial Service

A monthly billing cycle factor of **2.5** x estimated monthly bill - based on the Customer's average monthly load at the service location.

*"Existing" TBH Customer - Residential Service (RS)**

A bi-monthly billing cycle factor of **1.75** x estimated bimonthly bill - based on the Customer's highest monthly load at the service location.

*"Existing" TBH Customer – Commercial Service **

A monthly billing cycle factor of **2.5** x estimated monthly bill - based on the Customer's highest monthly load at the service location.

Where the payment history of a residential Customer discloses more than one disconnection notice in a relevant 12 month period, Thunder Bay Hydro may use that Customer's highest (actual or estimated) monthly load for the most recent 12 consecutive months within the past two (2) years for the purposes of making the calculation of the maximum amount of Security Deposit.

d. A Customer that is a corporation within the meaning of the *Condominium Act, 1998* who has an account with Thunder Bay Hydro shall be deemed a residential Customer and treated as such for the purposes of these Conditions of Service if the following conditions are met:
   i. The account relates to more than one unit on the property; and
   ii. The Customer has filed a declaration with Thunder Bay Hydro attesting to the Customer's status as a corporation within the meaning of the *Condominium Act, 1998*.

3. Acceptable forms of Payment:

The form of payment of a Security Deposit for a residential Customer shall be cash or cheque(s) at the discretion of the Customer or such other form as is acceptable to Thunder Bay Hydro.

The form of payment of a security deposit for a non-residential Customer shall be cash, cheque(s) or an automatically renewing, irrevocable letter of credit from a bank, at the discretion of the Customer, or such other form as is acceptable to Thunder Bay Hydro. Thunder Bay Hydro may also accept other forms of security such as surety bonds and third party guarantees.

If requested, Thunder Bay Hydro shall permit the Customer to provide a cash, money order or cheque (if acceptable to Thunder Bay Hydro) Security Deposit in equal installments paid over four months. A Customer may, at their discretion, choose to pay the Security Deposit over a shorter time period.

- Cash, Certified Cheque(s), Money Order(s) - which may be made in installments.
- Cheque(s) - this may be made in installments, if acceptable to Thunder Bay Hydro.
- An Irrevocable Letter of Credit from a chartered Canadian Bank or Credit Union.
- Government of Canada or Ontario Bearer Bonds.
- Band Council Resolution Guarantee.
- A Personal Guarantee signed by the Company Director(s) or Director of the Parent Company – this option is subject to credit approval by Thunder Bay Hydro.

4. Return of Security Deposits:

a. Thunder Bay Hydro shall review every Customer's Security Deposit at least once in a calendar year to determine whether the entire amount of the Security Deposit is to be returned to the Customer.

   The amount of the Security Deposit is to be adjusted, as part of this review, based on a re-calculation of the maximum amount of the Security Deposit. Where Thunder Bay Hydro determines in conducting a review that the amount of the Security Deposit is to be adjusted upward, Thunder Bay Hydro will require the Customer to pay this additional amount at the same time as that Customer's next regular bill comes due.

b. In the case of a Customer in a > 5000 kW demand rate class, where the Customer is now in a position that it would be exempt from paying a Security Deposit, Thunder Bay Hydro is only required to return 50% of the Security Deposit held by Thunder Bay Hydro.

c. A Customer may, no earlier than 12 months after the payment of a Security Deposit or the making of a prior demand for a review, request in writing that Thunder Bay Hydro undertake a review to determine whether the entire amount of the Security Deposit is to be returned to the Customer.

d. Where Thunder Bay Hydro determines that some or all of the Security Deposit is to be returned to the Customer, Thunder Bay Hydro shall promptly return this amount to the Customer by crediting the

amount of the deposit plus accrued interest onto the Customer's account or by other methods as determined by Thunder Bay Hydro.

e. Thunder Bay Hydro shall promptly return any Security Deposit received from the Customer upon closure of the Customer's account, subject to Thunder Bay Hydro's right to use the Security Deposit to set off other amounts owing by the Customer to Thunder Bay Hydro. The Security Deposit may be applied to the final bill or refunded as required. The Security Deposit plus applicable interest shall be returned within six weeks of the closure of an account.

f. Thunder Bay Hydro shall apply a security deposit to the final bill of a Customer where a Customer changes to a competitive retailer-consolidated billing or a Customer changes billing options from distributor-consolidated billing to split billing or retailer-consolidated billing. Thunder Bay Hydro shall promptly return any remaining amount of the security deposit to the Customer. Where a change is made from distributor-consolidated billing to split billing, Thunder Bay Hydro may retain a portion of the security deposit amount that reflects the non-payment risk associated with the new billing option.

g. Where all or part of the security deposit has been paid by a third party on behalf of a customer, the distributor shall return the amount of the security deposit paid by the third party, including interest, where applicable, to the third party.

This obligation shall apply where and to the extent that:

- The third party paid all or part (as applicable) of the security deposit to the distributor;
- The third party has requested, at the time the security deposit was paid or within a reasonable time thereafter, that the distributor return all or part (as applicable) of the security deposit to it rather than to the Customer; and
- There is not any amount overdue for payment by the Customer that Thunder Bay Hydro is permitted to set off using the security deposit.

5. Interest on Security Deposit:

Interest shall accrue monthly on Security Deposits commencing on receipt of the total deposit required by Thunder Bay Hydro. The interest rate shall be at the Prime Business Rate as determined by the Bank of Canada less two (2) percent, updated quarterly. The interest accrued shall be paid out at least once every 12 months, or on return of the Security Deposit, or closure of the account, whichever comes first. This interest may be paid by crediting the account of the Customer or by other methods as determined by Thunder Bay Hydro.

APPENDIX B

Distribution System Code (Appendix B)

Appendix B

Methodology and Assumptions for An Economic Evaluation Last Revised January 23, 2007

APPENDIX B – METHODOLOGY AND ASSUMPTIONS FOR AN ESTIMATE TO CONNECT ECONOMIC EVALUATION

B.1 COMMON ELEMENTS OF THE DISCOUNTED CASH FLOW MODEL

To achieve consistent business principles for the development of the elements of an Economic Evaluation model, the following parameters for the approach are to be followed by all distributors.
The discounted cash flow (DCF) calculation for individual projects will be based on a set of common elements and related assumptions listed below.

Revenue Forecasting

The common elements for any project will be as follows:

(a) Total forecasted customer additions over the Customer Connection Horizon, by class as specified below;

(b) Customer Revenue Horizon as specified below;

(c) Estimate of average energy and demand per added customer (by project) which reflects the mix of customers to be added B for various classes of customers; this should be carried out by class;

(d) Customer additions, as reflected in the model for each year of the Customer Connection Horizon; and

(e) Rates from the approved rate schedules for the particular distributor reflecting the distribution (wires only) rates.

Capital Costs

Common elements will be as follows:

(a) An estimate of all capital costs directly associated with the expansion to allow forecast customer additions.

(b) For expansions to the distribution system, costs of the following elements, where applicable, should be included:
- distribution stations;
- distribution lines;
- distribution transformers;

APPENDIX B – METHODOLOGY AND ASSUMPTIONS FOR AN ESTIMATE TO CONNECT ECONOMIC EVALUATION

- secondary busses;
- services; and
- land and land rights.

Note that the "Ownership Demarcation Point" as specified in the distributor=s Condition of Service would define the point of separation between a customers= facilities and distributor=s facilities.

(c) Estimate of incremental overheads applicable to distribution system expansion.

(d) A per kilowatt enhancement cost estimate – the per kilowatt enhancement cost estimate shall be set annually and shall be based on a historical three to five year rolling average of actual enhancement costs incurred in system expansions.

(e) For residential customers, the amount the cost of the basic connection referred to in section 3.1.4 of the Code.

(f) For non-residential customers, if the distributor has chosen to recover the non-residential basic connection charge as part of its revenue requirement, a description of, and the amount for, the connection charges referred to in section 3.1.5 of the Code that have been factored into the economic evaluation.

Expense Forecasting

Common elements will be as follows:

(a) Attributable incremental operating and maintenance expenditures - any incremental attributable costs directly associated with the addition of new customers to the system would be included in the operating and maintenance expenditures.

(b) Income and capital taxes based on tax rates underpinning the existing rate schedules.

(c) Municipal property taxes based on projected levels.

Specific Parameters/Assumptions

Specific parameters of the common elements include the following:

APPENDIX B – METHODOLOGY AND ASSUMPTIONS FOR AN ESTIMATE TO CONNECT ECONOMIC EVALUATION

(a) A maximum customer connection horizon of five (5) years, calculated from the energization date of the facilities. [1]

(b) A maximum customer revenue horizon of twenty five (25) years, calculated from the in service date of the new customers. [2]

(c) A discount rate equal to the incremental after-tax cost of capital, based on the prospective capital mix, debt and preference share cost rates, and the latest approved rate of return on common equity.

(d) Discounting to reflect the true timing of expenditures. Up-front capital expenditures will be discounted at the beginning of the project year and capital expended throughout the year will be mid-year discounted. The same approach to discounting will be used for revenues and operating and maintenance expenditures. [3]

[1] For customer connection periods of greater than 5 years an explanation of the extension of the period will be provided to the Board

[2] For example, that the revenue horizon for customers connected in year 1, is 25 years while for those connected in year 3, the revenue horizon is 22 years.

[3] For certain projects Capital Expenditures may be staged and can occur in any year of the five-year Connection Horizon.

APPENDIX B – METHODOLOGY AND ASSUMPTIONS FOR AN ESTIMATE TO CONNECT ECONOMIC EVALUATION

B.2 DISCOUNTED CASH FLOW (DCF) METHODOLOGY

Net Present Value ("NPV")	=	Present Value ("PV") of Operating Cash Flow + PV of CCA Tax Shield - PV of Capital
1. PV of Operating Cash Flow	=	P V of Net Operating Cash (before taxes) - P V of Taxes
a) PV of Net Operating Cash	=	PV of Net Operating Cash Discounted at the Company's discount rate for the customer revenue horizon. Mid-year discounting is applied. Incremental after tax weighted average cost of capital will be used in discounting.
Net (Wires) Operating Cash	=	(Annual(Wires) Revenues - Annual (Wires) O&M)
Annual (Wires) Revenue	=	Customer Additions * [Appropriate (Wires) Rates * Rate Determinant]
Annual (Wires) O&M	=	Customer Additions * Annual Marginal (Wires) O&M Cost/customer
b) PV of Taxes	=	PV of Municipal Taxes + PV of Capital Taxes + PV of Income Taxes (before Interest tax shield)
Annual Municipal Tax	=	Municipal Tax Rate * (Total Capital Cost)
Total Capital Cost	=	Distribution Capital Investment + Customer Related Investment + overheads at the project level
Annual Capital Taxes	=	(Capital Tax Rate) * (Closing Undepreciated Capital Cost Balance)
Annual Capital Tax	=	(Capital Tax Rate) * (Net Operating Cash - Annual Municipal Tax B Annual Capital Tax)

The Capital Tax Rate is a combination of the Provincial Capital Tax Rate and the Large Corporation Tax (Grossed up for income tax effect where appropriate).

Note: Above is discounted, using mid-year discounting, over the customer revenue horizon.

2. PV of Capital = P V of Total Annual Capital Expenditures

a) PV of Total Annual Capital Expenditures

Total Annual Capital Expenditures over the customer's revenue horizon discounted to time zero

Total Annual Capital Expenditure	=	(for New Facilities and/or Reinforcement Investments + Customer Specific Capital + Overheads at the project level). This applies for implicated system elements at the utility side of the Ownership Demarcation Line@.

Note: Above is discounted to the beginning of year one over the customer addition horizon

APPENDIX B –
METHODOLOGY AND ASSUMPTIONS FOR AN ESTIMATE TO CONNECT ECONOMIC EVALUATION

3. PV of CCA Tax Shield

P V of the CCA Tax Shield on [Total Annual Capital]

The PV of the perpetual tax shield may be calculated as:

PV at time zero of: $\frac{[(\text{Income tax Rate}) * (\text{CCA Rate}) * \text{Annual Total Capital}]}{(\text{CCA Rate} + \text{Discount Rate})}$

or,
Calculated annually and present valued in the PV of Taxes calculation.

Note: An adjustment is added to account for the ½ year CCA rule.

4. Discount Rate

PV is calculated with an incremental, after-tax discount rate.

APPENDIX C

Load Customer Application for Service

CUSTOMER IDENTIFICATION NUMBER: _____

AGREEMENT AND APPLICATION FOR THE SERVICE & SUPPLY OF ELECTRICAL ENERGY between THUNDER BAYHYDRO ELECTRICITY DISTRIBUTION INC. – hereinafter known as THUNDER BAY HYDRO and THE UNDERSIGNED – hereinafter known as the CONSUMER

Consumer's Full/Last Name:

_____
(please print)

First Name: _____ **Middle Name**: _____
(print, if applicable) *(print, if applicable)*

The Undersigned hereby requests Thunder Bay Hydro to supply Electrical Energy to the Consumer at the Service Location/Locations requested by the Consumer. This application will also include all rental equipment, owned by Thunder Bay Hydro, at the requested Location(s).

This application when signed by the consumer and Executed by the signature of a Thunder Bay Hydro representative shall be a contract between the Consumer and Thunder Bay Hydro. The Consumer and Thunder Bay Hydro agree to comply with the Terms of Agreement, which are available upon request, and agree that the said Terms of Agreement are part of this Contract.

The Consumer further agrees to pay Thunder Bay Hydro the applicable rates and charges as approved by the Ontario Energy Board.

Witnessed: _____ **Consumer:** _____

Accepted and Signed for Thunder Bay Hydro: Signature: _____

By: _____ **Title/Position:** _____

Date: _____ **Date of Application:** _____

CONSENT FORM for NEW THUNDER BAY HYDRO CUSTOMERS

Thunder Bay Hydro is pleased to be your provider of electricity distribution services. To provide you with a reliable source of electricity, Thunder Bay Hydro needs to collect and use certain personal information about you. As of January 1, 2004, federal legislation protecting your privacy requires that Thunder Bay Hydro obtain your written consent to collect, use and disclose your personal information for identified purposes. We invite you to read this notice carefully to understand our policies and practices with respect to personal information.

The nature of personal information we collect may include:

- Information we receive from you such as your name, address, contact information and general financial, credit and reference information;
- Facts about your historical and current consumption of power;
- Information about your transactions with us, such as meter number, account number, account balances, payment history, and account activity;
- Identifying information, such as a driver's licence.

Thunder Bay Hydro uses the information we collect for the following purposes:

- To provide you with continuous electric service and to bill you for that service;
- To assist us in the collection of accounts;
- To respond to your inquiries about energy use and billing;
- To prevent fraud with respect to both you and our company;
- To meet legal and regulatory requirements.

Because of the structure of the electricity sector in Ontario, it may be necessary to share your billing and consumption information with third party billing and settlement agencies. For example, your billing and consumption information may be provided to a retailer with whom you have chosen to enter into a separate contract. Your information may also be shared or disclosed to other agencies or organizations as required by law or regulation.

We have developed and implemented a Corporate Privacy Policy/Code for maintaining the confidentiality and security of your personal information. At any time, you have the right to request access to your personal information which we have collected and to request amendments to personal information about you to ensure its accuracy and completeness. To make a request for access to personal information we may have collected, disclosed or used about you, or to request that your personal information be amended, please contact our **Chief Privacy Officer, Human Resources & Safety**.

I have read and understood this statement of Thunder Bay Hydro regarding the collection, use and disclosure of my personal information, and I hereby consent to have Thunder Bay Hydro collect and use my personal information for the purposes stated above.

Dated : _____ Name *(please print)* : _____

Signed : _____

Terms of Agreement for Electrical Service

1. The Consumer agrees to use the energy only for the purpose for which it was connected and releases Thunder Bay Hydro from all claims for damage resulting from the use of electrical energy.

2. The Consumer agrees to pay for all the energy used and for all the other charges directly related to the continued supply of electrical energy at the authorized rate of Thunder Bay Hydro when due at the office of Thunder Bay Hydro or other authorized collection points. A late payment charge in accordance with the approved rate schedule shall apply to all accounts not paid to Thunder Bay Hydro on or before the due date.

3. This Agreement shall not be binding upon Thunder Bay Hydro until the application is accepted, such acceptance being conditional upon the information in the Credit Information Form / File being materially correct, and until the application is executed by the signature of the appropriate authorized Thunder Bay Hydro representative, and shall not be modified or affected by any promise, agreement or representation of any agent or employee of Thunder Bay Hydro unless same is in writing and made part of this Agreement.

4. Thunder Bay Hydro shall not be liable for any injury, loss or damage to persons or property accruing or resulting from the failure of the supply of energy, from the failure to maintain a constant frequency or voltage, from any surge from natural or from accident not caused by the negligence of Thunder Bay Hydro, or from the disconnection of the supply of energy due to nonpayment of account.

5. This Agreement shall continue in force from the date on which the service is connected and thereafter until terminated by at least five working days' notice, in writing, given by either party to the other.

6. Notwithstanding the provisions of Clause 5, Thunder Bay Hydro reserves the right to limit or discontinue the supply of energy without notice for repairs, want of supply, nonpayment of account after due date, insolvency of the Consumer, safety issues, or infraction of any rules established by Thunder Bay Hydro.

7. The Consumer consents to Thunder Bay Hydro, or its agents, to seek and obtain personal or financial information for the purpose of granting credit or recovering amounts due to Thunder Bay Hydro.

8. In accordance with Thunder Bay Hydro's Security Deposit Policy, should an account security deposit be required, the Consumer agrees to pay Thunder Bay Hydro the security deposit, at an amount in accordance with Thunder Bay Hydro's Security Deposit Policy, or provide a surety bond satisfactory to Thunder Bay Hydro in the same amount, which may, from time to time, be increased or decreased as determined by Thunder Bay Hydro. Such increases in the security deposit are to be paid forthwith on demand and shall form part of the Consumer's account. The Consumer agrees that Thunder Bay Hydro may, at its discretion, apply the security deposit, or any portion thereof, to his energy account with

Thunder Bay Hydro. On termination of this Agreement or upon the bankruptcy of the Consumer or upon appointment of a receiver or trustee for the Consumer, the balance of the security deposit held by Thunder Bay Hydro shall be returned to the Consumer or his legal representative after arrears, charges, damages or costs, if any, have been deducted therefrom. The Consumer acknowledges and agrees that the payment of the aforesaid security deposit or provision of the aforesaid surety bond is a condition precedent to Thunder Bay Hydro's acceptance of the Consumer's application, and to Thunder Bay Hydro's supply of electrical energy, services and goods to the Consumer.

9. In the event the Agreement is terminated pursuant to Clause 5 or whenever default is made in giving security as required by Clause 8, the Consumer hereby authorizes Thunder Bay Hydro, at its option, to enter onto the Consumer's present premises and remove therefrom, meters, lines, equipment and appliances installed thereon by Thunder Bay Hydro.

10. The Consumer agrees to provide space free of charge or rent in the Consumer's premises for the meters and any other equipment of Thunder Bay Hydro all of which shall be in the care and at the risk of the Consumer, and if destroyed or damaged by fire, or any cause whatsoever, other than ordinary wear and tear, the Consumer shall be liable to pay Thunder Bay Hydro the value of such meters and any other equipment, or the cost of repairing or replacing the same, and further agrees that the properly authorized agents of the Thunder Bay Hydro shall, at all reasonable hours, have the right to read, inspect, replace and remove any of the said equipment or to install any further equipment or apparatus which Thunder Bay Hydro deems necessary and have free access for this purpose to the said premises.

11. It is agreed that the signature of the parties hereto shall be binding upon their successors or assigns and that, subject to the fulfillment of their requirements of Clause 5, the vacating of the premises herein named shall not release the Consumer from this Agreement except at the option and by written consent of Thunder Bay Hydro.

12. If a meter in any month ceases to register or has registered incorrectly, the Consumer shall pay for the energy supplied and any other applicable charges during such a month a reasonable sum based on the reading of any meter formerly or subsequently installed on the premises, with due regard being given to any change in the character of the installation and/or demand.

13. In the event of a Consumer who has notified Thunder Bay Hydro to disconnect service, or whose service has been disconnected under Clause 6, or Clause 8 of this agreement, failing to arrange for the admittance of Thunder Bay Hydro's employees for the purpose of obtaining a final meter reading, the Consumer shall pay a reasonable sum based on former meter readings for the energy supplied since the last meter reading together with all outstanding indebtedness incurred by the Consumer prior to the date of final meter reading.

14. Thunder Bay Hydro agrees to use reasonable diligence in providing a regular and uninterrupted supply of electrical energy, but does not guarantee a constant supply of electrical energy, or the maintenance of unvaried frequency or voltage, and will not be liable in damages to the Consumer by reason of any failure in any respect thereof.

15. Thunder Bay Hydro, from time to time, may make tests to determine the electrical characteristics of the Consumer's load and may install and use meters and equipment that it deems necessary.

16. All electrical and mechanical equipment used by the Consumer shall so take and use electrical energy as not to endanger the equipment or other works of Thunder Bay Hydro or those of a third party or cause any wide or abnormal fluctuation of its line voltage. Any situation deemed by Thunder Bay Hydro to be an endangerment must be corrected by the Consumer at the Consumer's costs. Thunder Bay Hydro shall not be held responsible for any damages caused to other parties by the Consumer.

17. This agreement is subject to Thunder Bay Hydro's Conditions Service, as amended from time to time, issued by the Thunder Bay Hydro Engineering Department. Copies of Thunder Bay Hydro's "Conditions of Service" will be supplied upon request or are available for download from our website http://www.tbhydro.on.ca.

18. As Thunder Bay Hydro does not guarantee an uninterrupted power supply, those Consumers dependent on life-sustaining equipment or others who can not accept or accommodate planned or unplanned outages should purchase a backup generator.

APPENDIX D

Demarcation Points and Charges

Connection Charges

All Customers (regardless of Customer class) will be provided with or entitled to a Basic Connection Credit (which is the supply and installation of overhead distribution transformation capacity or an equivalent credit for transformation equipment and up to 30 m of overhead conductor or an equivalent credit. A Variable Connection Charge will be payable equaling the Actual Connection Costs minus the Basic Connection Credit.

Residential –Single Service

Service Type at Property Line	Ownership Demarcation Point	Variable Connection Charge	Service Disconnection Fee (Initiated by Customer Request)
Overhead Secondary (Not requiring transformation facilities on private property) Not available for new subdivision lots or those created by severance as shown in Condition 1	Top of Customer's service mast (As per Section 3.1.4 and Conditions 1 and 2 of Dwg. 07-SECSERVCOND-1A in Appendix D)	Actual costs for connection assets and installation beyond Basic Connection Credit	Recovered as part of Distribution Revenue Requirement and as such is part of Thunder Bay Hydro's rates.
Underground Secondary (Not requiring transformation facilities on private property)	Line-side of Customer's meter base (As per Section 3.1.4 and Condition 3 of Dwg. 07-SECSERVCOND-1A in Appendix D)	Actual costs for connection assets and installation beyond Basic Connection Credit	Recovered as part of Distribution Revenue Requirement and as such is part of Thunder Bay Hydro's rates.
Overhead Primary (Requiring transformation facilities on private property) Not available for new lots created by severance as shown in Condition 4	As per Section 3.1.4 and Conditions 4 and 5 of Dwg. 07-SECSERVCOND-2A in Appendix D	Actual costs for connection assets and installation beyond Basic Connection Credit	Recovered as part of Distribution Revenue Requirement and as such is part of Thunder Bay Hydro's rates.
Underground Primary (Requiring transformation facilities on private property solely to service a single customer)	As per Section 3.1.4 and Condition 6 of Dwg. 07-SECSERVCOND-2A in Appendix D	Actual costs for connection assets and installation beyond Basic Connection Credit	Recovered as part of Distribution Revenue Requirement and as such is part of Thunder Bay Hydro's rates.
Underground (Subdivision)	As per Subdivision Agreement and Condition 7 of Dwg. 07-SECSERVCOND-2A in Appendix D	Actual costs for connection assets and installation beyond Basic Connection Credit	Recovered as part of Distribution Revenue Requirement and as such is part of Thunder Bay Hydro's rates.

General Service (Under 50 kW)

Service Type At Property Line	Ownership Demarcation Point	Variable Connection Charge	Service Disconnection Fee (Initiated by Customer Request)
Overhead (Not requiring transformation facilities on private property) Not available for new lots created by severance	Top of Customer's service mast. Refer to Section 3.2.4	Actual costs for connection assets and installation beyond Basic Connection Credit	Recovered as part of Distribution Revenue Requirement and as such is part of Thunder Bay Hydro's rates.
Overhead (Requiring transformation facilities on private property)	First device on private property. Refer to Section 3.2.4	Actual costs for connection assets and installation beyond Basic Connection Credit	Recovered as part of Distribution Revenue Requirement and as such is part of Thunder Bay Hydro's rates.
Underground (Not requiring transformation facilities on private property)	Line-side of Customer's meter. Refer to Section 3.2.4	Actual costs for connection assets and installation beyond Basic Connection Credit	Recovered as part of Distribution Revenue Requirement and as such is part of Thunder Bay Hydro's rates.
Underground (Requiring transformation facilities on private property)	Secondary terminals of padmount transformer. Refer to Section 3.2.4	Actual costs for connection assets and installation beyond Basic Connection Credit	Recovered as part of Distribution Revenue Requirement and as such is part of Thunder Bay Hydro's rates.

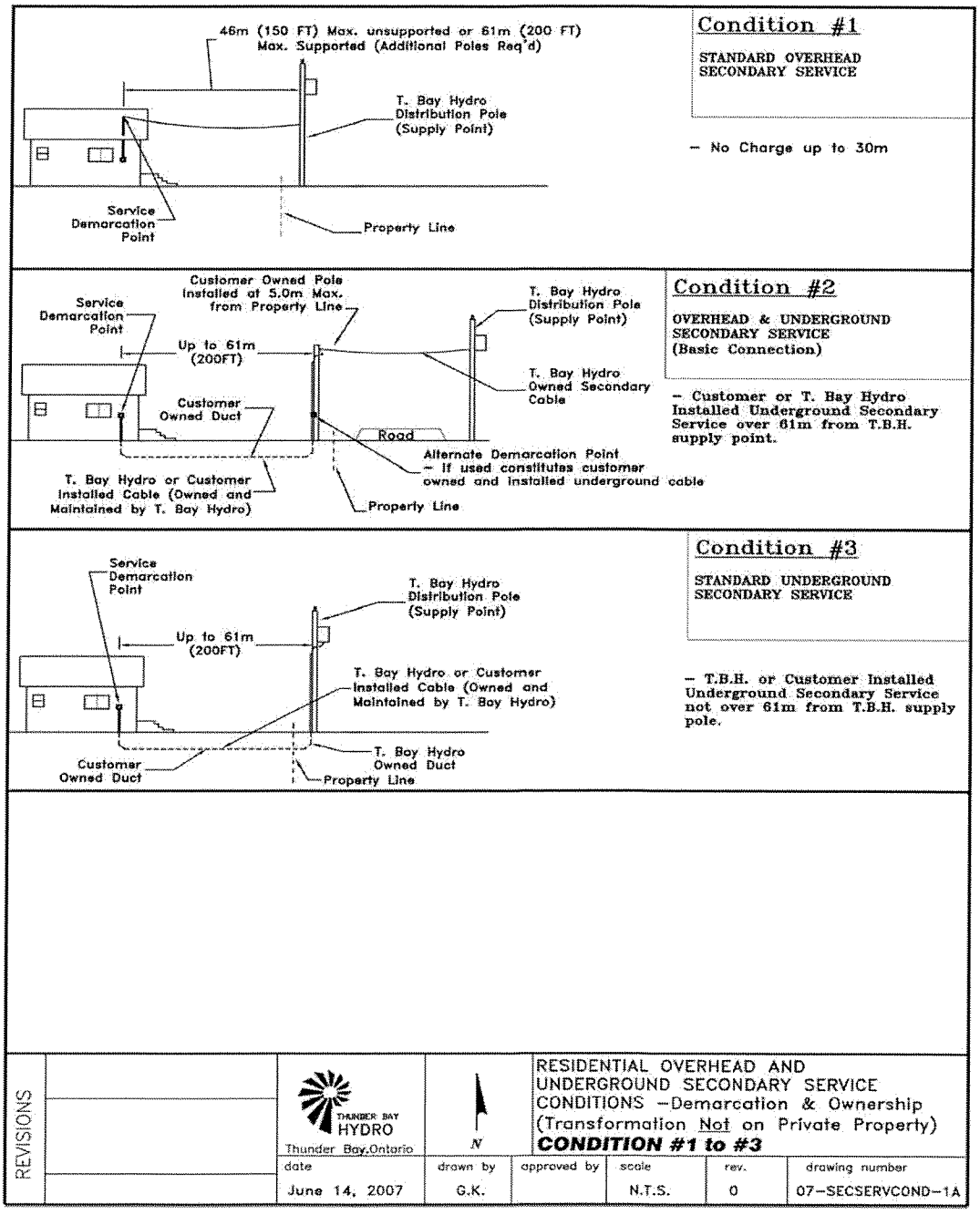
General Service (50 - 1000 kW)

Service Type at Property Line	Ownership Demarcation Point	Variable Connection Charge	Service Disconnection Fee (Initiated by Customer Request)
Overhead Secondary (Not requiring transformation facilities on private property)	Top of Customer's service mast. Refer to Section 3.3.4	Actual costs for connection assets and installation beyond Basic Connection Credit	Customer charged actual costs associated with disconnection and/or removal of connection assets up to the demarcation point.
Underground Secondary (Not requiring transformation facilities on private property)	Line-side of Customer's meter or junction box on the exterior of the Customer's building structure. Refer to Section 3.3.4	Actual costs for connection assets and installation beyond Basic Connection Credit	Customer charged actual costs associated with disconnection and/or removal of connection assets up to the demarcation point.
Overhead Primary (Requiring TBH owned transformation facilities on private property)	First point of attachment on private property. Refer to Section 3.3.4	Actual costs for connection assets and installation beyond Basic Connection Credit	Customer charged actual costs associated with disconnection and/or removal of connection assets up to the demarcation point and related switching/isolation.
Underground Secondary (Requiring TBH owned transformation facilities on private property)	Transformer secondary terminals. Refer to Section 3.3.4	Actual costs for connection assets and installation beyond Basic Connection Credit	Customer charged actual costs associated with disconnection and/or removal of connection assets up to the demarcation point.

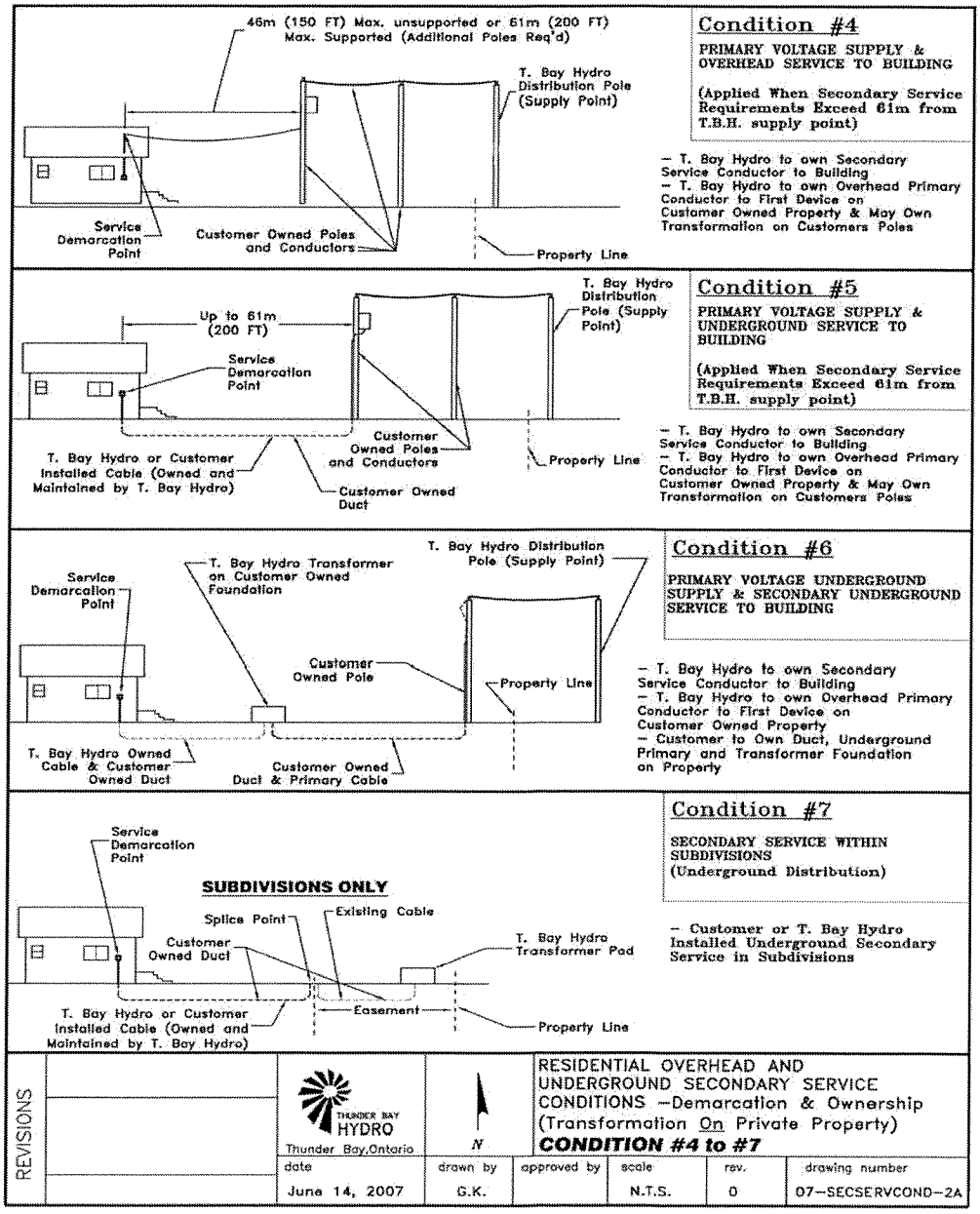
General Service (Above 1000 kW)

Service Type	Ownership Demarcation Point	Variable Connection Charge	Service Disconnection Fee (Initiated by Customer Request)
Overhead Primary (Customer owned transformation facilities on private property)	First point of attachment on private property. Refer to Section 3.4.4	Actual costs for connection assets and installation beyond Basic Connection Credit	Customer charged actual costs associated with disconnection and/or removal of connection assets up to the demarcation point. and related switching/isolation
Underground Primary (Customer owned substation/transformation on private property)	First point of attachment on private property. Refer to Section 3.4.4	Actual costs for connection assets and installation beyond Basic Connection Credit	Customer charged actual costs associated with disconnection and/or removal of connection assets up to the demarcation point. and related switching/isolation

Appendix D


46m (150 FT) Max. unsupported or 61m (200 FT) Max. Supported (Additional Poles Req'd)
T. Bay Hydro Distribution Pole (Supply Point)
Service Demarcation Point
Property Line
Condition #1
STANDARD OVERHEAD SECONDARY SERVICE
- No Charge up to 30m
Customer Owned Pole Installed at 5.0m Max. from Property Line
Service Demarcation Point
Up to 61m (200FT)
T. Bay Hydro Distribution Pole (Supply Point)
T. Bay Hydro Owned Secondary Cable
Customer Owned Duct
Road
Alternate Demarcation Point - If used constitutes customer owned and installed underground cable
T. Bay Hydro or Customer Installed Cable (Owned and Maintained by T. Bay Hydro)
Property Line
Condition #2
OVERHEAD & UNDERGROUND SECONDARY SERVICE (Basic Connection)
- Customer or T. Bay Hydro Installed Underground Secondary Service over 61m from T.B.H. supply point.
Service Demarcation Point
T. Bay Hydro Distribution Pole (Supply Point)
Up to 61m (200FT)
T. Bay Hydro or Customer Installed Cable (Owned and Maintained by T. Bay Hydro)
Customer Owned Duct
T. Bay Hydro Owned Duct
Property Line
Condition #3
STANDARD UNDERGROUND SECONDARY SERVICE
- T.B.H. or Customer Installed Underground Secondary Service not over 61m from T.B.H. supply pole.
REVISIONS
THUNDER BAY HYDRO
Thunder Bay, Ontario
N
RESIDENTIAL OVERHEAD AND UNDERGROUND SECONDARY SERVICE CONDITIONS -Demarcation & Ownership (Transformation Not on Private Property)
CONDITION #1 to #3
date
June 14, 2007
drawn by
G.K.
approved by
scale
N.T.S.
rev.
0
drawing number
07-SECSERVCOND-1A

Appendix D


46m (150 FT) Max. unsupported or 61m (200 FT) Max. Supported (Additional Poles Req'd)
T. Bay Hydro Distribution Pole (Supply Point)
Service Demarcation Point
Customer Owned Poles and Conductors
Property Line
Condition #4
PRIMARY VOLTAGE SUPPLY & OVERHEAD SERVICE TO BUILDING
(Applied When Secondary Service Requirements Exceed 61m from T.B.H. supply point)
– T. Bay Hydro to own Secondary Service Conductor to Building
– T. Bay Hydro to own Overhead Primary Conductor to First Device on Customer Owned Property & May Own Transformation on Customers Poles
Up to 61m (200 FT)
T. Bay Hydro Distribution Pole (Supply Point)
Service Demarcation Point
T. Bay Hydro or Customer Installed Cable (Owned and Maintained by T. Bay Hydro)
Customer Owned Poles and Conductors
Customer Owned Duct
Property Line
Condition #5
PRIMARY VOLTAGE SUPPLY & UNDERGROUND SERVICE TO BUILDING
(Applied When Secondary Service Requirements Exceed 61m from T.B.H. supply point)
– T. Bay Hydro to own Secondary Service Conductor to Building
– T. Bay Hydro to own Overhead Primary Conductor to First Device on Customer Owned Property & May Own Transformation on Customers Poles
Service Demarcation Point
T. Bay Hydro Transformer on Customer Owned Foundation
T. Bay Hydro Distribution Pole (Supply Point)
Customer Owned Pole
Property Line
T. Bay Hydro Owned Cable & Customer Owned Duct
Customer Owned Duct & Primary Cable
Condition #6
PRIMARY VOLTAGE UNDERGROUND SUPPLY & SECONDARY UNDERGROUND SERVICE TO BUILDING
– T. Bay Hydro to own Secondary Service Conductor to Building
– T. Bay Hydro to own Overhead Primary Conductor to First Device on Customer Owned Property
– Customer to Own Duct, Underground Primary and Transformer Foundation on Property
Service Demarcation Point
SUBDIVISIONS ONLY
Splice Point
Existing Cable
Customer Owned Duct
T. Bay Hydro Transformer Pad
T. Bay Hydro or Customer Installed Cable (Owned and Maintained by T. Bay Hydro)
Easement
Property Line
Condition #7
SECONDARY SERVICE WITHIN SUBDIVISIONS
(Underground Distribution)
– Customer or T. Bay Hydro Installed Underground Secondary Service in Subdivisions
REVISIONS
THUNDER BAY HYDRO
Thunder Bay,Ontario
N
RESIDENTIAL OVERHEAD AND UNDERGROUND SECONDARY SERVICE CONDITIONS –Demarcation & Ownership
(Transformation On Private Property)
CONDITION #4 to #7
date
June 14, 2007
drawn by
G.K.
approved by
scale
N.T.S.
rev.
0
drawing number
07–SECSERVCOND–2A

APPENDIX E

Ontario Energy Board Approved Rates for Miscellaneous Charges

Appendix E

Connection Charges and OEB-Approved Rates for Miscellaneous Charges

The following services are regulated and approved by the OEB. For the most current rates, please check with Customer Service.

Customer Administration

Late Payment	1.5% / month, 19.56% / annum
Account Setup Charge/Change of Occupancy Charge (plus credit agency costs if applicable)	$30.00 + Tax
Returned Cheque / Payment Charge (plus bank charges)	$25.00 + Tax
Arrears Certificate / Legal Letter Charge	$15.00 + Tax
Easement Letter Charge	$15.00 + Tax
Special Meter Reads	$30.00 + Tax
Meter Dispute Involvement Charge plus Measurement Canada fees (if meter found to be registering correctly)	$30.00 + Tax
Account Statement (*Account History*)	$15.00 + Tax

Non-Payment of TBH Account

Service Call / Collection of Account Charge	$30.00 + Tax
Disconnect/Reconnect Charge at Meter *During Regular Working Hours*	$65.00 + Tax
Disconnect/Reconnect Charge at Meter *After Regular Working Hours*	$185.00 + Tax
Disconnect/Reconnect Charge at Pole *During Regular Working Hours*	$185.00 + Tax
Disconnect/Reconnect Charge at Pole *After Regular Working Hours*	$415.00 + Tax
Install/Remove Load Control Device *During Regular Working Hours*	$65.00 + Tax
Install/Remove Load Control Device *After Regular Working Hours*	$185.00 + Tax

Service Calls - Vacancy Reconnects

Reconnection requested **before 2:00 pm** and completed during Regular TBH Working Hours
Vacancy Reconnect Charge - - Included in $30.00 Account Setup Charge

Reconnection requested **after 2:00 pm** and completed after Regular TBH Working Hours
Vacancy Reconnect Charge - **One of the following charges**

* *If reconnection is completed before **4:30 pm***
Service Call - Included in $30.00 Account Setup Charge
Reconnection completed between **4:30 pm to **8:00 pm***
Account Setup Charge *and* $30.00 + Tax

Service Call		$30.00 + Tax
*Reconnection completed after **8:00pm, Weekends / Holidays***		
Account Setup Charge	*and*	$30.00 + Tax
Service Call		$165.00 + Tax

**** Based on the availability of a TBH Serviceperson, the priority to TBH's System Maintenance and access to the Service Location.***

Allowances

Transformer Allowance for Ownership – per kW of billing demand/month	$(0.60)
Primary Metering Allowance for transformer losses	%(1.00)
(Applied to measured demand and energy)	

APPENDIX F

Metering Requirements

Meter Sockets

Voltage	Phase	Wires	Maximum Service Switch Size Rating (Amperes)
120/240	1	3	200
120/240	1	3	400*
102/208	2	3	200
120/208	3	4	200
347/600	3	4	200

* The self shorting meter mounting device shall contain a three (3) wire current transformer. Instrument Transformers will be supplied by Thunder Bay Hydro.

Note:

1) A list of approved meter sockets is available on request.

2) Meter sockets shall be mounted so that the midpoint of the meter is at 1700 mm ± 100 mm.

3) All poly-phase metering shall have a neutral conductor. Where the Customer does not require a neutral, a full size neutral conductor sized in accordance with Table 17 of the Ontario Electrical Safety Code must be provided to all meter cabinets or sockets. The neutral conductor is to be terminated in the socket (or cabinet) on an insulated block in accordance with the Ontario Electrical Safety Code.

Instrument Transformer Compartments (Switchgear)

Voltage	Phase	Wire	Service Size (Amperes)	Compartment Size	Number of Instrument Transformers	
					Current	Voltage
120/208	3	4	up to 800A	See TBH Engineering	3	0
120/208	3	4	over 800A	See TBH Engineering	3	0
347/600	3	4	up to 800A	See TBH Engineering	3	3
347/600	3	4	over 800A	See TBH Engineering	3	3

Notes:

1. For switchgear applications only.

2. Instrument transformers will be provided and installed by Thunder Bay Hydro.

3. Voltage transformer connections shall be connected on the line-side of the current transformers. Current transformers shall be installed with their polarity marks towards the incoming Thunder Bay Hydro supply.

Meter Centres

Meter centres may be used for general service applications of 600V applications or less, provided they meet the following specifications:

1. Side hinged doors or panels shall be installed over all sections of the switchboard where Thunder Bay Hydro may be required to work, such as unmetered sections and those sections containing breakers, switches, and meter mounting devices. Hinged doors or panels shall have provision for sealing or padlocking in the closed position. Where bolts are used, they shall be of the captive knurled type. The hinged covers over breakers or switches shall be so constructed that the covers cannot be opened when sealed or padlocked.

2. Breakers or switch handles shall have provision for positive sealing and padlocking in the "off" position.

3. Meter mounting devices shall be wired so as to be on the "load" side of the breakers or switches.

4. Each combination meter socket and breaker panel shall have adequate space for permanent Customer identification with respect to street address and/or unit number.

5. The centre of the bottom row of meter sockets shall not be less than 600 mm from the finished floor. The centre of the top row of meter sockets shall not be greater than 1800 mm from the finished floor.

6. The distance between adjacent meter socket rims in the horizontal plane shall not be less than 152 mm.

7. The distance between adjacent meter socket rims in the vertical plane shall be as follows:

   a. For up to 200 A., 4 or 5-jaw, not less than 76 mm.
   b. For up to 200 A., 7-jaw, not less than 152 mm.

8. The meter mounting socket and sealing ring shall be acceptable to Thunder Bay Hydro.

9. Where a neutral is required, the meter mounting device shall have a pre-wired, ungrounded neutral connection to the 5th or 7th terminal. The connection, if not made directly to the neutral bus, shall be not less than #12 AWG copper.

LIST OF WITNESSES:

While Thunder Bay Hydro requests that this Application be disposed of by way of a written hearing, should an oral component be required, a list of witnesses will be provided.

The *Curricula Vitae* of any potential witnesses will accompany the list when provided.

SUMMARY OF THE APPLICATION:

Preamble

Thunder Bay Hydro's vision is:

> Thunder Bay Hydro is people working together, providing services of the best value and quality to our customers.

Thunder Bay Hydro is an electricity distribution company licensed by the Ontario Energy Board to provide electricity distribution services to customers within the City of Thunder Bay and Fort William First Nation Reserve.

Thunder Bay Hydro's priorities are defined in its Corporate Strategy :

> *Ensure that the Health and Safety of our Employees and Public is the Utility's first priority.*
>
> *Provide a reliable supply of electricity to the residents and businesses of Thunder Bay.*
>
> *Protect and grow the value of the utility to our Shareholder.*

In keeping with this vision to pursue health and safety as its top priority, Thunder Bay Hydro was recently recognized for it's completion of the ZeroQuest*Effort Level and was presented with the Silver Award for Effort by EUSA. Thunder Bay Hydro was also recently recognized by EUSA for achieving 250,000 of work without a lost time injury. Safety education, especially on the risks and hazards of electrical contacts, is a priority for Thunder Bay Hydro, both in-house and in the community. We offer an electrical safety presentation, titled Hi Line Hazards, to local students and service groups.

Thunder Bay Hydro is committed to helping our customers conserve and reducing 8.5 million kilowatt hours collectively by the end of 2008.

Thunder Bay Hydro's achieved levels of service quality for the year 2003 through 2007 are provided with this Schedule as "Appendix A".

Purpose and Need

Thunder Bay Hydro's requested revenue requirement for 2009 includes the recovery of its costs to provide distribution services, a Return on Equity ["ROE"] that is less than the OEB allowed return, and the funds necessary to service its debt required to meet the increased capital needs. The Corporation of the City of Thunder Bay, the sole shareholder of Thunder Bay Hydro Corporation (shareholder of Thunder Bay Hydro) provides the following governing principle in the Shareholder Declaration:

> "Distribution Co shall be operated in accordance with a "rate minimisation model" to the extent possible without jeopardising the reliability and efficiency of the electricity distribution system of Thunder Bay Hydro or the economic development of Thunder Bay."

Consistent with this principle, essentially to keep electricity rates as low as possible and to encourage economic development by foregoing debt and dividend payments, the Note Payable to the City of Thunder Bay was set up without any provision for the payment of interest or the repayment of principal. Additionally, the Corporation of the City of Thunder Bay does not seek a dividend from Thunder Bay Hydro.

Through this rate application, Thunder Bay Hydro seeks the recovery through rates of its proposed 2009 base revenue requirement in the amount of $17,518,938.

When its forecasted results for 2009 are considered, Thunder Bay Hydro estimates that its present rates will produce a deficiency in distribution revenue of $1,414,077 for the 2009 Test Year. Excluded from this estimate is the impact of energy costs.

Therefore, Thunder Bay 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 1, Tab 1, Schedule 5 to this Application.

The information presented in this Application is Thunder Bay Hydro's forecasted results for its 2009 Test Year. Due care and attention has been used in the preparation of the forecast information; however, actual results may vary from forecasts and any variation may be material. Forecasts, by their very nature, are subject to uncertainty and contingencies, many of which are outside the control of Thunder Bay Hydro. With the rates presently in effect, Thunder Bay Hydro estimates that its revenue for 2009 would not be sufficient to provide a reasonable return. Thunder Bay Hydro is also presenting the historical actual information for fiscal 2006, OEB-Approved data for 2006, actual information for fiscal 2007 as well as forecasted information for the fiscal 2008 Bridge Year.

Timing

The financial information supporting the Test Year for this Application will be Thunder Bay Hydro's fiscal year ending December 31, 2009 (the "2009 Test Year"). However, this information will be used to set rates for the period May 1, 2009 to April 30, 2010. The Test Year revenue requirement is that forecast by Thunder Bay Hydro as needed to allow it to continue to follow the "Rate Minimization Model" as mandated by the Shareholder and it should be noted that the rate of return is still well below the maximum rate of return permitted by the OEB for the 2009 Test Year**.** For the required revenues to match and appropriately offset the expected costs of service for the Test Year, revised rates reflecting the Board's Decision must be effective for volumes consumed on and after May 1, 2009.

Customer Impact

In preparing this application, Thunder Bay Hydro has considered the impacts on its customers, with a goal of minimizing those impacts. With respect to cost allocation, Thunder Bay Hydro notes that the revenue to cost ratio of the General Service < 50 kw, Sentinel and Unmetered Scattered Load class falls within the applicable threshold defined by the OEB in the OEB's November 28, 2007, Report on Application of Cost Allocation for Electricity Distributors. The revenue to cost ratios for the remaining classes is outside the range as set by the OEB. Thunder Bay Hydro has considered the results of the cost allocation and has designed its distribution rates to move towards the acceptable ranges.

Customer impacts including the percentage average Total Bill Impact and Average Dollar Impact, which include distribution rates [monthly service charge and volumetric rates], and revised retail transmission rates are set out in Table 1, below.

Table 1
AVERAGE TOTAL BILL IMPACT – PERCENT & DOLLAR

Class Average Total Bill Impact		**Average Total Bill Impact %**	**Average Dollar Impact**	**Average Delivery Line Bill Impact %**
Residential	1000 kwh	3.72	3.93	8.39
General Service <50 kW	2000 kwh	3.85	7.94	9.42
General Service >50 kW	100 kW	3.24	120.76	
Street Lighting	2500 kW	22.12	23,795	
Sentinel Lighting	1 kW	7.7	2.27	
Unmetered Scattered Load	500 kwh	16.74	11.31	

Major Issues

The issues to be reviewed in this case, as Thunder Bay Hydro sees them, are discussed in Exhibit 1, Tab Schedule 6 (Draft Issues List).

Thunder Bay Hydro also offers comments on the following matters:

Return on Equity

Thunder Bay Hydro has assumed a return on equity of 3.75% consistent with our Shareholder's "Rate Minimization Model". Thunder Bay Hydro acknowledges that this is well below the OEB approved MARR; however, is sufficient to fund the capital investment and operating and maintenance cost requirements.

Capital Expenditures

Thunder Bay Hydro continues to expand and reinforce its distribution system in order to maintain the reliability for existing customers and meet the demand of new and existing customers in its service territory. Given that Thunder Bay Hydro's load has been relatively flat for several years, the increase in demand comes mainly from distribution system replacements/upgrades needed in existing areas. Thunder Bay Hydro's core business is the safe, reliable delivery of electricity to the residents and businesses of Thunder Bay. To achieve this, a well-developed, long-term approach to infrastructure investment and maintenance is critical. As such, an effective AMP continues to be an important part of Thunder Bay Hydro's strategic initiatives. Thunder Bay Hydro is working on a 20-year rolling capital expenditure infrastructure replacement and growth plan. Thunder Bay Hydro has developed detailed capital project plans fro 2008 to 2011 and have projects scheduled to 2017 with an ultimate objective to have projects scheduled 20 years out. The projects for execution were selected and scheduled in accordance with the methodology described under the heading Ranking of Projects at Exhibit 2, Tab 1, Schedule 1

Operating and Maintenance Costs

Operating and maintenance costs have been updated to reflect the impact of inflation and expected changes in costs. Cost reduction and efficiency are always an important part of expenditure decisions at Thunder Bay Hydro. A significant increase in operating and maintenance costs are also a part of Thunder Bay Hydro's AMP (Forestry Management as an example). Other significant costs drivers include competition for skilled labour and succession planning for the potential retirements of a significant number of staff in the near future and the need to transfer knowledge/skills.

Based on the OEB's *Comparison of Ontario Electricity Distributors Costs [EB-2006-0268]*, as updated with 2007 Data issued in June 2008, Thunder Bay Hydro's OM&A costs per customer compare reasonably with its mid-size northern LDC cohorts. In 2007, the average OM&A cost per customer for the cohort was $232 while Thunder Bay Hydro's cost was $241. Over the 5-

year average from 2002 to 2006, Thunder Bay Hydro's cost was $229 while the average for the cohort was $227. Details of the calculations supporting this analysis are included in Appendix B to this Schedule.

APPENDIX A

ACHIEVED LEVEL OF

SERVICE QUALITY INDICATORS

THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.
PERFORMANCE BASED REGULATION
SERVICE RELIABILITY INDICES (2003-2007)

2007

OEB Approved Standard: Within the range of 3 years historical performance.						
	Total Customer Hours of Interruptions (1)	Total Customer Interruptions (2)	Total Number of Customers (3)	SAIDI (4) (1) / (3)	SAIFI (5) (2) / (3)	CAIDI (4) / (5)
Jan	1,548	7,213	49,481	**0.03**	**0.15**	**0.21**
Feb	3,462	5,297	49,545	**0.07**	**0.11**	**0.65**
Mar	8,043	14,954	49,569	**0.16**	**0.30**	**0.54**
Apr	13,936	19,688	49,694	**0.28**	**0.40**	**0.71**
May	10,982	17,718	49,759	**0.22**	**0.36**	**0.62**
Jun	30,317	41,127	49,733	**0.61**	**0.83**	**0.74**
Jul	12,798	19,561	49,588	**0.26**	**0.39**	**0.65**
Aug	1,612	9,761	49,814	**0.03**	**0.20**	**0.17**
Sep	2,195	7,512	49,619	**0.04**	**0.15**	**0.29**
Oct	7,485	11,989	49,625	**0.15**	**0.24**	**0.62**
Nov	5,188	5,618	49,643	**0.10**	**0.11**	**0.92**
Dec	1,602	3,420	49,484	**0.03**	**0.07**	**0.47**
Annual Total	**99,168**	**163,858**	**49,630**	**2.00**	**3.30**	**0.61**

2006

OEB Approved Standard: Within the range of 3 years historical performance.						
	Total Customer Hours of Interruptions (1)	Total Customer Interruptions (2)	Total Number of Customers (3)	SAIDI (4) (1) / (3)	SAIFI (5) (2) / (3)	CAIDI (4) / (5)
Jan	1,454	2,925	49,512	**0.03**	**0.06**	**0.50**
Feb	784	450	49,610	**0.02**	**0.01**	**1.74**
Mar	10,200	6,901	49,560	**0.21**	**0.14**	**1.48**
Apr	5,248	8,209	49,773	**0.11**	**0.16**	**0.64**
May	29,198	14,597	49,749	**0.59**	**0.29**	**2.00**
Jun	11,537	26,030	49,724	**0.23**	**0.52**	**0.44**
Jul	7,983	13,944	49,724	**0.16**	**0.28**	**0.57**
Aug	2,444	3,518	49,748	**0.05**	**0.07**	**0.69**
Sep	2,560	3,475	49,694	**0.05**	**0.07**	**0.74**
Oct	4,220	9,449	49,627	**0.09**	**0.19**	**0.45**
Nov	3,805	6,526	49,543	**0.08**	**0.13**	**0.58**
Dec	917	4,758	49,464	**0.02**	**0.10**	**0.19**
Annual Total	**80,350**	**100,782**	**49,644**	**1.62**	**2.03**	**0.80**

THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.
PERFORMANCE BASED REGULATION
SERVICE RELIABILITY INDICES (2003-2007)

2005

OEB Approved Standard: Within the range of 3 years historical performance.

	Total Customer Hours of Interruptions (1)	Total Customer Interruptions (2)	Total Number of Customers (3)	SAIDI (4) (1) / (3)	SAIFI (5) (2) / (3)	CAIDI (4) / (5)
Jan	550	2,261	49,415	**0.01**	**0.05**	**0.24**
Feb	2,822	1,151	49,435	**0.06**	**0.02**	**2.45**
Mar	1,176	2,030	49,496	**0.02**	**0.04**	**0.58**
Apr	2,773	9,876	49,621	**0.06**	**0.20**	**0.28**
May	6,895	9,994	49,543	**0.14**	**0.20**	**0.69**
Jun	19,860	43,458	49,594	**0.40**	**0.88**	**0.46**
Jul	6,089	10,502	49,562	**0.12**	**0.21**	**0.58**
Aug	2,818	2,354	49,683	**0.06**	**0.05**	**1.20**
Sep	18,891	19,645	49,602	**0.38**	**0.40**	**0.96**
Oct	3,212	5,201	49,647	**0.06**	**0.10**	**0.62**
Nov	29,093	27,885	49,606	**0.59**	**0.56**	**1.04**
Dec	2,156	5,618	49,529	**0.04**	**0.11**	**0.38**
Annual Total	**96,335**	**139,975**	**49,561**	**1.94**	**2.82**	**0.69**

2004

OEB Approved Standard: Within the range of 3 years historical performance.

	Total Customer Hours of Interruptions (1)	Total Customer Interruptions (2)	Total Number of Customers (3)	SAIDI (4) (1) / (3)	SAIFI (5) (2) / (3)	CAIDI (4) / (5)
Jan	980	5,200	49,266	**0.02**	**0.11**	**0.19**
Feb	886	495	49,250	**0.02**	**0.01**	**1.79**
Mar	2,718	3,066	49,247	**0.06**	**0.06**	**0.89**
Apr	1,352	3,109	49,455	**0.03**	**0.06**	**0.43**
May	1,674	2,759	49,420	**0.03**	**0.06**	**0.61**
Jun	5,255	29,213	49,446	**0.11**	**0.59**	**0.18**
Jul	8,774	43,213	49,445	**0.18**	**0.87**	**0.20**
Aug	60,742	33,892	49,497	**1.23**	**0.68**	**1.79**
Sep	3,016	3,431	49,481	**0.06**	**0.07**	**0.88**
Oct	6,835	4,265	49,475	**0.14**	**0.09**	**1.60**
Nov	1,889	1,236	49,547	**0.04**	**0.02**	**1.53**
Dec	2,886	4,342	49,310	**0.06**	**0.09**	**0.66**
Annual Total	**97,007**	**134,221**	**49,403**	**1.96**	**2.72**	**0.72**

THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.
PERFORMANCE BASED REGULATION
SERVICE RELIABILITY INDICES (2003-2007)

2003

OEB Approved Standard: Within the range of 3 years historical performance.

	Total Customer Hours of Interruptions (1)	Total Customer Interruptions (2)	Total Number of Customers (3)	SAIDI (4) (1) / (3)	SAIFI (5) (2) / (3)	CAIDI (4) / (5)
Jan	5,392	7,389	49,515	**0.11**	**0.15**	**0.73**
Feb	230	336	49,515	**0.00**	**0.01**	**0.68**
Mar	2,311	2,575	49,515	**0.05**	**0.05**	**0.90**
Apr	4,660	13,386	49,515	**0.09**	**0.27**	**0.35**
May	11,150	12,477	49,515	**0.23**	**0.25**	**0.89**
Jun	1,842	1,544	49,515	**0.04**	**0.03**	**1.19**
Jul	8,064	15,249	49,584	**0.16**	**0.31**	**0.53**
Aug	5,110	6,150	49,584	**0.10**	**0.12**	**0.83**
Sep	6,402	10,484	49,584	**0.13**	**0.21**	**0.61**
Oct	795	1,593	49,238	**0.02**	**0.03**	**0.50**
Nov	2,767	9,358	49,238	**0.06**	**0.19**	**0.30**
Dec	1,228	8,889	49,238	**0.02**	**0.18**	**0.14**
Annual Total	**49,951**	**89,430**	**49,463**	**1.01**	**1.81**	**0.56**

THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.
PERFORMANCE BASED REGULATION
CONNECTION OF NEW SERVICES (2003-2007)

2007

	Total No. of Connections <750 Volts	No. of Connections within 5 working days <750 volts	Total No. of Connections >750 volts	No. of Connections within 10 working days >750 volts	%
Jan	17	17	2	2	**100%**
Feb	9	9	1	1	**100%**
Mar	5	5	1	1	**100%**
Apr	2	2	1	1	**100%**
May	15	16	0	0	**94%**
Jun	23	24	2	2	**96%**
Jul	17	17	1	1	**100%**
Aug	24	24	2	2	**100%**
Sep	20	23	0	0	**87%**
Oct	29	32	0	0	**91%**
Nov	33	35	0	0	**94%**
Dec	23	24	4	4	**96%**
Annual Total	**217**	**228**	**14**	**14**	**95%**

2006

	Total No. of Connections <750 Volts	No. of Connections within 5 working days <750 volts	Total No. of Connections >750 volts	No. of Connections within 10 working days >750 volts	%
Jan	12	12	0	0	**100%**
Feb	2	2	1	1	**100%**
Mar	2	2	1	1	**100%**
Apr	6	6	0	0	**100%**
May	10	10	0	0	**100%**
Jun	8	9	1	1	**90%**
Jul	18	18	1	1	**100%**
Aug	18	21	1	1	**86%**
Sep	23	23	1	1	**100%**
Oct	21	25	0	0	**84%**
Nov	19	20	1	1	**95%**
Dec	26	32	2	2	**82%**
Annual Total	**165**	**180**	**9**	**9**	**92%**

THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.
PERFORMANCE BASED REGULATION
CONNECTION OF NEW SERVICES (2003-2007)

2005

	Total No. of Connections <750 Volts	No. of Connections within 5 working days <750 volts	Total No. of Connections >750 volts	No. of Connections within 10 working days >750 volts	%
Jan	4	4	1	1	**100%**
Feb	1	1	0	0	**100%**
Mar	27	27	2	2	**100%**
Apr	9	10	0	0	**90%**
May	45	47	1	1	**96%**
Jun	8	9	0	0	**89%**
Jul	18	22	2	2	**83%**
Aug	19	26	5	5	**77%**
Sep	32	33	4	4	**97%**
Oct	21	22	0	0	**95%**
Nov	43	46	0	0	**93%**
Dec	63	64	1	1	**98%**
Annual Total	**290**	**311**	**16**	**16**	**94%**

2004

	Total No. of Connections <750 Volts	No. of Connections within 5 working days <750 volts	Total No. of Connections >750 volts	No. of Connections within 10 working days >750 volts	%
Jan	8	8	0	0	**100%**
Feb	1	1	0	0	**100%**
Mar	2	2	0	0	**100%**
Apr	6	7	0	0	**86%**
May	17	18	0	0	**94%**
Jun	16	19	1	1	**85%**
Jul	37	39	4	4	**95%**
Aug	24	28	1	1	**86%**
Sep	39	43	6	6	**92%**
Oct	29	34	4	5	**85%**
Nov	59	63	5	5	**94%**
Dec	22	22	0	0	**100%**
Annual Total	**260**	**284**	**21**	**22**	**92%**

THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.
PERFORMANCE BASED REGULATION
CONNECTION OF NEW SERVICES (2003-2007)

2003					
	Total No. of Connections <750 Volts	No. of Connections within 5 working days <750 volts	Total No. of Connections >750 volts	No. of Connections within 10 working days >750 volts	%
Jan	13	13	0	0	**100%**
Feb	3	3	1	1	**100%**
Mar	4	4	0	0	**100%**
Apr	8	8	0	0	**100%**
May	11	12	1	1	**92%**
Jun	19	20	2	2	**95%**
Jul	24	29	4	4	**85%**
Aug	19	22	2	2	**88%**
Sep	28	35	3	3	**82%**
Oct	26	26	2	2	**100%**
Nov	37	41	3	3	**91%**
Dec	28	28	2	2	**100%**
Annual Total	**220**	**241**	**20**	**20**	**92%**

THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.
PERFORMANCE BASED REGULATION
CUSTOMER SERVICE (Telephone Accessibility) (2003-2007)

2007

	No. of General Inquiry Calls	No. of Calls Answered Within 30 Seconds	% of Incoming Calls Answered Within 30 Seconds
Jan	4,240	4,070	**96%**
Feb	3,926	3,769	**96%**
Mar	4,752	4,485	**94%**
Apr	4,579	4,253	**93%**
May	5,408	5,034	**93%**
Jun	5,039	4,710	**93%**
Jul	5,060	4,647	**92%**
Aug	5,142	4,809	**94%**
Sep	4,662	4,361	**94%**
Oct	5,017	4,892	**98%**
Nov	4,476	4,369	**98%**
Dec	3,027	2,958	**98%**
Annual Total	**55,328**	**52,357**	**95%**

2006

	No. of General Inquiry Calls	No. of Calls Answered Within 30 Seconds	% of Incoming Calls Answered Within 30 Seconds
Jan	4,274	4,189	**98%**
Feb	3,626	3,517	**97%**
Mar	4,292	4,163	**97%**
Apr	4,487	4,308	**96%**
May	5,364	5,096	**95%**
Jun	5,112	4,856	**95%**
Jul	4,764	4,335	**91%**
Aug	5,158	4,797	**93%**
Sep	4,801	4,561	**95%**
Oct	5,008	4,858	**97%**
Nov	4,569	4,386	**96%**
Dec	3,403	3,301	**97%**
Annual Total	**54,858**	**52,367**	**95%**

THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.
PERFORMANCE BASED REGULATION
CUSTOMER SERVICE (Telephone Accessibility) (2003-2007)

2005

	No. of General Inquiry Calls	No. of Calls Answered Within 30 Seconds	% of Incoming Calls Answered Within 30 Seconds
Jan	4,143	3,894	**94%**
Feb	3,716	3,493	**94%**
Mar	4,356	4,051	**93%**
Apr	4,601	4,371	**95%**
May	4,688	4,360	**93%**
Jun	5,580	5,078	**91%**
Jul	4,677	4,303	**92%**
Aug	5,508	5,012	**91%**
Sep	5,442	5,007	**92%**
Oct	4,486	4,172	**93%**
Nov	4,646	4,414	**95%**
Dec	3,724	3,575	**96%**
Annual Total	**55,567**	**51,730**	**93%**

2004

	No. of General Inquiry Calls	No. of Calls Answered Within 30 Seconds	% of Incoming Calls Answered Within 30 Seconds
Jan	4,148	4,024	**97%**
Feb	3,633	3,488	**96%**
Mar	4,376	4,157	**95%**
Apr	4,539	4,267	**94%**
May	4,743	4,458	**94%**
Jun	4,977	4,728	**95%**
Jul	4,653	4,327	**93%**
Aug	5,645	5,081	**90%**
Sep	4,876	4,583	**94%**
Oct	4,552	4,279	**94%**
Nov	4,386	4,167	**95%**
Dec	3,160	2,939	**93%**
Annual Total	**53,688**	**50,498**	**94%**

THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.
PERFORMANCE BASED REGULATION
CUSTOMER SERVICE (Telephone Accessibility) (2003-2007)

2003			
	No. of General Inquiry Calls	No. of Calls Answered Within 30 Seconds	% of Incoming Calls Answered Within 30 Seconds
Jan	4,947	4,650	**94%**
Feb	3,611	3,467	**96%**
Mar	4,027	3,866	**96%**
Apr	4,375	4,113	**94%**
May	4,497	4,317	**96%**
Jun	4,329	4,113	**95%**
Jul	4,655	4,329	**93%**
Aug	4,733	4,449	**94%**
Sep	4,805	4,467	**93%**
Oct	4,482	4,303	**96%**
Nov	3,783	3,632	**96%**
Dec	3,355	3,221	**96%**
Annual Total	**51,599**	**48,927**	**95%**

THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.
PERFORMANCE BASED REGULATION
APPOINTMENTS (2003-2007)

2007

	No. of Appointments to Customer Site	No. of Appointments to Customer Site Where Time/Date Met	% of Appointments Met
Jan	2	2	**100%**
Feb	4	4	**100%**
Mar	10	10	**100%**
Apr	19	19	**100%**
May	39	39	**100%**
Jun	34	34	**100%**
Jul	24	24	**100%**
Aug	34	34	**100%**
Sep	14	14	**100%**
Oct	37	37	**100%**
Nov	20	20	**100%**
Dec	3	3	**100%**
Annual Total	**240**	**240**	**100%**

2006

	No. of Appointments to Customer Site	No. of Appointments to Customer Site Where Time/Date Met	% of Appointments Met
Jan	3	3	**100%**
Feb	2	2	**100%**
Mar	3	3	**100%**
Apr	3	3	**100%**
May	5	5	**100%**
Jun	3	3	**100%**
Jul	2	2	**100%**
Aug	2	2	**100%**
Sep	1	1	**100%**
Oct	2	2	**100%**
Nov	2	2	**100%**
Dec	1	1	**100%**
Annual Total	**29**	**29**	**100%**

THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.
PERFORMANCE BASED REGULATION
APPOINTMENTS (2003-2007)

2005

	No. of Appointments to Customer Site	No. of Appointments to Customer Site Where Time/Date Met	% of Appointments Met
Jan	39	39	**100%**
Feb	53	53	**100%**
Mar	64	64	**100%**
Apr	68	68	**100%**
May	48	47	**98%**
Jun	65	65	**100%**
Jul	98	97	**99%**
Aug	108	108	**100%**
Sep	66	63	**95%**
Oct	77	76	**99%**
Nov	80	78	**98%**
Dec	43	42	**98%**
Annual Total	**809**	**800**	**99%**

2004

	No. of Appointments to Customer Site	No. of Appointments to Customer Site Where Time/Date Met	% of Appointments Met
Jan	43	41	**95%**
Feb	35	34	**97%**
Mar	59	58	**98%**
Apr	71	69	**97%**
May	70	68	**97%**
Jun	61	58	**95%**
Jul	74	68	**92%**
Aug	57	55	**96%**
Sep	55	53	**96%**
Oct	44	43	**98%**
Nov	50	48	**96%**
Dec	29	27	**93%**
Annual Total	**648**	**622**	**96%**

THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.
PERFORMANCE BASED REGULATION
APPOINTMENTS (2003-2007)

2003			
	No. of Appointments to Customer Site	No. of Appointments to Customer Site Where Time/Date Met	% of Appointments Met
Jan	52	51	**98%**
Feb	33	31	**94%**
Mar	58	53	**91%**
Apr	63	62	**98%**
May	71	67	**94%**
Jun	57	55	**96%**
Jul	69	66	**96%**
Aug	51	49	**96%**
Sep	69	64	**93%**
Oct	57	55	**96%**
Nov	65	63	**97%**
Dec	47	45	**96%**
Annual Total	**692**	**661**	**96%**

THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.
PERFORMANCE BASED REGULATION
WRITTEN RESPONSES TO INQUIRIES (2003-2007)

2007

	No. of Requests for Written Responses	No. of Requests for Written Responses Provided Within 10 Working Days	% of Written Responses Met
Jan	3	3	**100%**
Feb	1	1	**100%**
Mar	0	0	**0%**
Apr	0	0	**0%**
May	0	0	**0%**
Jun	0	0	**0%**
Jul	1	1	**100%**
Aug	0	0	**0%**
Sep	1	1	**100%**
Oct	2	2	**100%**
Nov	1	1	**100%**
Dec	1	1	**100%**
Annual Total	**10**	**10**	**100%**

2006

	No. of Requests for Written Responses	No. of Requests for Written Responses Provided Within 10 Working Days	% of Written Responses Met
Jan	2	2	**100%**
Feb	1	1	**100%**
Mar	2	2	**100%**
Apr	4	4	**100%**
May	1	1	**100%**
Jun	2	2	**100%**
Jul	1	1	**100%**
Aug	2	2	**100%**
Sep	2	2	**100%**
Oct	2	2	**100%**
Nov	2	2	**100%**
Dec	3	3	**100%**
Annual Total	**24**	**24**	**100%**

THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.
PERFORMANCE BASED REGULATION
WRITTEN RESPONSES TO INQUIRIES (2003-2007)

2005

	No. of Requests for Written Responses	No. of Requests for Written Responses Provided Within 10 Working Days	% of Written Responses Met
Jan	0	0	**0%**
Feb	3	3	**100%**
Mar	1	1	**100%**
Apr	5	5	**100%**
May	3	3	**100%**
Jun	2	2	**100%**
Jul	0	0	**0%**
Aug	1	1	**100%**
Sep	4	4	**100%**
Oct	3	3	**100%**
Nov	4	4	**100%**
Dec	3	3	**100%**
Annual Total	**29**	**29**	**100%**

2004

	No. of Requests for Written Responses	No. of Requests for Written Responses Provided Within 10 Working Days	% of Written Responses Met
Jan	0	0	**0%**
Feb	1	1	**100%**
Mar	1	1	**100%**
Apr	1	1	**100%**
May	1	1	**100%**
Jun	2	2	**100%**
Jul	1	1	**100%**
Aug	2	2	**100%**
Sep	0	0	**0%**
Oct	1	1	**100%**
Nov	1	1	**100%**
Dec	0	0	**0%**
Annual Total	**11**	**11**	**100%**

THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.
PERFORMANCE BASED REGULATION
WRITTEN RESPONSES TO INQUIRIES (2003-2007)

2003

	No. of Requests for Written Responses	No. of Requests for Written Responses Provided Within 10 Working Days	% of Written Responses Met
Jan	0	0	**0%**
Feb	0	0	**0%**
Mar	1	1	**100%**
Apr	0	0	**0%**
May	0	0	**0%**
Jun	0	0	**0%**
Jul	1	1	**100%**
Aug	0	0	**0%**
Sep	0	0	**0%**
Oct	1	1	**100%**
Nov	0	0	**0%**
Dec	0	0	**0%**
Annual Total	**3**	**3**	**100%**

THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.
PERFORMANCE BASED REGULATION
EMERGENCY RESPONSE (Urban) (2003-2007)

2007

	No. of Emergency Urban Calls	No. of Emergency Urban Calls Within 60 Minutes	% of Urban Calls Met Within 60 Minutes
Jan	4	4	**100%**
Feb	12	12	**100%**
Mar	8	8	**100%**
Apr	3	3	**100%**
May	7	7	**100%**
Jun	7	7	**100%**
Jul	12	12	**100%**
Aug	4	4	**100%**
Sep	9	8	**89%**
Oct	5	5	**100%**
Nov	2	2	**100%**
Dec	8	8	**100%**
Annual Total	**81**	**80**	**99%**

2006

	No. of Emergency Urban Calls	No. of Emergency Urban Calls Within 60 Minutes	% of Urban Calls Met Within 60 Minutes
Jan	3	3	**100%**
Feb	4	4	**100%**
Mar	10	10	**100%**
Apr	3	3	**100%**
May	13	12	**92%**
Jun	7	7	**100%**
Jul	4	4	**100%**
Aug	8	8	**100%**
Sep	6	6	**100%**
Oct	5	5	**100%**
Nov	4	4	**100%**
Dec	4	4	**100%**
Annual Total	**71**	**70**	**99%**

THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.
PERFORMANCE BASED REGULATION
EMERGENCY RESPONSE (Urban) (2003-2007)

2005

	No. of Emergency Urban Calls	No. of Emergency Urban Calls Within 60 Minutes	% of Urban Calls Met Within 60 Minutes
Jan	2	2	**100%**
Feb	4	4	**100%**
Mar	5	5	**100%**
Apr	4	4	**100%**
May	11	11	**100%**
Jun	5	5	**100%**
Jul	4	4	**100%**
Aug	5	5	**100%**
Sep	6	6	**100%**
Oct	7	7	**100%**
Nov	8	8	**100%**
Dec	3	3	**100%**
Annual Total	**64**	**64**	**100%**

2004

	No. of Emergency Urban Calls	No. of Emergency Urban Calls Within 60 Minutes	% of Urban Calls Met Within 60 Minutes
Jan	6	6	**100%**
Feb	7	7	**100%**
Mar	6	6	**100%**
Apr	5	5	**100%**
May	4	4	**100%**
Jun	3	3	**100%**
Jul	5	5	**100%**
Aug	14	14	**100%**
Sep	4	4	**100%**
Oct	4	4	**100%**
Nov	5	5	**100%**
Dec	4	4	**100%**
Annual Total	**67**	**67**	**100%**

THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.
PERFORMANCE BASED REGULATION
EMERGENCY RESPONSE (Urban) (2003-2007)

2003

	No. of Emergency Urban Calls	No. of Emergency Urban Calls Within 60 Minutes	% of Urban Calls Met Within 60 Minutes
Jan	11	11	**100%**
Feb	1	1	**100%**
Mar	11	11	**100%**
Apr	7	7	**100%**
May	13	13	**100%**
Jun	10	10	**100%**
Jul	17	16	**94%**
Aug	8	8	**100%**
Sep	7	7	**100%**
Oct	10	10	**100%**
Nov	8	8	**100%**
Dec	6	6	**100%**
Annual Total	**109**	**108**	**99%**

THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.
PERFORMANCE BASED REGULATION
EMERGENCY RESPONSE (Rural) (2003-2007)

2007

	No. of Emergency Rural Calls	No. of Emergency Rural Calls Within 120 Minutes	% of Rural Calls Met Within 120 Minutes
Jan	3	3	**100%**
Feb	1	1	**100%**
Mar	1	1	**100%**
Apr	4	4	**100%**
May	2	2	**100%**
Jun	1	1	**100%**
Jul	1	1	**100%**
Aug	0	0	**0%**
Sep	1	1	**100%**
Oct	2	2	**100%**
Nov	6	6	**100%**
Dec	1	1	**100%**
Annual Total	**23**	**23**	**100%**

2006

	No. of Emergency Rural Calls	No. of Emergency Rural Calls Within 120 Minutes	% of Rural Calls Met Within 120 Minutes
Jan	1	1	**100%**
Feb	0	0	**0%**
Mar	2	2	**100%**
Apr	2	2	**100%**
May	9	6	**67%**
Jun	1	1	**100%**
Jul	3	3	**100%**
Aug	2	1	**50%**
Sep	0	0	**0%**
Oct	1	1	**100%**
Nov	1	1	**100%**
Dec	4	4	**100%**
Annual Total	**26**	**22**	**85%**

THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.
PERFORMANCE BASED REGULATION
EMERGENCY RESPONSE (Rural) (2003-2007)

2005

	No. of Emergency Rural Calls	No. of Emergency Rural Calls Within 120 Minutes	% of Rural Calls Met Within 120 Minutes
Jan	1	1	**100%**
Feb	0	0	**0%**
Mar	2	2	**100%**
Apr	0	0	**0%**
May	0	0	**0%**
Jun	1	1	**100%**
Jul	1	1	**100%**
Aug	0	0	**0%**
Sep	1	1	**100%**
Oct	1	1	**100%**
Nov	6	6	**100%**
Dec	0	0	**0%**
Annual Total	**13**	**13**	**100%**

2004

	No. of Emergency Rural Calls	No. of Emergency Rural Calls Within 120 Minutes	% of Rural Calls Met Within 120 Minutes
Jan	0	0	**0%**
Feb	0	0	**0%**
Mar	2	2	**100%**
Apr	0	0	**0%**
May	2	2	**100%**
Jun	2	2	**100%**
Jul	0	0	**0%**
Aug	1	1	**100%**
Sep	0	0	**0%**
Oct	0	0	**0%**
Nov	0	0	**0%**
Dec	5	5	**100%**
Annual Total	**12**	**12**	**100%**

THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.
PERFORMANCE BASED REGULATION
EMERGENCY RESPONSE (Rural) (2003-2007)

2003

	No. of Emergency Rural Calls	No. of Emergency Rural Calls Within 120 Minutes	% of Rural Calls Met Within 120 Minutes
Jan	1	1	**100%**
Feb	0	0	**0%**
Mar	1	1	**100%**
Apr	0	0	**0%**
May	2	1	**50%**
Jun	1	1	**100%**
Jul	1	1	**100%**
Aug	0	0	**0%**
Sep	1	1	**100%**
Oct	1	1	**100%**
Nov	0	0	**0%**
Dec	2	2	**100%**
Annual Total	**10**	**9**	**90%**

APPENDIX B

COMPARISON OF THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC. OM&A COSTS TO "MID-SIZE NORTHERN LDC" COHORT GROUPING

SUMMARY OF THE APPLICATION

COMPARISON OF THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC. OM&A COSTS TO "Mid-Size Northern LDC" COHORT GROUPING

Cohort Groupings	**Total OM&A**	
Mid-Size Northern LDC	**Average**	**2007**
North Bay Hydro Distribution Limited	$221	$219
PUC Distribution Inc.	$222	$239
Thunder Bay Hydro Electricity Distribution Inc.	**$223**	**$241**
Greater Sudbury Hydro Inc.	$263	$365
Average for Cohort Group	$232	$266

SOURCE:

Comparison of Ontario Electricity Distributors Costs [EB-2006-0268], updated with 2007 Data Issued June 25, 2008.

BUDGET DIRECTIVES:

Thunder Bay 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 2008 Bridge Year and the 2009 Test Year.

Revenue Forecast

Thunder Bay Hydro's energy sales and revenue forecast model was updated to reflect more recent information. This model was then used to prepare the revenues sales and throughput volume for the calculation of the revenue forecast at existing rates for fiscal 2008 and 2009. The forecast is also used to design the proposed rates in this Application. The forecast is weather normalized as outlined in Exhibit 3, Tab 2, Schedule 3 and considers such factors as historical load, weather and economic data.

Operating Maintenance and Administration ("OM&A") Expense Forecast

The OM&A expenses for the 2008 Bridge Year and the 2009 Test Year have been based on an in-depth review of operating priorities and requirements and is strongly influenced by prior year experience. All unavoidable increases and unmet needs from the prior budget period are identified and reviewed in detail. Each item is reviewed account by account for each of the forecast years with indirect costs allocated to direct costs for budget presentation.

Capital Budget

The forecast is prepared over a 3-year period and is influenced, among other factors, by Thunder Bay Hydro's AMP. Indirect costs are allocated to direct costs in the capital budget. All proposed capital projects are assessed within the framework of its capital budget priority-setting criteria. Those criteria are discussed in greater detail in Exhibit 2 Tab 3 Schedule 1 (Capital Budget by Project).

CHANGES IN METHODOLOGY:

Thunder Bay Hydro's approach to how we charge for connecting new customers has changed. Previously, an estimate for work to be performed was given to the customer as a firm price. The customer would pay the amount on the estimate, sign for power, and once the ESA inspection was in place, the service was energized with the costs charged to a standing capital work order number for new customers.

Now connection costs for new customers are presented to the customer on an 'Estimate to Connect' where all costs are broken down for the customer. The customer is responsible for all costs associated with the connection of their service and those costs are reflected on the Estimate to Connect.

An individual work order number is taken out for each new customer connection in order to track all costs. As in the past, payment of the estimate is required along with an ESA inspection and a signature for power before being energized; however the process no longer ends there.

Each work order is reviewed to compare the difference between the actual charges and the Estimate to Connect (a true-up). If the variance is greater than $100, that difference is either returned or charged to the customer, whichever is applicable. The process is clearly defined in our Conditions of Service and a Customer Guideline document that is given to each customer prior to any work taking place. The customer is made fully aware that the original cost paid is only an estimate prior to the work being initiated.

Capital Focus

A strategic direction change has been undertaken to make the most efficient use of capital resources available and increase the effectiveness of our capital programs while ensuring that the assets remain functional during the execution of the plan.

Firstly, Thunder Bay Hydro has implemented a philosophy of only building the minimum infrastructure to connect given the customer's known requirements today and not building for possible future requirements**.** All savings have been applied to Thunder Bay Hydro's replacement capital program. Another philosophy change has been the reduction of the number of small like-for-like replacement projects Thunder Bay Hydro performs with maintenance crews. These have been replaced with larger scale construction crew rebuilds which take advantage of the economies of scale and improved efficiency.

Use of Risk Assessments

Moving forward, Thunder Bay Hydro will use risk assessments to determine where plant needs to be changed due to danger to the public or workers, and then change only that plant rather than programming small replacements throughout the system. This allows Thunder Bay Hydro to concentrate resources on large scale replacements where it can be most efficient. This also supports the overall 20-year capital plan that seeks to address the failing overhead lines and underground cables, while eliminating some of our 4kV substations.

The development of a detailed risk assessment, 20-year capital plan, and maintenance plans are an important part of Thunder Bay Hydro's asset management approach. Effective work execution will ensure efficiency in the capital and maintenance programs.

In the past, ongoing design changes and material shortages slowed construction and added costs to projects. In order to minimize the resulting slowdown in construction once it was already underway, a more coordinated effort and change in methodology was required. The new process requires getting the project drawing(s) into the hands of those doing the construction sooner. This now allows for a 'walking of the job' by the Lines Superintendent, Lines Supervisor, Lead Hand, and crew, while the project is still in the design stages. This process will identify problem areas in the design and this information can be relayed back to the Engineering group in order for drawing changes to take place prior to the print being issued for construction. This minimizes

delays in the field, thus increasing overall efficiencies. Going forward, better planning will equate to more work being completed at a lower cost.

Outage Management

A One Outage per Customer per Year Policy has also been introduced to allow work to be undertaken while equipment is de-energized. While the practice of de-energizing is not new, the Policy allows those arrangements to go more smoothly with customers. Although cost savings may be realized, the primary benefit of this Policy is the health and safety of our workers.

Forestry Management

Regular scheduled forestry practices for line clearing were downsized in the past by a well meaning desire to maintain rates as low as possible. Forestry operations occurred on a small scale or on an "as needed" basis. As a result, vegetation has been allowed to grow relatively unchecked into the power lines causing many unscheduled power interruptions and increasing the safety risk to the public and power line workers. A risk assessment of the overhead circuits for interfering vegetation has revealed that 75-80% of all overhead lines currently require some degree of line clearing and that 40% of all overhead lines require immediate action to prevent hazardous conditions and unscheduled service interruptions.

Data from the past eight years indicates that the level of spending for vegetation management has been below that required for a sustainable tree trimming cycle. The table below includes a combined total of both Thunder Bay Hydro Lines personnel and the efforts of various private tree trimming contractors over the period examined.

Historical Line Clearing Costs
2000 – 2007

Fiscal Year	$ Annual Line Clearing Totals
2000	$327,174
2001	$261,586
2002	$309,992
2003	$275,675
2004	$361,042
2005	$290,356
2006	$286,445
2007	$545,858

Present levels of vegetation that are in proximity to overhead lines will require 10 years of intense management in order to reduce both hazardous situations and achieve a sustainable trimming cycle.

The following chart approximates the total cost over a ten year period using the cost per meter of line clearing depending on the asset type and access considerations. Average costs per meter have been determined using examples of recently conducted line clearing operations in similar conditions.

Total Estimated Costs to Clear Overhead Power Lines over a 10 Year Period

Asset Type	Km of Asset	% Requiring Line Clearing	% Difficult (Off Road) Access	Difficult Access Cost/Metre	% Readily (Truck) Accessible	Readily Accessible Cost/Meter	Estimated Line Clearing Cost
Two Circuits & Greater /Pole	99.88	80%	30%	$30.86	70%	$8.03	**$1,188,892**
One Circuit & Less/Pole	769.13	80%	45%	$18.41	55%	$4.08	**$6,478,228**
Total	869.01						**$7,667,120**

In order to correct the current situation and to comply with the legal obligation to maintain safe clearances, an increase in funding over this intensive management period to the level of approximately $767,000 annually ($716,115 in 2009) will be required to achieve these goals.

Once the current situation is addressed, a trimming cycle of seven years will maintain vegetation to an acceptable level. The chart below outlines the total costs over one complete tree trimming cycle of seven years.

Total Estimated Costs to Maintain a Sustainable Level of Vegetation over One Complete Cycle (7 years)

Asset Type	Km of Asset	% Requiring Line Clearing	%Difficult (Off Road) Access	Sustainable Cost/Metre	% Readily (Truck) Accessible	Sustainable Cost/Metre	Estimated Sustainable Line Clearing Cost
Two Circuits & Greater /Pole	99.88	80%	30%	$9.25	70%	$5.25	**$644,266**
One Circuit & Less/Pole	769.13	80%	45%	$5.25	55%	$2.75	**$2,980,378**
Total	869.01						**$3,624,644**

The annual budget amounts for the sustainable trimming cycle based on the data below will be approximately $518,000.

Professional utility forestry practices that follow approved standards have been proven to reduce costs, number and duration of power interruptions and improve risk potential for unintentional contact with energized sources. While placing emphasis on obtaining proper safe clearances initially and encouraging suitable tree replacement, long term financial benefits will be realized.

Forestry Education & Awareness

With the growing concern toward climate change and an increase of awareness of the public of the benefits of the urban forest toward the effects of climate change, a tree replacement program

of suitable species outside of the limits of right-of-way will need to be initiated. This program will have an immediate benefit in addressing customer concerns regarding removal of inappropriate vegetation. A second long term benefit will also be obtained in that suitable replacement vegetation will be selected and planted so that the frequency and intensity of tree trimming can either be reduced or eliminated.

A public education program toward “Plant the Right Tree in the Right Place” promoting planting smaller suitable species along with the dangers of trees in power lines that will eventually aid in reducing safety risks and line clearing costs has been initiated on a small scale and has already been successful.

Additional funding of approximately $16,000 annually for both of the above programs will be required on a trial basis. By addressing the long term problem with public education and replacing unsuitable vegetation with species that will not grow into proximity a further reduction in cycle trimming costs will be achieved.

PCB Removal

Polychlorinated biphenyls (PCBs) are a class of organic compounds commercially produced in response to the electrical industry's need for a "safer" cooling and insulating fluid for industrial transformers and capacitors. Concerns over the toxicity of PCBs in the environment led to the USA banning the production in 1977. Some use continues in closed systems such as transformers at Thunder Bay Hydro and other utilities. A few studies of workers indicate that PCBs are associated with specific kinds of cancer in humans, such as cancer of the liver and biliary tract. Rats that ate food containing high levels of PCBs for two years developed liver cancer.

Despite the large reductions in PCB inventories by utilities since the implementation of regulatory controls, PCB use continues and the potential for release to the environment through spills and fires continues to exist. Environment Canada is concerned that the goal of elimination of PCBs from Canada may not be reached for another generation at the present pace of reduction. In addition Canada is signatory to several international agreements on the phase-out

PCBs thus leading to the new legislation. Environment Canada has therefore proposed revisions to the existing Chlorobiphenyl Regulations and the Storage of PCB Material Regulations of the Canadian Environmental Protection Act 1999 (CEPA 1999) that would set specific dates for the complete destruction of all PCBs in service and in storage. The proposed legislation was made available for comment in November of 2006 and the comment period ended January 2, 2007. While the legislation has not become law yet the very short time lines within this proposed legislation required some action.

The legislation originally proposed to be introduced in 2008 by the Canadian federal government required that PCBs still in use be phased out completely as outlined:

- From 2008 onward a maximum storage period of one year for PCBs and products that contain PCBs at the owner's PCB storage site
- At the end of 2010 all PCBs in concentrations > 500 PPM are to be removed from service
- At the end of 2010 all PCBs in concentrations > 50 PPM PCBs in environmentally sensitive areas are to be removed from service
- At the end of 2014 all remaining PCBs in concentrations > 50 PPM are to be removed from service

A full copy of the proposed legislation may be downloaded from:
http://www.ec.gc.ca/ceparegistry/documents/regs/g1-14044_r1.pdf

PCBs are presently contained only in station breakers and distribution transformers at Thunder Bay Hydro as all other equipment types have be verified to be PCB free that can be done so without the destruction of the equipment in accordance with existing regulations.

The station breakers will be managed through a retro fill program where they are refilled with PCB free oil until the PCB contamination levels are below the required guidelines. This will occur in 2008 and monitoring in 2009 will verify the results.

Presently Thunder Bay Hydro owns 6900 distribution transformers and a long term PCB elimination program has been underway since the late 1990s. Of Thunder Bay Hydro's existing transformers, 238 are >50 ppm and 33 are >500ppm and remain outstanding at an approximate cost of about $3M to remove, replace and dispose of all waste.

Thunder Bay Hydro's long term plan to address these transformers is to remove all 33 >500ppm transformers in 2009 and then remove approximately 48 each year of the >50ppm transformers for a further 5 years. The cost of this replacement program will be approximately $0.5M each year over its 6 year life and is further detailed in the table below.

Year	Required Testing / Sampling	Transformer Replacement (avg 10,000 ea)	Oil Destruction For all PCB+ Transformers (ARO)	Destruction of PCB Solid Waste Material (ARO)	Additional Destruction (norm activity) (ARO)	Transport (ARO)	Estimated Cost
2008	-	-	**$87.50**	**$1,930**	**$25,000**	**$15,000**	**$42,017**
2009	-	**$330,000**	**$19,391**	**$13,890**	**$25,000**	**$15,000**	**$403,281**
2010	-	**$480,000**	**$21,168**	**$12,000**	**$25,000**	**$15,000**	**$553,168**
2011	-	**$480,000**	**$21,168**	**$12,000**	**$25,000**	**$15,000**	**$553,168**
2012	-	**$480,000**	**$21,168**	**$12,000**	**$25,000**	**$15,000**	**$553,168**
2013	-	**$480,000**	**$21,168**	**$12,000**	**$25,000**	**$15,000**	**$553,168**
2014	-	**$460,000**	**$20,286**	**$11,500**	**$25,000**	**$15,000**	**$531,786**
TOTAL							**$3,189,756**

Should the legislation come into force and Thunder Bay Hydro's present plan not ensure compliance, the plan will have to become accelerated and a variance account created to track all costs above the existing planned replacements.

CALCULATION OF REVENUE DEFICIENCY
2009 TEST YEAR

	2009 Test Existing Rates	2009 Test Proposed Rates
Revenue		
Suff/ Def From Below.		$1,414,077
Distribution Revenue	$16,104,861	$16,104,861
Other Operating Revenue (Net)	$1,802,790	$1,802,790
Total Revenue	$17,907,651	$19,321,728
Distribution Costs		
Operation, Maintenance, and Administration	$12,340,964	$12,340,964
Depreciation & Amortization	$4,573,436	$4,573,436
Property & Capital Taxes	$169,466	$169,466
Interest- Deemed Interest	$216,623	$216,623
Total Costs and Expenses	$17,300,489	$17,300,489
Utility Income Before Income Taxes	$607,162	$2,021,239
Net Adjustments per 2009 Pils	$585,415	$585,415
Taxable Income	$1,192,577	$2,606,654
Income Tax (Tax Rate 30.72%)	$366,317	$800,672
Utility Income	$240,845	$1,220,567
Rate Base	$75,169,648	$75,169,648
Equity	43.30%	43.30%
Equity Component Rate Base	$32,548,458	$32,548,458
Income / Equity Rate Base %	0.74%	3.75%
Target Return -Equity on Rate Base	3.75%	3.75%
Return- Equity on Rate Base	$1,220,567	$1,220,567
Revenue Deficiency	$979,722	
Revenue Deficiency (Gross-up)	$1,414,077	

CAUSES OF REVENUE DEFICIENCY:

Thunder Bay Hydro's net revenue deficiency is calculated as $979,722 and when grossed up for PILs, the revenue deficiency is $1,414,077. Thunder Bay Hydro's calculation of its 2009 revenue deficiency is provided in Exhibit 1, Tab 2, Schedule 4 and Exhibit 6, Tab 1, Schedule 1.

The revenue deficiency is primarily the result of:

- Projected increases in OM&A costs including depreciation expense for the 2009 Test Year as discussed in further detail in Exhibit 4, Tab 1 (Overview) and Tab 2 (OM&A Costs); and

- Projected increases in investments in gross assets which increases the rate base on which the rate of return is based as discussed further in Exhibit 2 Tab 1 ((Rate Base) and Tab 2 (Gross Assets – Property, Plant and Equipment).

FINANCIAL STATEMENTS – 2006 and 2007:

The Thunder Bay Hydro's Audited 2006 and 2007 Financial Statements accompany this Schedule as Appendix A.

APPENDIX A

COPY OF AUDITED FINANCIAL STATEMENTS FOR 2006 AND 2007

Thunder Bay Hydro Electricity Distribution Inc.
Financial Statements
December 31, 2006

Grant Thornton

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Grant Thornton

Grant Thornton LLP
Chartered Accountants
Management Consultants

Auditors' Report

To the Shareholder of
Thunder Bay Hydro Electricity Distribution Inc.

We have audited the balance sheet of **Thunder Bay Hydro Electricity Distribution Inc.** as at December 31, 2006 and the statements of operations and retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audit.

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

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2006 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Grant Thornton LLP

Thunder Bay, Canada
March 23, 2007

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Thunder Bay Hydro Electricity Distribution Inc.
Balance Sheet

As at December 31	2006	2005
	$	$
ASSETS		
Current		
Cash and cash equivalents	11,020,351	13,520,477
Investment	—	4,000,000
Accounts receivable	7,069,105	5,284,446
Unbilled revenue	11,226,341	12,653,597
Payments in lieu of corporate income taxes receivable	1,479,320	—
Due from associated companies *[note 3]*	171,003	259,157
Stores inventory	1,361,446	1,217,460
Prepaid expenses	170,531	132,902
Total current assets	32,498,097	37,068,039
Regulatory assets *[note 4]*	1,634,330	5,640,422
Capital assets		
Capital assets, net *[note 5[a]]*	66,114,164	63,916,531
Capital contributions, net *[note 5[b]]*	(5,727,950)	(4,932,881)
Construction-in-progress	323,066	670,783
Capital assets, net	60,709,280	59,654,433
	94,841,707	102,362,894

See accompanying notes to the financial statements.

On behalf of the Board:

Director Director

	2006	2005
	$	$
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current		
Accounts payable and accrued liabilities	9,698,374	12,800,975
Debt retirement charge	547,440	606,395
Deferred revenue	355,489	220,499
Accrued vacation payable	824,630	794,125
Payments in lieu of corporate income taxes liability	—	605,874
Customer deposits	1,902,184	1,844,942
Current portion of capital lease obligation *[note 9]*	36,825	35,707
Total current liabilities	13,364,942	16,908,517
Long-term		
Regulatory liabilities *[note 4]*	6,703,790	11,149,977
Employee future benefits *[note 7]*	2,130,773	2,171,076
Note payable to City of Thunder Bay *[note 8]*	33,490,500	33,490,500
Capital lease obligation *[note 9]*	9,385	46,209
Total long-term liabilities	42,334,448	46,857,762
Shareholder's equity		
Share capital		
Authorized		
Unlimited common shares		
Issued		
1,000 common shares	34,931,625	34,931,625
Retained earnings	4,210,692	3,664,990
Total shareholder's equity	39,142,317	38,596,615
	94,841,707	102,362,894

Thunder Bay Hydro Electricity Distribution Inc.
Statement of Operations and Retained Earnings

Year ended December 31

	2006	2005
	$	$
Revenues and flow-through charges		
Flow-through charges plus distribution revenues	86,720,375	89,819,640
Flow-through costs of energy	(70,895,278)	(74,155,766)
Distribution revenue *[note 11]*	15,825,097	15,663,874
Other operating revenue *[note 10]*	2,144,223	2,666,267
	17,969,320	18,330,141
Expenses		
Operation and maintenance *[schedule]*	5,886,330	5,434,349
Utility services *[schedule]*	—	341,489
Conservation and Demand Management *[note 11]*	355,350	346,516
Administration *[schedule]*	5,309,795	5,051,897
Amortization *[note 12]*	4,244,752	4,105,449
Provision for payments in lieu of capital tax	236,292	139,116
	16,032,519	15,418,816
Earnings before the following	1,936,801	2,911,325
Interest on capital lease obligation	2,025	1,954
Carrying charges (interest) on regulatory assets/liabilities, net	175,366	(212,295)
Earnings before provision for taxes	1,759,410	3,121,666
Provision for payments in lieu of corporate income taxes *[note 18]*	1,213,708	1,365,000
Earnings for year	545,702	1,756,666
Retained earnings, beginning of year	3,664,990	1,908,324
Retained earnings, end of year	4,210,692	3,664,990

See accompanying notes to the financial statements.

Thunder Bay Hydro Electricity Distribution Inc.
Statement of Cash Flows

Year ended December 31

	2006	2005
	$	$
OPERATING ACTIVITIES		
Earnings for year	545,702	1,756,666
Add charges (deduct credits) to earnings not involving a current payment (receipt) of cash		
Amortization *[note 12]*	4,629,472	4,468,388
Increase (decrease) in employee future benefits	(40,303)	3,524
Gain on disposal of capital assets	(2,979)	(4,700)
	5,131,892	6,223,878
Change in non-cash working capital balances related to operations *[note 14[a]]*	(5,474,877)	6,278,512
Cash provided by (used in) operating activities	(342,985)	12,502,390
INVESTMENT ACTIVITIES		
Proceeds on sale of capital assets	14,311	7,727
Additions to capital assets, net *[note 14[b]]*	(5,891,657)	(4,491,573)
Amortization *[note 12]*	196,006	196,712
Decrease (increase) in investment	4,000,000	(4,000,000)
Cash used in investment activities	(1,681,340)	(8,287,134)
FINANCING ACTIVITIES		
Decrease (increase) in regulatory assets	4,006,092	(2,316,953)
Increase (decrease) in regulatory liabilities	(4,446,187)	3,034,083
Capital lease obligation repayments	(35,706)	(23,201)
Cash provided by (used in) financing activities	(475,801)	693,929
Increase (decrease) in cash and cash equivalents during year	(2,500,126)	4,909,185
Cash and cash equivalents, beginning of year	13,520,477	8,611,292
Cash and cash equivalents, end of year	11,020,351	13,520,477

See accompanying notes to the financial statements.

Thunder Bay Hydro Electricity Distribution Inc.
Notes to the Financial Statements
December 31, 2006

GENERAL

Thunder Bay Hydro Electricity Distribution Inc. ("TBHEDI") is a wholly-owned subsidiary company of Thunder Bay Hydro Corporation, providing electrical distribution services to the inhabitants of the City of Thunder Bay, as regulated by the Ontario Energy Board ("OEB").

1. ELECTRICITY ACT, 1998 AND ELECTRICITY PRICING CONSERVATION AND SUPPLY ACT 2004 (BILL 210)

The Energy Competition Act, 1998 (the "Act") was given Royal Assent on October 30, 1998. The Act provides for a competitive market in the sale of electricity, in addition to the regulation of the monopoly electricity delivery system in the Province of Ontario, by the OEB. Open Access commenced on May 1, 2002, the date on which transmitters and distributors were required to provide generators, retailers and consumers with non-discriminatory access to the transmission and distribution systems in Ontario in accordance with their licences under the Electricity Act, 1998.

The OEB has regulatory authority over the electricity distribution sector. The Act sets out the OEB's powers to issue a distribution licence which must be obtained by any person owning or operating a distribution system under the revised OEB Act, 1998. The OEB Act allows the OEB to prescribe licence requirements and conditions to electricity distributors which may include, among other considerations, specified accounting records, regulatory accounting principles, separation of accounts for separate businesses and filing/processing requirements for rate-setting purposes.

Upon market opening, the cost of power and all costs related to the operations of the electricity grid including transmission, connection and administration costs are flowed through to the consumer. Rates are typically established each year as set out in the Distribution Rate Handbook.

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

[i] Electricity Price. The electricity price represents a pass through of the commodity cost of electricity.

[ii] Distribution Rate. The distribution rate is designed to recover the costs incurred by TBHEDI in delivering electricity to customers and provide TBHEDI with the OEB-allowed rate of return. Distribution rates are regulated by the OEB and typically comprise a fixed charge and a usage-based (consumption) charge. The volume of electricity consumed by TBHEDI's customers during any period is governed by events largely outside TBHEDI's control (principally, sustained periods of hot or cold weather which increase the consumption of electricity and sustained periods of moderate weather which decrease the consumption of electricity).

[iii] Retail Transmission Rate. The retail transmission rate represents a pass through of wholesale costs incurred by distributors in respect of the transmission of electricity from generating stations to local areas. Retail transmission rates are regulated by the OEB.

[iv] Wholesale Market Service Charge. The wholesale market service charge represents a pass through of various wholesale market support costs. Retail rates for the recovery of wholesale market service charges are regulated by the OEB.

Bill 210, which became law on December 9, 2002, effectively implemented a rate cap for the cost of electricity consumed (as well as for delivery costs) by low-volume and designated customers (retroactive to May 1, 2002). Retail settlement variance accounts ("RSVA") and certain other accounts prescribed by the OEB were defined as "regulatory assets" under Bill 210. The price freeze and rate caps were originally expected to continue until at least May 1, 2006; however, in November, 2003, the Province announced its intention to increase (effective April 1, 2004) the price of electricity payable by low-volume and designated customers from 4.3 cents to 4.7 cents per kWh on the first 750 kWh consumed during a month and 5.5 cents thereafter and directed the OEB to develop new pricing mechanisms (to take effect no later than May 1, 2005) for setting the price of electricity payable by low-volume and designated customers.

During the period that the price protection is in effect, it is expected that electricity distributors and retailers will be compensated by the Ontario Electricity Financial Corporation:

[i] in the case of electricity distributors, for amounts by which the purchase price of the electricity purchased by them in the Independent Electricity System Operator (IESO) - administered wholesale market on behalf of low-volume consumers and designated consumers is greater than the fixed price per kWh charged to customers; and

[ii] in the case of electricity retailers, for amounts by which the retail contract price agreed to between retailers and low-volume consumers and designated consumers is greater than the fixed price per kWh charged to customers.

In November, 2003, the Province also announced its intention to permit electricity distributors to make rate applications to the OEB earlier than had been contemplated under Bill 210 with respect to the:

[a] recovery of "regulatory assets" (based on year-end balances at December 31, 2002) to be phased in over a four-year period effective March 1, 2004; and

[b] third adjustment necessary to achieve a market-based rate of return (subject to a one-time investment in conservation and demand management initiatives equal to one year of additional revenue resulting from such rate increase), effective March 1, 2005.

In December, 2003, the OEB issued filing guidelines with respect to the recovery of regulatory assets. The OEB's filing guidelines provided that:

[a] distributors were permitted to recover 25% of regulatory assets in rate adjustments effective March 1, 2004;

[b] the 2004 rate adjustment was implemented on April 1, 2004 (with a gross-up added to the recovered amount to allow recovery over 11 months); and

[c] permitted recoveries would continue to be phased in over a three-year period (2005, 2006 and 2007).

In 2004, TBHEDI filed a rate application requesting OEB authorization with respect to an increase in distribution rates to allow for the recovery of approximately $688,000 (representing approximately 25% of TBHEDI's regulatory assets as at December 31, 2002). The regulatory balances as at December 31, 2003 had moved into a net liability position and as such, the rate application for 2005 included a reduction to distribution rates to reflect the repayment of the amounts that have been over-collected. Approved in the rates was the recovery of 70% of the non-RSVA regulatory assets and repayment of 100% of the RSVA regulatory liabilities for a net repayment of approximately $887,000.

The 2005 rate application also requested OEB authorization with respect to an increase in distribution rates to allow for, among other items, the funding for a Conservation and Demand Management Plan (CDM). TBHEDI's approved plan for CDM was for expenditures totaling $1,606,665. It is expected that TBHEDI will complete the CDM initiative spending by September, 2007 *[note 11]*.

Consumers other than the designated consumers who annually utilize more than 250,000 kWh are eligible to receive an Ontario Power Generation rebate (OPG Rebate). The "OPG Rebate" is the difference, if any, between the revenue limit for some OPG generators and the price they would have received in the IESO wholesale spot market. It applies to electricity consumption between May 1, 2006 and May 31, 2007. It is also referred to as the "Ontario Non-Prescribed Asset (ONPA) Rebate".

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.

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 licenced 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 TBHEDI is being tracked in a variance account and is currently reflected as a RSVA regulatory liability. The disposition of the variance account balance shall be in accordance with the OEB's guidelines for reviewing variance and deferral accounts.

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, 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 a customers' electricity consumption is metered – 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.

At the request of the Minister of Energy, the OEB developed an electricity price plan that provides stable and predictable electricity pricing, encourages conservation and ensures the price consumers pay for electricity better reflects the price paid to generators. Under the price plan effective November 1, 2006, eligible consumers pay 5.5 cents per kilowatt hour (kWh) up to a certain threshold each month, and 6.4 cents per kWh for electricity used per month over this amount. This amount is reflected on the "Electricity" line on consumers' bills.

The price threshold – the amount of electricity that is charged at the lower price – changes twice a year for residential consumers. The price threshold will be 600 kWh per month in the summer (May 1st to October 31st) and 1,000 kWh per month in the winter (November 1st to April 30th). Prices will be reviewed more frequently by the Board and may change every six months based on an updated Board forecast and any accumulated differences between the amount that consumers paid for electricity and the amount paid to generators in the previous price-setting period.

The continuing restructuring of Ontario's electricity industry and other regulatory developments, including current and future possible consultations between the OEB and corporate interested stakeholders, may affect the distribution rates, including payments in lieu of income taxes ("PILS") collected from customers that TBHEDI may charge and the costs that TBHEDI may recover, including the balance of its regulatory assets.

2. SIGNIFICANT ACCOUNTING POLICIES

These financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"); including accounting principles prescribed by the OEB in the handbook "Accounting Procedures Handbook for Electric Distribution Utilities ("AP Handbook")", and reflects the significant accounting policies summarized below.

Rate setting and regulation

The OEB Act, 1998 gave the OEB increased powers and responsibilities to regulate the electricity industry. These powers and responsibilities include the power to approve or 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 for ensuring the distribution companies fulfill obligations to connect and service customers. In its capacity to approve or fix rates, the OEB has specified the following regulatory treatments that have resulted in accounting treatments differing from GAAP for enterprises operating in a non-regulated environment:

Thunder Bay Hydro Electricity Distribution Inc.
Notes to the Financial Statements
December 31, 2006

[a] Regulatory Assets and Liabilities

Effective December 31, 2005, TBHEDI adopted the Canadian Institute of Chartered Accountants Accounting Guideline 19 "Disclosures by Entities Subject to Rate Regulation". Certain costs and variance account balances are deemed to be "regulatory assets" or "regulatory liabilities" and are reflected on the balance sheet until the manner and timing of the disposition is determined by the OEB *[note 4]*.

[b] Rebates to customers/Business Protection Plan Rebate

Funding for the rebates is recorded as a reduction in the flow-through cost of energy.

Cash and cash equivalents

Cash and cash equivalents consist of cash on hand and in banks.

Investments

Investments are accounted for using the cost method. The carrying value of an investment is written-down to its net recoverable amount if a decline in market value is judged to be other than temporary.

Stores inventory

Stores inventory consists principally of maintenance and construction materials and is valued at the lower of cost and net realizable value. Cost is determined using the average cost method.

Capital assets

Capital assets are stated at cost. Gains or losses on retirement or disposition of such assets are credited or charged to other operating revenue. Amortization is provided on a straight-line basis for capital assets over their estimated service lives at the following annual rates:

Buildings	2%
Distribution and transformation equipment	3% to 4%
Other assets	10% to 20%
Rolling stock	12½% to 20%

Pension plan

TBHEDI 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 [note 13]. TBHEDI recognizes the expense related to this plan as contributions are made.

Other post-employment benefits

Employee future benefits provided by TBHEDI include medical and life insurance benefits and accumulated sick leave credits. These plans provide benefits to certain employees when they are no longer providing active service. Employee future benefit expense is recognized in the period in which the employees render the services. Employee future benefits are recorded on an accrual basis. The accrued benefit obligations and current service cost are calculated using the projected benefit method pro-rated on service and based on assumptions that reflect management's best estimate. The current service cost for a period is equal to the actuarial present value of benefits attributed to employees' services rendered in the period. Past service costs from plan amendments are amortized on a straight-line basis over the average remaining service period of employees active at the date of amendment. Actuarial gains (losses) are amortized into expense on a straight-line basis over the average remaining service period of active employees to full eligibility. The effects of a curtailment gain or loss are recognized in earnings in the year of the event-giving rise to the curtailment. The effects of a settlement gain or loss are recognized in earnings for the period in which a settlement occurs.

Revenue recognition

Distribution revenue is recognized on the basis of regular meter readings. Estimates of customer usage since the last meter reading date, to the end of the year are recorded as unbilled revenue.

Pole line revenue is recognized based on annual contracted rates and agreed-upon pole counts.

Other revenue is recognized when the requirements as to performance for transactions involving the sale of goods or services are met and ultimate collection is reasonably assured at the time of performance.

Contributions in aid of construction

Effective January 1, 2001, TBHEDI prospectively adopted the change in accounting policy for contributions received in aid of construction (contributed capital), as prescribed by the OEB "Accounting Procedures Handbook for Electric Distribution Utilities". Capital contributions are required contributions received from outside sources, used to finance additions to capital assets. Capital contributions received after January 1, 2001 are treated as a "credit" contra account included in the determination of capital assets. The amount is subsequently amortized by a charge to accumulated amortization and a credit to amortization expense, at an equivalent rate to that used for the amortization of the related capital assets. Capital contributions received for capital assets prior to January 1, 2001 were treated as contributed capital, a permanent component of equity, which was not amortized.

Customer deposits

Customers' advance deposits are cash collections from customers or Energy Retailers to guarantee the payment of energy-related bills. The deposits bear interest that is paid annually to customers.

Thunder Bay Hydro Electricity Distribution Inc.
Notes to the Financial Statements
December 31, 2006

Use of estimates

The preparation of financial statements in conformity with Canadian generally accepted accounting principles ("GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses for the year. Actual results could differ from those estimates.

Corporate income taxes and capital taxes

The current tax-exempt status of TBHEDI under the Income Tax Act (Canada) and the Corporations Tax Act (Ontario) reflects the fact that TBHEDI is wholly-owned by a municipality. This tax-exempt status might be lost in a number of circumstances, including if the municipality ceases to own 90% or more of the shares or capital of TBHEDI, or if a non-government entity has rights immediately or in the future, either absolutely or contingently, to acquire more than 10% of the shares of TBHEDI.

Commencing October 1, 2001, TBHEDI was required, under the Electricity Act, 1998, to make payments in lieu of corporate taxes ("PILS") to the OEFC. These payments are calculated 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) as modified by the Electricity Act, 1998, and related regulations.

TBHEDI provides for PILS relating to its regulated business using the taxes payable method as directed by the OEB. Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax bases of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered from the customers of TBHEDI at that time.

Provision for environmental costs

TBHEDI will incur future costs associated with the disposal of contaminated waste and site restoration for certain of its properties. Although these costs cannot be reasonably determined for some of the properties at this time, a contingent liability exists. Where reasonably determinable, TBHEDI has provided for future costs, net of expected recoveries, by charges to income. Actual costs are charged to the provision for environmental costs as incurred.

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3. DUE FROM ASSOCIATED COMPANIES

The balances due from associated companies represent balances owing from the following common control enterprises:

	2006 $	2005 $
Thunder Bay Hydro Energy Services Inc.	8,127	33,454
Transmission Northwest Inc.	107,406	107,400
Thunder Bay Hydro Utility Services Inc.	52,032	114,865
Thunder Bay Hydro Corporation	3,438	3,438
	171,003	259,157

The balances are non-interest bearing with no specific terms of repayment.

4. REGULATORY ASSETS (LIABILITIES)

	2006 $	2005 $
Regulatory Assets		
Rebate costs *	—	68,530
Deferral for cash pension contributions	544,924	379,510
Deferral for OEB annual cost assessment	144,987	108,469
Pre-market opening cost of power *	—	1,517,784
	689,911	2,074,293
Wholesale market services *	—	1,954,231
Commodity *	—	1,321,082
Retail settlement variances	—	3,275,313
Retailer cost variance *	194,510	290,816
Deferred rate impact (Vary Order)	206,189	—
Repayment of regulatory balances	543,720	—
Regulatory Assets	1,634,330	5,640,422
Regulatory Liabilities		
Recovery of regulatory balances	—	(104,459)
PILS deferral	(1,498,641)	(1,214,712)
Smart Meter deferrals	(84,604)	—
	(1,583,245)	(1,319,171)
Wholesale market services *	(788,636)	—
Network transmission charges *	(1,075,963)	(3,265,001)
Connection transmission charges *	(1,727,171)	(6,565,805)
Commodity *	(1,528,775)	—
Retail settlement variances	(5,120,545)	(9,830,806)
Regulatory Liabilities	(6,703,790)	(11,149,977)

In the absence of rate regulation, expenses would have been $268,204 [2005 - $644,196] higher. In the absence of rate regulation, carrying charges on regulatory assets and liabilities in 2006 would have decreased by $175,366 [2005 - increased by $212,295] (see Statement of Operations and Retained Earnings).

The OEB-approved balances as at December 31, 2004 in the accounts noted with an asterisk (*) above were closed to the account called Repayment of Regulatory Balances, effective April 30, 2006. The net asset entry closing the asset and liability accounts to the Repayment of Regulatory Balances amounted to $473,574.

Retail Settlement Variances arising subsequent to December 31, 2004 will be reviewed quarterly for disposition for commodity and annually for non-commodity.

The regulatory assets and liabilities balances of TBHEDI are defined as follows:

[a] Recovery/Repayment of regulatory asset balances:

This represents recoveries on the net regulatory asset balances as at December 31, 2004 [December 31, 2003 for 2005]. The approved rate adjustment account is debited or credited with paid/recovery amounts and is debited or credited by the OEB prescribed carrying charges. In the absence of rate regulation, income would have increased in 2005 by the amount of the carrying charges on regulatory liabilities of $26,851 [2005 - $45,517].

[b] Pre-market opening energy electricity variance:

Traditionally, customers who were not billed using time-of-use rates were charged an average rate for their power throughout the year to incorporate the winter and summer rates that were charged to TBHEDI on the purchase of power. Upon market opening, May 1, 2002, TBHEDI commenced charging customers at approved rates for debt retirement, transmission, connection, distribution and wholesale market services plus the hourly Ontario Energy price for commodity consumption. As a result of the timing of market opening, TBHEDI experienced a loss on the energy sales to the non-time-of-use customers.

The OEB has allowed TBHEDI to recognize the pre-market opening energy electricity variance for the period January 1, 2001 to April 30, 2002, the date of market opening. Accordingly, TBHEDI has deferred these expenditures in accordance with the criteria set out in the AP Handbook. The balance in this account, plus carrying charges to April 30, 2006, was transferred to the "Repayment of Regulatory Balances" account. In the absence of rate regulation, income would have reduced in 2006 by the amount of the carrying charges on regulatory assets/liabilities of $21,836 [2005 - $312,994].

[c] Retail settlement variance accounts:

The OEB has allowed TBHEDI to defer settlement variances from May 1, 2002 to December 31, 2005. This balance represents the variances between amounts charged by TBHEDI to customers (based on regulated rates) and the corresponding cost of non-competitive electricity service incurred by it in the wholesale market administered by the IESO after May 1, 2002. The settlement variances relate primarily to service charges, non-competitive electricity charges, imported power charges and the global adjustment. Accordingly, TBHEDI has deferred these recoveries in accordance with the criteria set out in the AP Handbook.

The balance in this account, plus carrying charges to April 30, 2006 was transferred to the "Repayment of Regulatory Balances" account.

[d] Retail cost variance accounts:

The OEB has allowed TBHEDI to defer the net costs of services relating to the supply of competitive electricity to retailer customers. Accordingly, TBHEDI has deferred these expenditures in accordance with the criteria set out in the AP Handbook.

Under such regulation, variances are allowed to be deferred which would be recorded as revenue and expenses when incurred under Canadian GAAP for unregulated businesses. In the absence of rate regulation, revenues in 2006 would have been $77,267 higher [2005 - $269,845] and expenses in 2006 would have been $170,845 higher [2005 - $527,276]. The deferred balance for settlement variances continues to be calculated and attract carrying charges in accordance with the OEB's direction.

The balance in this account, plus carrying charges to April 30, 2006, was transferred to the "Repayment of Regulatory Balances" account.

[e] Deferred rate impact (Vary Order)

During the year, it was discovered that a correction to the 2006 Electricity Distribution Rate (EDR) application was required to remove the rate mitigation adjustments that were not accepted by the OEB. There was a Vary Order issued by the OEB effective January 1, 2007, that partially addressed this correction. Thunder Bay Hydro is in the process of appealing this Vary Order to allow for the correction of the entire error. It is TBHEDI's objective to have this error recovered through a rate rider for the 2007 rates.

[f] Smart Meter deferrals

The OEB approved funding of $0.30 per residential meter in the 2006 EDR and has directed Local Distribution Companies (LDC's), in a June, 2006 letter, to defer differences between the amounts funded in rates to the actual costs. Costs to date are $5,800.

The deferral would be recorded as revenue and expense when incurred under Canadian GAAP for unregulated businesses. In the absence of rate regulation, revenue in 2006 would have been $84,604 higher [2005 - $nil].

[g] Deferral account for cash pension contributions

The OEB has allowed for the deferral of the incremental OMERS pension expenditures for the fiscal years commencing January 1, 2005 and continuing until April 30, 2006. Accordingly, TBHEDI has deferred these expenditures in accordance with the criteria set out in the AP Handbook.

Under such regulation, expenditures are allowed to be deferred which would be expensed under Canadian GAAP for unregulated businesses. In the absence of rate regulation, expenses in 2006 would have been $144,517 higher [2005 - $373,078]. The deferred balance continues to attract carrying charges in accordance with the OEB's direction.

The 2006 rate application included the OMERS pension cost in the distributor's rate base and therefore, no deferral is required effective May 1, 2006.

[h] Deferral account for OEB annual cost assessments:

The OEB has allowed for the deferral of the incremental OEB annual cost assessments for the fiscal years commencing January 1, 2004. Accordingly, TBHEDI has deferred these expenditures in accordance with the criteria set out in the AP Handbook.

Under such regulation, expenditures are allowed to be deferred which would be expensed under Canadian GAAP for unregulated businesses. In the absence of rate regulation, expenses in 2006 would have been $30,110 higher [2005 - $102,958]. The deferred balance continues to attract carrying charges in accordance with the OEB's direction.

The 2006 rate application included the OEB annual cost assessments in the distributor's rate base and therefore, no deferral is required effective May 1, 2006.

The manner and timing of the disposition for the deferral for cash contributions and OEB annual cost assessment has not been determined by the OEB.

5. CAPITAL ASSETS

[a] Details of year-end capital asset balances are as follows:

	2006		2005	
	Cost $	Accumulated amortization $	Cost $	Accumulated amortization $
Buildings	3,894,355	1,423,675	3,894,355	1,345,756
Distribution equipment	110,652,088	52,920,066	104,899,772	49,192,528
General office equipment	4,312,970	3,702,408	4,149,200	3,456,649
Land	133,038	—	133,038	—
Other equipment	2,493,772	2,132,502	2,443,620	2,075,586
Rolling stock	5,039,357	3,757,130	4,418,756	3,513,804
Transformation equipment	8,562,720	5,038,355	8,403,526	4,841,413
	135,088,300	68,974,136	128,342,267	64,425,736
Capital assets, net	66,114,164		63,916,531	

[b] Details of year-end capital contributions balances are as follows:

	2006		2005	
	Capital contributions $	Accumulated amortization $	Capital contributions $	Accumulated amortization $
Distribution equipment	6,676,650	948,700	5,631,381	698,500
Capital contributions, net	**5,727,950**		4,932,881	

6. BANK CREDITS

[a] TBHEDI has an operating loan available to them in the amount of $6,395,495 [2005 - $6,395,495] by way of prime rate based loans or bankers' acceptances. $Nil [2005 - $nil] was utilized at December 31, 2006. The prime rate based loans bear interest at bank prime. Prime at December 31, 2006 was 6.0% [2005 - 5.0%]. The bankers' acceptances bear a stamping fee at 0.5% per annum.

The operating loan is secured by:

[i] Guarantee of Advance, unlimited, as executed by Thunder Bay Hydro Corporation;

[ii] Authorized copy of borrowing by-laws permitting TBHEDI to borrow up to $18,000,000 by way of operating loans, B/As, L/Cs and L/Gs;

[iii] Subordination Agreement with respect to the $33,490,550 promissory note given to the City of Thunder Bay, with said Subordination Agreement providing for no acceleration rights, as approved by the Bank's legal department; and

[iv] Visa Indemnity Agreement.

[b] TBHEDI has a letter of credit or stand-by letters of guarantee available to them in the amount of $11,604,505 [2005 - $11,604,505] of which $11,604,505 [2005 - $11,604,505] was issued at December 31, 2006. This credit will be used by TBHEDI to assist in meeting its prudential obligations to the IESO. The credit bears interest at bank prime. Prime at December 31, 2006 was 6.0% [2005 - 5.0%].

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7. EMPLOYEE FUTURE BENEFITS

TBHEDI has a number of unfunded benefit plans providing retirement and post-employment benefits (excluding pension) to most of its employees.

Information about TBHEDI's defined benefit plans is as follows:

	2006 $	2005 $
Change in accrued benefit obligation		
Accrued benefit obligation at January 1	2,171,076	2,167,552
Current service costs	86,814	114,407
Interest cost	108,426	119,152
Actuarial losses	39,348	39,348
Benefits paid in the year or moved to current liability	(274,891)	(269,383)
Accrued benefit obligation, end of year	2,130,773	2,171,076
Projected accrued benefit obligation at December 31, using a 5.75% [2005 – 5.75%] discount rate	2,369,311	2,445,782
Unamortized actuarial gain (loss)	(238,538)	(274,706)
Accrued benefit liability	2,130,773	2,171,076

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

[a] General inflation

Future general inflation levels, as measured by changes in the Consumer Price Index ("CPI"), were assumed at 2.1% in 2004 and thereafter.

[b] Interest (discount) rate

The obligation as at December 31, 2006, of the present value of future liabilities and the expense for the year, were determined using an annual discount rate of 5.75%.

[c] Salary levels

Future general salary and wage levels were assumed to increase at 3% per annum.

[d] Medical costs

Medical costs were assumed to increase at a rate of 10% in 2004 graded-down by 1% per annum leveling off at 5% in 2013 and thereafter.

[e] Dental costs

Dental costs were assumed to increase at a rate of 5% per annum in 2004 and thereafter.

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8. NOTE PAYABLE TO CITY OF THUNDER BAY

	2006 $	2005 $
Note payable to City of Thunder Bay	**33,490,500**	33,490,500

The note is a non-interest bearing note payable to The Corporation of the City of Thunder Bay (sole shareholder of Thunder Bay Hydro Corporation, TBHEDI's parent company). Principal repayment in the next twelve months is expected to be $nil.

9. OBLIGATION UNDER CAPITAL LEASE

TBHEDI entered into a three-year lease agreement for computer equipment. The interest rate implicit in the lease is 3.13%. The lease agreement ends March, 2008. The future minimum annual lease payments are as follows:

	$
2007	37,733
2008	9,433
Total amount of future minimum lease payments	47,166
Less interest	956
Current portion	46,210
Long-term portion	36,825
	9,385

10. OTHER OPERATING REVENUE

	2006 $	2005 $
Pole line rentals	**426,289**	518,897
Competitive market revenues	**205,195**	197,779
Interest earned	**606,301**	330,160
Utility services	—	805,281
Sundry earnings	**906,438**	814,150
	2,144,223	2,666,267

11. CONSERVATION AND DEMAND MANAGEMENT

The OEB approved a Conservation and Demand Management plan for $1,606,665. During 2006, approximately $678,750 [2005 - $1,567,000] has been recognized as part of distribution revenue (this represents the CDM plus the additional PILS funding relating to the CDM). The plan covered a variety of CDM initiatives including $549,000 of capital expenditures. The funding for the planned expenditures was included as part of the 2005 approved distribution rates.

Thunder Bay Hydro Electricity Distribution Inc.
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12. AMORTIZATION

Amortization provided during the year consists of:

	2006 $	2005 $
Amortization of general plant	4,382,084	4,124,609
Amortization of capital contributions	(250,200)	(205,000)
Amortization of unallocated office and data processing equipment	112,868	145,840
Amortization of organization costs	—	40,000
	4,244,752	4,105,449
Amortization of other capital assets included in relevant expense categories in the Statement of Operations and Retained Earnings	580,726	559,651
	4,825,478	4,665,100

13. PENSION PLAN

TBHEDI's current service pension costs for the year ended December 31, 2006 were $569,614 [2005 - $502,833]. Of this amount, $144,517 [2005 - $373,078] has been deferred in a regulatory asset account *[note 4]*.

14. STATEMENT OF CASH FLOWS

[a] The net change in non-cash working capital balances related to operations is represented by the following:

	2006 $	2005 $
Decrease (increase) in current assets		
Accounts receivable	(1,784,659)	2,112,109
Unbilled revenue	1,427,256	(2,227,186)
Payments in lieu of corporate income taxes receivable	(1,479,320)	128,767
Due from associated companies	88,154	(26,713)
Stores inventory	(143,986)	(153,449)
Prepaid expenses	(37,629)	163,634
	(1,930,184)	(2,838)
Increase (decrease) in current liabilities		
Accounts payable and accrued liabilities	(3,102,601)	5,672,091
Debt retirement charge	(58,955)	(19,752)
Deferred revenue	134,990	24,441
Accrued vacation payable	30,505	63,147
Payments in lieu of corporate income taxes liability	(605,874)	605,874
Customer deposits	57,242	(64,451)
	(3,544,693)	6,281,350
	(5,474,877)	6,278,512

[b] During the year, capital assets were acquired at an aggregate cost of $6,936,925 [2005 - $5,760,884], of which $602,324 [2005 - $726,214] was funded by cash contributions, $442,944 [2005 - $437,980] was funded by contributions in-kind, $nil [2005 - $105,117] was funded by the proceeds from capital lease obligations and $5,891,657 [2005 - $4,491,573] was funded by cash.

[c] Cash outflows during the year for interest and income taxes were as follows:

	2006 $	2005 $
Interest paid (received)	28,417	(3,006)
Income taxes paid	1,536,287	897,885

15. REBATES

During the year, TBHEDI received $2,685,407 [2005 - $7,448,394] from the IESO in connection with the Ontario Power Generation (OPG) rebate (2005 - Business protection plan rebate - BPPR) for the periods commencing April 1, 2005 and ending July 31, 2006 (2005 included the $5,110,642 Ontario Price Credit relating to low-volume consumption for the period April 1, 2004 to March 31, 2005). Of the OPG rebate, $1,971,021 was allocated to customers. The remaining $714,386 was forwarded to various electricity retailers.

16. RELATED PARTIES

TBHEDI provides certain services to The Corporation of the City of Thunder Bay (TBHEDI's parent) in the normal course of business at commercial rates.

For the year ended December 31, 2006, pole rental revenue from The Corporation of the City of Thunder Bay in the amount of $305,748 [2005 - $289,937] and other sundry revenues in the amount of $63,010 [2005 - $133,889] were recorded. The Corporation of the City of Thunder Bay also contributed towards capital construction during the year in the amount of $18,210 [2005 - $82,921]. Included in "Accounts receivable" is $26,525 [2005 - $146,348] receivable from The Corporation of the City of Thunder Bay related to these other activities.

For the year ended December 31, 2006, TBHEDI billed electricity revenues in the amount of $8,200,420 [2005 - $6,909,635] to The Corporation of the City of Thunder Bay. At December 31, 2006, included in "Accounts receivable" is $380,588 [2005 - $11,797] receivable from The Corporation of the City of Thunder Bay, related to this electricity revenue.

TBHEDI purchases certain services from The Corporation of the City of Thunder Bay in the normal course of business at commercial rates.

For the year ended December 31, 2006, TBHEDI incurred rent of $288,475 [2005 - $288,475] and property taxes payable to The Corporation of the City of Thunder Bay of $155,107 [2005 - $172,361]. During 2006, TBHEDI also incurred $166,500 [2005 - $241,000] for Conservation and Demand Management Activities.

TBHEDI manages and administers the rental water heater operations for Thunder Bay Hydro Energy Services Inc. (TBHESI). During 2006, TBHEDI charged TBHESI administration fees of $45,000 [2005 - $45,000].

TBHEDI provides services to Thunder Bay Hydro Utility Services Inc. (TBHUSI) at cost plus bank prime plus 2%. Gross billings to TBHUSI during 2006 amounted to $282,000.

17. CONTINGENCIES

[a] Consumers' Gas Decision

On April 22, 2004, in a decision for a class action commenced against The Consumers' Gas Company Limited (now Enbridge Gas Distribution Inc.), the Supreme Court of Canada [the "Supreme Court"] ruled that The Consumers' Gas Company ["Consumers' Gas"] was required to repay the portion of certain late payment charges collected by it from its customers that were in excess of the interest limit stipulated in section 347 of the Criminal Code. Although the claim related to charges collected by Consumers' Gas after the enactment of section 347 of the Criminal Code in 1981, the Supreme Court limited recovery to charges collected after the action was initiated in 1994. The Supreme Court remitted the matter back to the Ontario Superior Court of Justice for a determination of the plaintiffs' damages.

TBHEDI is not a party to the Consumers' Gas class action. It is, however, subject to the class action described below in which the issues are analogous.

Griffith et al. v. Toronto Hydro-Electric Commission et al.

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 proceeding brought against Enbridge Gas Distribution Inc. (formerly Consumers Gas).

On April 22, 2004, the Supreme Court of Canada released a decision in the Consumers Gas 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.

After the release by the Supreme Court of Canada of its 2004 decision in the Consumers Gas 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 Consumers Gas.

TBHEDI collected total late payment penalties of approximately $3.2 million from and after 1994. No determination of the portion of these payments which may have constituted interest at an impermissible rate has been made.

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

[b] Ministry of Finance Audit

The Ministry of Finance has conducted an audit of TBHEDI's Payments in Lieu of Taxes (PILS) filings for the years 2001 and 2002. Certain filing positions taken by TBHEDI with respect to the treatment of some regulatory assets/liabilities were challenged and resulted in the Ministry of Finance issuing Notices of Reassessments for each of the 2001 to 2004 fiscal years. The reassessments resulted in additional PILS payable of $1,128,844 plus interest of $174,696 which have been recorded as part of the Payments in lieu of corporate income taxes receivable. TBHEDI has filed a Notice of Objection to the reassessments. If the Objection is denied, TBHEDI will recognize the reassessed taxes in the year of denial in accordance with generally accepted accounting principles.

18. CORPORATE INCOME AND CAPITAL TAXES

The provision for payments in lieu of corporate income and capital taxes differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate.

The impact of differences between TBHEDI's reported income tax expense on operating income and the expense that would otherwise result from the application of statutory rates is as follows:

	2006 $	2005 $
Earnings before provision for taxes	1,759,410	3,121,666
Statutory Canadian federal and provincial income tax rate	36.12%	36.12%
Expected provision	635,500	1,127,545
Increase in income taxes resulting from		
Large Corporations Tax net of surtax	—	12,259
Timing differences		
Amortization and capital cost allowance	267,632	363,065
Amortization and eligible capital expenditure amortization	(2,370)	11,901
Regulatory asset recovery	204,304	(156,157)
Other	108,642	6,387
Provision for payments in lieu of corporate income taxes	1,213,708	1,365,000
Effective tax rate	68.96%	43.73%

Future income taxes relating to TBHEDI have not been recorded in the accounts as they are expected to be recovered through future revenues. As at and for the year ended December 31, 2006, the following future income tax asset and expense (recovery) have not been recorded in the financial statements:

	Gross $	Future income tax asset not recorded in financial statements $	Future income tax expense (recovery) not recognized in financial statements $
Deductible temporary and permanent differences	14,000,000	5,056,800	(377,000)

19. FINANCIAL INSTRUMENTS AND CREDIT RISK

[a] Fair value of financial instruments

The carrying amount of cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, capital lease obligation and interfund balances approximate their fair values due to the relatively short periods to maturity of the instruments. The carrying value of the note payable to the City of Thunder Bay will differ from the fair value due to the interest rate and repayment terms of that instrument.

[b] Credit risk

Credit risk is the risk that a counter party will fail to discharge its obligation to TBHEDI reducing the expected cash inflow from the Corporation assets recorded at the balance sheet date. Credit risk can be concentrated in debtors that are similarly affected by economic or other conditions. TBHEDI provides for an allowance for doubtful accounts to absorb credit losses. TBHEDI has assessed that there are no significant concentrations of credit risk with respect of any class of financial assets.

[c] Interest rate risk

TBHEDI is exposed to interest rate risk for certain of its financial assets and liabilities. Under the revolving terms of credit, TBHEDI may have short-term borrowings for working capital purposes, which would expose TBHEDI to fluctuations in short-term interest rates (borrowings in the form of prime rate loans in Canadian dollars).

20. MEASUREMENT UNCERTAINTY

Measurement uncertainty relates to the uncertainty in the determination at which an item is recognized in the financial statements. There is a degree of uncertainty associated with the measurement of certain regulatory assets in the financial statements (OEB annual cost assessment and deferral for cash pension contributions) due to the fact that the OEB has not yet allowed for disposition of these accounts, nor has it indicated that disposition is assured through future rates or other mechanisms. It is reasonably possible that the recognized amount could change by a material amount in the near term should the OEB determine that disposition of these balances will not be allowed through future rates. The assets subject to uncertainty total $689,911 [2005 - $487,979] and are recorded on the Balance Sheet.

Thunder Bay Hydro Electricity Distribution Inc.
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21. COMPARATIVE FIGURES

Certain of the 2005 comparative balances have been restated to conform with the current year's presentation.

Thunder Bay Hydro Electricity Distribution Inc. Schedule
Expenses

Year ended December 31	2006	2005
	$	$
OPERATION AND MAINTENANCE		
Customer premises/meters and devices	748,691	779,102
Distribution	3,131,610	2,523,753
Safety and training	323,277	289,895
System control/station maintenance	1,308,480	1,451,905
Transformer	374,272	389,694
Total operation and maintenance expenses	5,886,330	5,434,349
UTILITY SERVICES		
Meter service provider	—	245,978
Utility management services	—	95,511
Total utility services expenses	—	341,489
ADMINISTRATION		
Customer related		
Bad debts	105,590	236,697
Billing	199,574	177,952
Cashiers	348,337	307,707
Customer information and service	1,304,119	1,099,193
Data processing	667,417	662,722
Meter reading	494,298	492,951
Total customer related administration expenses	3,119,335	2,977,222
General		
Corporate	617,865	482,168
Directors' expenses	53,363	60,675
Finance - accounting	451,214	362,043
- administration	219,612	208,284
Human resources	344,217	245,245
President's office	315,506	292,450
Power Systems Administration	188,683	423,810
Total general administration expenses	2,190,460	2,074,675
Total administration expenses	5,309,795	5,051,897
TOTAL EXPENSES	11,196,125	10,827,735

Thunder Bay Hydro Electricity Distribution Inc. Schedule 1
Expenses

Year ended December 31	2007	2006
	$	$
OPERATIONS AND MAINTENANCE		
Customer premises/meters and devices	710,190	748,691
Distribution	3,310,178	3,131,065
Safety and training	398,206	323,822
System control/station maintenance	1,436,240	1,308,480
Transformer	810,394	374,272
Total operations and maintenance expenses	6,665,208	5,886,330
ADMINISTRATION		
Customer-related		
Bad debts	80,362	105,590
Billing and collecting	719,679	711,419
Customer information service	1,100,408	1,140,611
Data processing	666,845	667,417
Meter reading	528,359	494,298
Total customer-related administration expenses	3,095,653	3,119,335
General		
Corporate	655,269	617,865
Directors' expenses	64,084	53,363
Finance	778,460	670,826
Human resources	294,734	344,217
President's office	328,667	315,506
Power systems administration	269,540	188,683
Total general administration expenses	2,390,754	2,190,460
Total administration expenses	5,486,407	5,309,795
TOTAL EXPENSES	12,151,615	11,196,125



Grant Thornton

Financial Statements

Thunder Bay Hydro Electricity Distribution Inc.

December 31, 2007

Thunder Bay Hydro Electricity Distribution Inc.

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Auditors' Report

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To the Shareholder of

Thunder Bay Hydro Electricity Distribution Inc.

We have audited the balance sheet of Thunder Bay Hydro Electricity Distribution Inc. as at December 31, 2007 and the statements of operations and retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audit.

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

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2007 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Grant Thornton LLP

Thunder Bay, Canada
March 14, 2008

Chartered Accountants
Licensed Public Accountants

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Thunder Bay Hydro Electricity Distribution Inc.
Balance Sheet

As at December 31	2007	2006
	$	$ [restated - note 24]
ASSETS		
Current		
Cash and cash equivalents	**11,906,690**	11,020,351
Accounts receivable	**6,750,426**	7,275,294
Unbilled revenue	**10,899,214**	11,226,341
Payments in lieu of corporate income taxes receivable	**1,767,361**	1,479,320
Due from associated companies *[note 4]*	**210,524**	171,003
Stores inventory	**1,422,442**	1,361,446
Prepaid expenses	**254,879**	170,531
Total current assets	**33,211,536**	32,704,286
Other		
Regulatory assets *[note 5]*	**1,289,218**	1,428,141
Other long-term assets *[note 6]*	**34,080**	-
Total other assets	**1,323,298**	1,428,141
Property, plant and equipment, at cost		
Property, plant and equipment, net *[note 7[a]]*	**67,027,168**	66,114,164
Capital contributions, net *[note 7[b]]*	**(6,401,324)**	(5,727,950)
Construction-in-progress	**101,799**	323,066
Property, plant and equipment, net	**60,727,643**	60,709,280
	95,262,477	94,841,707

See accompanying notes to the financial statements.

On behalf of the Board:

Director Director

	2007	2006
	$	$ *[restated - note 24]*
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current		
Accounts payable and accrued liabilities	**8,340,068**	8,693,900
Debt retirement charge	**531,415**	547,440
Deferred revenue and contributions	**352,102**	355,489
Accrued vacation pay payable	**833,890**	824,630
Customer deposits	**2,022,708**	1,902,184
Current portion of obligation under capital lease *[note 11]*	**9,385**	36,825
Total current liabilities	**12,089,568**	12,360,468
Long-term		
Regulatory liabilities *[note 5]*	**7,442,817**	7,708,264
Employee future benefits *[note 9]*	**2,477,300**	2,130,773
Note payable to City of Thunder Bay *[note 10]*	**33,490,500**	33,490,500
Obligation under capital lease *[note 11]*	**-**	9,385
Asset retirement obligation *[note 12]*	**325,000**	-
Total long-term liabilities	**43,735,617**	43,338,922
Shareholder's equity		
Share capital		
Authorized		
Unlimited common shares		
Issued		
1,000 common shares	**34,931,625**	34,931,625
Retained earnings	**4,505,667**	4,210,692
Total shareholder's equity	**39,437,292**	39,142,317
	95,262,477	94,841,707

Thunder Bay Hydro Electricity Distribution Inc.
Statement of Operations and Retained Earnings

Year ended December 31	2007	2006
	$	$ *[restated - note 24]*
REVENUES AND FLOW-THROUGH CHARGES		
Flow-through charges plus distribution revenues	87,322,348	85,715,901
Flow-through costs of energy	(71,336,950)	(69,890,804)
Distribution revenue	15,985,398	15,825,097
Other operating revenue *[note 13]*	2,248,725	2,144,223
	18,234,123	17,969,320
EXPENSES		
Administration *[schedule]*	5,486,407	5,309,795
Amortization *[note 14]*	4,420,552	4,244,752
Conservation and demand management	333,695	355,350
Operations and maintenance *[schedule]*	6,665,208	5,886,330
Provision for payments in lieu of capital tax	218,000	236,292
	17,123,862	16,032,519
Earnings before the following	1,110,261	1,936,801
Interest on obligation under capital lease	908	2,025
Carrying charges (interest) on regulatory assets/liabilities, net	204,378	175,366
	205,286	177,391
Earnings before provision for taxes	904,975	1,759,410
Provision for payments in lieu of corporate income taxes *[note 15]*	610,000	1,213,708
Earnings for year	294,975	545,702
Retained earnings, beginning of year	4,210,692	3,664,990
Retained earnings, end of year	4,505,667	4,210,692

See accompanying notes to the financial statements.

Thunder Bay Hydro Electricity Distribution Inc.
Statement of Cash Flows

Year ended December 31	2007	2006
	$	$ *[restated - note 24]*
OPERATING ACTIVITIES		
Earnings for year	294,975	545,702
Add charges (deduct credits) to operations not involving a current payment (receipt) of cash		
Amortization *[note 14]*	4,828,980	4,629,472
Increase (decrease) in employee future benefits	346,527	(40,303)
Gain on disposal of property, plant and equipment	(8,799)	(2,979)
	5,461,683	5,131,892
Net change in non-cash working capital balances related to operations *[note 17[a]]*	135,629	(6,685,540)
Cash provided by (used in) operating activities	5,597,312	(1,553,648)
INVESTMENT ACTIVITIES		
Proceeds on sale of property, plant and equipment	8,799	14,311
Additions to other long-term assets	(34,080)	-
Additions to property, plant and equipment, net *[note 17[b]]*	(4,522,343)	(5,695,651)
Decrease in investment	-	4,000,000
Cash used in investment activities	(4,547,624)	(1,681,340)
FINANCING ACTIVITIES		
Decrease in regulatory assets	138,923	4,212,281
Decrease in regulatory liabilities	(265,447)	(3,441,713)
Repayments of obligation under capital lease	(36,825)	(35,706)
Cash (used in) provided by financing activities	(163,349)	734,862
Increase (decrease) in cash and cash equivalents during year	886,339	(2,500,126)
Cash and cash equivalents, beginning of year	11,020,351	13,520,477
Cash and cash equivalents, end of year	11,906,690	11,020,351

See accompanying notes to the financial statements.

Thunder Bay Hydro Electricity Distribution Inc.
Notes to the Financial Statements
December 31, 2007

GENERAL

Thunder Bay Hydro Electricity Distribution Inc. ("the Corporation") is a wholly-owned subsidiary company of Thunder Bay Hydro Corporation, providing electrical distribution services to the inhabitants of the City of Thunder Bay, as regulated by the Ontario Energy Board ("OEB").

1. SIGNIFICANT ACCOUNTING POLICIES

These financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"), including accounting principles prescribed by the OEB in the handbook "Accounting Procedures Handbook for Electric Distribution Utilities ("AP Handbook")", and reflects the significant accounting policies summarized below.

Rate setting and regulation

The OEB Act, 1998 gave the OEB increased powers and responsibilities to regulate the electricity industry. These powers and responsibilities include the power to approve or 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 for ensuring the distribution companies fulfill obligations to connect and service customers. In its capacity to approve or fix rates, the OEB has specified the following regulatory treatments that have resulted in accounting treatments differing from GAAP for enterprises operating in a non-regulated environment:

[a] Regulatory Assets and Liabilities

Effective December 31, 2005, the Corporation adopted the Canadian Institute of Chartered Accountants Accounting Guideline 19 "Disclosures by Entities Subject to Rate Regulation". Certain costs and variance account balances are deemed to be "regulatory assets" or "regulatory liabilities" and are reflected on the balance sheet until the manner and timing of the disposition is determined by the OEB [note 5].

Regulatory assets and liabilities can arise from differences in amounts billed to customers (based on regulated rates) and the corresponding cost of non-competitive electricity service incurred by the Corporation in the wholesale market administered by the Independent Electricity System Operator ("IESO"). These will be recovered or repaid through a future rate setting process.

[b] Rebates to customers/Business Protection Plan Rebate

Funding for the rebates is recorded as a reduction in the flow-through cost of energy.

Cash and cash equivalents

Cash and cash equivalents consist of cash on hand and in banks.

Stores inventory

Stores inventory consists principally of maintenance and construction materials and is valued at the lower of cost and net realizable value. Cost is determined using the average cost method.

Property, plant and equipment

Property, plant and equipment are stated at cost. Gains or losses on retirement or disposition of such assets are credited or charged to other operating revenue. Amortization is provided on a straight-line basis for property, plant and equipment over their estimated service lives at the following annual rates:

Buildings	2%
Distribution and transformation equipment	3% to 4%
Other assets	10% to 20%
Rolling stock	12½% to 20%

As necessary, these assets are tested for impairment.

Pension plan

The Corporation 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 [note 16]. The Corporation recognizes the expense related to this plan as contributions are made.

Other post-employment benefits

Employee future benefits provided by the Corporation include medical and life insurance benefits and accumulated sick leave credits. These plans provide benefits to certain employees when they are no longer providing active service. Employee future benefit expense is recognized in the period in which the employees render the services. Employee future benefits are recorded on an accrual basis. The accrued benefit obligations and current service cost are calculated using the projected benefit method pro-rated on service and based on assumptions that reflect management's best estimate. The current service cost for a period is equal to the actuarial present value of benefits attributed to employees' services rendered in the period. Past service costs from plan amendments are amortized on a straight-line basis over the average remaining service period of employees active at the date of amendment. Actuarial gains (losses) are amortized into expense on a straight-line basis over the average remaining service period of active employees to full eligibility. The effects of a curtailment gain or loss are recognized in earnings in the year of the event giving rise to the curtailment. The effects of a settlement gain or loss are recognized in earnings for the period in which a settlement occurs.

Revenue recognition

Distribution revenue is recognized on the basis of regular meter readings. Estimates of customer usage since the last meter reading date, to the end of the year are recorded as unbilled revenue.

Pole line revenue is recognized based on annual contracted rates and agreed-upon pole counts.

Other revenue is recognized when the requirements as to performance for transactions involving the sale of goods or services are met and ultimate collection is reasonably assured at the time of performance.

Construction-in-progress

Construction-in-progress is comprised of the costs of assets not yet placed into service, assets under construction, and pre-construction activities related to projects expected to be completed. These amounts are not amortized. Upon energization of assets the amounts are transferred to property, plant and equipment and are amortized on a straight-line basis over the expected service life of the asset.

Other long-term assets

Other long-term assets consist of amounts paid to Hydro One under capital cost recovery agreements currently being developed. These costs will be amortized over the life of the agreements.

Thunder Bay Hydro Electricity Distribution Inc.
Notes to the Financial Statements
December 31, 2007

Contributions in aid of construction

Capital contributions are required contributions received from outside sources, used to finance additions to property, plant and equipment. Capital contributions received after January 1, 2001 are treated as a "credit" contra account included in the determination of property, plant and equipment. The amount is subsequently amortized by a charge to accumulated amortization and a credit to amortization expense, at an equivalent rate to that used for the amortization of the related property, plant and equipment. Capital contributions received for property, plant and equipment prior to January 1, 2001 were treated as contributed capital, a permanent component of equity, which was not amortized.

Customer deposits

Customers' advance deposits are cash collections from customers or Energy Retailers to guarantee the payment of energy-related bills. The deposits bear interest at prime less 2% that is paid annually to customers.

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 the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses for the year. Actual results could differ from those estimates.

Corporate income taxes and capital taxes

The current tax-exempt status of the Corporation under the Income Tax Act (Canada) and the Corporations Tax Act (Ontario) reflects the fact that the Corporation is wholly-owned by a municipality. This tax-exempt status might be lost in a number of circumstances, including if the municipality ceases to own 90% or more of the shares or capital of the Corporation, or if a non-government entity has rights immediately or in the future, either absolutely or contingently, to acquire more than 10% of the shares of the Corporation.

Commencing October 1, 2001, the Corporation was required, under the Electricity Act, 1998, to make payments in lieu of corporate taxes ("PILS") to the Ontario Electricity Financing Corporation ("OEFC"). These payments are calculated 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) as modified by the Electricity Act, 1998, and related regulations.

The Corporation provides for PILS relating to its regulated business using the taxes payable method as directed by the OEB. Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax bases of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered from the customers of the Corporation at that time.

Asset retirement obligations

The Corporation recognizes a liability for the future removal and handling cost for contamination in distribution equipment and units in storage. Initially, the liability is measured at present value and the amount of the liability is added to the carrying amount of the related asset. In subsequent periods, the asset is amortized and the liability is adjusted annually for the discount applied upon initial recognition of the liability ("accretion expense") and for changes in the underlying assumptions. The liability is recognized when the asset retirement obligation ("ARO") is incurred and when the fair value is determined.

Financial instruments

Effective January 1, 2007, the Corporation adopted the CICA Handbook Sections 3855 - "Financial Instruments - Recognition and Measurement", 3861 - "Financial Instruments - Disclosure and Presentation", 3865 - "Hedges", 1530 - "Comprehensive Income" and the revised CICA Handbook Section 3251 - "Equity" [the "Handbook Sections"]. As provided under the standards, the comparative financial statements have not been restated. These new Handbook Sections have led to changes in the accounting for financial instruments and hedging transactions. All relevant changes are outlined below.

Financial Instruments - Recognition and Measurement - Section 3855

This Section establishes the standards for the recognition and measurement of financial assets and financial liabilities. At inception, all financial instruments which meet the definition of a financial asset or financial liability are to be recorded at fair value, unless fair value cannot be reliably determined. Depending on the nature of the financial instrument, revenues, expenses, gains and losses would be reported in either net income or other comprehensive income. Subsequent measurement of each financial instrument will depend on the balance sheet classification elected by the Corporation. As of January 1, 2007, the Corporation has elected the following balance sheet classification with respect to its financial assets and financial liabilities:

Cash is classified as "Assets Held-for-Trading" and is measured at fair value.

Accounts receivable and interfund balances are classified as "Loans and Receivables" and are measured at amortized cost, which upon initial recognition, is considered equivalent to fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method.

Accounts payable and accrued liabilities and capital lease liabilities are classified as "Other Financial Liabilities" and are initially measured at their fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method.

Note payable to the City of Thunder Bay is classified as "Other Financial Liability. It was originally recognized in accordance with CICA 3840, Related Party Transactions, being the amount of consideration established by contract. There is no requirement to fair value the amount on initial recognition because of the non-market rate of interest. Subsequent measurements are determined in accordance with CICA 3840 which provides the basis for subsequent measurement at amortized cost. The only changes to the amount initially recognized are changes in principal balances.

Comprehensive Income - Section 1530

This Section describes the recognition and disclosure requirements with respect to comprehensive income. Comprehensive income consists of net income and other comprehensive income. Other comprehensive income represents the changes in the fair value of a financial instrument which has not been included in net income.

As the Corporation had no adjustments to other comprehensive income during the year ended December 31, 2007, the adoption of this standard does not have an impact on the December 31, 2007 financial statements.

Hedges - Section 3865

This Section establishes standards regarding the use of hedge accounting, in particular, the criteria to be met for the application of hedge accounting and the methods executing various hedging strategies. As the Corporation has not entered into any hedging transactions as at December 31, 2007, the adoption of this standard does not have an impact on the December 31, 2007 financial statements.

2. ELECTRICITY ACT, 1998 AND ELECTRICITY PRICING CONSERVATION AND SUPPLY ACT 2004 (BILL 210)

The Energy Competition Act, 1998 (the "Act") was given Royal Assent on October 30, 1998. The Act provides for a competitive market in the sale of electricity, in addition to the regulation of the monopoly electricity delivery system in the Province of Ontario, by the OEB.

The cost of power and all costs other than distribution related to the operations of the electricity grid including transmission, connection and administration costs are flowed through to the consumer.

The distribution revenue is designed to recover the costs incurred by the Corporation in delivering electricity to customers and provide the Corporation with the OEB-allowed rate of return. Distribution rates are regulated by the OEB and typically comprise a fixed charge and a usage-based (consumption) charge.

Bill 210, which became law on December 9, 2002, effectively implemented a rate cap for the cost of electricity consumed (as well as for delivery costs) by low-volume and designated customers (retroactive to May 1, 2002). Retail settlement variance accounts ("RSVA") and certain other accounts prescribed by the OEB were defined as "regulatory assets" under Bill 210.

During the period, that the price protection is in effect, electricity distributors will be compensated by the OEFC for amounts by which the purchase price of the electricity purchased is greater than the fixed price per kWh charged to price protected customers, or the contract price paid to retailers.

Consumers other than the price-protected consumers are eligible to receive an Ontario Power Generation Rebate ("OPG Rebate"). The OPG Rebate is the difference, if any, between the revenue limit for some OPG generators and the price they would have received in the IESO wholesale spot market.

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 licenced retailers.

At the request of the Minister of Energy, the OEB developed an electricity price plan that provides stable and predictable electricity pricing, encourages conservation and ensures the price consumers pay for electricity better reflects the price paid to generators.

The price threshold – the amount of electricity that is charged at the lower price – changes twice a year for residential consumers. Prices will be reviewed more frequently by the Board and may change every six months based on an updated Board forecast and any accumulated differences between the amount that consumers paid for electricity and the amount paid to generators in the previous price-setting period.

3. ACCOUNTING CHANGES

[a] In 2006, the Corporation adopted Section 3110 of the CICA Handbook, "Asset Retirement Obligations," which establishes the recognition, measurement and disclosure of liabilities for asset retirement obligations and the associated asset retirement costs. This adoption has been applied prospectively. As a result of implementation, there was an increase in distribution assets in 2007 of $325,000 and an increase to asset retirement obligation of $325,000.

Thunder Bay Hydro Electricity Distribution Inc.
Notes to the Financial Statements
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[b] In July, 2006, the CICA issued Section 1506 of the CICA Handbook, "Accounting Changes," which describes the criteria for changing accounting policies, along with the accounting and disclosure for changes in accounting policies, changes in accounting estimates and corrections of errors. The Section specifies that a change in accounting policy, if not required by a primary source of GAAP, should only be made if it results in more reliable and relevant information.

Section 1506 also includes disclosure rules regarding the description and the impact on the Corporation's financial results of future accounting standards not yet applied. These changes came into effect as of January 1, 2007 and were adopted by the Corporation in the current fiscal year.

Future accounting standards

In 2007, the CICA has issued Handbook Sections 3862, "Financial Instruments - Disclosure" and 3863, "Financial Instruments – Presentation" which will effectively replace existing Handbook Section 3861, "Financial Instruments - Disclosure and Presentation." Section 3862 requires disclosure by class of financial instruments that enables users to evaluate the significance of financial instruments to the company's financial position and performance. Disclosures are also required of qualitative and quantitative information that enable users of financial statements to evaluate the nature and extent of the company's exposure to the risks arising from financial instruments, specifically credit risks, liquidity risks and market risks. Quantitative disclosures must also include a sensitivity analysis for each type of market risk the Corporation is exposed to and how earnings and other comprehensive income would be affected. Section 3863 carries forward the presentation requirements of 3861. The new standard is effective for fiscal years beginning on or after October 1, 2007 and will impact the Corporation's reporting periods beginning January 1, 2008. The Corporation is currently assessing the impact, if any, of the adoption of this new Section on its financial position or results of operations.

In June, 2007, the CICA issued Section 3031, "Inventories," which has replaced Section 3030 with the same title. The new Section establishes practices for the measurement and disclosure of inventories. Section 3031 requires the measurement of inventories at the lower of cost and net realizable value; clarifies the allocation of overhead and other costs to inventory; narrows the permitted cost formulae; requires the reversal of write-downs when there is a subsequent increase in the net realizable value and enhances financial statement disclosure. The new standard is effective for fiscal years beginning on or after January 1, 2008 and will impact the Corporation's reporting periods beginning January 1, 2008. The Corporation is currently assessing the impact, if any, of the adoption of this new Section on its financial position or results of operations.

In December, 2006, the CICA issued Section 1535, "Capital Disclosures." The new Section specifies the disclosure of an entity's objectives, policies and processes for managing capital; quantitative data about what the entity regards as capital; whether the entity has complied with any capital requirements and if it has not complied, the consequences of such non-compliance. The new standard is effective for fiscal years beginning on or after October 1, 2007 and will impact the Corporation's reporting periods beginning January 1, 2008. The Corporation is currently assessing the impact, if any, of the adoption of this new Section on its financial position or results of operations.

Thunder Bay Hydro Electricity Distribution Inc.
Notes to the Financial Statements
December 31, 2007

4. DUE FROM ASSOCIATED COMPANIES

The balances due from associated companies represent balances owing from the following common control enterprises:

	2007 $	2006 $
Thunder Bay Hydro Energy Services Inc.	**19,367**	8,127
Thunder Bay Renewable Power Incorporated	**154,946**	107,406
Thunder Bay Hydro Utility Services Inc.	**32,773**	52,032
Thunder Bay Hydro Corporation	**3,438**	3,438
	210,524	171,003

The balances are non-interest bearing with no specific terms of repayment.

5. REGULATORY ASSETS (LIABILITIES)

	2007 $	2006 $ *[restated - note 24]*
Regulatory Assets		
Deferral for cash pension contributions	**569,394**	544,924
Deferral for OEB annual cost assessment	**151,277**	144,987
	720,671	689,911
Retailer cost variance *	**320,067**	194,510
Repayment of regulatory balances	**248,480**	543,720
Regulatory Assets	**1,289,218**	1,428,141
Regulatory Liabilities		
PILS deferral	**(1,563,815)**	(1,498,641)
Smart Meter deferrals	**(230,406)**	(84,604)
	(1,794,221)	(1,583,245)
Wholesale market services *	**(2,150,907)**	(788,636)
Network transmission services *	**(825,305)**	(1,075,963)
Connection transmission charges *	**(589,654)**	(1,727,171)
Commodity *	**(2,082,730)**	(2,533,249)
Retail settlement variances	**(5,648,596)**	(6,125,019)
Regulatory Liabilities	**(7,442,817)**	(7,708,264)

In the absence of rate regulation, expenses would have been $116,768 [2006 - $268,204] higher. In the absence of rate regulation, carrying charges on regulatory assets and liabilities in 2007 would have decreased by $204,378 [2006 - decreased by $175,366] (see Statement of Operations and Retained Earnings).

The OEB-approved balances as at December 31, 2004 in the accounts noted with an asterisk (*) above were closed to the account called Repayment of Regulatory Balances, effective April 30, 2006. The net asset entry closing the asset and liability accounts amounted to $473,574.

Retail Settlement Variances arising subsequent to December 31, 2004 will be reviewed quarterly for disposition for commodity and annually for non-commodity.

The regulatory assets and liabilities balances of the Corporation are defined as follows:

[a] Recovery/Repayment of regulatory asset balances

This account consists of the net regulatory balances as at December 31, 2004. The approved rate adjustment account is debited or credited with paid/recovered amounts and is adjusted by the OEB prescribed carrying charges. In the absence of rate regulation, income would have increased in 2007 by the amount of the carrying charges on regulatory liabilities of $6,279 [2006 - $26,851].

[b] Retail settlement variance accounts

These balances represent the variances between amounts charged by the Corporation to customers (based on regulated rates) and the corresponding cost of non-competitive electricity service incurred since January 1, 2005.

[c] Retail cost variance accounts

As per the criteria in the AP Handbook, the Corporation defers the net costs of services relating to the supply of competitive electricity to retailer customers since January 1, 2005.

Under such regulation, variances are allowed to be deferred which would be recorded as revenue and expenses when incurred under GAAP for unregulated businesses. In the absence of rate regulation, revenues in 2007 would have been $87,152 higher [2006 - $77,267] and expenses in 2007 would have been $189,367 higher [2006 - $170,845]. The deferred balance for settlement variances continues to be calculated and attract carrying charges in accordance with the OEB's direction.

[d] Smart Meter deferrals

The OEB approved funding of $0.30 per residential meter in the 2006 Electricity Distribution Rate and has directed Local Distribution Companies (LDC's), in a June, 2006 letter to defer differences between the amounts funded in rates to the actual costs. Costs to date are $13,585 [2006 - $5,800].

The deferral would be recorded as revenue and expense when incurred under GAAP for unregulated businesses. In the absence of rate regulation, revenue in 2007 would have been $158,300 higher [2006 - $84,604].

[e] Deferral account for cash pension contributions

The OEB has allowed for the deferral of the incremental OMERS pension expenditures for the fiscal years commencing January 1, 2005 and continuing until April 30, 2006.

The expenditures are no longer allowed to be deferred, however the expenditures deferred that would have been expensed under GAAP for unregulated businesses amounted to $144,517 in 2006. The deferred balance continues to attract carrying charges in accordance with the OEB's direction.

[f] Deferral account for OEB annual cost assessments

The OEB has allowed for the deferral of the incremental OEB annual cost assessments for the fiscal years commencing January 1, 2004.

The expenditures are no longer allowed to be deferred, however the expenditures deferred that would have been expensed under GAAP for unregulated businesses amounted to $30,110 in 2006. The deferred balance continues to attract carrying charges in accordance with the OEB's direction.

The manner and timing of the disposition for the deferral for cash pension contributions and OEB annual cost assessment has not been determined by the OEB.

6. OTHER LONG-TERM ASSETS

The Corporation is in the process of entering into an agreement with Hydro One for the right to use the instrument transformers related to the meter stations. Once the agreement has been signed, the asset will be amortized over the term of the agreement.

	2007 $	2006 $
Deferred assets - Hydro One	34,080	-

Thunder Bay Hydro Electricity Distribution Inc.
Notes to the Financial Statements
December 31, 2007

7. PROPERTY, PLANT AND EQUIPMENT

[a] Details of year-end property, plant and equipment balances are as follows:

	2007		2006	
	Cost $	Accumulated amortization $	Cost $	Accumulated amortization $
Buildings	3,894,355	1,501,596	3,894,355	1,423,675
Distribution equipment	115,602,591	56,518,197	110,652,088	52,920,066
General office equipment	4,466,474	3,967,211	4,312,970	3,702,408
Land	133,038	-	133,038	-
Other equipment	2,611,065	2,215,118	2,493,772	2,132,502
Rolling stock	4,959,296	3,779,699	5,039,357	3,757,130
Transformation equipment	8,580,577	5,238,407	8,562,720	5,038,355
	140,247,396	73,220,228	135,088,300	68,974,136
Property, plant and equipment, net	67,027,168		66,114,164	

See note 14 for details of the amortization for the year.

[b] Details of year-end capital contributions balances are as follows:

	2007		2006	
	Capital contributions $	Accumulated amortization $	Capital contributions $	Accumulated amortization $
Distribution equipment	7,630,024	1,228,700	6,676,650	948,700
Capital contributions, net	6,401,324		5,727,950	

Thunder Bay Hydro Electricity Distribution Inc.
Notes to the Financial Statements
December 31, 2007

7. PROPERTY, PLANT AND EQUIPMENT

[a] Details of year-end property, plant and equipment balances are as follows:

	2007		2006	
	Cost $	Accumulated amortization $	Cost $	Accumulated amortization $
Buildings	3,894,355	1,501,596	3,894,355	1,423,675
Distribution equipment	115,602,591	56,518,197	110,652,088	52,920,066
General office equipment	4,466,474	3,967,211	4,312,970	3,702,408
Land	133,038	-	133,038	-
Other equipment	2,611,065	2,215,118	2,493,772	2,132,502
Rolling stock	4,959,296	3,779,699	5,039,357	3,757,130
Transformation equipment	8,580,577	5,238,407	8,562,720	5,038,355
	140,247,396	73,220,228	135,088,300	68,974,136
Property, plant and equipment, net		67,027,168		66,114,164

See note 14 for details of the amortization for the year.

[b] Details of year-end capital contributions balances are as follows:

	2007		2006	
	Capital contributions $	Accumulated amortization $	Capital contributions $	Accumulated amortization $
Distribution equipment	7,630,024	1,228,700	6,676,650	948,700
Capital contributions, net		6,401,324		5,727,950

Thunder Bay Hydro Electricity Distribution Inc.
Notes to the Financial Statements
December 31, 2007

8. BANK CREDITS

[a] The Corporation has an operating loan available to them in the amount of $6,395,495 [2006 - $6,395,495] by way of prime rate based loans or bankers' acceptances. $Nil [2006 - $nil] was utilized at December 31, 2007. The prime rate based loans bear interest at bank prime. Prime at December 31, 2007 was 6.0% [2006 - 6.0%]. The bankers' acceptances bear a stamping fee at 0.5% per annum.

The operating loan is secured by:

[i] Guarantee of Advance, unlimited, as executed by Thunder Bay Hydro Corporation;

[ii] Authorized copy of borrowing by-laws permitting TBHEDI to borrow up to $18,000,000 by way of operating loans, B/As, L/Cs and L/Gs;

[iii] Subordination Agreement with respect to the $33,490,550 promissory note given to the City of Thunder Bay, with said Subordination Agreement providing for no acceleration rights, as approved by the Bank's legal department; and

[iv] Visa Indemnity Agreement.

[b] The Corporation has a letter of credit or stand-by letters of guarantee available to them in the amount of $9,708,637 [2006 - $11,604,505] of which $9,708,637 [2006 - $11,604,505] was issued at December 31, 2007. This credit will be used by TBHEDI to assist in meeting its prudential obligations to the IESO. The credit bears interest at bank prime. Prime at December 31, 2007 was 6.0% [2006 - 6.0%]. Amounts payable to the IESO are recorded in current liabilities on the balance sheet.

Thunder Bay Hydro Electricity Distribution Inc.
Notes to the Financial Statements
December 31, 2007

9. EMPLOYEE FUTURE BENEFITS

The Corporation has a number of unfunded benefit plans providing retirement and post-employment benefits (excluding pension) to most of its employees.

Information about the Corporation's defined benefit plans is as follows:

	2007 $	2006 $
Accrued benefit obligation at January 1	2,369,311	2,409,614
Experience loss at beginning of year	321,761	-
Current service costs	221,444	86,814
Interest cost	154,815	108,426
Actuarial losses	102,427	39,348
Benefits paid in the year or moved to current liability	(132,159)	(274,891)
Accrued benefit obligation, end of year	3,037,599	2,369,311
Projected accrued benefit obligation at December 31, using a 5.25% [2006 - 5.75%] discount rate	3,037,599	2,369,311
Unamortized actuarial loss	(560,299)	(238,538)
Accrued benefit liability	2,477,300	2,130,773

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

[a] General inflation

Future general inflation levels, as measured by changes in the Consumer Price Index ("CPI"), were assumed at 2.0% in 2007 and thereafter.

[b] Interest (discount) rate

The obligation as at December 31, 2007, of the present value of future liabilities and the expense for the year, were determined using an annual discount rate of 5.25%.

[c] Salary levels

Future general salary and wage levels were assumed to increase at 3.3% per annum.

[d] Medical costs

Medical costs were assumed to increase at a rate of 5.8% in 2007, 9.0% in 2008 graded-down by 1% per annum leveling off at 5% in 2012 and thereafter.

Thunder Bay Hydro Electricity Distribution Inc.
Notes to the Financial Statements
December 31, 2007

10. NOTE PAYABLE TO CITY OF THUNDER BAY

The note is a non-interest bearing note payable to The Corporation of the City of Thunder Bay (sole shareholder of Thunder Bay Hydro Corporation, the Corporation's parent company). Principal repayment in the next twelve months is expected to be $nil.

	2007 $	2006 $
Note payable to City of Thunder Bay	33,490,500	33,490,500

11. OBLIGATION UNDER CAPITAL LEASE

The Corporation entered into a three-year lease agreement for computer equipment. The interest rate implicit in the lease is 3.13%. The lease agreement ends March, 2008. The future minimum annual lease payments are as follows:

	$
2008	9,433
Less interest	48
	9,385
Less current portion	9,385
Long-term portion	-

12. ASSET RETIREMENT OBLIGATIONS

A reconciliation between the opening and closing ARO liability balances is as follows:

	2007 $	2006 $
Balance, beginning of year	-	-
ARO liabilities incurred in the year	325,000	-
ARO liabilities settled in the year	-	-
Accretion expense	-	-
Balance, end of year	325,000	-

At December 31, 2007, the Corporation estimates the undiscounted amount of cash flows required over the next eight years to settle the ARO is $420,000 [2006 - $nil]. A discount rate of 6.0% was used to calculate the carrying value of the ARO liabilities. No assets have been legally restricted for settlement of the liability.

Thunder Bay Hydro Electricity Distribution Inc.
Notes to the Financial Statements
December 31, 2007

13. OTHER OPERATING REVENUE

	2007 $	2006 $
Pole line rentals	426,289	426,289
Competitive market revenues	211,922	205,195
Interest earned	565,892	606,301
Utility services	192,592	304,152
Sundry earnings	852,030	602,286
	2,248,725	2,144,223

14. AMORTIZATION

	2007 $	2006 $
Amortization of general plant	4,582,244	4,382,084
Amortization of capital contributions	(280,000)	(250,200)
Amortization of unallocated office and data processing equipment	118,308	112,868
	4,420,552	4,244,752
Amortization of other property, plant and equipment included in relevant expense categories in the Statement of Operations and Retained Earnings	626,229	580,726
	5,046,781	4,825,478
Amortization included in capitalized expenditures	217,801	196,006
Amortization of property, plant and equipment	4,828,980	4,629,472
	5,046,781	4,825,478

Thunder Bay Hydro Electricity Distribution Inc.
Notes to the Financial Statements
December 31, 2007

15. CORPORATE INCOME AND CAPITAL TAXES

The provision for payments in lieu of corporate income and capital taxes differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate.

The impact of differences between the Corporation's reported income tax expense on operating income and the expense that would otherwise result from the application of statutory rates is as follows:

	2007 $	2006 $
Earnings before provision for taxes	904,975	1,759,410
Statutory Canadian federal and provincial income tax rate (%)	36.12	36.12
Expected provision	326,880	635,500
Timing differences		
Amortization and capital cost allowance	282,807	267,632
Amortization and eligible capital expenditure amortization	(2,203)	(2,370)
Regulatory asset (repayment) recovery	(2,758)	204,304
Other	5,274	108,642
	610,000	1,213,708
Effective tax rate (%)	67.40	68.96

Future income taxes relating to the Corporation have not been recorded in the accounts as they are expected to be recovered through future revenues. As at and for the year ended December 31, 2007, the following future income tax asset and expense (recovery) have not been recorded in the financial statements:

	Gross $	Future income tax asset not recorded in financial statements $	Future income tax expense (recovery) not recorded in financial statements $
Deductible temporary and permanent differences	14,950,000	5,399,940	(348,000)

16. PENSION PLAN

The Corporation's current service pension costs for the year ended December 31, 2007 were $570,641 [2006 - $569,614]. Of this amount, $nil [2006 - $144,517] has been deferred in a regulatory asset account [note 5].

Thunder Bay Hydro Electricity Distribution Inc.
Notes to the Financial Statements
December 31, 2007

17. STATEMENT OF CASH FLOWS

[a] The net change in non-cash working capital balances related to operations consists of the following:

	2007 $	2006 $ [restated - note 24]
Decrease (increase) in current assets		
Accounts receivable	524,868	(1,990,848)
Unbilled revenue	327,127	1,427,256
Payments in lieu of corporate income taxes receivable	(288,041)	(1,479,320)
Due from associated companies	(39,521)	88,154
Stores inventory	(60,996)	(143,986)
Prepaid expenses	(84,348)	(37,629)
	379,089	(2,136,373)
Increase (decrease) in current liabilities		
Accounts payable and accrued liabilities	(353,832)	(4,107,075)
Debt retirement charge	(16,025)	(58,955)
Deferred revenue and contributions	(3,387)	134,990
Accrued vacation pay payable	9,260	30,505
Customer deposits	120,524	57,242
Payment in lieu of corporate income taxes liability	-	(605,874)
	(243,460)	(4,549,167)
	135,629	(6,685,540)

[b] During the year, property, plant and equipment were acquired at an aggregate cost of $6,018,518 [2006 - $6,936,925], of which $691,598 [2006 - $602,324] was funded by cash contributions, $261,776 [2006 - $442,944] was funded by contributions in-kind, $325,000 [2006 - $nil] was funded by long-term liability, $217,801 [2006 - $196,006] was funded by capitalized amortization, and $4,522,343 [2006 - $5,695,651] was funded by cash.

[c] Cash outflows (inflows) during the year for interest and income taxes were as follows:

	2007 $	2006 $
Interest paid (received)	(1,553)	28,417
Income taxes paid	1,143,039	1,536,287

Thunder Bay Hydro Electricity Distribution Inc.
Notes to the Financial Statements
December 31, 2007

18. REBATES

During the year, the Corporation received $504,143 [2006 - $2,685,407] from the IESO in connection with the OPG Rebate. Of the OPG Rebate, $367,036 was allocated to customers. The remaining $137,107 was forwarded to various electricity retailers.

19. RELATED PARTY TRANSACTIONS

The Corporation provides certain services to The Corporation of the City of Thunder Bay (the Corporation's parent) in the normal course of business at commercial rates.

For the year ended December 31, 2007, pole rental revenue from The Corporation of the City of Thunder Bay in the amount of $305,748 [2006 - $305,748] and other sundry revenues in the amount of $57,911 [2006 - $63,010] were recorded. The Corporation of the City of Thunder Bay also contributed towards capital construction during the year in the amount of $17,071 [2006 - $18,210]. Included in "Accounts receivable" is $25,241 [2006 - $26,525] receivable from The Corporation of the City of Thunder Bay related to these other activities.

For the year ended December 31, 2007, the Corporation billed electricity revenues in the amount of $8,301,003 [2006 - $8,200,420] to The Corporation of the City of Thunder Bay. At December 31, 2007, included in "Accounts receivable" is $538,327 [2006 - $380,588] receivable from The Corporation of the City of Thunder Bay, related to this electricity revenue.

The Corporation purchases certain services from The Corporation of the City of Thunder Bay in the normal course of business at commercial rates.

For the year ended December 31, 2007, the Corporation incurred rent of $293,474 [2006 - $288,475] and property taxes payable to The Corporation of the City of Thunder Bay of $149,757 [2006 - $155,107]. During 2007, the Corporation also incurred $63,000 [2006 - $166,500] for Conservation and Demand Management Activities.

The Corporation manages and administers the rental water heater operations for Thunder Bay Hydro Energy Services Inc. (TBHESI). During 2007, the Corporation charged TBHESI administration fees of $45,000 [2006 - $45,000].

The Corporation provides services to Thunder Bay Hydro Utility Services Inc. (TBHUSI) at cost plus bank prime plus 2%. Gross billings to TBHUSI during 2007 amounted to $234,307 [2006 - $282,000].

Thunder Bay Hydro Electricity Distribution Inc.
Notes to the Financial Statements
December 31, 2007

20. CONTINGENCIES

[a] Griffith et al. v. Toronto Hydro-Electric Commission et al.

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 proceeding brought against Enbridge Gas Distribution Inc. (formerly Consumers Gas).

On April 22, 2004, the Supreme Court of Canada released a decision in the Consumers Gas 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. 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 Consumers Gas 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 Consumers Gas.

The Corporation collected total late payment penalties of approximately $3.2 million from and after 1994. No determination of the portion of these payments which may have constituted interest at an impermissible rate has been made.

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

[b] Ministry of Finance Audit

The Ministry of Finance has conducted an audit of the Corporation's Payments in Lieu of Taxes (PILS) filings for the years 2001 and 2002. Certain filing positions taken by the Corporation with respect to the treatment of some regulatory assets/liabilities were challenged and resulted in the Ministry of Finance issuing Notices of Reassessments for each of the 2001 to 2004 fiscal years. The reassessments resulted in additional PILS payable of $1,128,844 plus interest of $174,693 which have been recorded as part of the Payments in lieu of corporate income taxes receivable. The Corporation has filed a Notice of Objection to the reassessments. If the Objection is denied, the Corporation will recognize the reassessed taxes in the year of denial in accordance with Canadian generally accepted accounting principles.

21. FINANCIAL INSTRUMENTS

[a] Fair value of financial instruments

The carrying amount of cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, obligation under capital lease and interfund balances approximate their fair values due to the relatively short periods to maturity of the instruments. The carrying value of the note payable to the City of Thunder Bay will differ from the fair value due to the interest rate and repayment terms of that instrument.

[b] Credit risk

Credit risk is the risk that a counter party will fail to discharge its obligation to the Corporation reducing the expected cash inflow from the Corporation assets recorded at the balance sheet date. Credit risk can be concentrated in debtors that are similarly affected by economic or other conditions. The Corporation provides for an allowance for doubtful accounts to absorb credit losses. The Corporation has assessed that there are no significant concentrations of credit risk with respect of any class of financial assets.

[c] Interest rate risk

The Corporation is exposed to interest rate risk for certain of its financial assets and liabilities. Under the revolving terms of credit, the Corporation may have short-term borrowings for working capital purposes, which would expose the Corporation to fluctuations in short-term interest rates (borrowings in the form of prime rate loans in Canadian dollars).

22. LIABILITY INSURANCE

The Corporation belongs to the Municipal Electrical Reciprocal Insurance Exchange ("MEARIE"). MEARIE is a self-insurance plan that pools the risks of all of its members. Any losses experienced by MEARIE are shared amongst its members. As at December 31, 2007, the Corporation has not been made aware of any assessments for losses.

Thunder Bay Hydro Electricity Distribution Inc.
Notes to the Financial Statements
December 31, 2007

23. MEASUREMENT UNCERTAINTY

Measurement uncertainty relates to the uncertainty in the determination at which an item is recognized in the financial statements. There is a degree of uncertainty associated with the measurement of certain regulatory assets in the financial statements (OEB annual cost assessment and deferral for cash pension contributions) due to the fact that the OEB has not yet allowed for disposition of these accounts, nor has it indicated that disposition is assured through future rates or other mechanisms. It is reasonably possible that the recognized amount could change by a material amount in the near term should the OEB determine that disposition of these balances will not be allowed through future rates. The assets subject to uncertainty total $720,671 [2006 - $689,911] and are recorded on the Balance Sheet.

24. COMPARATIVE FINANCIAL STATEMENTS

[a] An error in the calculation of the annual payable/receivable from the IESO relating to claims for the Global Adjustment component of the Regulated Pricing Settlements was made during the fiscal year 2006. This error resulted in an understatement of the commodity variance, which is a regulatory liability and an overstatement of the current accounts payable to the IESO. The total decrease to the accounts payable and accrued liabilities as at December 31, 2006 and the corresponding increase to the regulatory liabilities is $1,004,474. As a result of the adjustment to the regulatory liability, the corresponding flow-through charges and cost of energy were also decreased by $1,004,474. There was no impact to the prior period earnings for the year. The prior year's figures have been restated to correct this error.

[b] The comparative financial statements have been reclassified from statements previously presented to conform to the presentation of the 2007 financial statements.

PRO FORMA FINANCIAL STATEMENTS - 2008 AND 2009:

The Thunder Bay Hydro's Pro Forma Statements for the 2008 Bridge Year and the 2009 Test Year accompany this Schedule as Appendix A and Appendix B respectively.

APPENDIX A

COPY OF THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC. 2008 PRO FORMA STATEMENTS

THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.
PRO FORMA FINANCIAL STATEMENTS
AT DECEMBER 31, 2008

2008 BALANCE SHEET

, License Number ED-2002-0529, File Number EB-2008-0245

Thunder Bay Hydro Electricity Distribution Inc.

2008 BALANCE SHEET

Account Description	Total
1050-Current Assets	
1005-Cash	11,643,474.81
1010-Cash Advances and Working Funds	400.00
1020-Interest Special Deposits	-
1040-Other Special Deposits	-
1100-Customer Accounts Receivable	6,534,102.34
1102-Accounts Receivable - Services	-
1104-Accounts Receivable - Recoverable Work	13,972.56
1105-Accounts Receivable - Merchandise, Jobbing, etc.	-
1110-Other Accounts Receivable	355,243.65
1120-Accrued Utility Revenues	10,899,213.57
1130-Accumulated Provision for Uncollectible Accounts--Credit	(672,398.86)
1140-Interest and Dividends Receivable	47,989.14
1150-Rents Receivable	-
1180-Prepayments	247,315.70
1200-Accounts Receivable from Associated Companies	774,970.84
1210-Notes Receivable from Associated Companies	-
1050-Current Assets Total	**29,844,283.75**

1100-Inventory	
1330-Plant Materials and Operating Supplies	1,446,227.89
1305-Fuel Stock	4,572.70
1350-Other Materials and Supplies	-
1100-Inventory Total	**1,450,800.59**

1150-Non-Current Assets	
1405-Long Term Investments in Non-Associated Companies	-

1200-Other Assets and Deferred Charges	
1508-Other Regulatory Assets	746,566.82
1518-RCVARetail	205,263.98
1525-Miscellaneous Deferred Debits	53.00
1548-RCVASTR	233,276.36
1550-LV Variance Account	-
1555-Smart Meters Capital Variance Account	(284,010.54)
1556-Smart Meters OM&A Variance Account	(114,657.00)
1562-Deferred Payments in Lieu of Taxes	(1,619,323.59)
1565-Conservation and Demand Management Expenditures and Recoveries	-
1566-CDM Contra Account	-
1570-Qualifying Transition Costs	-
1571-Pre-market Opening Energy Variance	-
1572-Extraordinary Event Costs	-
1580-RSVAWMS	(2,320,305.90)
1582-RSVAONE-TIME	67,613.55
1584-RSVANW	(853,100.30)
1586-RSVACN	(588,708.74)
1588-RSVAPOWER	(2,079,435.08)
1590-Recovery of Regulatory Asset Balances	153,079.77
1200-Other Assets and Deferred Charges Total	**(6,453,687.67)**

1450-Distribution Plant	
1805-Land	133,037.50
1806-Land Rights	-
1808-Buildings and Fixtures	3,934,354.50
1810-Leasehold Improvements	-
1815-Transformer Station Equipment - Normally Primary above 50 kV	
1820-Distribution Station Equipment - Normally Primary below 50 kV	8,099,698.35
1825-Storage Battery Equipment	-
1830-Poles, Towers and Fixtures	21,332,647.50
1835-Overhead Conductors and Devices	24,417,046.11
1840-Underground Conduit	11,847,751.16
1845-Underground Conductors and Devices	15,119,656.80
1850-Line Transformers	23,823,042.51
1855-Services	17,790,622.31
1860-Meters	5,980,066.67
1996-Hydro One Current and Voltage Transformer Upgrades	580,665.31
1450-Distribution Plant Total	**132,477,923.41**

1500-General Plant	
1905-Land	-
1906-Land Rights	-
1908-Buildings and Fixtures	-
1915-Office Furniture and Equipment	1,296,737.89
1920-Computer Equipment - Hardware	2,734,852.95
1925-Computer Software	737,646.38
1930-Transportation Equipment	5,166,733.82
1935-Stores Equipment	63,417.16
1940-Tools, Shop and Garage Equipment	2,288,349.28
1945-Measurement and Testing Equipment	215,524.16
1950-Power Operated Equipment	13,583.39
1955-Communication Equipment	163,391.53
1960-Miscellaneous Equipment	-
1970-Load Management Controls - Customer Premises	-
1980-System Supervisory Equipment	515,151.70
1985-Sentinel Lighting Units	-
1995-Contributions and Grants - Credit	(7,695,359.15)
1500-General Plant Total	**5,500,029.11**

1550-Other Capital Assets	
2055-Construction Work in Progress--Electric	-
2055-Construction Work in Progress--Electric	494,000.00
2060-Electric Plant Acquisition Adjustment	-
2070-Other Utility Plant	-
1550-Other Capital Assets Total	**494,000.00**

1600-Accumulated Amortization	
2105-Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	(76,881,949.11)
2160-Accumulated Amortization of Other Utility Plant	-
1600-Accumulated Amortization Total	**(76,881,949.11)**

Total Assets	**86,431,400.08**

1650-Current Liabilities	
2205-Accounts Payable	6,873,664.21
2208-Customer Credit Balances	893,089.00
2210-Current Portion of Customer Deposits	1,699,387.30
2220-Miscellaneous Current and Accrued Liabilities	1,262,224.51
2240-Accounts Payable to Associated Companies	52,630.28
2250-Debt Retirement Charges(DRC) Payable	589,513.68
2260-Current Portion of Long Term Debt	-
2290-Commodity Taxes	(262,113.00)
2292-Payroll Deductions / Expenses Payable	91,530.30
2294-Accrual for Taxes, Payments in Lieu of Taxes, Etc.	(1,767,361.00)
2296-Future Income Taxes - Current	-
1650-Current Liabilities Total	**9,432,565.28**

1700-Non-Current Liabilities	
2306-Employee Future Benefits	2,043,215.89
2310-Vested Sick Leave Liability	711,788.97
2320-Other Miscellaneous Non-Current Liabilities	306,429.00
2325 - Obligations under capital leases	-
2335-Long Term Customer Deposits	
2350-Future Income Tax - Non-Current	-
2405-Other Regulatory Liabilities	-
2425-Other Deferred Credits	675,422.95
1700-Non-Current Liabilities Total	**3,736,856.81**

1800-Long-Term Debt	
2505-Debentures outstanding - long term debt	-
2550-Advances from Associated Companies	33,490,500.04
1800-Long-Term Debt Total	**33,490,500.04**

1850-Shareholders' Equity	
3005-Common Shares Issued	21,899,072.00
3010-Contributed Surplus	-
3030-Miscellaneous Paid-In Capital	13,032,553.69
3045-Unappropriated Retained Earnings	4,453,808.58
3046-Balance Transferred From Income	386,043.68
3049-Dividends Payable-Common Shares	-
1850-Shareholders' Equity Total	**39,771,477.95**

Total Liabilities & Shareholder's Equity	**86,431,400.08**

Balance Sheet Total	(0.00)

2008 STATEMENT OF INCOME AND RETAINED EARNINGS

Account Description	Total
3000-Sales of Electricity	
4006-Residential Energy Sales	(19,462,189.87)
4010-Commercial Energy Sales	-
4015-Industrial Energy Sales	-
4020-Energy Sales to Large Users	-
4025-Street Lighting Energy Sales	(790,142.78)
4030-Sentinel Lighting Energy Sales	(8,298.41)
4035-General Energy Sales	(39,244,159.57)
4050-Revenue Adjustment	-
4055-Energy Sales for Resale	-
4060-Interdepartmental Energy Sales	(170,000.00)
4062-Billed WMS	(5,767,384.00)
4066-Billed NW	(3,979,641.00)
4068-Billed CN	(3,518,433.00)
3000-Sales of Electricity Total	**(72,940,248.63)**
3050-Revenues From Services - Distirbution	
4080-Distribution Services Revenue	(16,210,197.46)
4082-Retail Services Revenues	(71,800.00)
4084-Service Transaction Requests (STR) Revenues	(3,400.00)
4090-Electric Services Incidental to Energy Sales	
3050-Revenues From Services - Distirbution Total	**(16,285,397.46)**
3100-Other Operating Revenues	
4210-Rent from Electric Property	(436,300.00)
4215-Other Utility Income	-
4220-Other Electric Revenues	(2,521.00)
4225-Late Payment Charges	(282,000.00)
4230-Sales of Water and Water Power	
4235-Miscellaneous Service Revenues	(308,700.00)
4240-Provision for Rate Refunds	-
3100-Other Operating Revenues Total	**(1,029,521.00)**

3150-Other Income & Deductions	
4325-Revenues from Merchandise, Jobbing, Etc.	-
4330-Costs and Expenses of Merchandising, Jobbing, Etc.	-
4355-Gain on Disposition of Utility and Other Property	-
4375-Revenues of Non-Utility Operations	(155,000.00)
4380-Expenses of Non-Utility Operations	83,267.00
4390-Miscellaneous Non-Operating Income	(127,544.00)
4398-Foreign Exchange Gains and Losses, Including Amortization	-
3150-Other Income & Deductions Total	**(199,277.00)**
3200-Investment Income	
4405-Interest and Dividend Income	(439,000.00)
3200-Investment Income Total	**(439,000.00)**
3350-Power Supply Expenses	
4705-Power Purchased	59,674,790.63
4708-Charges-WMS	5,767,384.00
4710-Cost of Power Adjustments	
4714-Charges-NW	3,979,641.00
4715-System Control and Load Dispatching	
4716-Charges-CN	3,518,433.00
4730-Rural Rate Assistance Expense	-
3350-Power Supply Expenses Total	**72,940,248.63**
3500-Distribution Expenses - Operation	
5005-Operation Supervision and Engineering	302,451.77
5010-Load Dispatching	769,838.00
5012-Station Buildings and Fixtures Expense	309,836.40
5014-Transformer Station Equipment - Operation Labour	-
5015-Transformer Station Equipment - Operation Supplies and Expenses	-
5016-Distribution Station Equipment - Operation Labour	-
5017-Distribution Station Equipment - Operation Supplies and Expenses	119,349.60
5020-Overhead Distribution Lines and Feeders - Operation Labour	122,284.00
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	406,621.00
5030-Overhead Subtransmission Feeders - Operation	-
5035-Overhead Distribution Transformers- Operation	88,703.00
5040-Underground Distribution Lines and Feeders - Operation Labour	23,202.00
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	11,653.00
5055-Underground Distribution Transformers - Operation	91,227.00
5065-Meter Expense	485,380.00
5070-Customer Premises - Operation Labour	11,131.00
5075-Customer Premises - Materials and Expenses	11,172.00
5085-Miscellaneous Distribution Expense	-
5095-Overhead Distribution Lines and Feeders - Rental Paid	
5096-Other Rent	-
3500-Distribution Expenses - Operation Total	**2,752,848.77**

3550-Distribution Expenses - Maintenance	
5105-Maintenance Supervision and Engineering	654,104.33
5110-Maintenance of Buildings and Fixtures - Distribution Stations	12,498.59
5114-Maintenance of Distribution Station Equipment	192,696.41
5120-Maintenance of Poles, Towers and Fixtures	165,297.00
5125-Maintenance of Overhead Conductors and Devices	790,769.00
5130-Maintenance of Overhead Services	303,356.00
5135-Overhead Distribution Lines and Feeders - Right of Way	483,555.00
5145-Maintenance of Underground Conduit	17,606.00
5150-Maintenance of Underground Conductors and Devices	128,393.00
5155-Maintenance of Underground Services	146,536.00
5160-Maintenance of Line Transformers	101,256.00
5170-Sentinel Lights - Labour	-
5172-Sentinel Lights - Material & Expenses	-
5175-Maintenance of Meters	-
3550-Distribution Expenses - Maintenance Total	**2,996,067.33**
3650-Billing and Collecting	
5305-Supervision	-
5310-Meter Reading Expense	275,059.00
5315-Customer Billing	1,290,661.90
5320-Collecting	688,411.89
5325-Collecting cash over or short	-
5330-Collection Charges	
5335-Bad Debt Expense	160,000.00
5340-Miscellaneous Customer Accounts Expenses	-
3650-Billing and Collecting Total	**2,414,132.79**
3700-Community Relations	
5405-Supervision	-
5410-Community Relations - Sundry	-
5415-Energy Conservation	58,431.00
5420-Community Safety Program	14,600.00
5510-Demonstrating and Selling Expense	-
5515-Advertising Expense	122,285.00
5520-Miscellaneous Sales Expense	-
3700-Community Relations Total	**195,316.00**

3800-Administrative and General Expenses	
5605-Executive Salaries and Expenses	977,940.00
5610-Management Salaries and Expenses	-
5615-General Administrative Salaries and Expenses	1,173,476.11
5620-Office Supplies and Expenses	193,042.00
5625-Administrative Expense Transferred Credit	-
5630-Outside Services Employed	226,700.00
5635-Property Insurance	37,874.00
5640-Injuries and Damages	297,604.00
5645-Employee Pensions and Benefits	-
5655-Regulatory Expenses	-
5660-General Advertising Expenses	-
5665-Miscellaneous General Expenses	272,750.46
5672-Rent	303,512.00
5675-Maintenance of General Plant	78,218.00
3800-Administrative and General Expenses Total	**3,561,116.57**
3850-Amortization Expense	
5705-Amortization Expense - Property, Plant, and Equipment	4,526,556.88
3850-Amortization Expense Total	**4,526,556.88**
3900-Interest Expense	
6005-Interest on Long Term Debt	50.00
6030-Interest on Debt to Associated Companies	-
6035-Other Interest Expense	256,416.00
6042-Allowance For Other Funds Used During Construction	
3900-Interest Expense Total	**256,466.00**
3950-Taxes Other Than Income Taxes	
6105-Taxes Other Than Income Taxes	165,896.57
3950-Taxes Other Than Income Taxes Total	**165,896.57**
4000-Income Taxes	
6110-Income Taxes	655,911.22
6115-Provision for Future Income Taxes	
4000-Income Taxes Total	**655,911.22**
4100-Extraordinary & Other Items	
6205-Donations	-
6310-Extraordinary Deductions	
4100-Extraordinary & Other Items Total	**-**
Net Income	**(428,883.33)**

APPENDIX B

COPY OF THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC. 2009 PRO FORMA STATEMENTS

THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.
PRO FORMA FINANCIAL STATEMENTS
AT
DECEMBER 31, 2009

2009 BALANCE SHEET

Account Description	Total
1050-Current Assets	
1005-Cash	11,963,680.66
1010-Cash Advances and Working Funds	400.00
1020-Interest Special Deposits	-
1040-Other Special Deposits	-
1100-Customer Accounts Receivable	6,256,397.34
1102-Accounts Receivable - Services	-
1104-Accounts Receivable - Recoverable Work	13,972.56
1105-Accounts Receivable - Merchandise, Jobbing, etc.	-
1110-Other Accounts Receivable	355,243.65
1120-Accrued Utility Revenues	10,899,213.57
1130-Accumulated Provision for Uncollectible Accounts--Credit	(672,398.86)
1140-Interest and Dividends Receivable	47,989.14
1150-Rents Receivable	-
1180-Prepayments	252,261.70
1200-Accounts Receivable from Associated Companies	774,970.84
1210-Notes Receivable from Associated Companies	-
1050-Current Assets Total	**29,891,730.60**
1100-Inventory	
1330-Plant Materials and Operating Supplies	1,475,243.89
1305-Fuel Stock	4,572.70
1350-Other Materials and Supplies	-
1100-Inventory Total	**1,479,816.59**
1150-Non-Current Assets	
1405-Long Term Investments in Non-Associated Companies	-
1410-Other Special or Collateral Funds	-
1460-Other Non-Current Assets	-
1150-Non-Current Assets Total	**-**
1200-Other Assets and Deferred Charges	
1508-Other Regulatory Assets	768,363.82
1518-RCVARetail	262,583.98
1525-Miscellaneous Deferred Debits	98.00
1548-RCVASTR	296,030.36
1550-LV Variance Account	-
1555-Smart Meters Capital Variance Account	(395,995.00)
1556-Smart Meters OM&A Variance Account	(173,746.54)
1562-Deferred Payments in Lieu of Taxes	(1,666,046.59)
1565-Conservation and Demand Management Expenditures and Recoveries	-
1566-CDM Contra Account	-
1570-Qualifying Transition Costs	-
1571-Pre-market Opening Energy Variance	-
1572-Extraordinary Event Costs	-
1580-RSVAWMS	(2,463,643.90)
1582-RSVAONE-TIME	69,624.55
1584-RSVANW	(895,773.30)
1586-RSVACN	(553,132.74)
1588-RSVAPOWER	(2,104,170.08)
1590-Recovery of Regulatory Asset Balances	157,763.77
1200-Other Assets and Deferred Charges Total	**(6,698,043.67)**

1450-Distribution Plant	
1805-Land	133,037.50
1806-Land Rights	-
1808-Buildings and Fixtures	4,029,354.50
1810-Leasehold Improvements	-
1815-Transformer Station Equipment - Normally Primary above 50 kV	
1820-Distribution Station Equipment - Normally Primary below 50 kV	8,099,698.35
1825-Storage Battery Equipment	-
1830-Poles, Towers and Fixtures	22,598,260.43
1835-Overhead Conductors and Devices	26,085,933.21
1840-Underground Conduit	12,177,358.16
1845-Underground Conductors and Devices	16,186,137.79
1850-Line Transformers	24,990,795.32
1855-Services	18,611,502.46
1860-Meters	6,027,260.67
1996-Hydro One Current and Voltage Transformer Upgrades	1,355,872.83
1450-Distribution Plant Total	**138,939,338.39**

1500-General Plant	
1905-Land	-
1906-Land Rights	-
1908-Buildings and Fixtures	-
1915-Office Furniture and Equipment	1,351,787.89
1920-Computer Equipment - Hardware	2,812,162.95
1925-Computer Software	775,496.38
1930-Transportation Equipment	5,695,964.30
1935-Stores Equipment	63,417.16
1940-Tools, Shop and Garage Equipment	2,332,649.28
1945-Measurement and Testing Equipment	221,724.16
1950-Power Operated Equipment	133,583.39
1955-Communication Equipment	163,391.53
1960-Miscellaneous Equipment	-
1970-Load Management Controls - Customer Premises	-
1980-System Supervisory Equipment	515,151.70
1985-Sentinel Lighting Units	-
1995-Contributions and Grants - Credit	(7,570,151.63)
1500-General Plant Total	**6,495,177.11**

1550-Other Capital Assets	
2055-Construction Work in Progress--Electric	-
2055-Construction Work in Progress--Electric	494,000.00
2060-Electric Plant Acquisition Adjustment	-
2070-Other Utility Plant	-
1550-Other Capital Assets Total	**494,000.00**

1600-Accumulated Amortization	
2105-Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	(81,830,062.08)
2160-Accumulated Amortization of Other Utility Plant	-
1600-Accumulated Amortization Total	**(81,830,062.08)**

Total Assets	**88,771,956.94**

1650-Current Liabilities	
2205-Accounts Payable	6,873,719.75
2208-Customer Credit Balances	893,089.00
2210-Current Portion of Customer Deposits	1,699,387.30
2220-Miscellaneous Current and Accrued Liabilities	1,262,224.51
2240-Accounts Payable to Associated Companies	52,630.28
2250-Debt Retirement Charges(DRC) Payable	580,181.68
2260-Current Portion of Long Term Debt	25,034.00
2290-Commodity Taxes	(262,113.00)
2292-Payroll Deductions / Expenses Payable	91,530.30
2294-Accrual for Taxes, Payments in Lieu of Taxes, Etc.	(1,767,361.00)
2296-Future Income Taxes - Current	-
1650-Current Liabilities Total	**9,448,322.82**

1700-Non-Current Liabilities	
2306-Employee Future Benefits	2,177,336.44
2310-Vested Sick Leave Liability	666,341.42
2320-Other Miscellaneous Non-Current Liabilities	251,923.00
2325 - Obligations under capital leases	-
2335-Long Term Customer Deposits	
2350-Future Income Tax - Non-Current	-
2405-Other Regulatory Liabilities	-
2425-Other Deferred Credits	675,422.95
1700-Non-Current Liabilities Total	**3,771,023.81**

1800-Long-Term Debt	
2505-Debentures outstanding - long term debt	1,153,142.00
2550-Advances from Associated Companies	33,490,500.04
1800-Long-Term Debt Total	**34,643,642.04**

1850-Shareholders' Equity	
3005-Common Shares Issued	21,899,072.00
3010-Contributed Surplus	-
3030-Miscellaneous Paid-In Capital	13,032,553.69
3045-Unappropriated Retained Earnings	4,911,226.54
3046-Balance Transferred From Income	1,066,116.04
3049-Dividends Payable-Common Shares	-
1850-Shareholders' Equity Total	**40,908,968.27**

Total Liabilities & Shareholder's Equity	**88,771,956.94**

Balance Sheet Total	0.00

2009 STATEMENT OF INCOME AND RETAINED EARNINGS

Account Description	Total
3000-Sales of Electricity	
4006-Residential Energy Sales	(19,510,448.46)
4010-Commercial Energy Sales	-
4015-Industrial Energy Sales	-
4020-Energy Sales to Large Users	-
4025-Street Lighting Energy Sales	(792,102.02)
4030-Sentinel Lighting Energy Sales	(8,910.10)
4035-General Energy Sales	(39,330,891.20)
4050-Revenue Adjustment	-
4055-Energy Sales for Resale	-
4060-Interdepartmental Energy Sales	(181,000.00)
4062-Billed WMS	(5,781,742.00)
4066-Billed NW	(3,989,549.00)
4068-Billed CN	(3,527,192.00)
3000-Sales of Electricity Total	**(73,121,834.78)**
3050-Revenues From Services - Distirbution	
4080-Distribution Services Revenue	(17,650,437.60)
4082-Retail Services Revenues	(71,800.00)
4084-Service Transaction Requests (STR) Revenues	(3,400.00)
4090-Electric Services Incidental to Energy Sales	
3050-Revenues From Services - Distirbution Total	**(17,725,637.60)**
3100-Other Operating Revenues	
4210-Rent from Electric Property	(436,300.00)
4215-Other Utility Income	-
4220-Other Electric Revenues	(2,710.00)
4225-Late Payment Charges	(282,000.00)
4230-Sales of Water and Water Power	
4235-Miscellaneous Service Revenues	(308,700.00)
4240-Provision for Rate Refunds	-
3100-Other Operating Revenues Total	**(1,029,710.00)**
3150-Other Income & Deductions	
4325-Revenues from Merchandise, Jobbing, Etc.	-
4330-Costs and Expenses of Merchandising, Jobbing, Etc.	-
4355-Gain on Disposition of Utility and Other Property	-
4375-Revenues of Non-Utility Operations	(25,000.00)
4380-Expenses of Non-Utility Operations	18,114.00
4390-Miscellaneous Non-Operating Income	(120,494.00)
4398-Foreign Exchange Gains and Losses, Including Amortization	-
3150-Other Income & Deductions Total	**(127,380.00)**

3200-Investment Income	
4405-Interest and Dividend Income	(439,000.00)
3200-Investment Income Total	**(439,000.00)**
3350-Power Supply Expenses	
4705-Power Purchased	59,823,351.78
4708-Charges-WMS	5,781,742.00
4710-Cost of Power Adjustments	
4714-Charges-NW	3,989,549.00
4715-System Control and Load Dispatching	
4716-Charges-CN	3,527,192.00
4730-Rural Rate Assistance Expense	-
3350-Power Supply Expenses Total	**73,121,834.78**
3500-Distribution Expenses - Operation	
5005-Operation Supervision and Engineering	264,373.28
5010-Load Dispatching	816,699.00
5012-Station Buildings and Fixtures Expense	309,836.40
5014-Transformer Station Equipment - Operation Labour	-
5015-Transformer Station Equipment - Operation Supplies and Expenses	-
5016-Distribution Station Equipment - Operation Labour	-
5017-Distribution Station Equipment - Operation Supplies and Expenses	93,129.60
5020-Overhead Distribution Lines and Feeders - Operation Labour	106,084.00
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	414,815.00
5030-Overhead Subtransmission Feeders - Operation	-
5035-Overhead Distribution Transformers- Operation	341,548.00
5040-Underground Distribution Lines and Feeders - Operation Labour	10,287.00
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	5,809.00
5055-Underground Distribution Transformers - Operation	71,865.00
5065-Meter Expense	544,081.00
5070-Customer Premises - Operation Labour	8,773.00
5075-Customer Premises - Materials and Expenses	37,465.00
5085-Miscellaneous Distribution Expense	-
5095-Overhead Distribution Lines and Feeders - Rental Paid	
5096-Other Rent	-
3500-Distribution Expenses - Operation Total	**3,024,765.28**

3550-Distribution Expenses - Maintenance	
5105-Maintenance Supervision and Engineering	548,396.26
5110-Maintenance of Buildings and Fixtures - Distribution Stations	12,498.59
5114-Maintenance of Distribution Station Equipment	286,238.41
5120-Maintenance of Poles, Towers and Fixtures	133,991.00
5125-Maintenance of Overhead Conductors and Devices	686,177.00
5130-Maintenance of Overhead Services	344,777.00
5135-Overhead Distribution Lines and Feeders - Right of Way	716,115.00
5145-Maintenance of Underground Conduit	17,669.00
5150-Maintenance of Underground Conductors and Devices	164,495.00
5155-Maintenance of Underground Services	74,510.00
5160-Maintenance of Line Transformers	64,866.00
5170-Sentinel Lights - Labour	-
5172-Sentinel Lights - Material & Expenses	-
5175-Maintenance of Meters	-
3550-Distribution Expenses - Maintenance Total	**3,049,733.26**
3650-Billing and Collecting	
5305-Supervision	-
5310-Meter Reading Expense	281,316.00
5315-Customer Billing	1,271,382.19
5320-Collecting	679,307.84
5325-Collecting cash over or short	
5330-Collection Charges	
5335-Bad Debt Expense	160,000.00
5340-Miscellaneous Customer Accounts Expenses	-
3650-Billing and Collecting Total	**2,392,006.03**
3700-Community Relations	
5405-Supervision	-
5410-Community Relations - Sundry	-
5415-Energy Conservation	78,732.00
5420-Community Safety Program	14,892.00
5510-Demonstrating and Selling Expense	-
5515-Advertising Expense	134,715.00
5520-Miscellaneous Sales Expense	-
3700-Community Relations Total	**228,339.00**

3800-Administrative and General Expenses	
5605-Executive Salaries and Expenses	966,552.00
5610-Management Salaries and Expenses	-
5615-General Administrative Salaries and Expenses	1,258,112.43
5620-Office Supplies and Expenses	191,768.00
5625-Administrative Expense Transferred Credit	-
5630-Outside Services Employed	239,149.00
5635-Property Insurance	32,550.00
5640-Injuries and Damages	315,652.00
5645-Employee Pensions and Benefits	-
5655-Regulatory Expenses	-
5660-General Advertising Expenses	-
5665-Miscellaneous General Expenses	258,406.00
5672-Rent	308,288.00
5675-Maintenance of General Plant	75,643.00
3800-Administrative and General Expenses Total	**3,646,120.43**
3850-Amortization Expense	
5705-Amortization Expense - Property, Plant, and Equipment	4,573,435.70
3850-Amortization Expense Total	**4,573,435.70**
3900-Interest Expense	
6005-Interest on Long Term Debt	57,481.00
6030-Interest on Debt to Associated Companies	-
6035-Other Interest Expense	313,593.00
6042-Allowance For Other Funds Used During Construction	
3900-Interest Expense Total	**371,074.00**
3950-Taxes Other Than Income Taxes	
6105-Taxes Other Than Income Taxes	169,466.13
3950-Taxes Other Than Income Taxes Total	**169,466.13**
4000-Income Taxes	
6110-Income Taxes	800,671.73
6115-Provision for Future Income Taxes	
4000-Income Taxes Total	**800,671.73**
4100-Extraordinary & Other Items	
6205-Donations	-
6310-Extraordinary Deductions	
4100-Extraordinary & Other Items Total	**-**
Net Income	**(1,066,116.04)**

RECONCILIATION BETWEEN FINANCIAL STATEMENTS AND FINANCIAL RESULTS FILED:

The following table reconciles the 2007 Audited Financial Statements to the regulatory financial results filed in this Application.

2007 Net Income Reconciliation		
		2007
Net Income - per TBH Audited Financial Statements		**$ 294,975**
Add Non-Wires: Sentinel Lighting Expenses	8,190	
Deduct: Smart Meter Cost Deferrals	(5,925)	
	2,265	2,265
Net Income - per OEB Filing		**$ 297,240**

PROPOSED ACCOUNTING TREATMENT FOR PROJECTS WITH A PROJECT LIFE CYCLE GREATER THAN ONE YEAR:

Thunder Bay Hydro does not include the cost of funds in the capital cost of projects as very few projects require more than one year for completion.

INFORMATION ON PARENT AND SUBSIDIARIES

The Thunder Bay Hydro Corporation 2007 Annual Report, which describes the activities and consolidated financial results of Thunder Bay Hydro's group of companies is included in Appendix A to this schedule.

A more detailed description of the group of companies is set out in Exhibit 1, Tab 1, Schedule 13 (Corporate Entities Relationships Chart).

Thunder Bay Hydro advises that it does not prepare a Management Discussion and Analysis ("MD&A") Report.

APPENDIX A

COPY OF THUNDER BAY HYDRO CORPORATION 2007 ANNUAL REPORT

2007 ANNUAL REPORT

THUNDER BAY HYDRO

ABOUT THUNDER BAY HYDRO



Thunder Bay Hydro distributes electricity to over 49,000 customers via a network of over 1,300 kilometers (815 miles) of overhead and underground power lines - that's almost the distance between here and Toronto!

The energy to do all of this comes from our staff of 128* employees.
Thunder Bay Hydro is responsible for the electrical distribution system within the city limits of Thunder Bay which delivers electricity to homes and businesses.

We plan and maintain the local power line system and provide 24-hour emergency response to power outages. We also answer billing questions, provide for the reading of meters and offer energy conservation advice and programs.

* staffing as of December 31, 2007

OUR CORPORATE STRATEGY

Ensure that the Health and Safety of our Employees and Public is the utility's first priority.

The potential danger associated with the product we work with everyday cannot be overstated. It is critical that the utility's primary focus remain on the safety of our operations.

Provide a reliable supply of electricity to the residents and businesses of Thunder Bay.

The provision of electricity to the residents and businesses of Thunder Bay is our reason for existence and is critical to the economy of the City and the quality of life of its citizens.

Protect and grow the value of the utility to our Shareholder.

Thunder Bay Hydro is a valuable asset, owned by the City of Thunder Bay. The owner has the right to expect that the value of this asset will increase. The Board and Management of the utility must make this growth a priority.

Our programs are the foundation to fulfill these mandates

A MESSAGE FROM THE PRESIDENT AND THE CHAIR OF THE BOARD OF DIRECTORS

Two thousand and seven has been a year of challenges and opportunities for Thunder Bay Hydro.

At the Board level, the directors have been working to strengthen the principles of good corporate governance during this crucial time of transition within the industry. This included planning a day-long Board Governance workshop aimed at learning best practices to strengthen Board Governance of the Thunder Bay Hydro Corporation and its affiliate companies, as well as identifying opportunities for improvement. The issue of governance was regularly addressed during Board meetings and we are committed to continuing the process in the year to come.

At the provincial level, 2007 saw the Liberal party returned to power. As such, many of their energy-related policies will continue to be promoted. Their priorities include ensuring long-term adequacy of generation capacity and the development of a *Conservation Culture* in Ontario to ensure people use the limited resources wisely in the future.

A significant development in supporting generation capacity was the development of the Integrated Power System Plan (IPSP). This is the first comprehensive, long-term supply/demand plan for Ontario since the Ontario Hydro days. It has direct impact on our company through the growing importance of the connection of small renewable generation sources. The resulting increase in interest from renewable generators requires us to assess potential projects and work with generators to safely and reliably connect them to our distribution system.

We have managed to maintain a strong health and safety culture, hold the line on costs, and continue to meet or even exceed the service indicator standards of the province.

Our own development of the John Street Landfill generation project which will turn environmentally harmful methane gas into electricity is ongoing. In 2007, our work included the milestones of receiving an OEB Generator's License and entering into 20-year Power Purchase agreement with the OPA.

The regulatory and reporting requirements of our industry continue to place a significant burden on our organization and the industry as a whole. Yet, as a local distribution company in a fairly isolated area with a position of diminishing electricity demand, we have managed to maintain a strong health and safety culture, hold the line on costs, and continue to meet or even exceed the service indicator standards of the province. This, in turn, has ultimately enhanced our ability to meet our long term corporate goals outlined at the front of this report.

For example, the OEB is continuing to turn its attention to measuring and comparing the performance of LDC's under a Performance Based Regulation scheme. Our staff anticipated this in previous years and went through the hard work of expense reduction over the past several years. This has paid off. Our costs compare well to similar LDC's in the Province – an ongoing challenge given the rugged terrain of much of our service territory and our geographic location.

Our strong commitment to Health and Safety resulted in some noteworthy highlights. We saw an outstanding record set during 2007 with zero lost time incidents over the course of the entire year. By December 31, 2007 we had worked 630 days in total without a lost time incident.

We continued efforts to improve our Health & Safety system, with a priority on building on our 2006 Bronze certification by reaching closer to a Silver certification level during the year. We also were recognized with the Electrical & Utility

Safety Association President's Award for 250,000 hours without a lost time incident achieved June 15, 2007.



Robert Mace, President Ralph Falcioni, Chair

You will see that our company has produced good financial results for 2007 despite continued weakness in the local economy. A continued focus on LDC expense management along with consistent performance from the competitive affiliate companies contributed to these results.

A combination of the Rate Minimization Philosophy established by the Shareholder and our ongoing commitment to expense management allows us to continue to offer electricity costs that are among the lowest in the Province. In 2007, the average Thunder Bay Hydro residential customer paid a total bill for electricity use that was lower than those paid to 87% of the LDC's in Ontario.

Over the past year we were able to continue with our priority of completing a thorough evaluation of the condition of our distribution system and to continue work on our 20-year Capital Investment plan. Over the past several years, increased costs associated with regulatory requirements, changes to the market and new legislation have squeezed resources available for distribution system replacement.

Late in 2007, our Board approved a $1 million increase for 2008 in funds allocated to distribution system replacement as part of our ongoing commitment to maintaining a robust, reliable distribution system to serve our community.

Thunder Bay Hydro's conservation program delivery has continued to bring a *Conservation Culture* to Thunder Bay residents and businesses. By the end of 2007, we had delivered more than $1.6 million in programs to our customers over a three-year period. This included supporting Project Porchlight to deliver CFLs to city households, completion of the conversion of city traffic lights to LED bulbs, and the conversion of lighting in city businesses.

The Provincial Smart Metering initiative continues to move ahead slowly in Ontario. We are working with a consortium of 17 other LDC's to select an Automatic Meter Infrastructure (AMI) vendor. It is expected that a Board decision on Smart Meter implementation will be made later in 2008.

Ultimately, our 2007 achievements demonstrate our commitment to Safety, Reliability, and Shareholder Value. The could not have been achieved without the diligent work of our other board members, David O'Brien, Lawrence Timko, Councillor Mark Bentz, and Councillor Trevor Giertuga and a concerted effort from all management and individual staff members.

Our thanks go out to them for a successful year of operation.

Respectfully submitted,

Ralph Falcioni, Chair Robert Mace, President

SUPPORTING OUR CORPORATE GOALS

In order to support our corporate goals, we have developed and implemented multi-year plans to address these areas:

- Health and Safety
- Asset Management
- Cost Management
- Information Systems Strategy
- Non-Distribution Revenue Growth
- Conservation Strategy
- Distribution Business Growth Strategy
- Succession Planning



A LOOK AT THE CHALLENGES AND OPPORTUNITIES

Local Market

Over the past ten years, Thunder Bay Hydro customer growth has been very slight, averaging a .5% annual increase in the number of customers. The total number of business class customers, however, has seen a drop of 4% in the past year.

Although an accurate prediction of future economic performance is difficult, it would appear that a 'best case' scenario over the next few years would be a relatively flat economy.

Demographics

Turnover of experienced employees is beginning. Retirement of 'baby boomers' will result in shortages of those working in skilled trades.

The impending concern of ensuring long-term sustainability of critical utility skills is a cross-province issue.

Competition for trades, engineering, regulatory and experienced management is rapidly increasing. As a result, attracting and retaining these staff will present an increased challenge.

Aging Infrastructure

Aging infrastructure is an industry-wide issue.

The provision of electricity is our reason for existence and is critical to the economy of the City as well as the quality of life of its residents. As the equipment we use ages, it must be replaced and is best upgraded to meet modern needs.

Smart Meters

The provincial Smart Meter initiative is slowed while awaiting appropriate legislation. Many US locations are poised to move in this direction which may restrict access to limited technology resources.

Promotion of a Conservation Culture

The province has been promoting a conservation culture through a variety of agencies and programs.

The OPA has begun to offer a standard slate of conservation programs with funding and marketing support.

IPSP

The Integrated Power System Plan has been established by the Ontario Power Authority to meet the long-term electricity needs of Ontario. The Standard Offer Program promotes renewable generation.

A LOOK AT SOME OF THE PROGRAMS WE ARE IMPLEMENTING

Seeking to Grow Revenue

In order to protect our value to our shareholder, we have developed and implemented multi-year plans for achieving resource efficiency while maintaining a customer service focus.

Moving forward with our affiliate company to generate power at the local landfill and offering billing services to regional utilities are strategies that will continue to enhance our value to the shareholder.

Health and Safety Culture

The Target Zero program has been an indisputable success for the utility since its introduction and we have supported this program by ensuring awareness and competency regarding safe work practices in everything we do.



Recruitment and Retention

Our Human Resources department is looking at the way we market ourselves to potential employees as well as how our work environment can become more attractive. This means ensuring that we have a fulfilling, fair, and challenging work environment that allows us to attract, develop, engage and retain high quality staff. These strategies will need to be augmented by specific initiatives to place us in an ideal position to attract future staff.

The 'talent war' is very real and will continue to intensify within the industry and throughout North America. In 2007, we began the marketing of trades and technical work related to our industry directly to high school students.

Asset Management

In order to ensure the continuing performance of reliable electrical service, a well-developed, long-term approach to infrastructure investment and maintenance is critical. A twenty-year capital expenditure and operating and maintenance growth plan is being established.

The goal of beginning with a three-year plan was successfully achieved in 2007. The objective of creating a further ten-year plan is being pursued in 2008.

In 2007, the Board approved a 22% increase (or $1 million) in capital expenditures to go toward projects slated for 2008.

Smart Meter Implementation

Ultimately, this will become a $6-10 million investment. Our work with the Smart Meter consortium has allowed us to take the time to hire a qualified consultant and agree on consistent standards that will save us time and money in the longer term.

We are also taking the position of standing back and choosing not to be the leading edge implementers. This way we can learn from others and execute our work in the most cost-effective way.

Conservation Programs

In 2007, we wrapped up our three-year 1.6 million dollar expenditure on local programs which included CFL giveaways, appliance rebate program, and parking lot control purchase incentives. We completed our traffic LED light conversion program.

Additionally, we participated in three OPA programs for summer focused electricity load reduction, retirement of older appliances and business retrofit incentives.

Generation of Electricity

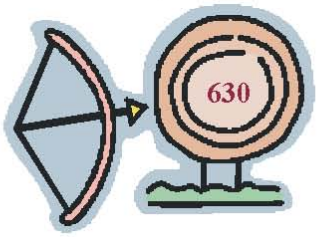
In partnership with the city, we did preparation work for the John St. Landfill Generation Project. In November 2007, we received our OEB Generator's licence and signed the OPA Stand Offer Contract. We have also filed an application for the Certificate of Approval (Co of A) (Air) with the Ministry of Environment.

OUR PERFORMANCE

Health & Safety

As of December 31, 2007 we had achieved 630 days without a lost time incident.

For the period of April 9, 2006 to June 15, 2007, we qualified for the EUSA President's Award which celebrates 250,000 hours without a lost time incident.



Workplace Recognition and Rewards were implemented with staff and assisted with the development of a database to track the points.

As well, we sponsored Threads of Life and Smart Risk Heroes in the community.

Asset Management Projects

- Vickers Street Area Conversion to 25kV
- Hardisty Street Line Relocation and Conversion to 25 kV
- Grey Cres Area Conversion to 25kV
- Frankwood St Area Conversion to 25kV
- Tarbutt St Area Conversion to 25kV
- Harbour Terrace Underground Replacement

CONSERVATION AND DEMAND MANAGEMENT

City residents and businesses were offered a variety of incentives to conserve and reduce their electricity load.

Through Project Porchlight over 30,000 compact fluorescent lamps were distributed.

Twenty-seven intersections were converted to LED traffic lights.

Thirteen commercial customers upgraded old lighting systems to new energy efficient lighting systems receiving over $9500 in incentives.

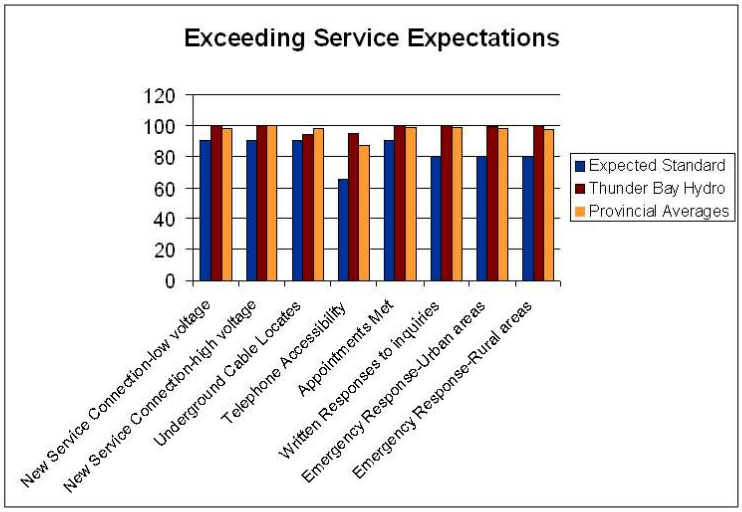
Over $10,000 in rebates were awarded for the purchase of more than $177,000 in Energy Star Clothes Washers or refrigerators.

Commercial customers received 142 rebates for Intelligent Parking Lot Plugs for city business lots.

We exchanged and recycled 400 strings of old incandescent Christmas lights and substituted Seasonal LED's for local residents.

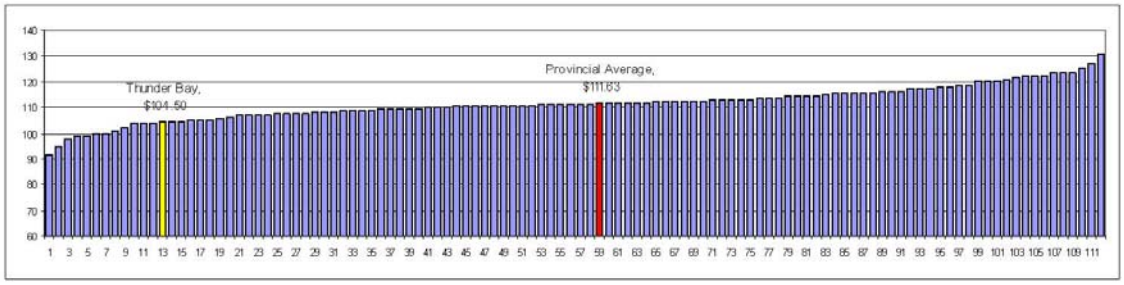
We also worked with the OPA to locally deliver three programs:

In the Great Refrigerator Roundup, 603 refrigerators, 154 freezers and 4 window air conditioners were removed from the grid. Over $139,000 in rebates were credited to 10,802 qualifying customers who reduced energy by 10% during the 10/10 Summer Savings. Fifteen commercial customers applied for $33,000 in incentives for work to be completed in 2008 using the Electricity Retrofit program.



FINANCIAL PICTURE

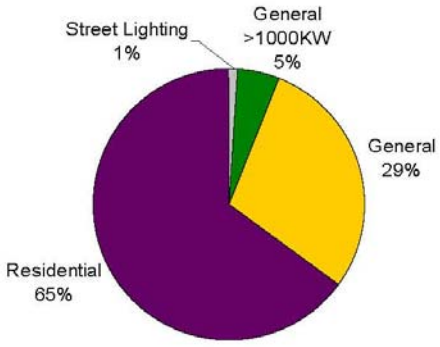
On average, our customers pay less than at other provincial utilities.
Based on a typical residence using 1000 kWh in a month.



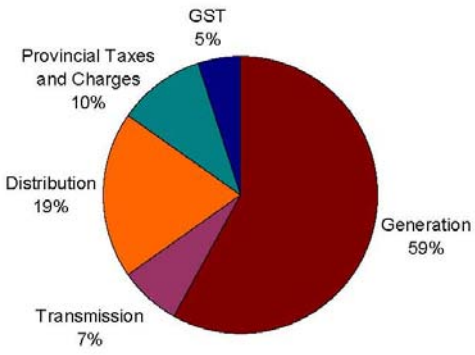
Our Customers	
Residential	44,460
Gen Service	4942
Gen Service >1000	19
Total customers as of Dec 31, 2007	49,421

Financial Highlights for 2007	
Total Revenue	$19,489,510
Total Expenses	$17,908,767
Earnings before taxes	$1,580,743
Payment in lieu of taxes	$891,700
Earnings for the year	$689,043

2007 Distribution Revenues



Where $1 of Electricity Cost Goes



LOOKING TO THE FUTURE

Capital Plan

Significant infrastructure projects in the Tarbutt Street, Rockwood Avenue, Hill Street and County Park areas are taking place.

Long-term plans include investing at a higher level to sustain our ongoing commitment to maintaining a robust, reliable distribution system to serve our community.

Rates

For the first time, our industry is working on a new process to establish distribution rates for a three-year cycle.

The planning for this application is critical in establishing accurate distribution rates to fund appropriate capital investment, ongoing operating requirements and support a proactive response to our imminent Human Resources challenges.

Generation

We anticipate a commissioning of the John Street Landfill Generation Project in the latter half of 2009.

Conservation

We will continue to support the objective of creating a *Conservation Culture* within the province. We will work with the province to ensure that marketing delivered locally is geared to our northern audience.

Smart Metering

We will continue the process of selecting a vendor and formalize a plan to start the implementation of Advanced Metering Infrastructure in the next year. We anticipate having this plan approved by our Board and the regulator by the end of the current year.

Ongoing

The goals of organizational efficiency and the safety of our employees and residents will continue to be part of our ongoing planning.



CONTACTS

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Superintendent Design, Construction and Asset Management
Hydro One Remote Communities Inc.

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Exhibit	Tab	Schedule	Appendix	Contents
2 – Rate Base				
	1			**Overview**
		1		Rate Base Overview
		2		Rate Base Variance Analysis
	2			**Gross Assets – Property, Plant and Equipment Accumulated Depreciation**
		1		Continuity Statements
		2		Gross Assets Table
		3		Variance Analysis on Gross Assets
		4		Accumulated Depreciation Table
		5		Variance Analysis on Accumulated Depreciation
	3			**Capital Budget**
		1		Overview and Capital Budget by Project
			A	Historical Review of Capital Expenditures
			B	Copy of Thunder Bay Hydro's Business Case Reviews – 2008 "Part B" Capital Projects
			C	Copy of Thunder Bay Hydro's Business Case Reviews – 2009 "Part B" Capital Projects/"Part C" Capital Purchases
		2		Capital Contributions
		3		Capitalization Policy
		4		Working Capital Calculation

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 2009 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 rate base calculation excludes any non-distribution assets. Controllable expenses include operations and maintenance, billing and collecting and administration expenses.

Thunder Bay Hydro has provided its rate base calculations for the years 2006 Board Approved, 2006 Actual, 2007 Actual, 2008 Bridge Year and 2009 Test Year as shown at Schedule 2, in Table 1 (Rate Base Summary). The 2009 rate base is $75,169,648.

Thunder Bay 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 Bridge Year and 2009 Test Year in Table 2, below.

Table 1

Summary of Rate Base

Description	2006 OEB Approved	2006 Actual	2007 Actual Year	2008 Bridge Year	2009 Test Year
Gross Fixed Assets	117,366,079	128,359,838	132,593,627	137,977,953	145,434,516
Accumulated Depreciation	58,223,541	68,017,440	71,981,194	76,881,949	81,830,062
Net Book Value	59,142,538	60,342,398	60,612,433	61,096,003	63,604,453
Average Net Book Value	59,043,741	59,643,671	60,477,415	60,854,218	62,350,228
Working Capital *	80,701,290	80,899,106	85,177,351	84,859,730	85,462,799
Working Capital Allowance	12,105,193	12,134,866	12,776,603	12,728,960	12,819,420
Rate Base	71,148,934	71,778,537	73,254,018	73,583,178	75,169,648

* In completing this cost of service application, a classification error was noted in the 2006 OEB Approved working capital. The $548,438 incorrectly included as part of the working capital has been adjusted, as well as the resulting rate base.

Table 2

Summary of Working Capital Calculation

Description	2006 OEB Approved	2006 Actual	2007 Actual Year	2008 Bridge Year	2009 Test Year
Cost of Power	70,198,553	69,890,867	73,125,717	72,940,249	73,121,835
Operations	2,011,898	2,713,521	2,784,785	2,752,849	3,024,765
Maintenance	2,977,751	2,650,405	3,271,159	2,996,067	3,049,733
Billing & Collecting	2,432,919	2,284,014	2,286,306	2,414,133	2,392,006
Community Relations	169,039	547,031	502,544	195,316	228,339
Administration & General Expense	2,911,130	2,813,268	3,206,840	3,561,117	3,646,120
Property Taxes	0	0	0	0	0
Working Capital	80,701,290	80,899,106	85,177,351	84,859,730	85,462,799

Thunder Bay Hydro's Distribution System

Thunder Bay Hydro owns and operates the electricity distribution system in its licensed service area in the City of Thunder Bay and the Fort William First Nation Reserve serving approximately 49,500 Residential, General Service, and unmetered scattered load customers.

Thunder Bay Hydro is supplied through the Hydro One transmission system at voltages of 115 kV and 230 kV. Electricity is then distributed through urban/rural service area of 55/326 square kilometres over 231 kilometres of underground cable and 929 kilometres of overhead cable and 19,410 poles. Thunder Bay Hydro owns 19 distribution sub-stations stepping voltage down to 4 kV and 12 kV. Voltage is further stepped down in order to supply individual customers though approximately 6,900 transformers.

Thunder Bay Hydro monitors its distribution system through the control centre and operates the Supervisory Control and Data Acquisition ("SCADA") systems twenty-four hours a day, seven days a week.

Thunder Bay Hydro owns and maintains approximately 50,000 meters installed on its customers' premises for the purpose of measuring consumption of electricity for billing purposes. Meters vary in type by customer and include meters capable of measuring kWh consumption, kW and kVA demand, as well as hourly interval data. The corporation anticipates installing smart meters in collaboration with the province of Ontario's Smart Meter Initiative. Thunder Bay Hydro will have a total of 49,100 smart meters in place by the end of 2009. These meters are capable of measuring the quantity and time of day (time-of-use) electricity that the customer uses.

Thunder Bay Hydro's Smart Meter program and requested recovery are addressed in greater detail in Exhibit 2, Tab 3, Schedule 1.

In managing its distribution system assets, Thunder Bay Hydro's main objective is to optimize performance of the assets at a reasonable cost with due regard for system reliability, safety, and customer service requirements.

Asset Management Program

The development of a detailed risk assessment, 20-year capital plan, and maintenance plans are an imperative part of Thunder Bay Hydro's AMP. Effective work execution, as well as ongoing strategy development and enhancement, are important aspects in ensuring overall effectiveness of its capital and maintenance programs.

Thunder Bay Hydro's AMP has largely followed the methodology of PAS 55 a publicly available standard outlining best practices. This standard is organized into five key areas:

1. Policy and Strategy;
2. Information Systems, Risk Assessments and Planning;
3. Implementation and Operation;
4. Checking and Corrective Action; and
5. Management Review and Continual Improvement.

Asset management is implemented at Thunder Bay Hydro utilizing a systematic approach and imploring best practices. The overall program utilizes an Asset Management Strategy (AMS) as its foundation directing all initiatives and programs. This is the basis for the entire AMP. Next

Asset Risk Assessments (ARAs) are performed which drive both the Capital and Maintenance Programs which are the outputs of the AMP. Lastly Key Performance Indicators (KPIs) measure the success of the program's results and provide feedback on what corrective actions are required.

Policy and Strategy

It is imperative that the AMS align with the Corporate Strategic Plan to ensure sustainability of the AMP. Asset management makes up a large portion of our overall corporate strategy document ensuring support for it in the short and long term.

Safety of its employees and the public is a first priority at Thunder Bay Hydro and we will endeavor to ensure that safety is never compromised while designing, constructing, operating or maintaining our assets. Thunder Bay Hydro is committed to continual improvement of its processes ensuring value to both its shareholders and its customers while developing and adopting best industry practices within its AMP. Thunder Bay Hydro will ensure compliance of its programs with its regulators and all legal obligations.

The fundamental objective of the AMP at Thunder Bay Hydro is to sustain the asset base at the lowest possible life cycle cost while focusing on the following strategic objectives:

- Addressing significant health & safety issues;
- Addressing significant environmental risks;
- Regulatory and legal obligations;
- Completing customer demand work;
- Replacing end-of-life equipment; and
- Improving operational efficiency.

Having such a list of strategic objectives in order of priorities allows staff at all levels to make decisions that align with the direction of the AMP and ultimately the Corporate Strategic Plan.

The AMS is largely driven by risk mitigation because we can't immediately address every issue. The overall AMS within Thunder Bay Hydro's capital replacement and maintenance programs consists of the following initiatives:

- Wood pin removal;
- Porcelain LA replacement;
- Restricted conductor removal;
- Porcelain post standoff replacement;
- Replacement of end of life poles;
- PCB removal;
- Protective co-ordinations implementation;
- Conversion of 4kV to 25kV;
- Transformer substation removal; and
- Underground subdivision network replacement.

A strategic direction change was a reduction in small like-for-like replacement projects with an increase in larger scale rebuilds. This is a requirement due to the age of the system being such that small replacements are no longer effective in managing the assets and large scale rebuilds are required. This allows for more effective capital utilization given the economies of scale. This also allows the option of voltage conversions during rebuilds whereby lower voltage networks can be eliminated along with the need for the associated substation for little to no additional cost. This ultimately reduces line and stations losses while removing the liability of the substation.

An increased focus has been placed on the replacement of the overhead lines and underground cables to address the significant amount of end of life infrastructure operating at 4kV. Within Thunder Bay Hydro's 25/4kV substations there has been an increased focus on maintenance activities such that many of these assets can remain in service safely until they are no longer needed as a result of our line rebuilds.

A 20 year time horizon for the plan was selected because this allows for a complete view of Thunder Bay Hydro's asset replacements. This avoids knee jerk reactions and allows for more effective planning and coordination of assets. A 20 year view will raise issues not evident from a

shorter time horizon and also allows for effective system planning utilizing new technology that a shorter planning horizon does not. A 20 year Capital Plan will also facilitate prioritization of many long term initiatives. The budgetary estimates in the early years of the capital plan are based on preliminary engineering designs and are the basis for the 3-year capital budget projections. For the most part, cost estimates in later years are based on historical per unit costs applied to the predetermined scopes for each project.

Strategically the replacement capital spending in 2007 was maintained at historical levels below the sustaining capital level, recognizing the system risk assessments indicated an elevated amount of capital replacements was required. This was deliberate, anticipating process improvements would enhance the efficiencies of our capital execution. It was anticipated that once all improvements were in place Thunder Bay Hydro's capital work execution efficiency would approach or exceed industry levels demonstrating sound planning and work practices. The capital expenditures were not increased until 2008 to address the aging infrastructure when it was felt that our capital replacement program efficiencies were at least as good as Ontario wide best practice utility levels. Thunder Bay Hydro presently anticipates its large scale capital replacement projects will compare favourably with other like utilities in Ontario.

Information Systems, Risk Assessments and Planning

Thunder Bay Hydro opted to not purchase Asset Management software due to its size, and scale making it cost prohibitive to do so. However, a database of projects was developed which allows for effective management of its assets. All projects are listed in a central repository and include a problem statement, scope of work, cost of project, justification and evaluation of the project. Projects are ranked, evaluated and stored within the tool developed.

Thunder Bay Hydro does utilize an enterprise software system for its financial, work order, work flow and material management. Thunder Bay Hydro is presently working on developing its maintenance program within that system such that all maintenance work orders will automatically be generated as required to be executed.

Managing risk is a paramount requirement of the LDC business today. It is important to consider all types of risks that the utility is exposed to and ensure all significant risk types are managed effectively. In order to do this requires that a systematic approach be employed in the development and execution of risk assessments.

In order to manage risk effectively Thunder Bay Hydro must know in detail:

- Risk exposure at each asset
- Condition of each asset
- Operational data for each asset
- Location of each asset
- Anticipated life expectancy of each asset.

In support of developing a systematic approach to building a 20-year capital plan, as well as providing information for its maintenance plan, Thunder Bay Hydro developed WHOLE risk assessment tools for overhead lines, underground cables, and substations. These tools help us identify where our risks in the system exist, prioritize our greatest risks, and ensure they are addressed first. WHOLE represents all the aspects considered in performing the risk assessments. In 2007, risk assessments were completed for all Thunder Bay Hydro overhead lines, underground equipment, cables and substations. These assessments entailed inspecting each and every asset and performing a written inspection of each asset where the inspection tool allowed the user to evaluate the risk effectively in each specific location.

Utilizing detailed and system wide risk assessments to prioritize capital replacement projects provides a systematic approach to selecting which projects are executed and when, and ensures that the projects with the greatest need are executed first. This also ensures that all the issues are known about and dealt with in a prudent manner. Moving forward, Thunder Bay Hydro will continue to use risk assessments to determine where plant most needs to be replaced due to risk to the public or its workers.

Thunder Bay Hydro's Risk assessments are detailed inspections carried out every three years that require a visit to each asset, by skilled staff with asset knowledge, looking at all types of risk and utilizing risk management tools. The Risk Assessments completed by Thunder Bay Hydro

ensured that a detailed inventory was completed whereby the overhead lines, underground cables and substations were all assessed separately. Risk assessments are also imperative in understanding risks, providing justification for initiatives and useful in managing the risks of a "spread out" asset base. A complete risk assessment of the entire Thunder Bay Hydro system was completed in 2007 and the findings were significant and of concern with respect to a considerable amount of assets approaching end of life.

Safety concern reports arising from the Risk Assessments had to be dealt with and serious concerns had to be dealt with immediately. Immediate risks to the public and employees were given a top priority. Non immediate risks were deferred to the 20 Year Capital & Maintenance Plans. Approximately 50 concern reports were filed and dealt with immediately during 2007's assessments.

The results of Thunder Bay Hydro's Risk Assessments from 2007 can be made available if deemed necessary.

Outlined below are the required steps in specifically developing and maintaining Thunder Bay Hydro's 20-Year Capital Plan:

1. Perform detailed "WHOLE" risk assessments of all assets and associated work involving any impacted work groups;
2. Develop an inventory of all assets and an asset condition report;
3. Develop a strategic plan for the city by zones for the next 20 years, in consultation with impacted parties;
4. Prioritization of projects with a consistent criteria throughout the plan period;
5. Execution of the plan;
6. Annual risk assessments of one-third of the distribution system; and
7. Annual updates to the 20 year capital plan as further information becomes available.

Thunder Bay Hydro began the development of a 20-year Capital plan in late 2006 and it is expected to be completed near the end of 2009. The full scope of the 20-year plan is expected to be completed in 2010. The first projects output from the preliminary plan were for the 2008

budget. While the plan will be exhaustive once complete it will also continue to be developed, adjusted on an on-going basis, and further detail will be added. The plan structure by design has the flexibility to be easily modified to meet the changing conditions in the system and the community we serve.

Implementation and Operation

Thunder Bay Hydro's AMP was developed from a simple framework of the strategy setting the foundation for the entire program and risk assessments being utilized for directing the capital replacement and maintenance programs. Lastly appropriate KPI's are used to determine the effectiveness of the overall program and what adjustments are required to achieve the desired outcomes.

Outlined below are the steps in implementing Thunder Bay Hydro's AMP:

1. Develop an Asset Management Strategy;
2. Decide whether to invest in Asset Management Software;
3. Communicate Plan and Strategy to Staff;
4. Develop and Perform WHOLE Risk Assessments;
5. Communicate Assessment Findings to Shareholder;
6. Develop a Detailed Long Term Capital Plan;
7. Develop a Comprehensive Maintenance Plan;
8. Develop a Comprehensive KPI List;
9. Communicate Financial Requirements with Regulator and Shareholder;
10. Execute the Plans; and
11. Update Components as Required.

The fundamental objective of the maintenance program at Thunder Bay Hydro is to maintain its assets for the lowest possible life cycle cost while focusing on the following strategic objectives:

- Addressing any health & safety issues;
- Addressing any environmental risks;
- Regulatory compliance obligations; and
- Ensuring equipment reliability.

Three types of maintenance programs are widely used in industry and all others are variants of these three namely reactive, preventative, and predictive maintenance.

Reactive maintenance, as its name suggests, is solely reactive to failures or defects with only inspections or some basic tests being performed to determine whether the equipment is functioning as expected. This type of maintenance is most effective for low cost equipment where maintenance can be a significant portion of the replacement cost and the equipment is not critical should it fail. An example of this would be how we maintain lightning arrestors, cutouts, insulators and other line hardware.

Preventative maintenance, also as its name suggests, is an attempt to perform maintenance in fixed cycles based on industry knowledge of what period is anticipated to be optimal in terms of maintenance costs and failure costs. Preventative maintenance is more extensive than reactive and could include such activities as greasing breakers or switches annually to overhauling a recloser at a fixed number of operations. This type of maintenance is most effective for mid to high cost equipment where preventative maintenance is a good investment towards preventing a catastrophic failure. This type of maintenance is widely used where failure of equipment can be critical to the operation or where the cost of an unscheduled replacement significantly exceeds the cost of a scheduled replacement.

Predictive maintenance, also as its name suggests, is a methodology that attempts to anticipate when a failure will occur and schedule maintenance prior to the impending failure. This is the newest of the maintenance methodologies which attempts to reduce maintenance costs by extending the maintenance period beyond that of preventative maintenance. This type of maintenance also attempts to detect imminent failures that would have occurred under the preventative maintenance approach. Predictive maintenance is most effective for very high cost equipment or equipment which is very critical, and failures cannot be managed effectively. An example would be the use of dissolved gas analysis, furan analysis and doble testing to determine when it would be optimal to overhaul a substation transformer rather than perform the overhaul

at a fixed period. Of course this is not a perfect science and failures do occur even with some of the most sophisticated testing and monitoring equipment available.

Thunder Bay Hydro's maintenance program will utilize all of the above types of maintenance approaches on a best fit to the equipment basis. This is best described as RCM. RCM is characterized by determining what type of maintenance is appropriate, based on failure mechanisms and consequences. It is particularly suited to complex plants where there are many failure modes.

In Thunder Bay Hydro's case, low cost and low criticality equipment like lightning arrestors, distribution poles, fuse cutouts, distribution transformers, low priority cables, and line hardware will be reactively maintained. Mid cost and mid criticality equipment like breakers, reclosers, line switches, relays, high priority cables and most substation equipment will be maintained with the preventative methodology. Thunder Bay Hydro's most expensive and critical assets which are its substation transformers will be maintained with the predictive methodology. This approach also utilizes principles from reliability centered maintenance where the equipment's required availability, as well as maintenance costs, are considered in the program development.

Thunder Bay Hydro's maintenance activities are functionally organized such that on a periodic basis the inspection and detection of deficiencies/defects, as well as any minor maintenance functions, will be performed. Periodic maintenance can be further broken down into two separate components.

Firstly, "Patrolling & Visual Inspections" where in lines this is accomplished with the detailed risk assessments and a thermo graphic survey completed at each location every three years. In stations, each location is inspected monthly and a thermo graphic survey is conducted annually. Additionally, in stations a detailed risk assessment is conducted every three years.

Secondly, "Work & Test" maintenance is performed periodically where a piece of equipment is test operated to verify its proper operation. Additionally equipment that requires calibration is re-verified and/or any required testing is performed for predictive purposes i.e. doble testing, furan

analysis etc. In lines, equipment like reclosers and switches are test operated and lubricated every 3 years, and reclosers verified every 6 years. In the stations, transformers will receive dissolved gas in oil analysis along with other diagnostic testing annually. Breakers will be test operated/ lubricated and relays re-calibrated/verified every three years.

Corrective maintenance occurs only when the periodic maintenance activity has discovered a deficiency or defect. At that time, some corrective maintenance is scheduled like a part replacement, rebuild, or overhaul as deemed necessary to correct the problem discovered.

Thunder Bay Hydro is in the midst of implementing its maintenance program within its enterprise system where all periodic maintenance will be automatically generated. Additionally, corrective maintenance and failures will be traced to various equipment types, as well as each specific piece of equipment. The automated system is expected to be operational in the summer of 2009.

Checking and Corrective Action

KPIs are a vital means of determining how a business is operating and an imperative part of an Asset Management system. The right indicators will help to reduce: costs, outages and errors while increasing: productivity, employee/customer satisfaction and financial performance. KPIs indicate whether Thunder Bay Hydro is succeeding in its corporate mission, is above or below its desired performance and whether it is improving. A balanced set of KPIs allows Thunder Bay Hydro to fine tune its risk assessments, capital and maintenance plans even where fundamental conflicts exist (i.e. cost versus reliability and cost and customer service).

Thunder Bay Hydro's KPIs serve purposes beyond Asset Management and attempt to evaluate effectiveness in all of the following areas:

1. Health & Safety
2. Employee Excellence
3. Operational Excellence
4. Customer Service
5. Environmental Performance

6. Financial Performance.

Metrics will test Thunder Bay Hydro's progress in achieving its overall objectives. Metrics will provide individuals at all levels of the organization direction on what they need to accomplish and metrics measure performance as a tool to drive desired behaviors amongst staff.

Thunder Bay Hydro's Lines Department KPIs are as follows:

1. Zero serious Lost Time Incidents
2. # of safety concerns not responded to within 60 days
3. Zero reportable environmental incidents
4. Zero operating incidents
5. Zero reporting incidents
6. Zero grievances unsuccessfully defended
7. % risk assessments completed of target
8. SAIDI (< 2), CAIDI (<1) & SAIFI (< 2)
9. # of instances onsite response > 4 hrs
10. All OEB metrics met or exceeded:
    - % requests for low voltage service within minimum standard
    - % requests for high voltage service within minimum standard
    - % appointments at customer's premises or work site within minimum standard
    - % of emergency calls for urban customers met within 60 min.
    - % of emergency calls for rural customers met within 120 min.
11. < 100% of departmental Part A & C capital budget to be spent
12. Tarbutt project - completion date and within allotted budget
13. Hill St project - completion date and within allotted budget
14. County Fair project - completion date and within allotted budget
15. 10M7/10M10 project - completion date and within allotted budget
16. < 100% of departmental OM&A budget to be spent
17. 85% of planned maintenance program to be completed
18. # of poles changed per year (up to 5 pole jobs)
19. Average cost for a single pole replacement (up to 5 pole jobs)
20. Average cost for a switch pole replacement (up to 5 pole jobs)
21. # km of line rebuild per year (> 5 pole projects)

22. Average cost for constructing 1km of line (> 5 pole projects)
23. # km of cable replaced per year
24. Average cost for installing 1 km of cable
25. # of customer connections (up to 200 Amp)
26. Average Customer connection cost (up to 200 Amp)
27. # of connections (up to 200 Amp) outside of +10% and -25% of provided estimate
28. # of customer connections (> 200 Amp)
29. # of connections (> 200 Amp) outside of +10% and -25% of provided estimate
30. Average Customer connection cost (> 200 Amp)
31. # of average departmental sick days
32. # of customer issues elevated to the VP or higher.

Thunder Bay Hydro's Operations Department KPIs are as follows:

1. Zero serious Lost Time Incidents
2. # of safety concerns not responded to within 60 days
3. Zero reportable environmental incidents
4. Zero operating incidents
5. Zero reporting incidents
6. Zero grievances unsuccessfully defended
7. Zero customer identified metering errors
8. % risk assessments completed of target
9. % of planned meter verifications completed
10. SAIDI (< 2), CAIDI (<1) & SAIFI (< 2)
11. # of instances onsite response > 4 hrs
12. All OEB metrics met or exceeded:
    % of emergency calls for urban customers met within 60 min.
    % of emergency calls for rural customers met within 120 min.
13. # of Regulator orders issued (OEB, ESA, MTO, MC, etc.)
14. < 100% of departmental Part A & C capital budget to be spent
15. Stn 36 Fencing/Grounding/Concrete Leveling project - completion date and within allotted budget
16. < 100% of OM&A budget to be spent

17. 85% of planned maintenance program to be completed
18. Total Hrs of Fleet Large Vehicles (>5000kg) Unavailable
19. Total Hrs of Fleet Small Vehicles (<5000kg) Unavailable
20. # of average departmental sick days
21. # of customer issues elevated to the VP or higher.

Thunder Bay Hydro's Asset Management & Engineering Department KPIs are as follows:

1. Zero serious Lost Time Incidents
2. # of safety concerns not responded to within 60 days
3. Zero reportable environmental incidents
4. Zero dig ups due to Locates incident
5. Zero grievances unsuccessfully defended
6. % risk assessments completed of target
7. SAIDI (< 2), CAIDI (<1) & SAIFI (< 2)
8. All OEB metrics met or exceeded:
   % requests for high voltage service within minimum standard
   % underground locates met within minimum standard
   % appointments at customer's premises or work site within minimum standard
9. % completion of initial 5 years of capital plan
10. % of capital project designs completed prior to budget submission for next year
11. Ray Blvd project - completion date and within allotted budget
12. Kam River Crossing project - completion date and within allotted budget
13. FWTS Metering Upgrade project - completion date and within allotted budget
14. Tarbutt project - completion date and within allotted budget
15. Hill St project - completion date and within allotted budget
16. County Fair project - completion date and within allotted budget
17. 10M7/10M10 project - completion date and within allotted budget
18. 95% of divisional capital program completed
19. < 100% of departmental OM&A budget spent
20. 85% of divisional maintenance program completed
21. # of poles changed per year (up to 5 pole jobs)
22. Average cost for a single pole replacement (up to 5 pole jobs)

23. Average cost for a switch pole replacement (up to 5 pole jobs)
24. # km of line rebuild per year (> 5 pole projects)
25. Average cost for constructing 1km of line (> 5 pole projects)
26. # km of cable replaced per year
27. Average cost for installing 1 km of cable
28. # of customer connections (> 200 Amp)
29. Average Customer connection cost (> 200 Amp)
30. # of connections (> 200 Amp) outside of +10% and -25% of provided estimate
31. # of customer issues elevated to the VP or higher
32. # of average departmental sick days.

All projects within Thunder Bay Hydro's capital replacement program are prioritized annually based on a set of criteria that represent a complete approach to evaluating all proposed projects. This is done by developing a complete set of criteria, assigning a scoring scheme to each criterion, and establishing a clear guideline for each maximum and minimum score. This ensures that all projects are evaluated equally without bias as to the time or conditions under which each project is evaluated. The criteria, as well as the scoring system, are listed in the following table:

1

Thunder Bay Hydro Capital Project Ranking Criteria

Criteria	Min Score	Min Criteria Description	Max Score	Max Criteria Description
Prudence of Expense	0	Where there is uncertainty whether the regulator will support or interveners will reasonably question the project's requirements the project shall receive the minimum score	15	Where the project is driven by legislative or regulatory compliance requirements or the assets are clearly necessary to supply customers, the project shall receive the maximum score
Public Safety	0	Where the project will have no impact on public safety the project shall receive the minimum score	15	Where the project is likely to reduce a single public injury once every 10 years the project shall receive the maximum score
Worker Safety	0	Where the project will have no impact on worker safety the project shall receive the minimum score	15	Where the project is likely to reduce a single worker injury once every 10 years, the project shall receive the maximum score
Environmental	0	Where the project will have no impact on the reduction of environmental risk the project shall receive the minimum score	10	Where the project is likely to eliminate a single environmental incident once every 10 years, the project shall receive the maximum score Note: Additional consideration to be given to system losses
Reliability	0	Where the project will have no impact on system reliability, the project shall receive the minimum score	10	Where the project is likely to eliminate a single system 4 hr outage to at least 1000 customers once a year, the project shall receive the maximum score Note: Additional consideration to be given to multiple outage situations

Power Quality	0	Where the project will have no impact on voltage, the project shall receive the minimum score	5	Where the project will correct existing voltage concerns or problems of 200 or more customers, the project shall receive the maximum score. Note: Consideration also to be given to size of customers effected and the severity of the impact on the customer
Customer Perception	0	Where the project will have no perceived value to the public at large, the project shall receive the minimum score	10	Where the project will be perceived as an improvement to the system or the community by 1000 or more customers, the project shall receive the maximum score
End of Life	0	Where the equipment still retains 50% or more of its life expectancy, the project shall receive the minimum score	10	Where the equipment is at end of life and is not expected to be operable for more than two more years, the project shall receive the maximum score
Maintainability	0	Where maintenance workers will see no improvement in the maintainability of the system, the project shall receive the minimum score	5	Where maintenance workers will clearly perceive a substantial improvement in the maintainability of the system, the project shall receive the maximum score
Operability	0	Where operations staff will see no improvement in the operability of the system, the project shall receive the minimum score	5	Where operations staff will clearly perceive a substantial improvement in the operability of the system, the project shall receive the maximum score
Totals:	**0**	**Minimum Possible**	**100**	**Maximum Possible**

Ranking of the projects has been completed for the first nine (9) years of the 20-Year Capital Plan. The projects determined to have the greatest immediate need from the risk assessments were initiated in the first three years of the plan.

The overall methodology used to evaluate projects within the 20-Year Capital Plan is as follows:

Once the projects' scoring was completed, an overall ranking was done with the multiple evaluation criteria. Firstly, the projects with the highest point totals were listed and secondly the projects with the highest points/$ were listed. From these lists, the projects commonly ranking high were selected as projects to proceed with first. This set the basis for prioritizing Thunder Bay Hydro's projects within the first three years of its 20-Year Capital Plan.

Secondly, a strategic approach to dealing with the aging or at end-of-life substations and 4kV lines was factored into the overall ranking consideration, as well as how to effectively convert the city to 25kV, while minimizing impacts and risks to customers. Also considered in the ultimate project ranking was a common sense approach of using project portfolios; where synergies of projects would lower the overall cost of execution if coordination and consolidation could be achieved. Next, the overall project list was reviewed for any projects that required immediate attention from a worker/public health and safety, environmental, or a legal/regulatory vantage. Lastly, the ranked projects were broken down into manageable groups that would facilitate efficient and effective execution of annual capital programs given the resources available or anticipated to be available.

Asset Management Review and Continual Improvement

Annually, the AMP is reviewed for alignment with the corporate strategic directions and adjustments to the plan are made as required. This includes a review of KPI targets and whether new or updated KPIs are required.

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

The 2008 Bridge and 2009 Test Years' gross asset balances reflect the capital expenditure programs forecast for both years. These programs are described in detail in Thunder Bay Hydro's written evidence at Exhibit 2, Tab 3, Schedule 1. The justifications for capital projects in excess of 1% of total net fixed assets are also contained in that Schedule.

Thunder Bay Hydro's Budget Process:

The following comments provide an overview of Thunder Bay Hydro's budgeting process.

- **Overall Budget Process**

  The budget is prepared annually by management and is reviewed and approved by the Board of Directors. The budget is typically approved by the end of October and forwarded to the shareholder, The Corporation of the City of Thunder Bay. The budget then provides the plan against which actual results may be evaluated.

- **Responsibilities**

  - It is the responsibility of the Finance Division to coordinate the development of the operating budget, capital budget and forecast processes.
  - Each division is responsible for preparing its operating budget, capital budget, and rolling forecasts.
  - The Executive Management Team reviews the organizational budget as a group to ensure that each Vice President has a good understanding of the plans of other members of the Team for the upcoming year and to share respective business cases for anomaly expenditures.
  - The President is responsible for presenting and recommending the budget to the Board of Directors for approval.
  - It is the responsibility of the Board of Directors, on behalf of the shareholders, to approve the budget.

The budget is an important planning tool for Thunder Bay Hydro. It puts capital and operational plans into a common financial plan. The budget plan is done within our accounting software package and is budgeted at the element level. The following is our accounting software account structure:

Account Number Structure

Account Number		001-6556-420.42-01
Fund	001	THUNDER BAY HYDRO
Division	65	Operating
Department	56	O/H Lines & Feeders
Activity Basic	42	Distribution System
Sub-Activity	0	Distribution System
Element	42	Salary/Wages
Object	01	Regular

The divisional Budget Plans represent the output of the detailed departmental work plans based on required activities for the year. The final document provides a summarized package of the organization's budget that ensures that appropriate resources are designated for the various capital and operational needs of the utility for the coming year.

- **Budget Review Process:**

Thunder Bay Hydro's budget review process is as follows:

- The budget process starts with the issuance of directive memos to the Vice Presidents and the President outlining the approach, expectations and timelines for the budget process. The current year memos are provided in Exhibit 4, Tab 1, Schedule 1.
- Each department budget is reviewed and approved by the corresponding division Vice President and submitted to the Accounting Department.
- The Accounting Department consolidates all departmental work plan budgets to produce budget reports by division to be reviewed by the corresponding Executive Team member(s).
- The Vice President, Finance presents the draft budget to the Executive Team member(s) for a comprehensive review. Highlights of new staff complement and the rationale for such, anomaly costs and significant cost increases ongoing, are some of the issues that are discussed. This is the Vice President's opportunity to provide the business case for significant changes and make recommendations with respect to the organizational budget.

- The Vice President Finance presents the revised budget package to the President for further review and adjustment, bringing in the respective Vice President as necessary.

- The final budget package is presented to the President for approval.

- **The Actual-to-Budget Review Process:**

Once the budget is final, each Division Vice President reviews and tracks both operating and capital progress against the budget on a monthly basis. The Finance Department provides summary and/or detailed department cost information to the Vice Presidents on a monthly basis providing the budget, the costs to date, the percentage of budget spent to date as well as the percentage of the budget year that has elapsed. Explanations of significant/unusual variances are verbally discussed between Finance and the respective Vice Presidents as well as the President and respective Vice Presidents.

Further, quarterly financial statements are presented to the Board of Directors.

RATE BASE VARIANCE ANALYSIS:

The following Table 1 sets out Thunder Bay Hydro's rate base and working capital calculations for 2006 Board Approved and Actual, 2007 Actual, 2008 Bridge Year and 2009 Test Year, and the following variances:

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

Table 1
Rate Base Variances

Description	2006 OEB Approved*	2006 Actual	Variance from 2006 OEB Approved	2007 Actual Year	Variance from 2006 Actual	2008 Bridge Year	Variance from 2007 Actual Year	2009 Test Year	Variance from 2008 Bridge Year
Gross Fixed Assets	117,366,079	128,359,838	10,993,759	132,593,627	4,233,789	137,977,953	5,384,326	145,434,516	7,456,563
Accumulated Depreciation	58,223,541	68,017,440	9,793,899	71,981,194	3,963,754	76,881,949	4,900,755	81,830,062	4,948,113
Net Book Value	59,142,538	60,342,398	1,199,860	60,612,433	270,035	61,096,003	483,571	63,604,453	2,508,450
Average Net Book Value	59,043,741	59,643,671	599,930	60,477,415	833,744	60,854,218	376,803	62,350,228	1,496,010
Working Capital	80,701,290	80,899,106	197,816	85,177,351	4,278,245	84,859,730	(317,621)	85,462,799	603,069
Working Capital Allowance	12,105,193	12,134,866	29,673	12,776,603	641,737	12,728,960	(47,643)	12,819,420	90,460
Rate Base	71,148,934	71,778,537	629,602	73,254,018	1,475,481	73,583,178	329,160	75,169,648	1,586,471

*Note: The 2006 OEB Approved rate base was determined through the 2006 EDR process and is based on the 2004 year end rate base adjusted for Tier 1 Adjustments.

Thunder Bay Hydro has calculated the variance threshold on its rate base to be $603,424 in accordance with the Filing Requirements. This calculation is summarized in Table 2 below:

Table 2
Rate Base Materiality

Description	2006 OEB Approved	2006 Actual	2007 Actual Year	2008 Bridge Year	2009 Test Year
Gross Fixed Assets	$117,366,079	$128,359,838	$132,593,627	$137,977,953	$145,434,516
Accumulated Depreciation	$58,223,541	$68,017,440	$71,981,194	$76,881,949	$81,830,062
Net Book Value	$59,142,538	$60,342,398	$60,612,433	$61,096,003	$63,604,453
Variance calc 1% NBV		$603,424	$606,124	$610,960	$636,045

Thunder Bay Hydro offers the following comments in respect of the relevant variances identified above:

2009 Test Year:

As shown in Table 1 above, the total rate base in the 2009 test year is forecast to be $75,169,648. Average net fixed assets accounts for $62,350,228 of this total. The allowance for working capital totals $12,819,420.

- **Comparison to 2008 Bridge Year:**

The total rate base is expected to be $1,586,471 higher in the 2009 Test Year than in the 2008 Bridge Year. This increase is shown in Table 1 above and is attributed primarily to an increase in average net fixed assets of $1,496,011. The rationalization of the required increase in capital expenditures is addressed in the Capital Budget section of project in Exhibit 2, Tab 3, Schedule 1.

Further, the full detail by capital project for the “non-customer driven” work is provided in Exhibit 2, Tab 3, Schedule 1, Appendix A.

The working capital allowance increased by $90,460 from the 2008 Bridge Year. A detailed calculation of the working capital allowance for the 2009 Test Year can be found at Exhibit 2, Tab 3, Schedule 4.

2008 Bridge Year:

The total rate base for the 2008 Bridge Year is expected to be $73,583,178 which represents an increase of $329,160 over the 2007 Actual year. This change results in part from an increase in average net assets of $376,803. This change in rate base is below the variance analysis of $603,424 and as such an explanation of the variance is not required.

The working capital allowance decreased by $47,643 from 2007. A detailed calculation of the working capital allowance for the 2008 Bridge Year can be found at Exhibit 2, Tab 3, Schedule 4.

2007 Actual:

The rate base for 2007 Actual increased over 2006 Actual by $1,475,481. This increase is made up of an increase in average net assets of $833,744 and an increase in working capital allowance of $641,737. The increase in fixed assets is largely explained by the additional capital project undertaken in 2006 as a result of CDM funding from the OEB. Part of Thunder Bay Hydro's approved CDM plan included voltage conversions, urban 4 kv rebuild and transformer upgrades in the amount of $549,000.

2006 Actual:

The rate base for 2006 Actual increased over 2006 Board Approved by 629,602. This increase is made up of an increase in average net assets of $599,930 and a slight increase in working capital allowance of $29,673. This increase in rate base represents changes from 2006 Board Approved, which was based on 2004 year end plus or minus Tier 1 adjustments as provided in the 2006 EDR Handbook. As noted above, 2006 capital expenditures were higher given the OEB, CDM funding for voltage conversion. Additionally the budget carry-over of fleet replacement occurred in 2006.

CONTINUITY STATEMENTS:

Table 1
Thunder Bay Hydro - Distribution & Operations - 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 - Substations	133,037.50			133,037.50	0.00			0.00	133,037.50
1808	Buildings - Substations	3,894,354.50			3,894,354.50	1,345,755.52	77,920.01		1,423,675.53	2,470,678.97
1810	Leasehold Improvements									
1815	Transformer Station Equipment > 50 kV									
1820	Substation Equipment	7,986,951.65	105,583.05		8,092,534.70	4,829,073.76	187,992.99		5,017,066.75	3,075,467.95
1825	Storage Battery Equipment									
1830	Poles, Towers & Fixtures	16,910,541.21	1,908,960.75		18,819,501.96	7,602,097.47	723,472.38	29,574.71	8,295,995.14	10,523,506.82
1835	OH Conductors & Devices	19,906,203.81	1,750,596.97		21,656,800.78	8,948,791.15	832,545.80		9,781,336.95	11,875,463.83
1840	UG Conduit	10,937,555.19	348,041.00		11,285,596.19	4,916,954.44	433,848.74		5,350,803.18	5,934,793.01
1845	UG Conductors & Devices	13,539,793.84	693,414.74		14,233,208.58	6,086,785.23	547,162.90		6,633,948.13	7,599,260.45
1850	Line Transformers	21,466,816.86	739,459.20		22,206,276.06	11,813,837.04	698,441.09	173,864.45	12,338,413.68	9,867,862.38
1855	Services (OH & UG)	16,051,257.17	383,230.25		16,434,487.42	7,215,808.17	631,786.00		7,847,594.17	8,586,893.25
1860	Meters	6,042,951.75		78,547.38	5,964,404.37	2,602,308.15	335,936.68	274,265.76	2,663,979.07	3,300,425.30
1861	Smart Meters									
1905	Land									
1906	Land Rights									
1908	Buildings & Fixtures									
1910	Leasehold Improvements									
1915	Office Furniture & Equipment	1,193,697.39	16,483.68	4,985.32	1,205,195.75	983,460.05	33,948.12	3,902.56	1,013,505.61	191,690.14
1920	Computer - Hardware	2,420,835.60	83,217.40	16,032.17	2,488,020.83	2,158,107.48	133,209.20	16,032.17	2,275,284.51	212,736.32
1921	Computer - Hardware post Mar 22/04									
1921	Computer - Hardware post Mar19/07									
1925	Computer - Software	429,549.70	85,087.34		514,637.04	300,481.57	63,497.71		363,979.28	150,657.76
1930	Transportation Equipment	4,418,756.36	639,606.20	19,005.84	5,039,356.72	3,513,804.91	262,331.06	19,005.84	3,757,130.13	1,282,226.59
1935	Stores Equipment	63,417.16			63,417.16	62,835.45			62,835.45	581.71
1940	Tools, Shop & Garage Equipment	2,114,852.85	60,389.04	20,799.86	2,154,442.03	1,830,397.07	62,542.39	20,799.86	1,872,139.60	282,302.43
1945	Measurement & Testing Equipment	101,379.57	10,562.44		111,942.01	28,988.99	10,713.16		39,702.15	72,239.86
1950	Power operated Equipment	3,583.39			3,583.39	1,833.72	358.32		2,192.04	1,391.35
1955	Communications Equipment	160,386.97			160,386.97	151,530.62	4,101.14		155,631.76	4,755.21
1960	Miscellaneous Equipment									
1965	Water Heater Rental Units									
1970	Load Management controls									
1975	Load Management Controls Utility Premises									
1980	System Supervisory Equipment	416,574.56	53,612.20		470,186.76	12,338.73	8,949.79		21,288.52	448,898.24
1985	Sentinel Lighting Rental Units				0.00				0.00	0.00
1996	Hydro One Meter Upgrades									0.00
1995	Contributions & Grants	(5,631,381.35)	(1,045,268.32)		(6,676,649.67)	(698,500.00)	(250,200.00)		(948,700.00)	(5,727,949.67)
	Total before Work in Process	**122,561,115.68**	**5,832,975.94**	**139,370.57**	**128,254,721.05**	**63,706,689.52**	**4,798,557.48**	**537,445.35**	**67,967,801.65**	**60,286,919.40**
2005	Other capital assets: computer lease	105,117.00			105,117.00	14,599.59	35,039.04		49,638.63	55,478.37
		122,666,232.68	**5,832,975.94**	**139,370.57**	**128,359,838.05**	**63,721,289.11**	**4,833,596.52**	**537,445.35**	**68,017,440.28**	**60,342,397.77**
2055	Work in Process	670,783.00		347,640.41	323,142.59	0.00	0.00	0.00	0.00	323,142.59
	Total after Work in Process	**123,337,015.68**	**5,832,975.94**	**487,010.98**	**128,682,980.64**	**63,721,289.11**	**4,833,596.52**	**537,445.35**	**68,017,440.28**	**60,665,540.36**
	Amortization allocation to other trial balance accounts & overheads						**(451,206.82)**			
	Adjusted amortization expense						**4,382,389.70**			

Table 2
Thunder Bay Hydro - Distribution & Operations - Fixed Asset Continuity Schedule
As at December 31, 2007

		Cost				Accumulated Depreciation				
OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
1805	Land - Substations	133,037.50			133,037.50	0.00			0.00	133,037.50
1808	Buildings - Substations	3,894,354.50			3,894,354.50	1,423,675.53	77,919.00		1,501,594.53	2,392,759.97
1810	Leasehold Improvements									
1815	Transformer Station Equipment > 50 kV									
1820	Substation Equipment	8,092,534.70	7,163.65		8,099,698.35	5,017,066.75	189,665.66		5,206,732.41	2,892,965.94
1825	Storage Battery Equipment									
1830	Poles, Towers & Fixtures	18,819,501.96	1,564,990.26		20,384,492.22	8,295,995.14	775,838.40	176,610.65	8,895,222.89	11,489,269.33
1835	OH Conductors & Devices	21,656,800.78	1,295,655.29		22,952,456.07	9,781,336.95	873,575.69		10,654,912.64	12,297,543.43
1840	UG Conduit	11,285,596.19	247,168.82		11,532,765.01	5,350,803.18	438,939.67		5,789,742.85	5,743,022.16
1845	UG Conductors & Devices	14,233,208.58	508,736.64		14,741,945.22	6,633,948.13	561,081.78		7,195,029.91	7,546,915.31
1850	Line Transformers	22,206,276.06	707,559.35		22,913,835.41	12,338,413.68	716,811.90	420,003.79	12,635,221.79	10,278,613.62
1855	Services (OH & UG)	16,434,487.42	647,442.48		17,081,929.90	7,847,594.17	650,142.13		8,497,736.30	8,584,193.60
1860	Meters	5,964,404.37		27,061.84	5,937,342.53	2,663,979.07	372,566.72	196,546.00	2,839,999.79	3,097,342.74
1861	Smart Meters									
1905	Land									
1906	Land Rights									
1908	Buildings & Fixtures									
1910	Leasehold Improvements									
1915	Office Furniture & Equipment	1,205,195.75	29,501.50	13,167.36	1,221,529.89	1,013,505.61	35,793.93	13,167.36	1,036,132.18	185,397.71
1920	Computer - Hardware	2,488,020.83	42,632.52	1,355.40	2,529,297.95	2,275,284.51	126,551.56	1,355.40	2,400,480.67	128,817.28
1921	Computer - Hardware post Mar 22/04									
1921	Computer - Hardware post Mar19/07									
1925	Computer - Software	514,637.04	95,892.34		610,529.38	363,979.28	81,940.79		445,920.07	164,609.31
1930	Transportation Equipment	5,039,356.72	192,755.89	272,816.79	4,959,295.82	3,757,130.13	295,385.19	272,816.79	3,779,698.53	1,179,597.29
1935	Stores Equipment	63,417.16			63,417.16	62,835.45			62,835.45	581.71
1940	Tools, Shop & Garage Equipment	2,154,442.03	96,599.76	192.60	2,250,849.19	1,872,139.60	67,114.71	192.60	1,939,061.71	311,787.48
1945	Measurement & Testing Equipment	111,942.01	17,882.15		129,824.16	39,702.15	12,582.25		52,284.40	77,539.76
1950	Power operated Equipment	3,583.39			3,583.39	2,192.04	358.32		2,550.36	1,033.03
1955	Communications Equipment	160,386.97	3,004.56		163,391.53	155,631.76	2,753.92		158,385.68	5,005.85
1960	Miscellaneous Equipment									
1965	Water Heater Rental Units									
1970	Load Management controls									
1975	Load Management Controls Utility Premises									
1980	System Supervisory Equipment	470,186.76	10,692.00		480,878.76	21,288.52	10,385.58		31,674.10	449,204.66
1985	Sentinel Lighting Rental Units	0.00			0.00	0.00			0.00	0.00
1996	Hydro One Current and Voltage Transformer Upgrades		34,080.31		34,080.31					34,080.31
1995	Contributions & Grants	(6,676,649.67)	(953,374.79)		(7,630,024.46)	(948,700.00)	(280,000.00)		(1,228,700.00)	(6,401,324.46)
	Total before Work in Process	**128,254,721.05**	**4,548,382.73**	**314,593.99**	**132,488,509.79**	**67,967,801.65**	**5,009,407.20**	**1,080,692.59**	**71,896,516.26**	**60,591,993.53**
2005	Other capital assets computer lease	105,117.00			105,117.00	49,638.63	35,039.04	0.00	84,677.67	20,439.33
		128,359,838.05	**4,548,382.73**	**314,593.99**	**132,593,626.79**	**68,017,440.28**	**5,044,446.24**	**1,080,692.59**	**71,981,193.93**	**60,612,432.86**
	Work in Process	323,142.59		221,343.95	101,798.64	0.00	0.00	0.00	0.00	101,798.64
	Total after Work in Process	**128,682,980.64**	**4,548,382.73**	**535,937.94**	**132,695,425.43**	**68,017,440.28**	**5,044,446.24**	**1,080,692.59**	**71,981,193.93**	**60,714,231.50**
Amortization allocated to other trial balance accounts & overheads						**a**	**(479,673.23)**			
Adjusted amorization expense							**4,564,773.01**			

Table 3
Thunder Bay Hydro - Distribution & Operations - Fixed Asset Continuity Schedule
2008 Bridge Year

		Cost				Accumulated Depreciation				
OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
1805	Land - Substations	133,037.50			133,037.50	0.00			0.00	133,037.50
1808	Buildings - Substations	3,894,354.50	40,000.00		3,934,354.50	1,501,594.53	80,294.00		1,581,888.53	2,352,465.97
1810	Leasehold Improvements	0.00			0.00	0.00			0.00	0.00
1815	Transformer Station Equipment > 50 kV	0.00			0.00	0.00			0.00	0.00
1820	Substation Equipment	8,099,698.35			8,099,698.35	5,206,732.41	325,978.45		5,532,710.86	2,566,987.49
1825	Storage Battery Equipment	0.00			0.00	0.00			0.00	0.00
1830	Poles, Towers & Fixtures	20,384,492.22	948,155.28		21,332,647.50	8,895,222.89	719,092.56		9,614,315.45	11,718,332.05
1835	OH Conductors & Devices	22,952,456.07	1,464,590.04		24,417,046.11	10,654,912.64	823,063.15		11,477,975.79	12,939,070.32
1840	UG Conduit	11,532,765.01	314,986.15		11,847,751.16	5,789,742.85	399,370.49		6,189,113.34	5,658,637.82
1845	UG Conductors & Devices	14,741,945.22	377,711.58		15,119,656.80	7,195,029.91	509,661.67		7,704,691.58	7,414,965.22
1850	Line Transformers	22,913,835.41	909,207.10		23,823,042.51	12,635,221.79	922,085.98		13,557,307.77	10,265,734.74
1855	Services (OH & UG)	17,081,929.90	708,692.41		17,790,622.31	8,497,736.30	599,696.03		9,097,432.33	8,693,189.98
1860	Meters	5,937,342.53	42,724.14		5,980,066.67	2,839,999.79	231,462.28		3,071,462.07	2,908,604.60
1861	Smart Meters	0.00			0.00	0.00			0.00	0.00
1905	Land	0.00			0.00	0.00			0.00	0.00
1906	Land Rights	0.00			0.00	0.00			0.00	0.00
1908	Buildings & Fixtures	0.00			0.00	0.00			0.00	0.00
1910	Leasehold Improvements	0.00			0.00	0.00			0.00	0.00
1915	Office Furniture & Equipment	1,221,529.89	75,208.00		1,296,737.89	1,036,132.18	42,462.00		1,078,594.18	218,143.71
1920	Computer - Hardware	2,529,297.95	205,555.00		2,734,852.95	2,400,480.67	207,135.48		2,607,616.15	127,236.80
1921	Computer - Hardware post Mar 22/04	0.00			0.00	0.00			0.00	0.00
1921	Computer - Hardware post Mar 19/07	0.00			0.00	0.00			0.00	0.00
1925	Computer - Software	610,529.38	127,117.00		737,646.38	445,920.07	87,600.52	(84,677.67)	618,198.26	119,448.12
1930	Transportation Equipment	4,959,295.82	353,126.00	145,688.00	5,166,733.82	3,779,698.53	322,050.00	145,688.00	3,956,060.53	1,210,673.29
1935	Stores Equipment	63,417.16			63,417.16	62,835.45	0.00		62,835.45	581.71
1940	Tools, Shop & Garage Equipment	2,250,849.19	37,500.09		2,288,349.28	1,939,061.71	86,908.30		2,025,970.01	262,379.27
1945	Measurement & Testing Equipment	129,824.16	85,700.00		215,524.16	52,284.40			52,284.40	163,239.76
1950	Power operated Equipment	3,583.39	10,000.00		13,583.39	2,550.36	0.00		2,550.36	11,033.03
1955	Communications Equipment	163,391.53			163,391.53	158,385.68	2,843.00		161,228.68	2,162.85
1960	Miscellaneous Equipment	0.00			0.00	0.00			0.00	0.00
1965	Water Heater Rental Units	0.00			0.00	0.00			0.00	0.00
1970	Load Management controls	0.00			0.00	0.00			0.00	0.00
1975	Load Management Controls Utility Premises	0.00			0.00	0.00			0.00	0.00
1980	System Supervisory Equipment	480,878.76	34,272.94		515,151.70	31,674.10	19,939.27		51,613.37	463,538.33
1985	Sentinel Lighting Rental Units	0.00			0.00	0.00			0.00	0.00
1996	Hydro One Current & Voltage Transformer Upgrad	34,080.31	546,585.00		580,665.31	0.00			0.00	580,665.31
1995	Contributions & Grants	(7,630,024.46)	(646,000.00)		(8,276,024.46)	(1,228,700.00)	(333,200.00)		(1,561,900.00)	(6,714,124.46)
	Total before Work in Process	**132,488,509.79**	**5,635,130.73**	**145,688.00**	**137,977,952.52**	**71,896,516.26**	**5,046,443.18**	**61,010.33**	**76,881,949.11**	**61,096,003.41**
2005	Other capital assets computer lease	105,117.00	**(105,117.00)**		0.00	84,677.67		84,677.67	0.00	0.00
		132,593,626.79	**5,530,013.73**	**145,688.00**	**137,977,952.52**	**71,981,193.93**	**5,046,443.18**	**145,688.00**	**76,881,949.11**	**61,096,003.41**
	Work in Process	101,798.64	392,201.36		494,000.00	0.00			0.00	494,000.00
	Total after Work in Process	**132,695,425.43**	**5,922,215.09**	**145,688.00**	**138,471,952.52**	**71,981,193.93**	**5,046,443.18**	**145,688.00**	**76,881,949.11**	**61,590,003.41**
Amortization allocated to other trial balance accounts & overheads							**(519,886.30)**			
Adjusted amortization expense							**4,526,556.88**			

Table 4

Thunder Bay Hydro - Distribution & Operations -Fixed Asset Continuity Schedule
2009 Test Year

		Cost				Accumulated Depreciation				
OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
1805	Land - Substations	133,037.50			133,037.50	0.00			0.00	133,037.50
1808	Buildings - Substations	3,934,354.50	95,000.00		4,029,354.50	1,581,888.53	80,294.00		1,662,182.53	2,367,171.97
1810	Leasehold Improvements	0.00			0.00	0.00			0.00	0.00
1815	Transformer Station Equipment > 50 kV	0.00			0.00	0.00			0.00	0.00
1820	Substation Equipment	8,099,698.35			8,099,698.35	5,532,710.86	311,252.86		5,843,963.72	2,255,734.63
1825	Storage Battery Equipment	0.00			0.00	0.00			0.00	0.00
1830	Poles, Towers & Fixtures	21,332,647.50	1,265,612.93		22,598,260.43	9,614,315.45	732,604.79		10,346,920.24	12,251,340.19
1835	OH Conductors & Devices	24,417,046.11	1,668,887.10		26,085,933.21	11,477,975.79	845,365.19		12,323,340.98	13,762,592.23
1840	UG Conduit	11,847,751.16	329,607.00		12,177,358.16	6,189,113.34	395,163.48		6,584,276.82	5,593,081.34
1845	UG Conductors & Devices	15,119,656.80	1,066,480.99		16,186,137.79	7,704,691.58	525,809.03		8,230,500.61	7,955,637.18
1850	Line Transformers	23,823,042.51	1,167,752.81		24,990,795.32	13,557,307.77	923,029.26		14,480,337.03	10,510,458.29
1855	Services (OH & UG)	17,790,622.31	820,880.15		18,611,502.46	9,097,432.33	603,550.35		9,700,982.68	8,910,519.78
1860	Meters	5,980,066.67	47,194.00		6,027,260.67	3,071,462.07	222,750.47		3,294,212.54	2,733,048.13
1861	Smart Meters	0.00			0.00	0.00			0.00	0.00
1905	Land	0.00			0.00	0.00			0.00	0.00
1906	Land Rights	0.00			0.00	0.00			0.00	0.00
1908	Buildings & Fixtures	0.00			0.00	0.00			0.00	0.00
1910	Leasehold Improvements	0.00			0.00	0.00			0.00	0.00
1915	Office Furniture & Equipment	1,296,737.89	55,050.00		1,351,787.89	1,078,594.18	42,680.00		1,121,274.18	230,513.71
1920	Computer - Hardware	2,734,852.95	77,310.00		2,812,162.95	2,607,616.15	203,349.34		2,810,965.49	1,197.46
1921	Computer - Hardware post Mar 22/04	0.00			0.00	0.00			0.00	0.00
1921	Computer - Hardware post Mar 19/07	0.00			0.00	0.00			0.00	0.00
1925	Computer - Software	737,646.38	37,850.00		775,496.38	618,198.26	107,068.66		725,266.92	50,229.46
1930	Transportation Equipment	5,166,733.82	693,500.00	164,269.52	5,695,964.30	3,956,060.53	340,800.00	164,269.52	4,132,591.01	1,563,373.29
1935	Stores Equipment	63,417.16			63,417.16	62,835.45	581.71		63,417.16	0.00
1940	Tools, Shop & Garage Equipment	2,288,349.28	44,300.00		2,332,649.28	2,025,970.01	52,984.80		2,078,954.81	253,694.47
1945	Measurement & Testing Equipment	215,524.16	6,200.00		221,724.16	52,284.40	26,590.84		78,875.24	142,848.92
1950	Power operated Equipment	13,583.39	120,000.00		133,583.39	2,550.36	8,830.80		11,381.16	122,202.23
1955	Communications Equipment	163,391.53			163,391.53	161,228.68	2,162.85		163,391.53	0.00
1960	Miscellaneous Equipment	0.00			0.00	0.00			0.00	0.00
1965	Water Heater Rental Units	0.00			0.00	0.00			0.00	0.00
1970	Load Management controls	0.00			0.00	0.00			0.00	0.00
1975	Load Management Controls Utility Premises	0.00			0.00	0.00			0.00	0.00
1980	System Supervisory Equipment	515,151.70			515,151.70	51,613.37	19,038.35		70,651.72	444,499.98
1985	Sentinel Lighting Rental Units	0.00			0.00	0.00			0.00	0.00
1996	Hydro One Current & Voltage Transformer Upgrade	580,665.31	775,207.52		1,355,872.83	0.00	28,475.71		28,475.71	1,327,397.12
1995	Contributions & Grants	(8,276,024.46)	(650,000.00)		(8,926,024.46)	(1,561,900.00)	(360,000.00)		(1,921,900.00)	(7,004,124.46)
	Total before Work in Process	**137,977,952.52**	**7,620,832.50**	**164,269.52**	**145,434,515.50**	**76,881,949.11**	**5,112,382.49**	**164,269.52**	**81,830,062.08**	**63,604,453.42**
2005	Other capital assets computer lease	0.00			0.00	0.00			0.00	0.00
		137,977,952.52	**7,620,832.50**	**164,269.52**	**145,434,515.50**	**76,881,949.11**	**5,112,382.49**	**164,269.52**	**81,830,062.08**	**63,604,453.42**
	Work in Process	494,000.00			494,000.00	0.00			0.00	494,000.00
	Total after Work in Process	**138,471,952.52**	**7,620,832.50**	**164,269.52**	**145,928,515.50**	**76,881,949.11**	**5,112,382.49**	**164,269.52**	**81,830,062.08**	**64,098,453.42**
Amortization allocated to other trial balance accounts & overheads							**(538,946.79)**			
Adjusted amortization expense							**4,573,435.70**			

GROSS ASSETS TABLE: Table 1

Description	2006 Board Approved ($)	2006 Actual ($)	Variance from 2006	2007 Actual ($)	Variance from 2006	2008 Bridge ($)	Variance from 2007	2009 Test ($)	Variance from 2008
Land and Buildings									
1805-Land	133,038	133,038		133,038		133,038		133,038	
1806-Land Rights									
1808-Buildings and Fixtures	3,894,355	3,894,355		3,894,355		3,934,355	40,000	4,029,355	95,000
1905-Land									
1906-Land Rights									
1810-Leasehold Improvements									
Sub-Total-Land and Buildings	4,027,393	4,027,392		4,027,392		4,067,392	40,000	4,162,392	95,000
DS									
1820-Distribution Station Equipment - Normally Primary	7,814,045	8,092,535	278,490	8,099,698	7,164	8,099,698		8,099,698	
Sub-Total-DS	7,814,045	8,092,535	278,490	8,099,698	7,164	8,099,698		8,099,698	
Poles and Wires									
1830-Poles, Towers and Fixtures	14,980,471	18,819,502	3,839,031	20,384,492	1,564,990	21,332,648	948,155	22,598,260	1,265,613
1835-Overhead Conductors and Devices	18,420,815	21,656,801	3,235,986	22,952,456	1,295,655	24,417,046	1,464,590	26,085,933	1,668,887
1840-Underground Conduit	10,498,393	11,285,596	787,203	11,532,765	247,169	11,847,751	314,986	12,177,358	329,607
1845-Underground Conductors and Devices	12,350,995	14,233,209	1,882,214	14,741,945	508,737	15,119,657	377,712	16,186,138	1,066,481
Sub-Total-Poles and Wires	56,250,674	65,995,108	9,744,434	69,611,659	3,616,551	72,717,102	3,105,443	77,047,690	4,330,588
Line Transformers									
1850-Line Transformers	20,471,040	22,206,276	1,735,236	22,913,835	707,559	23,823,043	909,207	24,990,795	1,167,753
Sub-Total-Line Transformers	20,471,040	22,206,276	1,735,236	22,913,835	707,559	23,823,043	909,207	24,990,795	1,167,753
Services and Meters									
1855-Services	15,326,215	16,434,487	1,108,272	17,081,930	647,442	17,790,622	708,692	18,611,502	820,880
1860-Meters	6,082,872	5,964,404	(118,468)	5,937,343	(27,062)	5,980,067	42,724	6,027,261	47,194
1861-Smart Meters									
Sub-Total-Services and Meters	21,409,087	22,398,892	989,805	23,019,272	620,381	23,770,689	751,417	24,638,763	868,074

Description	2006 Board Approved ($)	2006 Actual ($)	Variance from 2006	2007 Actual ($)	Variance from 2006	2008 Bridge ($)	Variance from 2007	2009 Test ($)	Variance from 2008
IT Assets									
1920-Computer Equipment - Hardware	2,275,356	2,593,138	317,782	2,634,415	41,277	2,734,853	100,438	2,812,163	77,310
1925-Computer Software	330,517	514,637	184,120	610,529	95,892	737,646	127,117	775,496	37,850
Sub-Total-IT Assets	2,605,873	3,107,775	501,902	3,244,944	137,169	3,472,499	227,555	3,587,659	115,160
Equipment									
1915-Office Furniture and Equipment	1,152,446	1,205,196	52,750	1,221,530	16,334	1,296,738	75,208	1,351,788	55,050
1930-Transportation Equipment	4,309,873	5,039,357	729,484	4,959,296	(80,061)	5,166,734	207,438	5,695,964	529,230
1935-Stores Equipment	63,417	63,417	0	63,417		63,417		63,417	
1940-Tools, Shop and Garage Equipment	2,062,957	2,154,442	91,485	2,250,849	96,407	2,288,349	37,500	2,332,649	44,300
1945-Measurement and Testing Equipment	80,771	111,942	31,171	129,824	17,882	215,524	85,700	221,724	6,200
1950-Power Operated Equipment	3,583	3,583	0	3,583		13,583	10,000	133,583	120,000
1955-Communication Equipment	162,056	160,387	(1,669)	163,392	3,005	163,392		163,392	
1960-Miscellaneous Equipment									
Sub-Total-Equipment	7,835,103	8,738,324	903,221	8,791,891	53,567	9,207,737	415,846	9,962,518	754,780
Other Distribution Assets									
1825-Storage Battery Equipment									
1980-System Supervisory Equipment	373,170	470,187	97,017	480,879	10,692	515,152	34,273	515,152	
1985-Sentinel Lighting Rental Units									
1990-Other Tangible Property									
1995-Contributions and Grants - Credit	(3,694,801)	(6,676,650)	(2,981,849)	(7,630,024)	(953,375)	(8,276,024)	(646,000)	(8,926,024)	(650,000)
1996-Hydro One S/S Contribution				34,080	34,080	580,665	546,585	1,355,873	775,208
Sub-Total-Other Distribution Assets	(3,694,801)	(6,206,463)	(2,884,832)	(7,115,065)	(908,602)	(7,180,207)	(65,142)	(7,055,000)	125,208
GROSS ASSET TOTAL	116,718,414	128,359,838	11,268,255	132,593,627	4,233,789	137,977,953	5,384,326	145,434,516	7,456,563

VARIANCE ANALYSIS ON GROSS ASSETS:

The variance analysis for the 2009 Test Year is provided in Exhibit 2, Tab 3, Schedule 1. Thunder Bay Hydro has a variance analysis threshold for capital projects of $603,424. Thunder Bay Hydro has provided the Business Case Reviews for all of the "Part B" Projects (projects which are not customer driven) for the 2009 Test Year in Exhibit 2, Tab 3, Schedule 1, Appendix B.

The capital program in 2006 largely consisted of small replacement projects throughout the city in areas where the condition of the assets was deemed to be at end of life. This assessment was performed by field staff based on experience and their perception of the system as a whole. This approach was one of largely reactively replacing assets as they reached end of life based on field staff's knowledge of system conditions. Thus, all projects in 2006 were below the materiality limit. This approach was appropriate given that a formal risk assessment of the entire system had not been performed at that time and a formal asset management plan had not been developed.

In 2007, Thunder Bay Hydro undertook only one significant capital project called the Frankwood Rebuild. This project was required because many of the poles were at end of life and most of the others had less than two years of remaining life expectancy. There was a considerable amount of #6 AWG Copper (restricted conductor) within the area that was replaced. The restricted conductor posed an increased danger to our workers, as well as the general public, due to the potential to break under relatively light loads. Additionally, the transformers at our John St. Substation, which supplies the area, are at end-of-life. An outside transformer maintenance contractor has advised that the transformers should be replaced or retired by 2010. This work was started in June of 2007 and was completed in December of the same year.

This project was substantially under budget due to two factors. Firstly, the project was anticipated to cost approximately $1.2M however, given that this was the first very large scale complete rebuild undertaken and there being significant uncertainty with regards to potential customer issues, a sizeable contingency was included in the budgeted amount. Secondly,

Thunder Bay Hydro undertook an extensive re-organization of the Power Systems Division and its processes whereby improved coordination and planning led to greater efficiencies of Engineering and Construction groups. Additionally, new standards were purchased in 2007 that facilitated the construction of this project with a lower cost of materials, as well as less labour. A one outage per customer policy was introduced facilitating taking outages on this project, which also helped to expedite its execution.

The lessons learned from this project have been applied to all existing projects and Thunder Bay Hydro will continue to examine ways to reduce its per unit costs of construction going forward into the future. Additionally, this project has redefined how we estimate and budget for large scale distribution rebuilds going forward.

The 2008 capital projections include three capital projects that are expected to exceed the materiality threshold of $603,424. Refer to Exhibit 2, Schedule 3, Appendix A for the business case reviews for the Tarbutt Street area voltage conversion & rebuild, Kam River Crossing and Hill Street Area voltage conversion and rebuild.

The following Tables are a summary of the infrastructure capital projects:

Table 1

USofA Summary for Infrastructure Capital Projects - 2008								
	1830	**1835**	**1840**	**1845**	**1850**	**1855**	**1860**	**Total**
Tarbutt St Area Conversion/Rebuild - BCR #B812-03	54,055	537,634			270,220			861,909
10M6 Kam River Crossing - BCR #813-08	200,283	200,283	200,281	200,282				801,129
Hill St. Area Conversion/Rebuild - BCR #812-09	253,800	403,324	1,687	3,357	179,755	146,222		988,145
Sub-total	508,138	1,141,241	201,968	203,639	449,975	146,222	-	2,651,183
All Other Infrastructure Capital	$ 440,017	$ 323,349	$ 113,018	$ 174,073	$ 459,232	$ 562,470	$ 589,309	2,661,468
Total Capital	$ 948,155	$ 1,464,590	$ 314,986	$ 377,712	$ 909,207	$ 708,692	$ 589,309	$ 5,312,651

Table 2

USofA Summary for Infrastructure Capital Projects - 2009								
	1830	1835	1840	1845	1850	1855	1860	Total
County Fair Park Underground Line Rebuild - BCR # B914-05			220,211	880,842				1,101,053
Winnipeg Area Conversion/Rebuild - BCR #B912-11	425,143	675,613	2,826	5,623	301,110	244,938		1,655,253
Birch/Port Arthur							775,207	775,207
Sub-total	425,143	675,613	223,037	886,465	301,110	244,938	775,207	3,531,513
All Other Infrastructure Capital	$ 840,470	$ 993,274	$ 106,570	$ 180,016	$ 866,643	$ 575,942	$ 47,194	3,610,109
Total Capital	$ 1,265,613	$ 1,668,887	$ 329,607	$ 1,066,481	$ 1,167,753	$ 820,880	$ 822,401	$ 7,141,622

ACCUMULATED DEPRECIATION: Table 1

Description	2006 Board Approved ($)	2006 Actual ($)	Variance from 2006	2007 Actual ($)	Variance from 2006	2008 Bridge ($)	Variance from 2007	2009 Test ($)	Variance from 2008
Land and Buildings									
1805-Land									
1806-Land Rights									
1808-Buildings and Fixtures	1,267,835	1,423,676	155,841	1,501,595	77,919	1,581,889	80,294	1,662,183	80,294
1905-Land									
1906-Land Rights									
1810-Leasehold Improvements									
Sub-Total-Land and Buildings	1,267,835	1,423,676	155,841	1,501,595	77,919	1,581,889	80,294	1,662,183	80,294
DS									
1820-Distribution Station Equipment - Normally Primary below 50 kV	4,656,092	5,017,067	360,975	5,206,732	189,666	5,532,711	325,978	5,843,964	311,253
Sub-Total-DS	4,656,092	5,017,067	360,975	5,206,732	189,666	5,532,711	325,978	5,843,964	311,253
Poles and Wires									
1830-Poles, Towers and Fixtures	6,794,493	8,295,995	1,501,502	8,895,223	599,228	9,614,315	719,093	10,346,920	732,605
1835-Overhead Conductors and Devices	8,160,562	9,781,337	1,620,775	10,654,913	873,576	11,477,976	823,063	12,323,341	845,365
1840-Underground Conduit	4,627,233	5,350,803	723,570	5,789,743	438,940	6,189,113	399,370	6,584,277	395,163
1845-Underground Conductors and Devices	5,522,557	6,633,948	1,111,391	7,195,030	561,082	7,704,692	509,662	8,230,501	525,809
Sub-Total-Poles and Wires	25,104,845	30,062,083	4,957,238	32,534,908	2,472,825	34,986,096	2,451,188	37,485,039	2,498,942
Line Transformers									
1850-Line Transformers	11,252,097	12,338,414	1,086,317	12,635,222	296,808	13,557,308	922,086	14,480,337	923,029
Sub-Total-Line Transformers	11,252,097	12,338,414	1,086,317	12,635,222	296,808	13,557,308	922,086	14,480,337	923,029
Services and Meters									
1855-Services	6,740,301	7,847,594	1,107,293	8,497,736	650,142	9,097,432	599,696	9,700,983	603,550
1860-Meters	2,453,286	2,663,979	210,693	2,840,000	176,021	3,071,462	231,462	3,294,213	222,750
1861-Smart Meters									
Sub-Total-Services and Meters	9,193,587	10,511,573	1,317,986	11,337,736	826,163	12,168,894	831,158	12,995,195	826,301

Description	2006 Board Approved ($)	2006 Actual ($)	Variance from 2006	2007 Actual ($)	Variance from 2006	2008 Bridge ($)	Variance from 2007	2009 Test ($)	Variance from 2008
General Plant									
1908-Buildings and Fixtures									
1910-Leasehold Improvements									
Sub-Total-General Plant									
IT Assets									
1920-Computer Equipment - Hardware	2,026,910	2,324,923	298,013	2,485,158	160,235	2,607,616	122,458	2,810,965	203,349
1925-Computer Software	225,412	363,979	138,567	445,920	81,941	618,198	172,278	725,267	107,069
Sub-Total-IT Assets	2,252,322	2,688,902	436,580	2,931,078	242,176	3,225,814	294,736	3,536,232	310,418
Equipment									
1915-Office Furniture and Equipment	1,007,105	1,013,506	6,401	1,036,132	22,627	1,078,594	42,462	1,121,274	42,680
1930-Transportation Equipment	3,352,971	3,757,130	404,159	3,779,699	22,568	3,956,061	176,362	4,132,591	176,530
1935-Stores Equipment	62,685	62,835	150	62,835		62,835		63,417	582
1940-Tools, Shop and Garage Equipment	1,720,228	1,872,140	151,912	1,939,062	66,922	2,025,970	86,908	2,078,955	52,985
1945-Measurement and Testing Equipment	19,675	39,702	20,027	52,284	12,582	52,284		78,875	26,591
1950-Power Operated Equipment	49,097	2,192	(46,905)	2,550	358	2,550		11,381	8,831
1955-Communication Equipment	145,703	155,632	9,929	158,386	2,754	161,229	2,843	163,392	2,163
1960-Miscellaneous Equipment									
Sub-Total-Equipment	6,357,464	6,903,137	545,673	7,030,948	127,812	7,339,524	308,575	7,649,885	310,361
Other Distribution Assets									
1825-Storage Battery Equipment									
1980-System Supervisory Equipment		21,289	21,289	31,674	10,386	51,613	19,939	70,652	19,038
1985-Sentinel Lighting Rental Units	4,081		(4,081)						
1990-Other Tangible Property									
1995-Contributions and Grants - Credit		(948,700)	(948,700)	(1,228,700)	(280,000)	(1,561,900)	(333,200)	(1,921,900)	(360,000)
1996-Hydro One S/S Contribution								28,476	28,476
Sub-Total-Other Distribution Assets	4,081	(927,411)	(931,492)	(1,197,026)	(269,614)	(1,510,287)	(313,261)	(1,822,773)	(312,486)
ACCUMULATED DEPRECIATION TOTAL	60,088,323	68,017,440	7,929,117	71,981,194	3,963,754	76,881,949	4,900,755	81,830,062	4,948,113

VARIANCE ANALYSIS ON ACCUMULATED DEPRECIATION:

Changes in accumulated depreciation are directly affected by changes in fixed assets due to additions and the disposition of identifiable assets. The 2006 Board Approved closing balance for accumulated depreciation is based on Thunder Bay Hydro's 2004 year end account balances, plus Tier 1 capital adjustments approved in Thunder Bay Hydro's 2006 EDR Application. As such, the variance between 2006 Board Approved and 2006 Actual represents two years of depreciation changes, and in order to arrive at the annual impact, the variance must be divided by two.

As noted above, Thunder Bay Hydro has a variance analysis threshold of $603,424 The accumulated depreciation variances for the 2006 Actual to 2006 Board Approved, 2007 Actual to 2006 Actual, 2008 Bridge Year to the 2007 Actual Year and the 2009 Test Year to the 2008 Bridge Year exceed the variance threshold in the following OEB accounts: Poles, Tower, and Fixtures (Account 1830); Overhead Conductors and Devices (Account 1835); Underground Conduit (Account 1840); Underground Conductors and Devices (Account 1845); Line Transformers (Account 1850) and Services (Account 1855) . The Gross Asset Table provided in Exhibit 2, Tab 2, Schedule 1 above sets out the 2006 year end balances for each of these accounts. The OEB gross asset account balances at the end of 2006 are in excess of $15,085,600 for Poles, Towers and Fixtures, Overhead Conductors and Devices and Line Transformers and these asset balances increase annually with additions. Depreciation is written on a straight line basis over twenty five years, and as such, the annual additions to accumulated depreciation or each of these accounts would exceed the materiality threshold in subsequent years.

CAPITAL BUDGET:

Overview and Capital Budget by Project:

Thunder Bay Hydro has been, and continues to be, focused on maintaining the adequacy, reliability and quality of service to its distribution customers. The capital expenditures planned for 2009 reflect this ongoing focus. Thunder Bay Hydro's overall capital budget for 2009 is $7,620,833 reflecting an increase of $2,090,819 over 2008 projected capital ($5,530,014).

The capital budget is prepared annually by management and is reviewed and approved by Thunder Bay Hydro's Board of Directors typically in October. Once approved, the budget provides a plan against which actual results may be evaluated.

The capital budget process is a component of the overall budget process described in Exhibit 2, Tab 1, Schedule 1, above.

Over the past two years, the Board and management have become increasingly concerned that the recent level of capital expenditure is insufficient to ensure the integrity of the distribution system. As a simple illustration of this; of Thunder Bay Hydro's 19,410 pole system historically only about 350/year were replaced. This leads to a replacement program cycle which is approximately 55 years and well beyond a reasonable estimate of asset lifespan. Thus the Thunder Bay Hydro distribution system average age has been increasing over the past several years.

A historical review of capital expenditures at Exhibit 2, Tab 3, Schedule 1, Appendix A shows a steady increase in yearly expenditures on distribution system capital from 1970 through 1994. These increases reflect the yearly effect of inflation on the expenditure level. In 1995 this trend of increasing capital expenditures changes to a decreasing trend. This trend was precipitated by the decision of the then Hydro-Electric Commission of Thunder Bay to implement electricity rate reductions to the utility's customers. A total bill rate decrease on 1% was implemented in 1995. As this decrease was on the total electricity bill, and the wholesale cost of power was frozen at the time, the impact of this reduction was to reduce revenue available to fund utility

operations and capital investment by approximately 6.7% (based on distribution revenue being approximately 15% of the total electricity bill at the time). Further rate reductions of .4% and 1% followed in 1996 and 1997 respectively, further reducing funds available to the utility. The result of these rate decreases was reductions in both operating and capital expenditures by the utility. As the graphical analysis of Thunder Bay Hydro's capital expenditures in Exhibit 2, Tab 3, Schedule 1, Appendix A reflects, the rate reductions identified above combined with regular inflationary increases to utility resource inputs, contributed to a sustained reversal in the trend of regularly increasing capital expenditures. A simple extrapolation of yearly capital expenditures prior to 1996 indicates that yearly capital expenditures would be in the $10-$11 million dollar range if this trend reversal had not occurred.

As part of Thunder Bay Hydro's AMP, an extensive risk assessment of the entire Thunder Bay Hydro distribution system was carried out in 2006/7. The results confirmed that a significant portion of the overhead system is approaching end-of-life. An increase in the rate of replacement will be required over the next 10 years to ensure safety of employees and the public while maintaining reliable service to customers. Additionally, the underground assessment determined that the bulk of the system was constructed in the 70's and 80's and significant amounts of these assets will need to be replaced in the next 10 – 15 years due to end-of-life being reached. The risk assessments of the substations confirmed that some of these assets are at end-of-life and immediate replacement or offloading via voltage conversion is necessary.

Given the condition of Thunder Bay Hydro's distribution assets, the present replacement rate does not promote system sustainability, and capital replacement expenditures will have to be increased over the coming years. The Thunder Bay Hydro Board of Directors has considered this issue and the related risks and approved an increase in system replacement capital expenditures of approximately $1M for the 2008 budget year. This 2008 increase is funded through existing working capital rather than through distribution rates. However, a sustained increase in capital replacement activity will be required to stabilize the condition of the distribution system. The rate at which the capital program is increased must allow for efficient utilization of resources and

the acquiring of additional resources manageably. Thus, Thunder Bay Hydro is proposing to increase its capital replacement program by an approximate average incremental amount of $800,000/year over the next 3 years and re-evaluate its progress again at that time ($1.1M in 2009). An additional increase of $500,000/year on average for the next several years to replace 271 PCB contaminated distribution transformers is required over a 6 year period (approximately $200K per year capital and $300K maintenance).

Determining the appropriate planned capital replacement levels can be a very complex exercise and requires considering social issues like cost to customers and what rates are acceptable to our regulators, as well as our shareholder. Using the simple methodology of determining the present replacement cost of all existing assets and using the industry standard planning horizon for replacement of 40 years, we will determine a guideline for what the average annual replacement capital expenditures should be to meet the planning horizon. That figure will be used as a reference value to determine the required spending level to sustain the assets.

<u>Overhead Line Replacement Costs</u>

The per-unit cost of replacing Thunder Bay Hydro's overhead lines has been approximated in the following table, based on the amount of primary or secondary equipment on a km of overhead line and includes switching, protections and transformation requirements. The figures are based on recent contractor and internal per unit costs at Thunder Bay Hydro, as well as other recent and relevant projects.

Replacement of TBH Existing Overhead Line/Transformer Assets

Asset Type	km of Asset	Estimated Replacement Cost ($000/km)	Replacement Cost ($000,000)
Five Circuits/Pole	0.08	$ 713	$ 0.06
Four Circuits/Pole	1.96	$ 594	$ 1.16
Three Circuits/Pole	16.16	$ 475	$ 7.68
Two Circuits/Pole	79.45	$ 356	$ 28.30
One Circuit/Pole	337.41	$ 238	$ 80.13
Two Phases/Pole	8.86	$ 200	$ 1.77
Single Phase/Pole	362.29	$ 188	$ 67.93
Secondary Only	59.49	$ 132	$ 7.85
Total Overhead Line Replacement Cost			$ 194.89

An alternate approach using a typical per unit cost of a single pole replacement including: hardware, transformation, secondary equipment and complete with conductor restring results in an approximate cost of $9k – $11k/pole on average. This produces a comparable range of $175 – 213 million when applied to Thunder Bay Hydro's 19,410 poles.

Underground Cable Replacement Costs

The per-unit cost of replacing Thunder Bay Hydro's underground cables has been approximated below based on the amount of primary or secondary circuits in a single trench and includes switching and transformation requirements. The figures are based on recent per unit costs at Thunder Bay Hydro, contractor costs within subdivisions and other relevant projects.

Replacement of TBH Existing Underground Cable/Transformer/Switching Assets

Asset Type	km of Asset	Estimated Replacement Cost ($000/km)	Replacement Cost ($000,000)
Three Circuits/Trench	0.12	$ 728	$ 0.09
Two Circuits/Trench	0.78	$ 600	$ 0.47
One Circuit/Trench	90.13	$ 500	$ 45.07
Single Phase/Trench	138.99	$ 300	$ 41.70
Secondary Only	452.87	$ 225	$ 101.89
Total Underground Cable Replacement Cost			$ 189.21

The per unit figures above compare well against industry benchmarks of underground system costs being 2 – 3 times the equivalent overhead.

Substation Replacement Costs

Thunder Bay Hydro operates 19 substations within its distribution network that are presently required to service its low voltage customers (4 & 12kV). The expected replacement and remediation costs of each of these substations based on current market conditions and relevant recent projects would be approximately $1-2M per substation. Thus, the total replacement cost would be in the order of $28.5M.

Ultimately many of the substations will be removed from service facilitating a more efficient system. However, rerouting of feeders as well as the requirement for pole top equipment to replace much of that functionality contained within the substation will have to be incorporated into the system over the period of the 20-year capital plan. For simplicity the straight replacement cost of the substations has been left in the analysis until a more detailed plan for the substations is developed. It is anticipated however, that the actual replacement costs will be less than a like-for-like replacement of the substations.

Total System Replacement Costs

The total replacement cost for all distribution system assets including overhead lines, underground networks, and substations would be in the order of $412.6M. Thus, using a planning replacement horizon of 40 years or 2.5%, the expected annual expenditures on replacement capital is on average $412.6M x 2.5% or $10.3M/year.

Conversely the required average equipment replacements can be determined by aggregating all equipment types and dividing by the planning replacement horizon of 40 years. Thus, of the 19,410 poles, 485 should be replaced each year, as should 17 km of the 682 km of underground cables. Additionally, of the 19 substations; on average one should be rebuilt every two years. This type of analysis produces a very similar estimate for the annual replacement allotment.

The recent capital replacement programs have been well below the amount listed above with approximately $2.7 – 3.5M being allocated annually to capital plant replacement. Thus, the Thunder Bay Hydro asset condition has deteriorated given the significantly lower than sustaining levels of replacement spending that has occurred. As mentioned above, it is Thunder Bay Hydro's intention to increase future planned capital replacements by an approximate average incremental amount of $800,000/year ($1.1M in 2009) for the next 3 years to $9.2M/year in total capital, with planned capital replacements of $6.4M in 2011, and then re-evaluate its progress, as well as its requirements.

In 2008, Thunder Bay Hydro's capital program increased by approximately $1M to a total figure of $6.7M to address the asset conditions. This figure is comprised of $4.1M in replacement program, $1.6M for new connections and $1M in equipment, tools, and building capital. This continues to leave the replacement program well below the $10.3M/year sustaining level in the 2008 period. However, Thunder Bay Hydro recognizes that significantly increasing the level of capital expenditures means obtaining scarce resources to undertake the actual work. Immediately increasing the level of capital expenditures to a sustainable target level is unrealistic. Thunder Bay Hydro intends to develop this increased capacity, both internally and externally, over the next three years and anticipates that future EDR applications will reflect the need to continue to increase the level of system capital expenditures to a level that provides for the sustainability of the distribution system.

SMART METER PROGRAM:

Thunder Bay Hydro has commenced its Smart Meter program as approved by *Ontario Regulation 427/06* (Authorized Discretionary Metering Activity) and as amended by *Ontario Regulation 235/08*. Paragraph 4 Subsection 1 (1) has been amended to allow for "Metering activities conducted by a distributor that has procured its smart meters pursuant to and in compliance with the parameters and process established by the Request for Proposal for Advanced Metering Infrastructure (AMI) – Phase 1 Smart Meter Deployment dated August 14, 2007, together with any amendments to it, issued by London Hydro Inc."

Through its compliant participation in this process Thunder Bay Hydro has therefore been authorized to carry out discretionary metering activity.

As of the date of this filing, Thunder Bay Hydro, for the remainder of 2008 will issue three Request For Proposals (RFP). The first will be a vendor for Installation Services, the second for wide area network (WAN) requirements and the third for an operational data store (ODS) provider.

The installation services RFP is for the removal and installation of the smart meters themselves with vendor selection occurring by the end of October of 2008.

The WAN RFP is for the back hauling of meter data to the metering head end computer system in Thunder Bay prior to transmission to the IESO's MDM/R; vendor selection is planned to be completed by the end of November of 2008.

The ODS is a mission critical requirement for commissioning of the AMI system to prove system operability, to prove the operability meets the IESO's MDM/R data requirements, to reconcile data transfers between the IESO's MDM/R and Thunder Bay Hydro's billing system during testing, and to ensure meter data reliability for its customers on an ongoing basis. Vendor selection on this RFP will occur by the end of December of 2008.

On the metering front Thunder Bay Hydro will begin mass deployment of its smart meters in May of 2009 and plans to install the full requirement of approximately 49,100 meters for all residential and general service customers < 50kW by the end of October of 2009 via a steady state rollout. Vendor pricing negotiations for the metering are currently underway and are expected to be finalized by mid fall of 2008.

Thunder Bay Hydro worked with a consultant to develop a budget for the Smart Meter program. Total investment in Smart Meters is estimated at $7.704 million, plus $215K for computer software and hardware, and another $1.042 million incremental AMI and other administrative

and O&M costs. The total cost per installed meter is approximated at $182.50. The following Table 1 summarizes Thunder Bay Hydro's smart meter costs included in the rate adder section of this rate application.

Table 1

Smart Meter Costs – Rate Based	**2009 Test Year**
Total Smart Meter Costs	$8,960,950
Planned Installation of smart meters	49,100
Total cost per installed meter	$ 182.50

Based on its estimates, Thunder Bay Hydro has determined that to fully deploy the Smart Meter program as required a rate adder of $1.25 is required. The supporting calculation for the smart meter rate adder is included in this filing.

Table 2 below outlines the Smart Meter Program budget.

1

THUNDER BAY HYDRO
SMART METER PROGRAM SUMMARY

RATE FILLING	2008	2009	2010	2011	2012	TOTAL	UNIT COSTS/ METER
Total Meters Installed: 49,101							
Smart Meter Unit Costs	$0	$5,329,388	$61,888	$61,888	$61,888	$5,515,053	$112.32
Smart Meter Other Unit Costs	$77,801	$121,781	$46,301	$0	$0	$245,883	$5.01
Smart Meter Installation Costs Per Unit	$0	$1,572,859	$0	$0	$0	$1,572,859	$32.03
Smart Meter Other Costs Per Unit	$2,211	$367,994	$0	$0	$0	$370,205	$7.54
Smart Meter Unit Costs						$7,704,000	$156.90
AMI Computer Hardware Costs	$0	$157,879	$0	$0	$0	$157,879	
AMI Computer Software Costs	$0	$56,659	$0	$0	$0	$56,659	
Other Computer Hardware Costs	$0	$0	$0	$0	$0		
Other Computer Software Costs	$0	$0	$0	$0	$0		
Computer Hardware/Software Costs						$214,538	
							4 Yr Avg
Incremental AMI O&M Expenses	$0	$168,142	$405,145	$174,510	$177,814	$925,610	$231,403
Incremental AMI Admin Expenses	$0	$0	$3,402	$0	$0	$3,402	$851
Incremental Other O&M Expenses	$0	$28,350	$28,350	$28,350	$28,350	$113,400	$28,350
Incremental Other Admin Expenses	$0	$0	$0	$0	$0		
Incremental O&M and Admin Costs						$1,042,412	
Recoverable/Rate Adder Costs:						$8,960,950	$182.50
Deferrable Cost:							
Utility Safety & Mtce Capital Budget	$0	$556,805	$0	$0	$0	$556,805	
MDMR Cost:							
TOU Billing Budget	$0	$504,917	$463,882	$262,265	$262,499	$1,493,563	
TOTAL SMART METER COST:	$80,012	$8,864,774	$1,008,967	$527,013	$530,551	$11,011,318	

OTHER COMPUTER HARDWARE AND SOFTWARE:

- **Computer Hardware:**

Computer equipment is used in all departments of utility operations and is a key enabler in Thunder Bay Hydro initiatives to maintain and improve reliability, improve customer service and reduce costs.

New and replacement computer hardware consists of the following equipment:

- Desktops;
- Laptops;
- Monitors;
- Servers;
- Enterprise Main Frame;
- Printers;
- Network Infrastructure and Security

Thunder Bay Hydro utilizes a three-year life cycle for all computer and network infrastructure hardware with the exception of printers, which are extended to reasonable life expectancy, typically 5 years. Software is upgraded as required to maintain productivity, functionality and, where reasonable, currency within our ERP model. It is common industry practice to keep both the hardware and software environments up to date. Increased incidence of hardware failure reduced technical support, new technical standards and higher performance requirements of current operating systems and applications drive this lifecycle. The upgrade of aging servers and consolidation of multiple servers to a more manageable volume provide cost effective migration of workload with higher performance efficiencies and lower maintenance costs.

Other benefits of replacing computer equipment and adding new equipment include:

- Reducing the dependence on ISD resources to support older equipment;
- Ensuring third party support is available when required;

- Taking advantage of new technologies and increasing server utilization;
- Empowering employees to be more productive with the right equipment to do their jobs;
- Improving access to data and other information;
- Adhering to best practices; and
- Allowing for growth

The following table sets out Thunder Bay Hydro computer hardware-related capital expenditures for 2006, 2007, 2008 and 2009:

Project	**2006 Actual**	**2007 Actual**	**2008 Bridge**	**2009 Test**
New & replacement hardware: network infrastructure, enterprise resources, desktops, laptops, monitors, servers, printers and archiving devices.	$ 58,217	$ 27,533	$199,555	$ 70,810
Operating and engineering ISO resources	18,000	12,500	4,000	
Disk space and memory	7,000	2,600	2,000	6,500
Total	**$ 83,217**	**$ 42,633**	**$205,555**	**$ 77,310**

- **Computer Software:**

Computer software, whether operating system software or application software, are programs written in machine-readable languages, that control the operations of hardware or that enable users to perform certain tasks on computers.

The operating system software controls the hardware and manages its internal functions: controls input, output and storage and, handles its interaction with application programs. Application software enables users to accomplish particular tasks.

Today, the functioning of computer software is tied closely into the hardware it resides on and it is important that the specification of any PC or Server is appropriate for the software being installed.

Benefits of adding or replacing computer software include:

- Improvements in productivity from software enhancements;
- Empowering employees with the latest software technologies;
- Keeping up to date with industry standards;
- Ease of integration to other applications;
- Reduced costs using common operating system;
- Ensuring third party support is current
- Taking advantage of higher levels of security;
- Reduced dependence on ISD resources; and
- Improved tools for web development/design.

Adding and replacing computer software systems is necessary to support the running of all application programs. Software provides the support necessary for computers to interact with each other. Business Applications software processes transactions that are essential to running the business.

The following table sets out Thunder Bay Hydro's computer software-related capital expenditures for 2006, 2007, 2008 and 2009:

Project	**2006 Actual**	**2007 Actual**	**2008 Bridge**	**2009 Test**
New & replacement Software: enterprise system software upgrades, productivity tools, network security, distribution system analysis tools, database and external interface tools.	$ 85,087	$ 95,892	$ 22,000	$ 37,850
Total	**$ 85,087**	**$ 95,892**	**$ 22,000**	**$ 37,850**

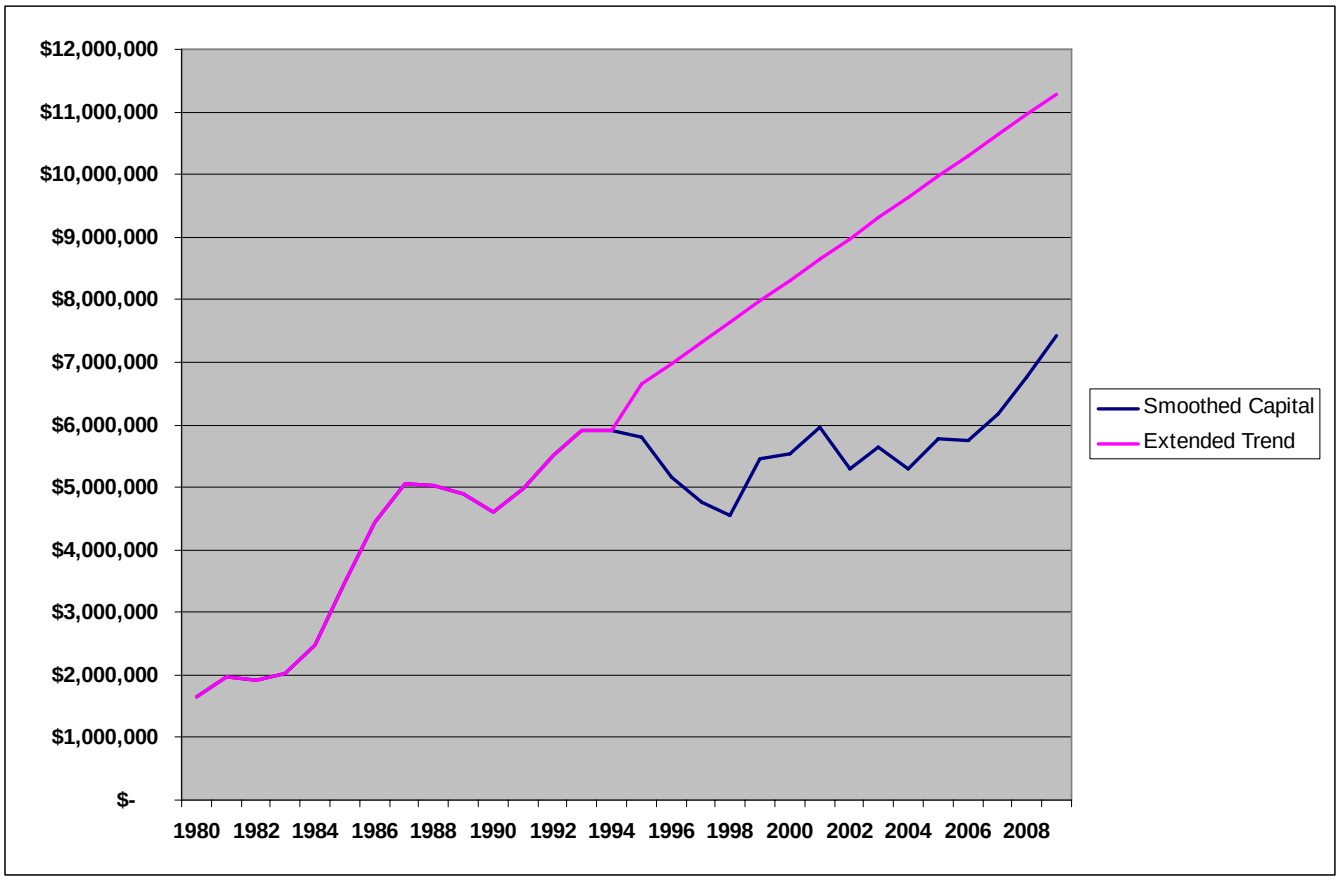
Thunder Bay Hydro's 2009 Business Case Reviews for non-customer driven capital projects as prepared by the Power Systems Engineering Department along with the 2009 Business Case Reviews for the Non-Infrastructure Capital are included in Exhibit 2, Tab 3, Schedule 1, Appendix C. The Business Case Reviews are prepared by the Engineering Department and approved by the Vice President, Power Systems prior to submission for budget.

APPENDIX A

HISTORICAL REVIEW OF CAPITAL EXPENDITURES

Historical Review of Capital Expenditures

1980 - 2008



APPENDIX B

COPY OF THUNDER BAY HYDRO'S 2008 BUSINESS CASE REVIEWS

"Part B" – Capital Projects

BUSINESS CASE REVIEW FORM

DEPARTMENT: A.M.E.	**DATE:** April 14. 2008	**BCR NO.** B812-03

TYPE OF REQUEST		
Initial ☒	Supplemental ☐	Scope Change ☐

CATEGORY			
Capital ☒	Major Repair ☐	Lease ☐	Other ☐

PROJECT TITLE

Tarbutt St. Area Conversion/Rebuild

BRIEF PROJECT DESCRIPTION (see page 2 for more details)

Replace 156 poles and conductors in the area between Empire Ave. and the CPR Tracks and between Sprague St. and Ford St., and convert the load from 4kV to 25kV.

PROJECT COST (see page 3 for more details)	
Estimate per this BCR	$ 861,909
Previously approved	$ 400,000
Total project Estimate (Including forward years)	$ 1261,909
Amount Included In 20-Year Capital Plan	$ 1261,909

FINANCIAL ANALYSIS	
Annual Benefits (additional revenues, cost savings.)	Payback period – years

SCHEDULE – Month/Year			
Beginning of Work:	**01/01/08**	Completion of Work:	**12/31/08**

APPROVALS

Title	Signature	Date
AME Manager Dipankar Chakrabarti		
Lines Superintendent Ken Dziver		
Operations Superintendent Ron Anderson		
VP, Power Systems Emanuel DaRosa		
VP, Finance Cindy Speziale		
President Rob Mace		

BUSINESS CASE REVIEW FORM – PROJECT DESCRIPTION

DEPARTMENT:	A.M.E.	DATE:	April 14. 2008	BCR NO.	B812-03

PROJECT TITLE

Tarbutt St. Area Conversion/Rebuild

DESCRIBE CURRENT SITUATION AND WHY PROJECT IS REQUIRED

This project refers to the area bounded by Empire Ave. to the north and the CPR tracks to the south, as well as Sprague St. in the east, and Ford St. in the west. The poles in this area are very rotten and have reached end-of-life. A considerable amount of conductor is restricted; ie #6 AWG copper. In addition, the load in the area is supplied at a voltage of 4kV (22F3).

In addition, the distribution substation reached end-of-life and needs replacement.

PROPOSED SOLUTION

Rebuild the plant in the area, replacing all poles, conductors, transformers, etc. Convert the load to 25kV, supplying it from 10M4 that is strung along the north end of the project on Empire Ave. This will off load the 4 kV substation and ultimately lead to its decommissioning.

BUSINESS CASE REVIEW FORM – PROJECT DESCRIPTION

OPTIONS EXAMINED
The plant is at end-of-life and doing nothing is not a safe option. The plant could be rebuilt to 4kV instead of 25kV, but this option is not as attractive as converting the load as the substation will also need to be replaced under this option. No cost is added for rebuilding at 25 kV instead of 4 kV.

EXPECTED BENEFITS (financial calculations if monetary benefits)
Nearly 1MVA of load will be removed from the 4kV system (22F3). The reduced losses will save money and energy. As the breakers are retired, they will no longer need maintainance and eventually the substations will be retired, which will further reduce the amount of money needed for upkeep and maintenance. This work will also eliminate the risks associated with failure of rotten poles, restricted conductors, and failure of the station.

VARIANCE – estimated cost versus annual plan	
Estimate cost per Page 1	$ 1261,909
Amount included in 20-Year Capital Plan Envelope	$ 1261,909
Variance	$ 0

BUSINESS CASE REVIEW FORM

DEPARTMENT: A.M.E.	**DATE:** April 14, 2008	**BCR NO.** B813-08

TYPE OF REQUEST		
Initial ☒	Supplemental ☐	Scope Change ☐

CATEGORY			
Capital ☒	Major Repair ☐	Lease ☐	Other ☐

PROJECT TITLE

10M6 Kam River Cable Crossing

BRIEF PROJECT DESCRIPTION (see page 2 for more details)

This project involves the direct boring of new ducts (appx. 210 metres) under the Kam River, beside the existing Kam Tunnel. New dip poles are to be installed on the north and south banks of the Kam River, near the existing dip poles. New cables, including a dedicated neutral conductor are to be pulled through the ducts and run up the new dip poles. The exisitng cables in the Kam Tunnel are to be abandoned.

PROJECT COST (see page 3 for more details)

Estimate per this BCR	$ 801,130
Previously approved	$ 0
Total project estimate (including forward years)	$ 801,130
Amount Included In 20-Year Capital Plan	$ 801,130

FINANCIAL ANALYSIS

Annual Benefits (additional revenues, cost savings.)	Payback period – years

SCHEDULE – Month/Year

Beginning of Work: **01/01/08**	Completion of Work: **12/31/08**

APPROVALS

Title	Signature	Date
AME Manager Dipankar Chakrabarti		
Lines Superintendent Ken Dziver		
Operations Superintendent Ron Anderson		
VP, Power Systems Emanuel DaRosa		
VP, Finance Cindy Speziale		
President Rob Mace		

BUSINESS CASE REVIEW FORM – PROJECT DESCRIPTION

DEPARTMENT:	**A.M.E.**	**DATE:**	**April14, 2008**	**BCR NO.**	B813-08

PROJECT TITLE

10M6 Kam River Cable Crossing

DESCRIBE CURRENT SITUATION AND WHY PROJECT IS REQUIRED

The tunnel under the Kam River through which the three-phase 10M6 trunk cables are pulled, is scheduled to be abandoned by the City of Thunder Bay. TBH does not want to be the last party in the tunnel to avoid assuming the responsibility to decommission the tunnel. This is a confined space and entry for maintenance is unsafe.

PROPOSED SOLUTION

Replace the existing cables with new cables in duct.
Boring under the Kam River and installing the duct will be performed by a contractor.
TBH will be responsible for laying and terminating the cables.

BUSINESS CASE REVIEW FORM – PROJECT DESCRIPTION

OPTIONS EXAMINED
The option of installing towers was examined; however erection and suspension of cables over the river would require an environmental assessment and permits, thus causing significant delays and jeopardizing project completion. Switching the 10M6 load onto 10M5 or 10M8 was examined. Switching the load onto 10M5 would prevent the paralleling of 10M5 and 10M8 because neither the 10M5 nor the 10M8 breakers would be able to support the load

EXPECTED BENEFITS (financial calculations if monetary benefits)
The new cables will have a 30-year life expectancy. The new cable will not need to be inspected where it lays under the river. Early exit of city-owned tunnel eliminates TBH responsibility to decommission.

VARIANCE – estimated cost versus annual plan	
Estimate cost per Page 1	$801,130
Amount included in 20-Year Capital Plan Envelope	$801,130
Variance	$ 0

BUSINESS CASE REVIEW FORM

DEPARTMENT: A.M.E.	**DATE:** May 6, 2008	**BCR NO.** B812-09

TYPE OF REQUEST		
Initial ☒	Supplemental ☐	Scope Change ☐

CATEGORY			
Capital ☒	Major Repair ☐	Lease ☐	Other ☐

PROJECT TITLE

Hill St. Area Conversion/Rebuild

BRIEF PROJECT DESCRIPTION (see page 2 for more details)

Replace 100 poles and conductors in the area between McKibbin St. and High St., Red River Road and John St. and convert the load from 4kV to 25kV.

PROJECT COST (see page 3 for more details)	
Estimate per this BCR	$ 988,145
Previously approved	$ 0
Total project Estimate (Including forward years)	$ 988,145
Amount Included In 20-Year Capital Plan	$ 988,145

FINANCIAL ANALYSIS	
Annual Benefits (additional revenues, cost savings.)	Payback period – years

SCHEDULE – Month/Year			
Beginning of Work:	**01/01/08**	Completion of Work:	**12/31/08**

APPROVALS

Title	Signature	Date
AME Manager Dipankar Chakrabarti		
Lines Superintendent Ken Dziver		
Operations Superintendent Duane Szyszka		
VP, Power Systems Emanuel DaRosa		
VP, Finance Cindy Speziale		
President Rob Mace		

BUSINESS CASE REVIEW FORM – PROJECT DESCRIPTION

DEPARTMENT: A.M.E.	DATE: May 6, 2008	BCR NO. B812-09

PROJECT TITLE

Hill St. Area Conversion/Rebuild

DESCRIBE CURRENT SITUATION AND WHY PROJECT IS REQUIRED

John St. Substation is at end-of-life and needs to be taken off line. Approximately 100 poles in the area between McKibbin St. and High St., Red River Rd. and John St., are at end-of-life. This area also contains a considerable amount of restricted conductor.

PROPOSED SOLUTION

Rebuild the area and convert the load to 25 kV.
# of poles to be replaced in Phase1 of this project (in 2008) = 100

BUSINESS CASE REVIEW FORM – PROJECT DESCRIPTION

OPTIONS EXAMINED
The plant is at end-of-life and doing nothing is not a safe option. The plant could be rebuilt to 4kV instead of 25kV. This option is not as attractive as converting the load as the substation will also need to be replaced under this option. No cost is added for rebuilding to 25 kV instead of 4 kV.

EXPECTED BENEFITS (financial calculations if monetary benefits)
Increase reliability, renewal of plant, and reduction of the load on John St. Substation.

VARIANCE – estimated cost versus annual plan	
Estimate cost per Page 1	$ 988,145
Amount included in 20-Year Capital Plan Envelope	$ 988,145
Variance	$ 0

APPENDIX C

COPY OF THUNDER BAY HYDRO'S 2009 BUSINESS CASE REVIEWS

"Part B" – Capital Projects
"Part C" – Capital Purchases

BUSINESS CASE REVIEW FORM

DEPARTMENT:	**DATE: April 03,2008**	**BCR NO. B923-17**

TYPE OF REQUEST		
Initial ☒	Supplemental ☐	Scope Change ☐

CATEGORY			
Capital ☒	Major Repair ☐	Lease ☐	Other ☐

PROJECT TITLE
Port Arthur TS Revenue Metering Upgrade

BRIEF PROJECT DESCRIPTION (see page 2 for more details)
Metering installation, design preparation, and design work of PTs and CTs on the T1 and T2 transformers, and rewiring of the existing bulk metering units.

PROJECT COST (see page 3 for more details)	
Estimate per this BCR	$ 256,143
Previously approved	$ 0
Total project Estimate (Including forward years)	$ 256,143
Amount Included In 20-Year Capital Plan	$ 256,143

FINANCIAL ANALYSIS	
Annual Benefits (additional revenues, cost savings.)	Payback period – years

SCHEDULE – Month/Year			
Beginning of Work:	**01/01/09**	Completion of Work:	**12/31/09**

APPROVALS		
Title	**Signature**	**Date**
AME Manager Dipankar Chakrabarti		
Lines Superintendent Ken Dziver		
Operations Superintendent Duane Szyszka		
VP, Power Systems Emanuel DaRosa		
VP, Finance Cindy Speziale		
President Rob Mace		

BUSINESS CASE REVIEW FORM – PROJECT DESCRIPTION

DEPARTMENT: A.M.E.	DATE: April 03,2008	BCR NO. B923-17

PROJECT TITLE

Port Arthur TS Revenue Metering Upgrade

DESCRIBE CURRENT SITUATION AND WHY PROJECT IS REQUIRED

Presently the revenue metering point in the Port Arthur TS Gate Station obtains its currents and voltages from instrument transformers that are not Measurement Canada approved and are presently on Measurement Canada temporary permission list, which expires in 2010. The IESO requires revenue metering installations to be Measurement Canada approved in Ontario. This means that instrument transformers used for trade purposes must have an accuracy of 0.3% or less and must be dedicated to the metering circuitry.

PROPOSED SOLUTION

Install dedicated Measurement Canada approved instrument transformers on Port Arthur T1 & T2.

Hydro One will decommission the existing arrangement, design and build the new arrangement in their transmission station.

BUSINESS CASE REVIEW FORM – PROJECT DESCRIPTION

OPTIONS EXAMINED
Doing nothing is not an option because legislation has been passed making dedicated Measurement Canada approved meters mandatory.

EXPECTED BENEFITS (financial calculations if monetary benefits)
By installing dedicated instrument transformers with known accuracy, more accurate billing of the energy consumed by Thunder Bay Hydro will be realized in compliance with market rules.

VARIANCE – estimated cost versus annual plan	
Estimate cost per Page 1	$256,143
Amount included in 20-Year Capital Plan Envelope	$ 256,143
Variance	$ 0

BUSINESS CASE REVIEW FORM

DEPARTMENT: A.M.E.	**DATE:** Apr 07, 2008	**BCR NO.** B912-11

TYPE OF REQUEST		
Initial ☒	Supplemental ☐	Scope Change ☐

CATEGORY			
Capital ☒	Major Repair ☐	Lease ☐	Other ☐

PROJECT TITLE

Winnipeg Area Conversion/Rebuild

BRIEF PROJECT DESCRIPTION (see page 2 for more details)

Replace 150 poles and conductors. Rebuild the area between Balmoral St., Oliver Road, Ontario St. and Inchiquin St., and convert the load from 4kV to 25kV.

PROJECT COST (see page 3 for more details)	
Estimate per this BCR	$1,655,277
Previously approved	$ 0
Total project Estimate (Including forward years)	$1,655,277
Amount Included In 20-Year Capital Plan	$1,655,277

FINANCIAL ANALYSIS	
Annual Benefits (additional revenues, cost savings.)	Payback period – years

SCHEDULE – Month/Year			
Beginning of Work:	**01/01/09**	Completion of Work:	**12/31/09**

APPROVALS

Title	**Signature**	**Date**
AME Manager Dipankar Chakrabarti		
Lines Superintendent Ken Dziver		
Operations Superintendent Duane Szyszka		
VP, Power Systems Emanuel DaRosa		
VP, Finance Cindy Speziale		
President Rob Mace		

BUSINESS CASE REVIEW FORM – PROJECT DESCRIPTION

DEPARTMENT: A.M.E.	DATE: Apr.07, 2008	BCR NO. B912-11

PROJECT TITLE

Winnipeg Area Conversion/Rebuild

DESCRIBE CURRENT SITUATION AND WHY PROJECT IS REQUIRED

This area is supplied by John St. Substation. The substation needs to be removed from service by 2012. Some of the conductors in the area (about 40%) are restricted, and the poles are at end-of-life. John St. Substation needs to be retired from service by 2012, and this load needs to be removed.

PROPOSED SOLUTION

String a three-phase semi-express feed through the area. This will create a 17M5 north/south trunk. Replace all of the poles, and string the laterals with 1/0 ASCR Al. Create an alternate 17M6 supply attachment point from the west on Ray Blvd. This will off-load the 4 kV substation and ultimately lead to its decommissioning.

BUSINESS CASE REVIEW FORM – PROJECT DESCRIPTION

OPTIONS EXAMINED
The risk of a catastrophic failure at John St. Substation is great. The risk of restricted conductor falling and a pole breaking is also a concern.

EXPECTED BENEFITS (financial calculations if monetary benefits)
Increase reliability, renewal of plant, reduction of the load on John St. Substation. Also eliminate the risk of failure due to rotten poles, restricted conductors, and failure of the station.

VARIANCE – estimated cost versus annual plan	
Estimate cost per Page 1	$1,655,277
Amount included in 20-Year Capital Plan Envelope	$1,655,277
Variance	$ 0

BUSINESS CASE REVIEW FORM

DEPARTMENT: A.M.E.	**DATE:** Apr 17, 2008	**BCR NO.** B912-21

TYPE OF REQUEST

Initial ☒	Supplemental ☐	Scope Change ☐

CATEGORY

Capital ☒	Major Repair ☐	Lease ☐	Other ☐

PROJECT TITLE

Durban-Brodie Area Conversion/Rebuild

BRIEF PROJECT DESCRIPTION (see page 2 for more details)

Replace all poles and conductors in the area between McKellar St. and May St. and between the McIntyre River and the Neebing River. Three phase line to be built in the lane north of Northern Ave. A three phase line is to be built in the lane between McKellar St. and Syndicate Ave., creating a tie point with 17M1 just south of the river. Three phase line to be constructed on Durban St., and in the lane between Brodie St. and May St..

PROJECT COST (see page 3 for more details)

Estimate per this BCR	$ 492,807
Previously approved	$ 0
Total project Estimate (Including forward years)	$ 492,807
Amount Included In 20-Year Capital Plan	$ 492,807

FINANCIAL ANALYSIS

Annual Benefits (additional revenues, cost savings.)	Payback period – years

SCHEDULE – Month/Year

Beginning of Work: **01/01/09**	Completion of Work: **12/31/09**

APPROVALS

Title	Signature	Date
AME Manager Dipankar Chakrabarti		
Lines Superintendent Ken Dziver		
Operations Superintendent Duane Szyszka		
VP, Power Systems Emanuel DaRosa		
VP, Finance Cindy Speziale		
President Rob Mace		

BUSINESS CASE REVIEW FORM – PROJECT DESCRIPTION

DEPARTMENT: A.M.E.	DATE: Apr.17, 2008	BCR NO. B912-21

PROJECT TITLE

Durban-Brodie Area Conversion/Rebuild

DESCRIBE CURRENT SITUATION AND WHY PROJECT IS REQUIRED

Most of the poles in the area north of Northern Ave., between McKellar St. and May St., north of Northern Ave. are rotten. Most of the conductors are #6 AWG Copper. In addition, the area is supplied from 4kV (4F1). The physical state of this area was identified as grave when assessed by our PLE performing the assessment.

PROPOSED SOLUTION

Rebuild the area and supply it from 25kV (10M1).

BUSINESS CASE REVIEW FORM – PROJECT DESCRIPTION

OPTIONS EXAMINED
The poles are rotten; much of the conductor is restricted. The plant is at end-of-life and doing nothing is not a safe option. The plant could be rebuilt to 4kV instead of 25kV. This option is not as attractive as converting the load as the substation would also need to be replaced under this option. There is no additional cost to this project to rebuild to 25 kV instead of 4 kV.

EXPECTED BENEFITS (financial calculations if monetary benefits)
The first benefit is that the #6 AWG copper (restricted conductor) will be replaced. The poles will be replaced and a tie between 10M1 and 17M1 will be created. This will also eliminate the risk due to failure of rotten poles, restricted conductors, and failure of the station.

VARIANCE – estimated cost versus annual plan	
Estimate cost per Page 1	$ 492,807
Amount included in 20-Year Capital Plan Envelope	$ 492,807
Variance	$ 0

BUSINESS CASE REVIEW FORM

DEPARTMENT: A.M.E.	**DATE:** Apr 17, 2008	**BCR NO.** B912-30

TYPE OF REQUEST		
Initial ☒	Supplemental ☐	Scope Change ☐

CATEGORY			
Capital ☒	Major Repair ☐	Lease ☐	Other ☐

PROJECT TITLE

Ontario/Banning Area Conversion/Rebuild

BRIEF PROJECT DESCRIPTION (see page 2 for more details)

Replace 42 poles and conductors in the area between Bay St. and John St. and between Machar Ave. and Crown St. and convert the load from 4kV to 25kV.

PROJECT COST (see page 3 for more details)	
Estimate per this BCR	$ 431,984
Previously approved	$ 0
Total project Estimate (Including forward years)	$ 431,984
Amount Included In 20-Year Capital Plan	$ 431,984

FINANCIAL ANALYSIS	
Annual Benefits (additional revenues, cost savings.)	Payback period – years

SCHEDULE – Month/Year			
Beginning of Work:	**01/01/09**	Completion of Work:	**12/31/09**

APPROVALS

Title	Signature	Date
AME Manager Dipankar Chakrabarti		
Lines Superintendent Ken Dziver		
Operations Superintendent Duane Szyszka		
VP, Power Systems Emanuel DaRosa		
VP, Finance Cindy Speziale		
President Rob Mace		

BUSINESS CASE REVIEW FORM – PROJECT DESCRIPTION

DEPARTMENT: A.M.E.	DATE: Apr.17, 2008	BCR NO. B912-30

PROJECT TITLE

Ontario/Banning Area Conversion/Rebuild

DESCRIBE CURRENT SITUATION AND WHY PROJECT IS REQUIRED

This project refers to the area bounded by Bay St. to the north, John St. to south, Machar Ave. to the east and Crown St. to west. This area is supplied by John St. Substation, and the substation needs to be removed from service by 2010. The poles in this area are very rotten and have reached end-of-life. A considerable amount of conductor in this area is restricted; ie #6 AWG copper.

PROPOSED SOLUTION

Transfer the existing circuits of 13F2 and 13F3 onto 17M5. Replace all poles and conductors in the area and convert load from 4kV to 25kV. This will off load the 4 kV substation and ultimately lead to its decommissioning.

BUSINESS CASE REVIEW FORM – PROJECT DESCRIPTION

OPTIONS EXAMINED
The poles are rotten, much of the conductor is restricted, and the substation needs to be retired. The plant is at end-of-life and doing nothing is not a safe option. The plant could be rebuilt to 4kV instead of 25kV, although this option is not as attractive as converting the load as the substation will also need to be replaced under this option. There is no additional cost added to the project to rebuild to 25 kV instead of 4 kV.

EXPECTED BENEFITS (financial calculations if monetary benefits)
13F2 and 13F3 load will be converted to 25kV. 119 poles and the restricted conductor will be replaced. This will eliminate the risk of failure due to rotten poles, restricted conductor, and failure of the station.

VARIANCE – estimated cost versus annual plan	
Estimate cost per Page 1	$ 431,984
Amount included in 20-Year Capital Plan Envelope	$ 431,984
Variance	$ 0

BUSINESS CASE REVIEW FORM

DEPARTMENT: A.M.E.	**DATE:** Apr 09, 2008	**BCR NO.** B912-37

TYPE OF REQUEST		
Initial ☒	Supplemental ☐	Scope Change ☐

CATEGORY			
Capital ☒	Major Repair ☐	Lease ☐	Other ☐

PROJECT TITLE

Amelia/Brown Area Conversion/Rebuild

BRIEF PROJECT DESCRIPTION (see page 2 for more details)

Replace 43 poles and conductors in the area between Brock St. and Frederica St. and between Edward St. and Heath St., and convert the load from 4kV to 25kV.

PROJECT COST (see page 3 for more details)	
Estimate per this BCR	$ 479,993
Previously approved	$ 0
Total project Estimate (Including forward years)	$ 479,993
Amount Included In 20-Year Capital Plan	$ 479,993

FINANCIAL ANALYSIS	
Annual Benefits (additional revenues, cost savings.)	Payback period – years

SCHEDULE – Month/Year			
Beginning of Work:	**01/01/09**	Completion of Work:	**12/31/09**

APPROVALS

Title	Signature	Date
AME Manager Dipankar Chakrabarti		
Lines Superintendent Ken Dziver		
Operations Superintendent Duane Szyszka		
VP, Power Systems Emanuel DaRosa		
VP, Finance Cindy Speziale		
President Rob Mace		

BUSINESS CASE REVIEW FORM – PROJECT DESCRIPTION

DEPARTMENT: A.M.E.	DATE: Apr.09, 2008	BCR NO. B912-37

PROJECT TITLE

Amelia/Brown Area Conversion/Rebuild

DESCRIBE CURRENT SITUATION AND WHY PROJECT IS REQUIRED

This project refers to the area bounded by Brock St. to the north, Frederica St. to south, Edward St. to east, and Heath St. to west. The poles in this area are very rotten and have reached end-of-life. A considerable amount of conductor is restricted; ie #6 AWG copper. In addition, the load in the area is supplied at a voltage of 4kV (22F1/22F6)

PROPOSED SOLUTION

Transfer the existing circuits of 22F1 and 22F6 onto 10M4. Replace all poles and conductors between Brock St. and Frederica St. This will off-load the 4 kV substation and ultimately lead to its decommissioning.

BUSINESS CASE REVIEW FORM – PROJECT DESCRIPTION

OPTIONS EXAMINED
The poles are rotten, much of the conductor is restricted, and the substation needs to be retired. The plant is at end-of-life and doing nothing is not a safe option. The plant could be rebuilt to 4kV instead of 25kV. This option is not as attractive as converting the load as the substation will also need to be replaced under this option. No cost is added for rebuilding at 25 kV instead of 4 kV.

EXPECTED BENEFITS (financial calculations if monetary benefits)
22F1 and 22F6 load will be converted to 25kV. 43 poles and the restricted conductor will be replaced. This work will eliminate the risk of failure of rotten poles, restricted conductors, and failure of station.

VARIANCE – estimated cost versus annual plan	
Estimate cost per Page 1	$ 479,993
Amount included in 20-Year Capital Plan Envelope	$ 479,993
Variance	$ 0

BUSINESS CASE REVIEW FORM

DEPARTMENT: A.M.E.	**DATE:** Apr 07, 2008	**BCR NO.** B914-05

TYPE OF REQUEST		
Initial ☒	Supplemental ☐	Scope Change ☐

CATEGORY			
Capital ☒	Major Repair ☐	Lease ☐	Other ☐

PROJECT TITLE

County Fair Park Underground Line Rebuild - Phase 1

BRIEF PROJECT DESCRIPTION (see page 2 for more details)

Install a new three phase full express feed (approx. 2km) through the park in County Park, from the overhead line behind County Fair Plaza to the overhead line on Wardrope Ave. Install padmounted switching centres to allow for connection of the underground loops in the area and at Our Lady of Charity School. (1- PMH9, 1PMH6, 3-sectionalizing cabinets).

PROJECT COST (see page 3 for more details)	
Estimate per this BCR	$1,101,053
Previously approved	$ 0
Total project estimate (Including forward years)	$1,101,053
Amount Included In 20-Year Capital Plan	$1,101,053

FINANCIAL ANALYSIS	
Annual Benefits (additional revenues, cost savings.)	Payback period – years

SCHEDULE – Month/Year			
Beginning of Work:	**1/1/09**	Completion of Work:	**12/31/09**

APPROVALS

Title	Signature	Date
AME Manager Dipankar Chakrabarti		
Lines Superintendent Ken Dziver		
Operations Superintendent Duane Szyszka		
VP, Power Systems Emanuel DaRosa		
VP, Finance Cindy Speziale		
President Rob Mace		

BUSINESS CASE REVIEW FORM – PROJECT DESCRIPTION

DEPARTMENT: A.M.E.	DATE: Apr 07, 2008	BCR NO. B914-05

PROJECT TITLE

County Fair Park Underground Line Rebuild – Phase 1

DESCRIBE CURRENT SITUATION AND WHY PROJECT IS REQUIRED

The County Park underground loops have become very old and fragile. The semi-express conductors tying the Wardrope circuit to the circuit south of County Park has been dug-up and severed several times. This semi-express is also problematic where the 200A bus in the transformer at Our Lady of Charity School, in the centre of the loop, carries the load. When 17M3 and 17M4 are paralleled, full feeder load is carried on this transformer bus.

PROPOSED SOLUTION

Replace the underground semi-express feed with a new three-phase full express feed through the park in County Park. Install padmounted switching centres to allow for connection of the underground loops, and at Our Lady of Charity School. Install 18 single-phase padmount transformers and single phase feeds.

BUSINESS CASE REVIEW FORM – PROJECT DESCRIPTION

OPTIONS EXAMINED
The County Park underground loops have become very old and fragile. The semi-express conductors tying the Wardrope circuit to the circuit south of County Park has been dug up and severed several times. This semi-express is also is problematic where the 200A bus in the transformer at Our Lady of Charity School in the centre of the loop carries the load when 17M3 and 17M4 are paralleled, and full feeder load is carried on this transformer bus. The plant is very old and fragile and doing nothing is not a safe option. Installing an overhead distribution circuit is not practical due location constraints.

EXPECTED BENEFITS (financial calculations if monetary benefits)
The underground cable will be renewed. The risk of outages will be reduced because the older damaged and repaired cable has been replaced. Two feed points will be provided for each loop providing back-up. Future maintenance will be much easier and outages for maintenance will affect fewer customers.

VARIANCE – estimated cost versus annual plan	
Estimate cost per Page 1	$1,101,053
Amount included in 20-Year Capital Plan Envelope	$1,101,053
Variance	$ 0

BUSINESS CASE REVIEW FORM

DEPARTMENT: A.M.E.	**DATE:** April 03,2008	**BCR NO.** B923-16

TYPE OF REQUEST		
Initial ☒	Supplemental ☐	Scope Change ☐

CATEGORY			
Capital ☒	Major Repair ☐	Lease ☐	Other ☐

PROJECT TITLE
Birch TS Revenue Metering Upgrade

BRIEF PROJECT DESCRIPTION (see page 2 for more details)
Design, supply, and installation of PTs and CTs on the T2, T3, and T4 transformers, and rewiring of the existing bulk metering units.

PROJECT COST (see page 3 for more details)	
Estimate per this BCR	$ 519,064
Previously approved	$ 0
Total project Estimate (Including forward years)	$ 519,064
Amount Included In 20-Year Capital Plan	$ 519,064

FINANCIAL ANALYSIS	
Annual Benefits (additional revenues, cost savings.)	Payback period – years

SCHEDULE – Month/Year			
Beginning of Work:	**01/01/09**	Completion of Work:	**12/31/09**

APPROVALS		
Title	**Signature**	**Date**
AME Manager Dipankar Chakrabarti		
Lines Superintendent Ken Dziver		
Operations Superintendent Duane Szyszka		
VP, Power Systems Emanuel DaRosa		
VP, Finance Cindy Speziale		
President Rob Mace		

BUSINESS CASE REVIEW FORM – PROJECT DESCRIPTION

DEPARTMENT:	**A.M.E.**	**DATE:**	**April 03,2008**	**BCR NO.**	B923-16

PROJECT TITLE

Birch Ts Revenue Metering Upgrade

DESCRIBE CURRENT SITUATION AND WHY PROJECT IS REQUIRED

Presently the revenue metering point in the Birch TS Gate Station obtains its currents and voltages from instrument transformers that are shared with the protection circuits. These instrument transformers, in addition to being shared, do not have a known accuracy. The IESO requires revenue metering installations to be Measurement Canada approved in Ontario. This means that instrument transformers used for trade purposes must have an accuracy of 0.3% or less and must be dedicated to the metering circuitry.

PROPOSED SOLUTION

Install dedicated Measurement Canada approved instrument transformers on Birch T2, T3 & T4.

Hydro One will decommission the existing arrangement and design and build the new arrangement in their transmission station.

BUSINESS CASE REVIEW FORM – PROJECT DESCRIPTION

OPTIONS EXAMINED
Doing nothing is not an option because legislation has ben passed making dedicated Measurement Canada approved meters mandatory.

EXPECTED BENEFITS (financial calculations if monetary benefits)
By installing dedicated instrument transformers with a known accuracy, more accurate billing of the energy consumed by Thunder Bay Hydro will be realized in compliance with market rules.

VARIANCE – estimated cost versus annual plan	
Estimate cost per Page 1	$ 519,064
Amount included in 20-Year Capital Plan Envelope	$ 519,064
Variance	$ 0

Power Systems Division
Part "C" Capital Budget Items
Under $10,000

Project ID:	C93400 (96034)	Date Entered:	May 14, 2008
Budget Year:	2009	Requested By:	Duane Szyszka
Department:	Operations/Lines	Reviewed By:	
GMBA #	001 6572 425 6917		

Project Title	Rolling Stock
	Rolling Stock - Under 3-Tons (miscellaneous equipment) - under $10,000

Items:

Description	**Cost**
None for Lines.	$ -
Gas powered pick-up truck sand spreader	$ 6,500
Total	**$ 6,500**

Description: Pick-up-truck-mounted gas powered sand spreader with internal cab controls.

Benefits: This spreader will allow for faster sanding activities, more thorough dispersion, and greater coverage of sand in the winter months. It will also reduce the amount of shoveling and hand-spreading that presently takes place.

Justification: Historically we have seen rain in December and January followed by freezing conditions, which create extreme slip and fall hazards. This spreader would be very mobile and could be used throughout our parking lots, Station driveways/sidewalks, and yard areas that are accessed by TBH personnel, including out in the Lines Construction areas of back lanes, roadsides, etc., where slippery surfaces exist. TBH presently uses a backhoe loader to spread sand onto icy surfaces, which is an inappropriate use of equipment and produces mediocre results. This spreader will reduce the potential for injury while personnel are shoveling or spreading sand onto slippery surfaces.

Power Systems Division
Part "C" Capital Budget Item
Greater Than $10,000

Project ID:	C93401 (96034)
Budget Year:	2009
Department:	Operations
GMBA #	001 6572 425 6917

Date Entered:	May 14, 2008
Requested By:	Duane Szyszka
Reviewed By:	

Project Title	Rolling Stock
Project Description:	Rolling Stock - Under 3-Tons - over $10,000

Estimated Cost:	$ 38,000
Description:	A new 3/4-ton, 4 x 4 replacement for truck #16 a 1995 regular cab, 1/2-ton which is presently assigned to the Fleet Department.
Benefits:	A new vehicle provides updated safety improvements such as air bags, anti-lock brakes, new seat, additional internal storage, as well as improved reliability, fuel economy, warranty, and improved appearance (no rust or body panel holes). The 4 x 4 will provide increased traction and winter usability.
Justification:	Truck #16 has received extensive body work and painting in the past and now has holes rusted through on various body panels. It will be a 14-year old vehicle in 2009 and should be replaced as per the TBH proposed vehicle replacement schedule. Truck #16 will be used as a trade-in for this vehicle. An MTO inspector also commented to one of our mechanics in April 2008, that this vehicle is due to be retired in the near future.

Power Systems Division
Part "C" Capital Budget Item
Greater Than $10,000

Project ID:	C93402 (96034)
Budget Year:	2009
Department:	Operations
GMBA #	001 6572 425 6917

Date Entered:	May 9, 2008
Requested By:	Duane Szyszka
Reviewed By:	

Project Title	Rolling Stock
Project Description:	Rolling Stock - Under 3-Tons - over $10,000

Estimated Cost:	$ 38,000
Description:	A new 1/2-ton extended cab 4 x 4 truck is requested to replace TBH's 1995 regular cab 1/2-ton truck #22, which is presently a spare truck.
Benefits:	A new extended cab vehicle provides increased internal storage space, updated safety improvements, such as air bags, anti-lock brakes, new seats, additional internal storage, as well as improved reliability, fuel economy, warranty, and improved appearance (no rust or body panel holes). The 4 x 4 will provide increased traction and winter usability.
Justification:	Truck #22 has extensive body panel/hood rusting, as well as holes rusted throughout the exterior body panels. It will be a 14-year old vehicle in 2009 and should be replaced as per the TBH proposed vehicle replacement schedule. Truck #22 will be used as a trade-in vehicle.

Power Systems Division
Part "C" Capital Budget Item
Greater Than $10,000

Project ID:	C93403 (96034)
Budget Year:	2009
Department:	Operations
GMBA #	001 6572 425 6917

Date Entered:	May 9, 2008
Requested By:	Duane Szyszka
Reviewed By:	

Project Title	Rolling Stock
Project Description:	Rolling Stock - Under 3-Tons - over $10,000

Estimated Cost:	$ 38,000
Description:	A new full-size 1/2-ton, extended cab, short box, 4x 4 truck to replace Truck 29.
Benefits:	A new vehicle provides updated safety improvements, such as air bags, anti-lock brakes, new seats, additional internal storage, as well as improved reliability, fuel economy, warranty, and improved appearance (no rust). The 4 x 4 will provide increased traction and winter usability.
Justification:	The new E&M Supervisor presently uses a 2000 regular cab 4 x 4 mini-truck (Truck #29) and cannot adjust the seat to fit his leg length or increase the head room. Truck #29 will be used as a trade-in vehicle. A larger vehicle will reduce the potential for an ergonomic concern or injury.

Power Systems Division
Part "C" Capital Budget Item
Greater Than $10,000

Project ID:	C93404 (96034)
Budget Year:	2009
Department:	Lines
GMBA #	001 6572 425 6918

Date Entered:	June 13, 2008
Requested By:	Ken Dziver
Reviewed By:	

Project Title	Rolling Stock
Project Description:	Rolling Stock - 3-Tons & Over - over $10,000

Estimated Cost:	$ 300,000
Description:	This is a new 55' double bucket, material handler.
Benefits:	Improved reliability and fuel consumption. Completion of capital/maintenance projects. Included in this price is $15,000 for new equipment for use with the truck.
Justification:	Due to the increase in staff levels in the Lines Department, we will require additional vehicles for live-line work.

Power Systems Division
Part "C" Capital Budget Item
Greater Than $10,000

Project ID:	C93405 (96034)
Budget Year:	2009
Department:	Lines
GMBA #	001 6572 425 6917

Date Entered:	June 13, 2008
Requested By:	Ken Dziver
Reviewed By:	

Project Title	Rolling Stock
Project Description:	Rolling Stock - Under 3-Tons - over $10,000

Estimated Cost:	$ 10,000
Description:	Utility trailer for various uses: used to haul fill for pole removals; transport materials like stand-off brackets, insulators, cases of bolts, etc. that are required for larger projects.
Benefits:	This trailer will reduce the number of vehicles and men required on a job-site.
Justification:	Presently there is only one utility trailer available. This trailer will be used in order to bring fill nearer to the required site. This trailer would also free-up larger dump trucks and backhoes.

Power Systems Division
Part "C" Capital Budget Item
Greater Than $10,000

Project ID:	C93406 (96034)
Budget Year:	2009
Department:	AME
GMBA #	001 6572 425 6917

Date Entered:	June 13, 2008
Requested By:	James Mann
Reviewed By:	Dipankar Chakrabarti

Project Title	Rolling Stock
Project Description:	Rolling Stock - Under 3-Tons - over $10,000

Estimated Cost:	$ 33,000
Description:	The existing utility mini-van (Unit #18), which is used by the Locate Department is 13 years old (1995) and the body is corroded. Exhaust gas comes partly inside the vehicle through holes in the flooring. It is suggested to purchase a new mini SUV to replace the existing vehicle. The old vehicle would be used as a trade-in.
Benefits:	Reduced downtime and increased availability. Increased reliability. Reduced maintenance cost. Four-wheel drive vehicle would have increased traction in winter. Increased body height from ground would allow vehicle to enter construction sites.
Justification:	Operation of this old vehicle is unsafe and less reliable. It is suggested that a proactive action be taken before the vehicle becomes completely unusable. Also, the maintenance of this vehicle has increased and its frequent downtime is adversely affecting operations. Existing vehicle is not a four-wheel drive and use during winter is avoided due to decreased traction causing unsafe conditions. Vehicle #18 will be used as a trade-in for the new vehicle.

Power Systems Division
Part "C" Capital Budget Item
Greater Than $10,000

Project ID:	C83402 (96034)	Date Entered:	June 19, 2007
Budget Year:	2008	Requested By:	Ken Dziver
Department:	Lines	Reviewed By:	
GMBA #	001 6572 425 6918		

Project Title	Rolling Stock
Project Description:	Rolling Stock - 3-Tons & Over - over $10,000

Estimated Cost:	$ 230,000
Description:	A new 47 foot reach RBD to replace truck #14 which has a 1987 chassis and a 1971 boom that was relocated on to the truck
Benefits:	This truck will assist in the completion of the 2008 Capital and Maintenance budgets. Reduced down time and truck maintenance costs. A new truck brings with it better safety features such as lighting bypass valves to help reduce injuries.
Justification:	Presently Lines is short 1 RBD as the existing truck 14 had to be permanently taken off the road due to safety issues. Crews are having to be sent to return to job sites in order to complete the work.

Power Systems Division
Part "C" Capital Budget Items
Under $10,000

Project ID:	C93700 (96037)	Date Entered:	June 13, 2008
Budget Year:	2009	Requested By:	Ken Dziver
Department:	Lines	Reviewed By:	
GMBA #	001 6556/9 480 69xx		

Project Title	Tools Lines
Project Description:	All tools and equipment required by the Lines Overhead & Underground staff - under $10,000

Items:

Description	Cost
Hydraulic tools (3 x $2000) (001 6556 480 6906)	$ 6,000
Gas drills (2 x $600) (001 6556 480 6906)	$ 1,200
Tilt transformer tester (2 x $600) (001 6556 480 6919)	$ 1,200
Chainsaws (2) (001 6556 480 6906)	$ 1,000
Travellers (20 x $300) (001 6556 480 6906)	$ 6,000
5kV Megger (001 6556 480 6919)	$ 2,000
Meter base jumper (001 6556 480 6906)	$ 5,000
Pilot ropes (4 x $600) (001 6556 480 6906)	$ 2,400
Hot line cutters (001 6556 480 6906)	$ 2,000
Hot line cutter holders (001 6559 480 6906)	$ 2,000
Pilot rope c/w reel (001 6559 480 6906)	$ 1,700
Battery tools (2 x $1000) (001 6559 480 6906)	$ 2,000
Bull rope (001 6556 420 6906)	$ 8,000
Total	**$ 40,500**

Description: As above.

Benefits: To replace worn tools and ropes. Improve crew and public safety. Reduce downtime.

Justification: As the tools wear out or break injuries may happen.

Power Systems Division
Part "C" Capital Budget Item
Greater Than $10,000

Project ID:	C93701 (96037)	Date Entered:	June 13, 2008
Budget Year:	2009	Requested By:	Ken Dziver
Department:	Lines - Supervisory	Reviewed By:	
GMBA #	001 6556 480 6920		

Project Title	Tools Lines
Project Description:	All tools and equipment required by the Lines Overhead & Underground staff - over $10,000

Estimated Cost:	$ 75,000
Description:	Stringing trailer to replace a 1978 Chance trailer.
Benefits:	Improved safety and reliability during stringing operations.
Justification:	This unit is to be paired-up with a 2007 purchase to perform voltage conversions. Improved designs have increased worker safety with options such as low noise engines and operator protection screens.

Power Systems Division
Part "C" Capital Budget Items
Under $10,000

Project ID:	C93800 (96038)
Budget Year:	2009
Department:	PSD
GMBA #	001 6562 421 6901

Date Entered:	May 14, 2008
Requested By:	Duane Szyszka
Reviewed By:	

Project Title	Tools - Supervisory
Project Description:	All furniture, tools, & equipment required by supervisory staff in both Lines and Operations Departments - under $10,000

Items:

Description	Cost
(2) New automatic external defibulators	$ 5,000
Total	**$ 5,000**

Description: Two new automatic external defibulators; one for the Operations Centre and one for the Fleet Garage.

Benefits: To provide all reasonable life saving techniques to employees if required. To potentially revive someone who goes into cardiac arrest.

Justification: The potential for a cardiac arrest is continually increasing and not all of our personnel work in large work groups (2-man teams such as the mechanics). The average EMS response time is 8-12 minutes and for every minute that goes by a cardiac arrest victim loses 10% chance of survival.

Power Systems Division
Part "C" Capital Budget Item
Greater Than $10,000

Project ID:	C93801 (96038)
Budget Year:	2009
Department:	PSD
GMBA #	001 6562 563 6901

Date Entered:	May 28, 2008
Requested By:	Rae Ann Westerback
Reviewed By:	

Project Title	Tools - Supervisory
Project Description:	All furniture, tools, & equipment required for General Administration - over $10,000

Estimated Cost:	$ 10,000

Description:	Replacement photocopier. Existing photocopier has been in-service since 2000. In the past year has required numerous repairs and is unreliable. A replacement unit would combine scanning, printing and faxing eliminating two other machines that are also at end of life.

Benefits:	New copier will be a colour photocopier which will eliminate the need to scan and print documents on a colour printer. Copies will be just as clear as the original document was. Copier will be networked to allow printing, collating, stapling, etc. from the original electronic document. Copies will also have faxing capabilities to eliminate the need for a fax machine.

Justification:	Existing copier is reaching end-of-life and replacement parts are difficult to obtain. Parts for the duplex attachment are not available at all. The existing fax machine is also reaching end-of-life and replacing the copier with a machine that will perform faxing as well, will eliminate the need to replace that machine. The total printing cost for colour copiers is approximately $0.12/page while smaller inkjet machines typically run $0.25/page. Thus the payback is at approximately 70,000 pages.

Power Systems Division
Part "C" Capital Budget Items
Under $10,000

Project ID:	C94000 (96041)
Budget Year:	2009
Department:	Operations - Stations
GMBA #	001 6577 485 69xx

Date Entered:	May 14, 2008
Requested By:	Duane Szyszka
Reviewed By:	

Project Title	Tools - Stations
Project Description:	Includes all tools and equipment required by the Stations and P & C staff - under $10,000

Items:

Description	Cost
Hilti DX460 Power actuated tool (6906)	$ 1,500
Thermal imaging camera telephoto lens	$ 3,500
Total	**$ 5,000**

Description:

As above.

Benefits:

1. To install fasteners so we can mount equipment and material to steel, wood, or concrete. This will increase productivity.

2. Greater accuracy for determining hot spots on overhead equipment.

Justification:

1. TBH's existing Hilti is no longer manufactured and parts are no longer available.

2. Presently, TBH has a wide-angle lens which is good for stations or ground level activities. The telephoto lens is required for use on the overhead lines when imaging from the ground.

Power Systems Division
Part "C" Capital Budget Items
Under $10,000

Project ID:	C94100 (96042)	Date Entered:	June 13, 2008
Budget Year:	2009	Requested By:	James Mann
Department:	AME	Reviewed By:	Dipankar Chakrabarti
GMBA #	001 3021 426 69XX		

Project Title	AME
Project Description:	Office Equipment & Furniture for Engineering Services Supervisor & services staff - under $10,000

Items:

Description	Cost
Laserjet colour printer (001 3021 426 6901)	$ -
Cable locator (001 3021 426 6919)	$ 5,000
Laptops (2) (001 3021 426 6902)	
Total	**$ 5,000**

Description:

1) Laser colour printer for 11 x 17 sheets. **Moved to IS budget**
2) Cable locator instrument.
3) Laptop for cable locators **Moved to IS budget**

Benefits:

1) Allows users to print maps and documents in colour. **Moved to IS budget**
2) The existing locate instrument is very old and needs frequent repairs. A new locating instrument would increase the reliability and availability of the instrument and cut downtime and maintenance costs.
3) Locators will be able to get access to the digital updated maps while they are in the field and will have the opportunity to edit the maps through internet. Currently the Locators used D-size maps that are rolled-up, a 11 x 17 binder, and 6 4-in ring binders to obtain mapping information in the field. Having field access to up-to-date maps would be more efficient and would give Locators more accurate information. **Moved to IS budget**

Justification:

1) The existing colour printer has become old and is causing frequent operation problems. Maintenance costs are getting higher and higher. It would be more economical to replace the printer with a new one instead of replacing parts. **Moved to IS budget**
2) The existing locate instrument has become old and frequently fails to operate and has reached end-of-life.
3) Reduce the use of paper maps and reduce the time for printing and editing the maps. **Moved to IS budget**

Power Systems Division
Part "C" Capital Budget Items
Under $10,000

Project ID:	C94200 (96043)
Budget Year:	2009
Department:	Operations - Fleet
GMBA #	001 6572 425 69XX

Date Entered:	May 14, 2008
Requested By:	Duane Szyszka
Reviewed By:	

Project Title	Tools Mechanics
Project Description:	Includes all tools and equipment required by the mechanics to maintain the Fleet - under $10,000

Items:

Description	Cost
1. Transmission jack 6906	$ 2,500
2. Plasma cutter 6906	$ 3,000
3. Industrial shelving & cabinets 6906	$ 4,000
Total	**$ 9,500**

Description:

1. Large capacity transmission jack
2. Plasma cutter
3. Engineered heavy duty industrial shelving.

Benefits:

1. Allow for the removal of any TBH vehicle transmission.
2. Improved cutting and fabricating capabilities. It will cut multiple types of metal and it is a safer way to cut this type of material.
3. Improve organization and usable floor space. Reduce the potential of tools and equipment going missing (cabinets that lock).

Justification:

1. The existing transmission jack is over ten years old. It's weight capacity is too small for some of the TBH requirements and it has been repaired and modified previously.
2. Presently, TBH does not have a plasma cutter. There are less contaminates released and a reduction in noise while using a plasma cutter compared to oxygen/acetylene. There is also less grinding and clean-up work after cutting is completed. The plasma cutter will also cut aluminum. There would be an ergonomic improvement for the mechanics as less grinding using a vibrating power tool would be required.
3. Cleaner work area is a safer work area.

Power Systems Division
Part "C" Capital Budget Item
Greater Than $10,000

Project ID:	C94201 (96043)
Budget Year:	2009
Department:	Operations - Op. Centre
GMBA #	001 6572 425 6920

Date Entered:	May 14, 2008
Requested By:	Duane Szyszka
Reviewed By:	

Project Title	Operations Centre
Project Description:	Includes all enhancements or upgrades to the Operations Centre, which services all of the crews and trades staff, as well as Engineering - over $10,000.

Estimated Cost:	$ 45,000
Description:	Mobile four-position 72,000 lb large vehicle lift.
Benefits:	These hoists will be lifting the large vehicle fleet or if necessary our smaller light vehicles. It will allow for improved inspection capabilities, increased production, faster repair times, and better working posture for the mechanics, which will reduce mechanic fatigue and potential for injury. Use of this hoisting system will allow our mechanics to stand up and work on the vehicles instead of laying on the ground.
Justification:	Improved ergonomics, reduced potential of MSD concerns or injuries. Our aging fleet will require better inspections and faster repair turnaround times. This will get the mechanics off of the floor and eliminate working from a horizontal position. These units can also be used as a two-position hoist device, which could allow for up to three vehicles to be hoisted independently of each other. Presently, TBH does not have a hoist that will lift the larger fleet vehicles. This hoist system is completely mobile via built-in pallet jacks and can be relocated outside or into another area of the shop if required.

Power Systems Division

Part "C" Capital Budget Item
Greater Than $10,000

Project ID:	C94402 (96045)	Date Entered:	May 30, 2008
Budget Year:	2009	Requested By:	Duane Szyszka
Department:	Operations - Op. Centre	Reviewed By:	
GMBA #	001 6574 487 6904		

Project Title	Operations Centre
Project Description:	Includes all enhancements or upgrades to the Operations Centre, which services all of the crews and trades staff, as well as Engineering - over $10,000.

Estimated Cost:	$15,000
Description:	Engineered heavy-duty industrial shelving.
Benefits:	To store the capital construction material in an accessible manner.
Justification:	The shelving will provide a more organized and better use of available yard space. Pending the removal of the Annex building, the capital program material will have to be placed in an accessible and organized location. The cable reels and smaller transformers can be placed on these shelves as well.

Power Systems Division
Part "C" Capital Budget Item
Greater Than $10,000

Project ID:	C94403 (96045)	Date Entered:	May 30, 2008
Budget Year:	2009	Requested By:	Duane Szyszka
Department:	Operations - Op. Centre	Reviewed By:	
GMBA #	001 6574 487 6904		

Project Title	Operations Centre
Project Description:	Includes all enhancements or upgrades to the Operations Centre, which services all of the crews and trades staff, as well as Engineering - over $10,000.

Estimated Cost:	$15,000
Description:	30-foot sea canisters
Benefits:	To provide a secure location to store the capital construction material in a weather-proof enclosure.
Justification:	The sea canisters will provide a weather proof, accessible and secure structure to store any capital construction material that is displaced during the removal of the Annex building. The capital program material will have to be placed in a secure location and these sea canisters will provide that capability for minimal cost.

Power Systems Division
Part "C" Capital Budget Item
Greater Than $10,000

Project ID:	C94404 (96045)
Budget Year:	2009
Department:	Operations - Op. Centre
GMBA #	001 6574 487 6904

Date Entered:	May 30, 2008
Requested By:	Duane Szyszka
Reviewed By:	

Project Title	Operations Centre
Project Description:	Includes all enhancements or upgrades to the Operations Centre, which services all of the crews and trades staff, as well as Engineering - over $10,000.

Estimated Cost:	$65,000

Description:	Fencing modifications are to be completed in 2008 as part of the yard improvement plan. The funds requested in 2009 will be for the installation of additional yard lights, outside security cameras, replacement/installation of two new motorized vehicle gates, installation of a gate entry/exit monitoring system, automated gate operations control device.

Benefits:	To provide security enhancement for the Operations Centre and yard, as well as improved accessibility by TBH vehicles entering and exiting the gates (automated open/close features).

Justification:	The changes will provide enhanced security over TBH's existing "open door" system, greater control over who and when yard entry occurs, the ability to track vehicle entry and exit times, and provide greater camera coverage area for after hours security monitoring..

CAPITAL CONTRIBUTIONS:

The following table sets out historical capital contributions for 2006 Actual, 2007 Actual, the 2008 Bridge Year and the 2009 Test Year.

Table 1
Capital Contributions 2006-2009 Total By Asset Category

	2009	2008	2007	2006
Infrastructure	**$**	**$**	**$**	**$**
Category/Year				
Overhead Infrastructure	71,707	71,266	144,126	77,763
Underground Infrastructure	370,549	368,269	496,124	648,820
Transformer Infrastructure	192,081	190,899	292,401	295,094
All Other Infrastructure	15,662	15,566	20,724	23,591
Total	650,000	646,000	953,374	1,045,268

Capital Contribution Methodology:

All capital projects involving the connection of a new customer to Thunder Bay Hydro infrastructure requires an Engineering Department assessment of the whether the situation will result in a system expansion as well as an analysis of the work to be completed. If the work will not result in a system expansion, the work completed is considered as connection costs and the appropriate variable connection costs will be billed to the customer. Variable connection costs collected from customers are considered as part of Capital Contributions.

Where the Engineering Department concludes that the work will result in a system expansion, Thunder Bay Hydro performs an economic evaluation (prepared in accordance with the OEB's prescribed valuation methodologies). The economic evaluation is used to determine if the stream of future revenues associated with the expansion is sufficient to pay for the capital cost and ongoing maintenance costs of the distribution system expansion to supply the service. If there is

a shortfall between the present value of the projected costs and revenues, the customer pays the difference as a capital contribution in accordance with the DSC.

Thunder Bay Hydro also records capital contributions as a result of infrastructure relocations. The primary drivers for these projects are requests by municipalities and road authorities for plant relocation and/or modifications. These projects generally occur due to road widening, resurfacing, and or realignment. The *Public Service Works on Highways Act* provides for a cost sharing arrangement whereby the road authority contributes 50% of the cost of labour and equipment for the project. Thunder Bay Hydro is responsible for the remaining 50% of the labour and equipment cost, and 100% of the cost of material for the project.

CAPITALIZATION POLICY:

Thunder Bay Hydro applies the following general capitalization policies and principles based on Generally Accepted Accounting Principles ("GAAP"), in particular CICA Handbook Section 3060 Capital Assets, as well as the APH guidelines set out by the Ontario Energy Board, where applicable:

- The amount to be capitalized is the cost to acquire or construct a capital asset, including any ancillary costs incurred to place a capital asset into its intended state of operation. Thunder Bay Hydro does not currently capitalize interest on funds for construction.

- Assets that are intended to be used on an on-going basis and are expected to provide future economic benefit (generally considered to be greater than one year) will be capitalized.

- Individual items with an estimated useful life greater than one year and valued at greater than $500 will be capitalized ($1,000 for computer hardware/software).

- Expenditures that create a physical betterment (defined as the cost incurred to enhance the service potential of a capital asset. Service potential may be enhanced when there is an increase in the previously assessed service capacity, associated operating costs are lowered, the useful life is extended or the quality of output is improved) will be capitalized.

WORKING CAPITAL CALCULATION:

- **OVERVIEW:**

Thunder Bay Hydro's working capital allowance is forecast to be $12,819,420 for 2009 and is based on the "15% of specific O&M accounts formula approach" referred to at page 15 of the Board's Filing Requirements. Thunder Bay Hydro has provided its calculations by account for each of 2006 Actual, 2007 Actual, the 2008 Bridge Year and the 2009 Test Year in Table 1 on the following page.

Table 1
Working Capital Calculation by Account

Description	2006 Actual	Allowance for Working Capital	2007 Actual	Allowance for Working Capital	2008 Bridge	Allowance for Working Capital	2009 Test	Allowance for Working Capital
Rate used for Working Capital Allowance		15%		15%		15%		15%
Operation								
5005-Operation Supervision and Engineering	192,586	28,888	246,985	37,048	302,452	45,368	264,373	39,656
5010-Load Dispatching	639,060	95,859	720,682	108,102	769,838	115,476	816,699	122,505
5012-Station Buildings and Fixtures Expense	383,251	57,488	321,047	48,157	309,836	46,475	309,836	46,475
5017-Distribution Station Equipment - Operation Supplies and Expenses	97,048	14,557	98,599	14,790	119,350	17,902	93,130	13,969
5020-Overhead Distribution Lines and Feeders - Operation Labour	155,176	23,276	127,636	19,145	122,284	18,343	106,084	15,913
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	387,412	58,112	406,105	60,916	406,621	60,993	414,815	62,222
5035-Overhead Distribution Transformers- Operation	117,182	17,577	212,752	31,913	88,703	13,305	341,548	51,232
5040-Underground Distribution Lines and Feeders - Operation Labour	23,410	3,512	18,655	2,798	23,202	3,480	10,287	1,543
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	8,114	1,217	5,391	809	11,653	1,748	5,809	871
5055-Underground Distribution Transformers - Operation	106,220	15,933	87,393	13,109	91,227	13,684	71,865	10,780
5065-Meter Expense	563,268	84,490	490,640	73,596	485,380	72,807	544,081	81,612
5070-Customer Premises - Operation Labour	24,749	3,712	20,077	3,011	11,131	1,670	8,773	1,316
5075-Customer Premises - Materials and Expenses	16,045	2,407	28,825	4,324	11,172	1,676	37,465	5,620
Sub-Total	**2,713,521**	**407,028**	**2,784,785**	**417,718**	**2,752,849**	**412,927**	**3,024,765**	**453,715**
Maintenance								
5105-Maintenance Supervision and Engineering	754,276	113,141	654,477	98,172	654,104	98,116	548,396	82,259
5110-Maintenance of Buildings and Fixtures - Distribution Stations	26,784	4,018	12,499	1,875	12,499	1,875	12,499	1,875
5114-Maintenance of Distribution Station Equipment	70,870	10,631	154,114	23,117	192,696	28,904	286,238	42,936
5120-Maintenance of Poles, Towers and Fixtures	142,498	21,375	139,885	20,983	165,297	24,795	133,991	20,099
5125-Maintenance of Overhead Conductors and Devices	789,575	118,436	882,978	132,447	790,769	118,615	686,177	102,927
5130-Maintenance of Overhead Services	310,963	46,644	256,757	38,514	303,356	45,503	344,777	51,717
5135-Overhead Distribution Lines and Feeders - Right of Way	277,983	41,697	522,385	78,358	483,555	72,533	716,115	107,417
5145-Maintenance of Underground Conduit	34,853	5,228	31,271	4,691	17,606	2,641	17,669	2,650
5150-Maintenance of Underground Conductors and Devices	117,236	17,585	112,952	16,943	128,393	19,259	164,495	24,674
5155-Maintenance of Underground Services	67,987	10,198	96,140	14,421	146,536	21,980	74,510	11,177
5160-Maintenance of Line Transformers	56,493	8,474	407,165	61,075	101,256	15,188	64,866	9,730
5175-Maintenance of Meters	888	133	537	81	0	0	0	0
Sub-Total	**2,650,405**	**397,561**	**3,271,159**	**490,674**	**2,996,067**	**449,410**	**3,049,733**	**457,460**

Description	2006 Actual	Allowance for Working Capital	2007 Actual	Allowance for Working Capital	2008 Bridge	Allowance for Working Capital	2009 Test	Allowance for Working Capital
Billing and Collections								
5305-Supervision	45,081	6,762	0	0	0	0	0	0
5310-Meter Reading Expense	418,282	62,742	425,989	63,898	275,059	41,259	281,316	42,197
5315-Customer Billing	1,141,557	171,234	1,138,862	170,829	1,290,662	193,599	1,271,382	190,707
5320-Collecting	573,514	86,027	641,092	96,164	688,412	103,262	679,308	101,896
5325-Collecting- Cash Over and Short	(10)		0		0		0	
5335-Bad Debt Expense	105,590	15,838	80,362	12,054	160,000	24,000	160,000	24,000
Sub-Total	**2,284,014**	**342,604**	**2,286,306**	**342,946**	**2,414,133**	**362,120**	**2,392,006**	**358,801**
Community Relations								
5405-Supervision	15,027	2,254	0	0	0	0	0	0
5415-Energy Conservation	401,746	60,262	381,627	57,244	58,431	8,765	78,732	11,810
5420-Community Safety Program	8,030	1,204	14,646	2,197	14,600	2,190	14,892	2,234
5515-Advertising Expense	122,228	18,334	106,270	15,940	122,285	18,343	134,715	20,207
Sub-Total	**547,031**	**82,055**	**502,544**	**75,382**	**195,316**	**29,297**	**228,339**	**34,251**
Administrative and General Expenses								
5605-Executive Salaries and Expenses	582,547	87,382	815,595	122,339	977,940	146,691	966,552	144,983
5615-General Administrative Salaries and Expenses	1,076,454	161,468	1,193,512	179,027	1,173,476	176,021	1,258,112	188,717
5620-Office Supplies and Expenses	182,881	27,432	169,123	25,369	193,042	28,956	191,768	28,765
5630-Outside Services Employed	237,678	35,652	181,373	27,206	226,700	34,005	239,149	35,872
5635-Property Insurance	30,818	4,623	31,255	4,688	37,874	5,681	32,550	4,883
5640-Injuries and Damages	170,407	25,561	208,509	31,276	297,604	44,641	315,652	47,348
5665-Miscellaneous General Expenses	194,209	29,131	243,650	36,547	272,750	40,913	258,406	38,761
5670-Rent	275,609	41,341	272,114	40,817	303,512	45,527	308,288	46,243
5675-Maintenance of General Plant	62,666	9,400	91,710	13,756	78,218	11,733	75,643	11,346
Sub-Total	**2,813,268**	**421,990**	**3,206,840**	**481,026**	**3,561,117**	**534,167**	**3,646,120**	**546,918**
Cost of Power								
4705-Power Purchased	55,006,605	8,250,991	60,350,781	9,052,617	59,674,791	8,951,219	59,823,352	8,973,503
4708-Charges-WMS	5,892,260	883,839	5,318,436	797,765	5,767,384	865,108	5,781,742	867,261
4714-Charges-NW	5,226,553	783,983	4,832,056	724,808	3,979,641	596,946	3,989,549	598,432
4716-Charges-CN	3,765,449	564,817	2,624,445	393,667	3,518,433	527,765	3,527,192	529,079
Sub-Total	**69,890,867**	**10,483,630**	**73,125,717**	**10,968,858**	**72,940,249**	**10,941,037**	**73,121,835**	**10,968,275**
WORKING CAPITAL ALLOWANCE TOTAL	**80,899,106**	**12,134,867**	**85,177,351**	**12,776,603**	**84,859,730**	**12,728,960**	**85,462,799**	**12,819,420**

Exhibit	Tab	Schedule	Appendix	Contents
3 – Operating Revenue				
	1			**Overview**
		1		Overview of Operating Revenue
		2		Summary of Operating Revenue Table
		3		Variance Analysis on Operating Revenue
	2			**Throughput Revenue**
		1		Weather Normalized Load and Customer/ Connection Forecast
			A	Monthly Data Used for Regression Analysis
	3			**Other Distribution Revenue**
		1		Summary of Other Distribution Revenue
		2		Variance Analysis on Other Distribution Revenue
	4			**Revenue Sharing**
		1		Description of Revenue Sharing

OVERVIEW OF OPERATING REVENUE:

This Exhibit provides the details of Thunder Bay Hydro's operating revenue for 2006 Board Approved, 2006 Actual, 2007 Actual, the 2008 Bridge Year and the 2009 Test Year. This Exhibit also provides a detailed variance analysis by rate class of the operating revenue components.

Distribution revenues have been calculated using the rates approved in the OEB's Decision and Order EB-2007-0880 dated April 15, 2008. Distribution revenue does not include revenue from commodity sales.

A summary of operating revenues is presented in Exhibit 3, Tab 1, Schedule 2.

Throughput Revenue:

Information related to Thunder Bay 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 LRAM/SSM and known economic conditions. Detailed variance analysis on the throughput revenue is set out in Exhibit 3, Tab 3, Schedules 1 and 2.

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.

Revenue Sharing:

As noted in Exhibit 3, Tab 4, Schedule 1, Thunder Bay Hydro does not have a revenue sharing practice in place.

SUMMARY OF OPERATING REVENUE TABLE

SUMMARY OF OPERATING REVENUE TABLE	2006 Board Approved ($'s)	2006 Actual ($'s)	Variance from 2006 Board Approved ($'s)	2007 Actual ($'s)	Variance from 2006 Actual ($'s)	2008 Bridge ($'s)	Variance from 2007Actual	2009 Test ($'s)	Variance from 2008 Actual ($'s)
Distribution Revenues									
Residential	$ 10,663,900	$ 10,232,624	$ (431,276)	$ 10,370,231	$ 137,606	$ 10,545,440	$ 175,209	$ 10,819,715	$ 274,274
GS<50	$ 2,740,846	$ 2,694,356	$ (46,490)	$ 2,684,083	$ (10,273)	$ 2,698,053	$ 13,971	$ 2,952,080	$ 254,027
GS>50-Regular	$ 1,762,327	$ 1,770,852	$ 8,525	$ 1,855,343	$ 84,491	$ 1,808,871	$ (46,471)	$ 2,198,802	$ 389,930
GS>1000 to 4999 kW	$ 789,375	$ 842,018	$ 52,643	$ 901,049	$ 59,031	$ 832,395	$ (68,654)	$ 1,069,706	$ 237,312
Large User	$ -	$ 19,122	$ 19,122		$ (19,122)		$ -		$ -
Street Light	$ 114,938	$ 108,124	$ (6,814)	$ 115,256	$ 7,132	$ 117,226	$ 1,971	$ 395,840	$ 278,614
Sentinel	$ 11,709	$ 818	$ (10,891)		$ (818)	$ 13,886	$ 13,886	$ 16,239	$ 2,353
Unmetered Scattered Load	$ 54,733		$ (54,733)		$ -	$ 62,825	$ 62,825	$ 66,556	$ 3,731
	$ 16,137,828	$ 15,667,914	$ (469,914)	$ 15,925,961	$ 258,047	$ 16,078,697	$ 152,737	$ 17,518,938	$ 1,440,241
Other Distribution Revenue									
Late Payment Charges	$ 234,804	$ 236,728	$ (1,924)	$ 274,296	$ 37,568	$ 282,000	$ 7,704	$ 282,000	$ -
Specific Service Charges	$ 656,412	$ 679,501	$ (23,089)	$ 767,392	$ 87,891	$ 745,000	$ (22,392)	$ 745,000	$ -
Other Distribution Revenue	$ 475,836	$ 909,116	$ (433,280)	$ 1,002,489	$ 93,373	$ 847,498	$ (154,991)	$ 775,790	$ (71,708)
	$ 1,367,052	$ 1,825,344	$ (458,292)	$ 2,044,177	$ 218,832	$ 1,874,498	$ (169,679)	$ 1,802,790	$ (71,708)
Total	$ 17,504,880	$ 17,493,259	$ (928,206)	$ 17,970,137	$ 476,879	$ 17,953,195	$ (16,942)	$ 19,321,728	$ 1,368,533

VARIANCE ANALYSIS ON OPERATING REVENUE:

Thunder Bay Hydro's distribution revenue has been calculated using its most recently approved rates. In particular, delivery rates are based on the EB-2007-0880 dated April 15, 2008. As noted above, distribution revenue does not include commodity-related revenue.

A summary of normalized operating revenues is presented in Exhibit 3, Tab 1, Schedule 2.

2006 Board Approved:

Thunder Bay Hydro's 2006 Board Approved operating revenue was forecast to be $17,504,880 as shown in Exhibit 3, Tab 1, Schedule 2. Distribution revenue totaled $16,137,828 or 92.2% of total revenues. Other operating revenue (net) accounts for the remaining revenue of $1,367,052

2006 Actual:

Thunder Bay Hydro's operating revenue in fiscal 2006 was $17,493,259 as shown in Exhibit 3, Tab 1, Schedule 2. Distribution revenue totaled $15,667,914 or 89.6% of total revenues. Other operating revenue (net), accounts for the remaining revenue of $1,825,344.

Comparison to 2006 Board Approved:

As shown in Exhibit 3, Tab 1, Schedule 2, the total operating revenue was $928,206 lower than the 2006 Board Approved level forecasted. This decrease resulted from lower than forecasted consumption levels, mainly in the residential rate class and other distribution revenue as explained in Exhibit 3, Tab 3, Schedule 2.

2007 Actual:

Thunder Bay Hydro's operating revenue in fiscal 2007 was $17,970,137, as shown in Exhibit 3, Tab 1, Schedule 2. Distribution revenue totaled $15,925,961 or 88.6% of total revenues. Other operating revenue (net), accounts for the remaining revenue of $2,044,177.

Comparison to 2006 Actual:

As shown in Exhibit 3, Tab 1, Schedule 2, the total operating revenue was $476,879 higher than the 2006 actual operating revenue. This increase resulted from increased distribution rates and the partial year realization of increased Specific Service Charge rates approved in the 2006 EDR as well as improved pricing on scrap material (copper).

2008 Bridge Year:

Thunder Bay Hydro's operating revenue is forecast to be $17,953,195 in fiscal 2008, as shown in Exhibit 3, Tab 1, Schedule 2. Distribution revenue totals $16,078,697 or 89.6% of total revenues. Other operating revenue (net), accounts for the remaining revenue of $1,874,498.

Comparison to 2007 Actual:

As shown in Exhibit 3, Tab 1, Schedule 2, the total operating revenue is expected to be $16,942 lower than the actual year level in fiscal 2007. This decrease is the result of forecasted reduced revenues from other distribution revenue (most significantly, lower interest income due to decreased rate of interest) in this period.

2009 Test Year:

Thunder Bay Hydro's operating revenue is forecast to be 19,321,728 in fiscal 2009, as shown in Exhibit 3, Tab 1, Schedule 2. Distribution revenue totals $17,518,938 or 90.7% of total revenues. Other operating revenue (net), accounts for the remaining revenue of $1,802,790.

Comparison to 2008 Bridge Year:

As shown in Exhibit 3, Tab 1, Schedule 2, the total operating revenue is expected to be $1,368,532 above the bridge year level in fiscal 2008. This increase is the result of an increase in revenue requirement for 2009. See Exhibit 6, Tab 1, Schedule 1 for an explanation of the revenue deficiency for 2009 test year.

WEATHER NORMALIZED LOAD AND CUSTOMER/CONNECTION FORECAST

The purpose of this evidence is to present the process used by Thunder Bay Hydro to prepare the weather normalized load and customer/connection forecast used to design the proposed distribution rates. In summary, Thunder Bay Hydro reviewed the various processes used by the 2008 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 2008, 2009 and 2010 rate application (EB-2007-0680). Tables 1, 2 and 3 below provides a summary of the weather normalized load and customer/connection forecast used in this application.

Table 1
Summary of Load and
Customer/Connection Forecast

Year	Billed (GWh)	Growth (GWh)	Percent Change	Customer/ Connection Count	Growth	Percent Change (%)
2000	999.8			49,366		
2001	1,004.1	4.4	0.44%	48,689	-678	-1.37%
2002	1,014.6	10.4	1.04%	61,555	12,866	26.43%
2003	1,051.7	37.1	3.66%	62,656	1,102	1.79%
2004	1,034.5	-17.1	-1.63%	62,554	-102	-0.16%
2005	1,053.1	18.5	1.79%	62,739	184	0.29%
2006	1,042.6	-10.4	-0.99%	63,087	349	0.56%
2007	1,023.0	-19.6	-1.88%	62,977	-110	-0.17%
2008 (B)	990.2	-32.8	-3.20%	63,155	178	0.28%
2009 (T)	992.7	2.5	0.25%	63,335	180	0.29%

The growth in 2002 is resulting from the introduction of billing streetlights and unmetered scattered load based on connections. Prior to market opening, such was not the case and therefore, the connection data is not readily available (Streetlight count in 2002 is 12, 692 and unmetered scattered load is 430 of this 12,866 growth, therefore, actual result is negative growth of 256).

2000 to 2007 are weather actual and 2008 and 2009 are weather normalized. Thunder Bay 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 2 and customer usage is shown in Table 3.

Table 2

Billed Energy and Number of Customers by Rate Class

Year	Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service > 1000 to 4999 kW	Streetlights	Sentinel Lights	Unmetered Loads	Total
Energy (GWh)								
2000	346.6	146.8	298.5	207.7	0.0	0.1	0.0	999.8
2001	348.5	147.1	297.8	210.7	0.0	0.1	0.0	1,004.1
2002	349.0	147.7	288.8	216.2	9.7	0.1	3.0	1,014.6
2003	362.0	145.4	302.0	228.3	10.7	0.1	3.1	1,051.7
2004	354.6	145.6	289.9	230.3	10.9	0.1	3.1	1,034.5
2005	357.7	146.3	299.8	235.4	10.9	0.1	3.0	1,053.1
2006	346.5	142.5	300.6	240.5	10.2	0.1	2.3	1,042.6
2007	344.5	139.4	295.8	230.5	10.5	0.1	2.1	1,023.0
2008 (B)	339.7	143.5	303.6	191.3	10.6	0.1	1.5	990.2
2009 (T)	337.8	144.0	304.7	194.1	10.6	0.1	1.3	992.7
Number of Customers/Connections								
2000	44,245	4,529	480	19	0	93	0	49,366
2001	43,627	4,463	475	19	0	105	0	48,689
2002	43,456	4,397	473	20	12,692	87	430	61,555
2003	44,318	4,414	499	20	12,841	135	430	62,656
2004	44,242	4,413	470	20	12,838	140	431	62,554
2005	44,379	4,423	475	18	12,858	153	432	62,739
2006	44,581	4,445	489	19	12,962	164	428	63,087
2007	44,526	4,372	496	19	12,976	153	435	62,977
2008 (B)	44,580	4,419	504	19	13,034	164	436	63,155
2009 (T)	44,635	4,466	511	19	13,091	176	437	63,335

Table 3

Annual Usage per Customer/Connection by Rate Class

Year	Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service > 1000 to 4999 kW	Streetlights	Sentinel Lights	Unmetered Loads
Energy Usage per Customer/Connection (kWh per customer/connection)							
2000	7,834	32,414	621,934	10,934,065	0	832	0
2001	7,989	32,953	626,745	11,087,456	0	832	0
2002	8,032	33,589	610,781	10,812,173	762	743	7,060
2003	8,168	32,933	605,595	11,416,074	836	1,024	7,178
2004	8,015	32,994	616,903	11,516,013	848	1,033	7,123
2005	8,059	33,083	630,859	13,075,130	845	832	6,871
2006	7,771	32,050	615,172	12,657,080	788	832	5,374
2007	7,738	31,891	595,863	12,130,343	811	832	4,778
2008 (B)	7,620	32,468	602,917	10,068,017	811	832	3,385
2009 (T)	7,567	32,234	596,619	10,217,319	811	832	3,055
Annual Growth Rate in Usage per Customer/Connection							
2000							
2001	2.0%	1.7%	0.8%	1.4%		0.0%	
2002	0.5%	1.9%	-2.5%	-2.5%		-10.7%	
2003	1.7%	-2.0%	-0.8%	5.6%	9.8%	37.8%	1.7%
2004	-1.9%	0.2%	1.9%	0.9%	1.4%	0.8%	-0.8%
2005	0.5%	0.3%	2.3%	13.5%	-0.3%	-19.4%	-3.5%
2006	-3.6%	-3.1%	-2.5%	-3.2%	-6.7%	0.0%	-21.8%
2007	-0.4%	-0.5%	-3.1%	-4.2%	2.9%	0.0%	-11.1%
2008 (B)	-1.5%	1.8%	1.2%	-17.0%	0.0%	0.0%	-29.2%
2009 (T)	-0.7%	-0.7%	-1.0%	1.5%	0.0%	0.0%	-9.7%

LOAD FORECAST AND METHODOLOGY

Thunder Bay 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 a historical loss factor 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. 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), population and calendar variables (days in month, seasonal). The regression model uses monthly kWh and monthly values of independent variables from January 1996 to December 2007 to determine the monthly regression coefficients.

Data for Thunder Bay Hydro's total system load is available as far back as January 1996. This provides over 140 monthly data points, which is a reasonable data set for use in a multiple regression analysis. Based on the recent global activity surrounding climate change, historical weather data is showing that there is a warming of the global climate system. In this regard it is Thunder Bay Hydro's view that it is appropriate to review the impact of weather since 1996 on

the energy usage and then determine the average weather conditions from 1996 to 2007 which would be applied in the forecasting process to determine a weather normalized forecast.

The multifactor regression model has determined primary drivers of year-over-year changes in Thunder Bay Hydro's load growth are economic conditions and weather. Both of these effects are captured within the multifactor regression model.

Economic growth – which encompasses population trends in the Thunder Bay Hydro's service area as well as general economic conditions, are captured in the model using an index of economic output, Ontario Real Gross Domestic Product ("GDP") and population statistics.

Weather impacts on load are apparent in both the winter heating season, and in the summer cooling season. For that reason, both Heating Degree Days (i.e. a measure of coldness in winter) and Cooling Degree Days (i.e. a measure of summer heat) are modeled.

The third main factor determining energy use in the monthly model can be classified as "calendar factors". For example, the number of days in a particular month will impact energy use. The modeling of purchased energy uses number of days in the month and a "flag" variable to capture the typically lower usage in the spring and fall months.

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 model chosen as the best predictor of kWh purchased by Thunder Bay Hydro is as follows:

Thunder Bay Hydro Monthly Predicted kWh Purchases

=	Heating Degree Days	x	36,582
+	Cooling Degree Days	x	160,735
+	Ontario Real GDP Monthly Index	x	127,809
+	Population	x	980

	+ Number of Days in the Month	x	2,863,731
	+ Spring Fall Flag	x	(2,603,072)
	+ Constant of		(137,503,312).

The monthly data used in the regression model and the resulting monthly prediction for the actual and forecasted years are provided in Appendix A.

The sources of data for the various data points are:

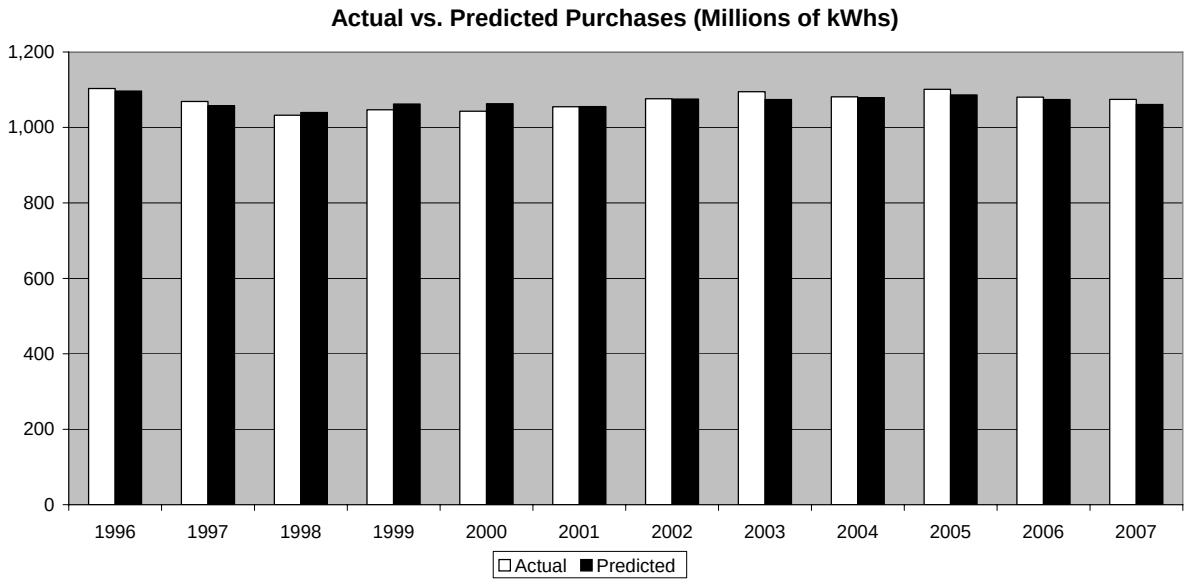
a) Environment Canada website for monthly heating degree day and cooling degree information. Data for the Thunder Bay AWOS weather station was used;

b) The 2008, 2009 and 2010 rate application (EB-2007-0680) for Toronto Hydro Electric System Ltd provided the Ontario real GDP monthly index;

c) Population data was based on Census population data for the City of Thunder Bay; and

d) The calendar provided information related to number of days in the month and the spring/fall flag.

The annual results of the above prediction formula compared to the actual annual purchases from 1996 to 2007 are shown in the chart below. The prediction formula has a statistical R^2 of 95% which generally indicates the formula has a very good fit to the actual data set.



The following table outlines the data that supports the above chart. In addition, the weather normalized forecast of total system purchases for Thunder Bay Hydro is provided for 2008 and 2009.

Table 4

Thunder Bay Hydro's Total System Purchases

	Actual	Predicted	% Difference
1996	1,103.4	1,096.8	-0.60%
1997	1,069.1	1,057.8	-1.06%
1998	1,032.3	1,039.3	0.69%
1999	1,046.5	1,061.9	1.46%
2000	1,042.9	1,062.9	1.91%
2001	1,054.6	1,055.3	0.07%
2002	1,076.3	1,075.5	-0.08%
2003	1,095.0	1,074.4	-1.88%
2004	1,081.3	1,079.5	-0.17%
2005	1,101.3	1,086.6	-1.33%
2006	1,080.4	1,074.2	-0.58%
2007	1,074.6	1,060.9	-1.28%
2008 (WN)		1,036.9	
2009 (WN)		1,039.5	

The forecasted weather normalized amount for 2008 and 2009 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 1996 to 2007 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 twelve 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). As a result, “manual” adjustments have been made to the forecast to reflect these changes. Table 5 shows the predicted purchases before and after the adjustments for those years in which adjustments were made.

Table 5

Predicted Purchases Before and After Adjustments

(GWh)	Predicted Before Adjustments	Adjustments	Predicted After Adjustments
2006	1,075.7	-1.5	1,074.2
2007	1,092.3	-31.4	1,060.9
2008 (WN)	1,096.8	-59.9	1,036.9
2009 (WN)	1,099.4	-59.9	1,039.5

The following table outlines the sources of the manual adjustments made to the forecast.

Table 6

Manual Adjustment to Forecast

(GWh)	Great West	Agricore	Northern Wood	CDM	Total
2006				1.5	1.5
2007	14.9	1.6	2.1	12.9	31.4
2008 (WN)	23.1	5.0	19.0	12.9	59.9
2009 (WN)	23.1	5.0	19.0	12.9	59.9

With regards to Great West, annual energy sales including losses has reduced by 14.9 (GWh) in 2007. Based on actual 2008 information from January to April it is expected the energy consumption will be reduced by 23.1 (GWh) in 2008 which is also the assumed reduction in energy for the 2009 forecast. There has been a significant reduction in energy usage for Great West since May of 2007, the month they announced an indefinite shutdown.

With regards to Agricore, annual energy consumption in 2007 has reduced by 1.6 (GWh) in 2007, including losses. Based on actual 2008 from January to April it is expected the energy consumption will be reduced by 5.0 (GWh) in 2008 which is also the assumed reduction in energy for the 2009 forecast. This reduction is a result of the decommissioning of one terminal, and significant drop in activity at other terminals at Agricore.

In the case of Northern Wood, annual energy consumption in 2007 has reduced by 2.1 (GWh) in 2007, including losses. Based on actual 2008 from January to May it is expected the energy consumption will be reduced by 19.0 (GWh) in 2008 which is also the assumed reduction in energy for the 2009 forecast. This reduction results from the continuing economic impact on the forestry/lumber industry.

Thunder Bay Hydro has implemented a number of CDM programs within its service area and the results have been very positive as can been seen in the decline in usage per customer since 2005. It is Thunder Bay Hydro's view that CDM programs that were offered prior to June 2006 have impacted the historical usage per customer but programs that have been initiated after June 2006 have not impacted the historical usage per customer. As explained further on in this evidence, historical usage is considered when the forecasted consumption by rate class is determined. Consequently, a manual adjustment to the forecast has been made to reflect the savings in energy since June 2006 resulting from the CDM programs initiated after June 2006. This adjustment including losses is 1.5 (GWh) in 2006 and 12.9 (GWh) in 2007. It is assume energy savings that have occurred in 2007 will continue in 2008 and 2009.

Billed KWh Load Forecast

To determine the total weather normalized energy billed forecast, the total system weather normalized purchases forecast is adjusted by a historical loss factor. As outlined in Table 7 below, historically the Thunder Bay Hydro loss factor on average has been 4.7%

Table 7

Historical Loss Factor

(GWh)	Actual Purchases	Actual Billed	Loss Factor
2000	1,042.9	999.8	4.3%
2001	1,054.6	1,004.1	5.0%
2002	1,076.3	1,014.6	6.1%
2003	1,095.0	1,051.7	4.1%
2004	1,081.3	1,034.5	4.5%
2005	1,101.3	1,053.1	4.6%
2006	1,080.4	1,042.6	3.6%
2007	1,074.6	1,023.0	5.1%
Average			4.7%

With this average loss factor the total weather normalized billed energy will be 990.2 (GWh) for 2008 (i.e. 1,036.9/1.047) and 992.7 (GWh) for 2009 (i.e. 1,039.5/1.047)

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 8 below.

Table 8

Historical Customer/Connection Data

	Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service > 1000 to 4999 kW	Streetlights	Sentinel Lights	Unmetered Loads	Total
Number of Customers/Connection								
1999	44,092	4,015	443	19	0	0	0	48,569
2000	44,245	4,529	480	19	0	93	0	49,366
2001	43,627	4,463	475	19	0	105	0	48,689
2002	43,456	4,397	473	20	12,692	87	430	61,555
2003	44,318	4,414	499	20	12,841	135	430	62,656
2004	44,242	4,413	470	20	12,838	140	431	62,554
2005	44,379	4,423	475	18	12,858	153	432	62,739
2006	44,581	4,445	489	19	12,962	164	428	63,087
2007	44,526	4,372	496	19	12,976	153	435	62,977

From the historical customer/connection data, the growth rate in customer/connection can be evaluated and is provided in Table 9 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 9

Growth Rate in Customer/Connections

	Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service > 1000 to 4999 kW	Streetlights	Sentinel Lights	Unmetered Loads
Growth Rate in Customer/Connection							
1999							
2000	0.35%	12.80%	8.35%	0.00%			
2001	-1.40%	-1.46%	-1.01%	0.00%		12.90%	
2002	-0.39%	-1.48%	-0.49%	5.26%		-17.14%	
2003	1.98%	0.39%	5.48%	0.00%	1.17%	55.17%	0.00%
2004	-0.17%	-0.02%	-5.78%	0.00%	-0.02%	3.70%	0.23%
2005	0.31%	0.23%	1.12%	-10.00%	0.16%	9.29%	0.23%
2006	0.45%	0.50%	2.82%	5.56%	0.81%	7.19%	-0.93%
2007	-0.12%	-1.64%	1.60%	0.00%	0.11%	-6.71%	1.64%
Geometric Mean	0.12%	1.07%	1.43%	0.00%	0.44%	7.37%	0.23%

The resulting geometric mean is applied to the 2007 customer/connection numbers to determine the forecast of customer/connections for 2008 and 2009. Table 10 outlines the forecast of customers by rate class for 2008 and 2009.

Table 10

Customer/Connection Forecast

	Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service > 1000 to 4999 kW	Streetlights	Sentinel Lights	Unmetered Loads	Total
Forecast number of Customers/Connection								
2008	44,580	4,419	504	19	13,034	164	436	63,155
2009	44,635	4,466	511	19	13,091	176	437	63,335

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 11 provides the average annual usage per customer by rate class from 1996 to 2007 where data is available.

Table 11

Historical Annual Usage per Customer

	Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service > 1000 to 4999 kW	Streetlights	Sentinel Lights	Unmetered Loads
Annual kWh Usage Per Customer/Connection							
2000	7,834	32,414	621,934	10,934,065	0	832	0
2001	7,989	32,953	626,745	11,087,456	0	832	0
2002	8,032	33,589	610,781	10,812,173	762	743	7,060
2003	8,168	32,933	605,595	11,416,074	836	1,024	7,178
2004	8,015	32,994	616,903	11,516,013	848	1,033	7,123
2005	8,059	33,083	630,859	13,075,130	845	832	6,871
2006	7,771	32,050	615,172	12,657,080	788	832	5,374
2007	7,738	31,891	595,863	12,130,343	811	832	4,778

Usage per customer/connection can only be determined for 2000 and onward since historical billed energy by rate class is only available from 2000. As can been seen from the above table

usage per customer/connection essentially declines for all classes after 2005. As stated previously, it is Thunder Bay 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 12. The geometric mean growth rate has also been shown.

Table 12

Growth Rate in Usage Per Customer/Connection

	Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service > 1000 to 4999 kW	Streetlights	Sentinel Lights	Unmetered Loads
Growth Rate in Usage Per Customer/Connection							
2000							
2001	1.98%	1.66%	0.77%	1.40%		0.00%	
2002	0.54%	1.93%	-2.55%	-2.48%		-10.71%	
2003	1.69%	-1.95%	-0.85%	5.59%	9.77%	37.84%	1.66%
2004	-1.87%	0.18%	1.87%	0.88%	1.40%	0.82%	-0.77%
2005	0.54%	0.27%	2.26%	13.54%	-0.32%	-19.42%	-3.54%
2006	-3.57%	-3.12%	-2.49%	-3.20%	-6.73%	0.00%	-21.78%
2007	-0.43%	-0.50%	-3.14%	-4.16%	2.85%	0.00%	-11.10%
Geometric Mean	-0.18%	-0.23%	-0.61%	1.49%	1.26%	0.00%	-7.51%

For the forecast of usage per customer/connection the historical geometric mean was used for all rate classes except Streetlights. For Streetlights, since the historical pattern in usage per connection was not consistent, the 2007 usage per customer/connection was assumed to be held constant for 2008 and 2009.

Table 13

Forecast Annual kWh Usage per Customer/Connection

	Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service > 1000 to 4999 kW	Streetlights	Sentinel Lights	Unmetered Loads
Forecast Annual kWh Usage per Customers/Connection							
2008	7,724	31,817	592,229	12,311,606	811	832	4,419
2009	7,711	31,743	588,617	12,495,578	811	832	4,087

With the preceding information the non-normalized weather billed energy forecast can be determine by applying the forecast number of customer/connection from Table 10 by the forecast of annual usage per customer/connection from Table 13. The resulting non-normalized weather billed energy forecast is shown in Table 14 below.

Table 14

Non-Normalized Weather Billed Energy Forecast

	Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service > 1000 to 4999 kW	Streetlights	Sentinel Lights	Unmetered Loads	Total
Non-normalized Weather Billed Energy Forecast (GWh)								
2008	344.4	140.6	298.2	233.9	10.6	0.1	1.9	1,029.7
2009	344.2	141.8	300.6	237.4	10.6	0.1	1.8	1,036.5

The non-normalized weather billed energy forecast has been determined but this needs to be adjusted in order to be aligned with the total weather normalized billed energy forecast. As previously determined, the total weather normalized billed energy forecast is 990.2 (GWh) for 2008 and 992.7 (GWh) for 2009 These forecast numbers reflect manual adjustment previously discussed but prior to the manual adjustments the total weather normalized billed energy forecast would have been 1,048.0 (GWh) in 2008 (i.e. 1,096.8 (GWh) from Table 5 divided by the loss factor of 1.047 from Table 7) and 1,048.4 (GWh) in 2009 (i.e. 1,099.4 (GWh) from Table 5 divided by the loss factor of 1.047 from Table 7).

The difference between the non-normalized and normalized forecast before manual adjustments is 18.3 GWh in 2008 (i.e. 1,048.0 – 1,029.7) and 11.9 GWh in 2009 (i.e. 1,048.4 – 1,036.5). This difference will be assigned to those rate classes that are weather sensitive. Based on the weather normalization work completed by Hydro One for Thunder Bay Hydro for the cost allocation study, which has been used to support this rate application, it was determined the weather sensitivity by rate classes is as follows.

Table 15

Weather Sensitivity by Rate Class

Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service > 1000 to 4999 kW	Streetlights	Sentinel Lights	Unmetered Loads
Weather Sensitivity						
100%	100%	89%	59%	0%	0%	0%

As a result, the difference between the non-normalized and normalized forecast has been assigned on a prorated basis to each rate class based on the above level of weather sensitivity. The following tables outline how the weather 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 16

Alignment of Non-Normal to Weather Normal Forecast

	Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service > 1000 to 4999 kW	Streetlights	Sentinel Lights	Unmetered Loads	Total
Non-normalized Weather Billed Energy Forecast (GWh)								
2008	344.4	140.6	298.2	233.9	10.6	0.1	1.9	1,029.7
2009	344.2	141.8	300.6	237.4	10.6	0.1	1.8	1,036.5
Adjustment for Weather (GWh)								
2008	7.1	2.9	5.4	2.8	0.0	0.0	0.0	18.2
2009	5.3	2.2	4.1	2.2	0.0	0.0	0.0	13.8
Manual Adjustment to Billed Energy Forecast for Loss of Load and CDM Savings (GWh)								
2008	-11.7	0.0	-0.1	-45.5	0.0	0.0	-0.5	-57.7
2009	-11.7	0.0	-0.1	-45.5	0.0	0.0	-0.5	-57.7
Weather Normalized Billed Energy Forecast (GWh)								
2008	339.7	143.5	303.6	191.3	10.6	0.1	1.5	990.2
2009	337.8	144.0	304.7	194.1	10.6	0.1	1.3	992.7

Billed KW Load Forecast

There four rate classes that charge volumetric distribution on a per kW basis. These include General Service > 50 to 999 kW, General Service > 1000 to 4999 kW, Streetlights and Sentinel Lights. 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. 2000 to 2007).

Table 17

Historical Annual kW per Applicable Rate Class

	General Service > 50 to 999 kW	General Service > 1000 to 4999 kW	Streetlights	Sentinel Lights
2000	438,364	709,818	0	0
2001	543,604	616,150	0	0
2002	668,803	606,436	29,864	304
2003	788,042	644,240	32,749	325
2004	757,436	650,100	30,346	339
2005	796,486	646,715	30,609	299
2006	799,110	650,281	30,584	321
2007	793,730	654,850	30,951	299

The following is the historical ratio of kW/kWh as well as the average ratio from 2000 to 2007.

Table 18

Historical kW/KWh Ratio per Applicable Rate Class

kW/kWh	General Service > 50 to 999 kW	General Service > 1000 to 4999 kW	Streetlights	Sentinel Lights
2000	0.1468%	0.3417%		
2001	0.1825%	0.2925%		
2002	0.2316%	0.2804%	0.3088%	0.4702%
2003	0.2609%	0.2822%	0.3050%	0.2350%
2004	0.2613%	0.2823%	0.2787%	0.2345%
2005	0.2657%	0.2748%	0.2816%	0.2350%
2006	0.2659%	0.2704%	0.2992%	0.2350%
2007	0.2683%	0.2841%	0.2941%	0.2350%
Average	0.2354%	0.2885%	0.2946%	0.2741%

The average ratio was applied to the weather normalized billed energy forecast in Table 16 to provide the forecast of kW by rate class as shown below.

The following outlines the forecast of kW for the applicable rate classes.

Table 19

kW Forecast by Applicable Rate Class

	General Service > 50 to 999 kW	General Service > 1000 to 4999 kW	Streetlights	Sentinel Lights
2008	714,591	551,960	31,138	375
2009	717,262	560,145	31,276	402

Summary of Forecast Data

	2006 Board Approved	2006 Actual	2007 Actual	2008 Weather Normal	2009 Weather Normal
Actual kWh Purchases		1,080,427,586	1,074,642,764		
Predicted kWh Purchases		1,075,663,016	1,092,300,747	1,096,799,813	1,099,381,294
Adjustments not in model		(1,481,458)	(31,447,675)	(59,857,541)	(59,857,541)
Revised Predicted kWh Purchases		1,074,181,558	1,060,853,072	1,036,942,272	1,039,523,753
% Difference		-0.6%	-1.3%		
Billed kWh		1,042,614,698	1,022,967,701	990,217,386	992,683,783
By Class					
Residential					
Customers	44,167	44,581	44,526	44,580	44,635
kWh	356,604,252	346,450,433	344,539,413	339,683,206	337,772,229
General Service < 50 kW					
Customers	4,495	4,445	4,372	4,419	4,466
kWh	147,826,584	142,460,073	139,426,299	143,471,665	143,961,424
General Service > 50 to 999 kW					
Customers	471	489	496	504	511
kWh		300,562,731	295,796,449	303,587,556	304,722,102
kW	719,611	799,110	793,730	714,591	717,262
General Service > 1000 to 4999 kW					
Customers	19	19	19	19	19
kWh		240,484,511	230,476,516	191,292,326	194,129,052
kW	553,018	650,281	654,850	551,960	560,145
Streetlights					
Connections	12,769	12,962	12,976	13,034	13,091
kWh		10,220,293	10,523,382	10,570,061	10,616,947
kW	30,411	30,584	30,951	31,138	31,276
Sentinel Lights					
Connections	140	164	153	164	176
kWh	130,673	136,481	127,327	136,712	146,789
kW	307	321	299	375	402
Unmetered Loads					
Connections	171	428	435	436	437
kWh	3,033,972	2,300,176	2,078,315	1,475,860	1,335,240
Total					
Customer/Connections	62,232	63,087	62,977	63,155	63,335
kWh	507,595,481	1,042,614,698	1,022,967,701	990,217,386	992,683,783
kW from applicable classes	1,303,347	1,480,296	1,479,830	1,298,064	1,309,085

APPENDIX A

MONTHLY DATA USED FOR REGRESSION ANALYSIS

Appendix A

	Purchased	Heating Degree Days	Cooling Degree Days	Ontario Real GDP Monthly %	Number of Days in Month	Spring Fall Flag	Population	Predicted Purchases
Jan-96	118,924,353	1139.4	0	95.66	31	0	113,690	116,605,031
Feb-96	103,230,148	925.8	0	95.75	29	0	113,686	103,071,061
Mar-96	100,151,654	855.9	0	95.85	31	1	113,681	103,645,841
Apr-96	88,254,077	550.4	0	95.94	30	1	113,676	89,613,709
May-96	84,605,626	325.9	0	96.03	31	1	113,672	84,272,222
Jun-96	76,423,467	106.8	12.4	96.13	30	0	113,667	77,997,017
Jul-96	78,708,299	60.4	13	96.22	31	0	113,662	79,267,311
Aug-96	79,084,941	38.2	16.6	96.32	31	0	113,582	78,967,156
Sep-96	78,492,721	164.2	8.7	96.41	30	1	113,502	76,773,316
Oct-96	87,615,659	384.1	0	96.51	31	1	113,421	86,216,572
Nov-96	99,614,530	680.8	0	96.60	30	1	113,341	94,140,353
Dec-96	108,297,151	862.4	0	96.70	31	0	113,261	106,184,108
Jan-97	112,854,920	992.7	0	96.79	31	0	113,181	110,884,452
Feb-97	94,727,312	815	0	97.14	28	0	113,101	95,758,063
Mar-97	96,127,715	514.4	0	97.48	31	1	113,021	90,715,232
Apr-97	86,404,530	488.5	0	97.83	30	1	112,941	86,869,929
May-97	83,525,136	346.3	0	98.18	31	1	112,861	84,497,774
Jun-97	79,463,583	75.6	15.7	98.52	30	0	112,781	76,824,152
Jul-97	82,883,498	41.4	28.2	98.87	31	0	112,702	80,412,506
Aug-97	79,856,599	94.4	18.1	99.23	31	0	112,622	80,694,711
Sep-97	78,391,924	149.4	0	99.58	30	1	112,542	74,297,610
Oct-97	78,391,924	406.8	0	99.93	31	1	112,463	86,544,832
Nov-97	95,284,837	613.6	0	100.29	30	1	112,383	91,213,739
Dec-97	101,164,072	679.4	0	100.64	31	0	112,304	99,055,287
Jan-98	103,859,060	808.1	0	101.00	31	0	112,224	103,731,278
Feb-98	85,271,199	594.5	0	102.10	28	0	112,145	87,388,902
Mar-98	92,908,536	652.1	0	103.10	31	1	112,065	95,534,248
Apr-98	80,142,779	322.9	0	103.60	30	1	111,986	80,613,840
May-98	75,365,976	202.8	1.3	104.10	31	1	111,907	79,279,274
Jun-98	75,422,182	108.2	10.8	104.60	30	0	111,828	77,071,250
Jul-98	79,113,453	23.4	36	105.20	31	0	111,749	80,882,501
Aug-98	78,898,391	34.3	36.7	105.80	31	0	111,670	81,392,995
Sep-98	77,554,880	122.5	7.3	106.50	30	1	111,591	74,439,210
Oct-98	84,620,662	328.1	0	107.40	31	1	111,512	83,688,590
Nov-98	92,162,535	574.9	0	108.40	30	1	111,433	89,903,901
Dec-98	106,933,632	848.1	0	109.40	31	0	111,354	105,415,576
Jan-99	112,653,597	994.7	0	110.00	31	0	111,275	110,778,053
Feb-99	91,844,791	718.7	0	110.70	28	0	111,197	92,102,473
Mar-99	94,187,868	710.1	0	111.40	31	1	111,118	97,788,382
Apr-99	83,302,867	407.7	0	112.20	30	1	111,040	83,887,380
May-99	79,992,116	224.7	2.6	113.00	31	1	110,961	80,499,739
Jun-99	77,505,957	91.9	11.4	113.80	30	0	110,883	76,820,753
Jul-99	82,122,401	24.2	59.3	114.30	31	0	110,804	84,894,123
Aug-99	78,031,999	74	12.2	114.70	31	0	110,726	79,119,625
Sep-99	69,444,119	194	5.7	115.20	30	1	110,647	76,985,086
Oct-99	84,165,425	423.1	0	115.90	31	1	110,569	87,326,419
Nov-99	89,152,256	500.7	0	116.50	30	1	110,491	87,301,527
Dec-99	104,140,645	817.1	0	117.20	31	0	110,413	104,355,869
Jan-00	107,111,201	963.5	0	117.50	31	0	110,335	109,673,340
Feb-00	93,736,958	711.5	0	117.90	29	0	110,257	94,701,777
Mar-00	90,806,910	574.6	0	118.20	31	1	110,179	92,779,968
Apr-00	83,542,339	485.6	0	118.40	30	1	110,101	86,609,605
May-00	79,464,457	260.5	0	118.50	31	1	110,023	81,175,120
Jun-00	75,943,873	155.7	2.3	118.70	30	0	109,945	77,399,626

Jul-00	78,797,711	55.7	20.8	119.10	31	0	109,867	79,553,643
Aug-00	75,332,986	63.4	9.8	119.60	31	0	109,790	78,054,996
Sep-00	67,696,548	223.3	0	120.00	30	1	109,712	76,837,534
Oct-00	83,136,508	372.2	0	120.00	31	1	109,635	85,072,336
Nov-00	92,345,975	561.6	0	119.90	30	1	109,557	89,048,532
Dec-00	115,028,094	1041.3	0	119.90	31	0	109,480	111,987,953
Jan-01	105,962,994	898.8	0	120.00	31	0	109,402	106,711,869
Feb-01	95,758,180	918.9	0	120.00	28	0	109,325	98,780,154
Mar-01	94,701,571	702.7	0	120.10	31	1	109,247	96,796,181
Apr-01	85,485,176	430.7	0	120.50	30	1	109,170	83,957,455
May-01	80,081,469	239.9	0	120.90	31	1	109,093	79,816,733
Jun-01	77,568,366	114	15.2	121.30	30	0	109,016	77,369,041
Jul-01	79,435,703	67.2	29.7	121.20	31	0	109,018	80,840,638
Aug-01	83,006,555	40.2	56.1	121.00	31	0	109,020	84,072,802
Sep-01	76,565,456	187.7	6.8	120.80	30	1	109,022	76,054,134
Oct-01	85,159,042	408.6	0	121.30	31	1	109,024	85,971,853
Nov-01	89,719,754	458.8	0	121.70	30	1	109,026	84,997,721
Dec-01	101,146,791	716.4	0	122.10	31	0	109,028	99,941,302
Jan-02	104,372,004	873.9	0	122.60	31	0	109,030	105,768,968
Feb-02	90,496,417	733	0	123.20	28	0	109,033	92,102,048
Mar-02	98,624,046	804.7	0	123.80	31	1	109,035	100,791,852
Apr-02	86,431,002	462.3	0	124.00	30	1	109,037	85,429,929
May-02	83,086,365	335	0.5	124.20	31	1	109,039	83,744,700
Jun-02	76,655,320	114.4	14.2	124.40	30	0	109,041	77,643,649
Jul-02	86,501,722	17.9	79.3	124.90	31	0	109,043	87,506,987
Aug-02	79,169,857	49.7	15.5	125.40	31	0	109,045	78,481,352
Sep-02	79,976,938	143.5	20.9	125.90	30	1	109,047	77,379,889
Oct-02	89,694,810	510.1	0	126.10	31	1	109,049	90,322,949
Nov-02	96,384,274	668	0	126.20	30	1	109,051	93,250,393
Dec-02	104,952,350	785.6	0	126.40	31	0	109,053	103,046,884
Jan-03	110,117,330	907.4	0	126.80	31	0	109,055	107,555,780
Feb-03	99,989,942	969.6	0	127.20	28	0	109,058	101,293,174
Mar-03	100,611,887	765.1	0	127.50	31	1	109,060	99,840,591
Apr-03	87,646,202	499.3	0	127.40	30	1	109,062	87,242,534
May-03	80,569,552	276.4	0	127.20	31	1	109,064	81,928,542
Jun-03	76,274,569	129.3	0	127.00	30	0	109,066	76,263,100
Jul-03	82,862,068	29.9	18.2	126.70	31	0	109,068	78,379,625
Aug-03	84,559,303	35.6	50.9	126.40	31	0	109,070	83,807,883
Sep-03	81,130,424	164	6.7	126.00	30	1	109,072	75,884,681
Oct-03	88,166,145	414.2	0	126.40	31	1	109,074	86,877,556
Nov-03	96,589,039	632.9	0	126.90	30	1	109,076	92,080,331
Dec-03	106,439,293	785.9	0	127.30	31	0	109,078	103,197,399

Jan-04	117,229,662	1140.6	0	127.40	31	0	109,080	116,187,981
Feb-04	97,191,208	778.3	0	127.50	29	0	109,083	97,221,559
Mar-04	96,946,958	684.3	0	127.70	31	1	109,085	96,934,814
Apr-04	85,520,823	472.4	0	128.30	30	1	109,087	86,398,012
May-04	80,898,890	333.2	0	128.90	31	1	109,089	84,248,209
Jun-04	75,735,633	145.8	3.1	129.60	30	0	109,091	77,721,805
Jul-04	80,150,183	67.4	22	130.20	31	0	109,093	80,834,103
Aug-04	79,099,794	123	1.8	130.90	31	0	109,095	79,712,741
Sep-04	78,363,447	132.9	4.7	131.50	30	1	109,097	75,152,964
Oct-04	85,874,753	372.7	0	131.90	31	1	109,099	86,086,853
Nov-04	92,765,450	554.9	0	132.20	30	1	109,101	89,928,811
Dec-04	111,527,089	926.6	0	132.50	31	0	109,103	109,033,658
Jan-05	114,618,042	1084.3	0	132.60	31	0	109,105	114,817,519
Feb-05	92,976,783	755.9	0	132.80	28	0	109,108	94,240,287
Mar-05	99,295,276	814.1	0	133.00	31	1	109,110	102,385,107
Apr-05	83,247,754	408.1	0	133.20	30	1	109,112	84,696,549
May-05	82,551,530	306.2	0	133.40	31	1	109,114	83,860,145
Jun-05	81,801,217	72.6	16.8	133.70	30	0	109,116	77,794,585
Jul-05	86,082,381	45.3	53	133.90	31	0	109,118	85,505,835
Aug-05	85,624,066	46.3	29.6	134.20	31	0	109,120	81,821,602
Sep-05	81,522,428	148.8	15.2	134.50	30	1	109,122	77,830,290
Oct-05	87,834,995	347.3	0	134.60	31	1	109,124	85,527,268
Nov-05	96,580,699	606.9	0	134.70	30	1	109,126	92,175,138
Dec-05	109,162,248	833.4	0	134.90	31	0	109,128	105,955,448
Jan-06	102,809,927	797	0	135.20	31	0	109,130	104,664,237
Feb-06	95,819,718	873.4	0	135.40	28	0	109,133	98,895,540
Mar-06	96,369,451	659	0	135.70	31	1	109,135	97,080,794
Apr-06	82,880,498	366	0	136.00	30	1	109,137	83,538,822
May-06	83,638,022	241.5	2.4	136.30	31	1	109,139	82,274,202
Jun-06	80,788,730	81.5	9.3	136.60	30	0	109,141	77,309,826
Jul-06	88,450,843	23.2	70.1	136.90	31	0	109,143	87,853,888
Aug-06	86,080,627	57.7	31.7	137.20	31	0	109,145	82,984,138
Sep-06	79,884,628	210.5	1.2	137.40	30	1	109,147	78,232,302
Oct-06	88,656,787	440.9	0	137.70	31	1	109,149	89,372,111
Nov-06	93,332,872	540.4	0	138.00	30	1	109,151	90,188,710
Dec-06	101,715,484	747.4	0	138.30	31	0	109,153	103,268,445
Jan-07	106,854,249	913.4	0	138.60	31	0	109,156	109,381,502
Feb-07	101,765,171	924.7	0	138.90	28	0	109,158	101,244,075
Mar-07	97,266,361	665	0	139.10	31	1	109,160	97,759,368
Apr-07	86,347,252	474.1	0	139.40	30	1	109,162	87,952,454
May-07	81,662,415	250.9	0.6	139.70	31	1	109,164	82,787,834
Jun-07	78,216,252	96.7	6.5	140.00	30	0	109,166	77,874,901
Jul-07	83,574,973	40.2	51.8	140.20	31	0	109,168	85,980,637
Aug-07	81,872,692	62.9	22.1	140.50	31	0	109,170	82,077,610
Sep-07	77,223,169	164.7	9.6	140.80	30	1	109,172	78,366,089
Oct-07	84,323,901	310.6	0	141.10	31	1	109,174	85,064,514
Nov-07	90,887,332	620.3	0	141.40	30	1	109,176	93,570,723
Dec-07	104,648,998	925.8	0	141.60	31	0	109,178	110,241,039
Jan-08		959	0	141.90	31	0	109,181	111,513,642
Feb-08		810	0	142.20	29	0	109,183	100,355,982
Mar-08		700	0	142.50	31	1	109,185	99,504,933
Apr-08		447	0	142.70	30	1	109,187	87,419,572
May-08		279	1	143.00	31	1	109,189	84,250,455
Jun-08		108	10	143.30	30	0	109,191	79,255,683
Jul-08		41	40	143.60	31	0	109,193	84,603,872
Aug-08		60	25	143.90	31	0	109,195	82,910,561
Sep-08		167	7	144.10	30	1	109,197	78,520,702
Oct-08		393	0	144.40	31	1	109,199	88,533,439
Nov-08		584	0	144.70	30	1	109,201	92,706,774
Dec-08		831	0	145.00	31	0	109,204	107,224,197
Jan-09		959	0	145.30	31	0	109,206	111,972,733
Feb-09		810	0	145.50	28	0	109,208	97,938,561
Mar-09		700	0	145.80	31	1	109,210	99,951,244
Apr-09		447	0	146.10	30	1	109,212	87,878,664
May-09		279	1	146.40	31	1	109,214	84,709,547
Jun-09		108	10	146.70	30	0	109,216	79,714,776
Jul-09		41	40	146.90	31	0	109,218	85,050,185
Aug-09		60	25	147.20	31	0	109,220	83,356,874
Sep-09		167	7	147.50	30	1	109,222	78,979,796
Oct-09		393	0	147.80	31	1	109,224	88,992,534
Nov-09		584	0	148.10	30	1	109,226	93,165,869
Dec-09		831	0	148.30	31	0	109,229	107,670,512

SUMMARY OF OTHER DISTRIBUTION REVENUE

		2006 Board Approved ($'s)	2006 Actual ($'s)	Variance from 2006 Board Approved ($'s)	2007 Actual ($'s)	Variance from 2006 Actual ($'s)	2008 Bridge ($'s)	Variance from 2007 Actual ($'s)	2009 Test ($'s)	Variance from 2008 Actual ($'s)
	Other Distribution Revenue									
4082	Retail Services Revenues	$ 76,894	$ 72,089	$ (4,805)	$ 80,964	$ 8,875	$ 71,800	$ (9,164)	$ 71,800	$ -
4084	Service Transaction Requests (STR) Revenues	$ 258	$ 5,177	$ 4,919	$ 6,180	$ 1,003	$ 3,400	$ (2,780)	$ 3,400	$ -
4210	Rent from Electric Property	$ 358,190	$ 436,622	$ 78,432	$ 443,900	$ 7,278	$ 436,300	$ (7,600)	$ 436,300	$ -
4215	Other Utility Operating Income	$ 145,527	$ 127,942	$ (17,585)	$ 124,728	$ (3,213)	$ 131,500	$ 6,772	$ 131,500	$ -
4220	Other Electric Revenues	$ -	$ 790	$ 790	$ 317	$ (473)	$ 2,521	$ 2,204	$ 2,710	$ 189
4225	Late Payment Charges	$ 234,804	$ 236,728	$ 1,924	$ 274,296	$ 37,568	$ 282,000	$ 7,704	$ 282,000	$ -
4235	Miscellaneous Service Revenues	$ 298,222	$ 242,878	$ (55,344)	$ 323,492	$ 80,613	$ 308,700	$ (14,792)	$ 308,700	$ -
4240	Provision for Rate Refunds	$ -	$ 0	$ 0	$ 0	$ 0	$ -	$ (0)	$ -	$ -
4355	Gain on Disposition of Utility and Other Property	$ 10,493	$ 4,371	$ (6,122)	$ 8,799	$ 4,428	$ -	$ (8,799)	$ -	$ -
4375	Revenues from Non-Utility Operations	$ -	$ 269,195	$ 269,195	$ 158,412	$ (110,783)	$ 155,000	$ (3,412)	$ 25,000	$ (130,000)
4380	Expenses of Non-Utility Operations	$ -	$ (245,296)	$ (245,296)	$ (129,794)	$ 115,502	$ (83,267)	$ 46,527	$ (18,114)	$ 65,153
4390	Miscellaneous Non-Operating Income	$ 23,869	$ 68,547	$ 44,678	$ 186,991	$ 118,444	$ 127,544	$ (59,447)	$ 120,494	$ (7,050)
4405	Interest and Dividend Income	$ 218,795	$ 606,301	$ 387,506	$ 565,892	$ (40,409)	$ 439,000	$ (126,892)	$ 439,000	$ -
	TOTAL	$ 1,367,052	$ 1,825,344	$ 458,292	$ 2,044,177	$ 218,832	$ 1,874,498	$ (169,679)	$ 1,802,790	$ (71,708)

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 1 per cent of total distribution expenses before PILs as set out in Table 1 below. The OM&A cost threshold was used because other distribution revenues, like OM&A costs, are recorded in Income Statement accounts.

TABLE 1

	2006 Actual	2007 Actual	2008 Bridge	2009 Test
Total Distribution Expenses before PILs	$15,390,629	$16,616,408	$16,446,038	$16,914,400
Materiality Threshold	$ 153,906	$ 166,164	$ 164,460	$ 169,144

To allow for the most detailed review of materiality on Other Distribution Revenue, Thunder Bay Hydro has selected the lowest materiality threshold of $153,906. Thunder Bay Hydro has provided explanations for the following variances, which exceed the materiality threshold. The following variances exceed the materiality threshold.

2007 ACTUAL TO 2008 BRIDGE YEAR

Account	2006 Board Approved	2006 Actual	Variance
4375 Revenues from Non-Utility Operations	$ -	$ 269,195	$ 269,195
4380 Expenses of Non-Utility Operations	$ -	$ (245,296)	$(245,296)

Explanation:

The 2006 Board Approved does not reflect the 2004 activity in these two OEB accounts as the 2006 EDR Model did not treat the foregoing accounts as revenue offsets, but rather they were considered “Unclassified”. For purposes of the 2009 forward test year, we have considered these accounts as forming part of the revenue offsets to our Revenue Requirement.

Account	2006 Board Approved	2006 Actual	Variance
4405. Interest and Dividend Income	$218,795	$606,301	$387,506

Explanation:

The variance from 2006 Board Approved to 2006 actual reflects the impact of the changing position of the regulatory deferral accounts from 2004 to 2006. Thunder Bay Hydro's net regulatory liability position increased substantially during this period of time largely due to the Retail Transmission Rates.

DESCRIPTION OF REVENUE SHARING:

Thunder Bay Hydro does not have a revenue sharing practice in place.

Exhibit	Tab	Schedule	Appendix	Contents
4 – Operating Costs				
	1			**Overview**
		1		Overview of Operating Costs / Summary of Operating Costs Table
	2			**OM&A Costs**
		1		OM&A Costs / OM&A Costs Table
		2		Variance Analysis on OM&A Costs Table
		3		Shared Services
			A	Service Agreements – Thunder Bay Hydro Energy Services Inc./Thunder Bay Hydro Utility Services Inc.
		4		Employee Compensation, Incentive Plan Expenses, Pension Expense and Post Retirement Benefits
		5		Depreciation, Amortization and Depletion
		6		Loss Adjustment Factor
	3			**Income Tax, Large Corporation Tax**
		1		Tax Calculations
		2		Interest Expense
		3		Capital Cost Allowance (CCA)
		4		2007 Annual PILS Returns (T2 and CT23)

OVERVIEW OF OPERATING COSTS:

Operating Costs:

The operating costs presented in this Exhibit represent the annual expenditures required to sustain Thunder Bay Hydro's distribution operations. Thunder Bay Hydro follows the OEB's Accounting Procedures Handbook (the "APH") in distinguishing work performed between operations and maintenance. A summary of Thunder Bay Hydro's operating costs for the 2006 Board Approved, 2006 Actual, 2007 Actual, 2008 Bridge Year and the 2009 Test Year including the determination of the variance amount for analysis, in accordance with the Filing Requirements, is provided in Table 1 below.

Table 1
Summary of Operating Costs

Description	2006 Board Approved	2006 Actual	2007 Actual	2008 Bridge	2009 Test
OM&A expenses					
Operation	2,011,898	2,713,521	2,784,785	2,752,849	3,024,765
Maintenance	2,977,751	2,650,405	3,271,159	2,996,067	3,049,733
Billing and Collections	2,432,919	2,284,014	2,286,306	2,414,133	2,392,006
Community Relations	169,039	547,031	502,544	195,316	228,339
Administrative and General Expenses	2,911,130	2,813,268	3,206,840	3,561,117	3,646,120
Controllable Costs - Sub-Total	**10,502,737**	**11,008,239**	**12,051,634**	**11,919,481**	**12,340,964**
Amortization Expenses	4,056,140	4,382,390	4,564,773	4,526,557	4,573,436
Total Operating Costs	**14,558,877**	**15,390,629**	**16,616,407**	**16,446,038**	**16,914,400**

Detailed information with respect to OM&A costs and variances, arranged by USoA account, is provided at Exhibit 4, Tab 2, Schedule 2, below.

The variance used to determine the OM&A accounts requiring analysis has been prescribed by the Filing Requirements as 1% of total distribution expenses before PILs. Thunder Bay Hydro has adopted a variance analysis threshold of $153,906 being the lowest of the variances among the years under review.

OM&A Costs:

OM&A costs in this Exhibit represent Thunder Bay Hydro's integrated set of asset maintenance and customer activity needs to meet public and employee safety objectives; to comply with the OEB's 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 Thunder Bay Hydro's distribution system, and meeting the requirements of the OEB's Standard Supply Service Code and Retail Settlement Code.

The proposed OM&A expenditures for the 2009 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.

Thunder Bay Hydro is proposing recovery of 2009 Test Year OM&A costs, including amortization and PILs of $17,884,538.

OM&A Budgeting Process Used by Thunder Bay Hydro:

The operating budget is prepared annually by management and is reviewed and approved by the Board of Directors. The budget is prepared before the start of each fiscal year. Once approved, the budget provides a plan against which actual results may be evaluated.

The operating budget is a component of the overall budget process described in Exhibit 2, Tab 1, Schedule 1.

Each Division Vice President is responsible for the preparation of the divisional budget. The directive provided to each Vice President is as outlined in the memos on the following pages:

THUNDER BAY HYDRO

MEMORANDUM

Finance

Date: April 22, 2008

To: Executive Management Team

From: Cindy Speziale

2009 BUDGET PROCESS

The purpose of this memo is to set the timelines for the 2009 Budget Process. As you are aware, we are working on a forward test year rate application for 2009. The application requires us to forecast the 2009 "test" year. As a result, the budget must be completed by **June 27, 2008.**

Departmental Input 2008 Projections	May 16, 2008
Departmental Input Budget including Parts A, B, and C Capital	May 30, 2008
Load forecasts for balance of 2008 and the 2009 budget year	May 2, 2008
Executive Management Team Review	Friday, June 13, 2008 (8:30 – 4:30 p.m.) Friday, June 20, 2008 (8:30 – 4:30 p.m.) Wednesday, June 25, 2008 (1:00 – 4:30 p.m.)
Board Meeting	

At the initial budget submission, I expect all miscellaneous information *(using the F8 – Miscellaneous Information key)* to be provided. This information should note those expenditures that are significant to that GMBA Account. Failure to provide the information at this time will only delay the process for everyone.

If there is a staff member that you would like to have the authority to enter budget or projection numbers, please let either the Controller or the Executive Assistant, Finance know so that they can arrange for the necessary changes. Once the departmental budget has been completed, authority to access will then be restricted.

I have taken the liberty of booking your calendars on these dates. Please let me know as soon as possible if you will not be able to attend one of the above-noted dates.

Please note, the labour costs related to the 2008 Projections and 2009 Budget will be calculated by the Finance Department as outlined in the Payroll and Benefits memos. We will also enter the preliminary labour driven overheads (Engineering, Supervisory and Downtime) based on 2008 budget percentage of powerline technical labour dollar distribution.

If you have any questions on the budget process or otherwise, please feel free to come and see me or give me a call.

Regards

Cindy Speziale, CA
Vice President, Finance

CS/dt

Attachment

cc: Terri-Ann Sylvester

THUNDER BAY HYDRO

MEMORANDUM

Finance

Date: April 22, 2008

To: Executive Management Team

From: Cindy Speziale

2008 PROJECTIONS – PAYROLL AND BENEFITS

We will be including the payroll and benefits projections with the initial 2008 projection worksheets provided to you. Please provide the following information so we may calculate and populate the information in the 2008 projections:

- Are there any current unfilled positions that you anticipate filling prior to the end of this fiscal year?
  - Position
  - Anticipated start date
  - Anticipated starting salary/wage
  - GMBA Distribution, providing multiple Div/Dept, if applicable, and percentage
- Will you be making additional staff complement increases?
  - Position
  - Anticipated start date
  - Anticipated starting salary/wage
  - GMBA Distribution, providing multiple Div/Dept, if applicable, and percentage
- Do you anticipate the level of overtime for your department from now to the end of the year to be in line with your budget? If not, what do you expect in terms of dollars?
- What is the FTE (full time equivalent) of your part-time/on-call staff for the remainder of the year?
- Are you anticipating any retirements?
  - Retiring staff member's name
  - Estimated date of retirement

This information is required by **Friday, April 25, 2007**.

Cindy Speziale, CA
Vice President, Finance

CS/dt

cc: T. Sylvester, Controller

THUNDER BAY HYDRO

MEMORANDUM

Finance

Date: April 22, 2008

To: Executive Management Team

From: Cindy Speziale

2009 BUDGET – PAYROLL AND BENEFITS

We will be including the payroll and benefits budget information with the initial 2009 Budget worksheets provided to you. To enable us to do this, please provide the following information:

- Provide detail with respect to current unfilled positions that you anticipate filling during 2009.
  - Position
  - Anticipated start date
  - Anticipated salary/wage
  - GMBA distribution, providing multiple splits as necessary.
- Provide detail regarding additional staff complements you will be budgeting for.
  - Position
  - Anticipated start date
  - Anticipated salary/wage
  - GMBA distribution, providing multiple splits as necessary.
- What is the anticipated level of overtime for your department for 2009? We require this information at the departmental level and for simplicity please use a percentage of your gross payroll.
- What is the FTE (full time equivalent) of your part-time/on-call staff for the remainder of the year?
- Are you anticipating any retirements?
  - Retiring staff member's name
  - Estimated date of retirement

Power Systems, please provide a complete annual labour budget reconciled to the actual existing labour positions, plus additional anticipated positions. These positions must flow 100% to the various O&M and Capital projects.

On the Annual Labour Base Hour Requirement, ensure that "Downtime" (6583 427) [vacation, sick time, meetings, stats, etc.] is shown in a separate column and subtracted from the Annual Base Hours to arrive at Total Productive Hours to be allocated to the projects.

Please clearly identify contracted-out labour (i.e. do not mix with the overtime). For simplicity, can overtime be proportionately allocated among all projects (is this a reasonable basis for budget?).

This information is required by **Friday, May 9, 2008**.

Cindy Speziale, CA
Vice President, Finance

CS/dt

cc: T. Sylvester, Controller

THUNDER BAY HYDRO

MEMORANDUM

Finance

Date: May 9, 2008

To: Executive Management Team

From: Cindy Speziale

DEPARTMENT/DIVISION PROJECTED 2008 ACTUALS

PROJECTIONS

Once again this year, a worksheet has been created that will allow you to enter your **2008 Projections** on-line. The name of the worksheet is as follows:
200 PROJECTED 2008 DEPT PROJECTIONS (see attached).

You will note that we have a column entitled Projected Actuals that will calculate a projected amount based on a simple extrapolation of the actuals to March 31, 2008.

Please review your anticipated expenditures for the final nine months of this year and enter the following information in the worksheet:

1) If your projections for object level totals are different by the **greater of +/- 5% or $5,000.00** from the projections on the printed worksheet shown in the column named **2008 Projected Actuals**, please enter your year-end projections in the object level line item in your Division's budget, otherwise please enter the amount as per the 2008 Projected Actuals.

2) The 2008 Actual including Unposted reflect amounts to current date of printing of the worksheet. We have added a new column this year to alert you to purchase requisitions in the works. This is entitled 2008 Encumbrances.

3) When you go into each account to enter your 2008 projections, the screen will show: the 2006 and 2007 actual; the 2008 year-to-date actual; and the 2008 budget amount. The F8 function key must be used to provide explanatory notes documenting any budget to projected variance at the object level that is greater than the greater of 5% or $5,000.

The Finance Department has already populated the wage, overtime and benefits for the 2008 Projections based on the information provided to us. As a result, please do not input anything for Element 42, 43 and 16.

Once completed, we request that these worksheets be returned to the Finance Department no later than **Friday, May 30, 2008**.

If you have any questions, please call me.

Cindy Speziale, CA
Vice President, Finance

CS/dt

Attachment

cc: Terri-Ann Sylvester, Controller

THUNDER BAY HYDRO

MEMORANDUM

Finance

Date: May 9, 2008

To: Executive Management Team

From: Cindy Speziale

2009 BUDGET PREPARATION

BUDGET

A worksheet has been created that will allow you to enter your 2009 Budget on-line. The name of the worksheet is **100 BUDGET 2009 DEPARTMENT INPUT** (See attached.)

The Finance Department has already populated the 2009 Labour Budget and labour related overheads based on information provided to us from the departments. As a result, please do not make changes to Element 42, 43,16, 6602, 6603 and 6604.

Please refer to the **2009 Budget-Preparation Tips** memo for guidance with inputting into the worksheet.

Once completed, we request that these worksheets be returned to the Finance Department no later than **Friday, May 30, 2008**.

If you have any questions, please call me.

Cindy Speziale, CA
Vice President, Finance

CS/dt

Attachment

cc: Terri-Ann Sylvester, Controller

THUNDER BAY HYDRO

MEMORANDUM

Finance

Date: June 9, 2008

To: Executive Management Team

From: Terri-Ann Sylvester

VERIFICATION OF THE ACCURACY OF THE PAYROLL FOR 2009 BUDGET

Attached, please find the following:

- A printout of the Payroll Projection Report for 2009. Please review the information for your department relative to accuracy for staff complement, hours for the part-time, summer student staffing and hours, GMBA distribution, etc.

Upon completion of your review, please initial the first page of the Payroll Projection Report and return the package to me for my budget file no later than **4:00 p.m. on June 10, 2008**. If there are corrections or changes that you would like made, please put a post-it on the appropriate page that explains the change required. If you would like copy of your own to retain, I would be happy to provide you with one.

If you have any questions, please do not hesitate to contact me. Thank you for your cooperation.

Regards,

Terri-Ann Sylvester, CA
Controller

TS/dt

Attachment.

DISCUSSIONS OF DEPARTMENTAL AND CORPORATE OM&A ACTIVITIES:

As discussed at Exhibit 2, Tab 1, Schedule 1, the development of a detailed risk assessment, 20-year capital plan, and maintenance plans are an imperative part of Thunder Bay Hydro's AMP . Additionally, effective work execution, as well as ongoing strategy development and enhancement, are important aspects in ensuring overall effectiveness in its capital and maintenance programs.

Maintenance Plan Overview

The foundation of the maintenance program at Thunder Bay Hydro is to maintain its assets for the lowest possible life cycle cost while focusing on the following strategic objectives:

- Addressing any health & safety issues;
- Addressing any environmental risks;
- Regulatory compliance obligations;
- Ensuring equipment reliability.

Three types of maintenance programs are widely used in industry and all others are variants of these three namely reactive, preventative, and predictive maintenance.

Reactive maintenance, as its name suggests, is solely reactive to failures or defects with only inspections or some basic tests being performed to determine whether the equipment is functioning as expected. This type of maintenance is most effective for low cost equipment where maintenance can be a significant portion of the replacement cost and the equipment is not critical should it fail. An example of this would be how we maintain lightning arrestors, cutouts, insulators and other line hardware.

Preventative maintenance, also as its name suggests, is an attempt to perform maintenance in fixed cycles based on industry knowledge of what period is anticipated to be optimal in terms of maintenance costs and failure costs. Preventative maintenance is more extensive than reactive and could include such activities as greasing breakers or switches annually to overhauling a

recloser at a fixed number of operations. This type of maintenance is most effective for mid to high cost equipment where preventative maintenance is a good investment towards preventing a catastrophic failure. This type of maintenance is widely used where failure of equipment can be critical to the operation or where the cost of an unscheduled replacement significantly exceeds the cost of a scheduled replacement.

Predictive maintenance, also as its name suggests, is a methodology that attempts to anticipate when a failure will occur and schedule maintenance prior to the impending failure. This is the newest of the maintenance methodologies which attempts to reduce maintenance costs by extending the maintenance period beyond that of preventative maintenance. This type of maintenance also attempts to detect imminent failures that would have occurred under the preventative maintenance approach. Predictive maintenance is most effective for very high cost equipment or equipment which is very critical, and failures cannot be managed effectively. An example for a substation transformer would be the use of dissolved gas analysis, furan analysis and doble testing to determine when it would be optimal to overhaul a substation transformer rather than perform the overhaul at a fixed period. Of course this is not a perfect science and failures do occur even with some of the most sophisticated testing and monitoring equipment available.

Thunder Bay Hydro's maintenance program will utilize all of the above types of maintenance approaches on a best fit to the equipment basis. This is best described as Reliability Centered Maintenance (RCM). RCM is characterized by determining what type of maintenance is appropriate, based on failure mechanisms and consequences. It is particularly suited to complex plants where there are many failure modes.

In Thunder Bay Hydro's case low cost and low criticality equipment like lightning arrestors, distribution poles, fuse cutouts, distribution transformers, low priority cables, and line hardware will be reactively maintained. Mid cost and mid criticality equipment like breakers, reclosers, line switches, relays, high priority cables and most substation equipment will be maintained with

the preventative methodology. Thunder Bay Hydro's most expensive and critical assets which are its substation transformers will be maintained with the predictive methodology. This approach also utilizes principles from reliability centered maintenance where the equipment's required availability, as well as maintenance costs, is considered in the program development.

Thunder Bay Hydro's maintenance activities are functionally organized such that on a periodic basis the inspection and detection of deficiencies/defects, as well as any minor maintenance functions, will be performed. Periodic maintenance can be further broken down into two separate components.

Firstly, "Patrolling & Visual Inspections" where in Lines this is accomplished with the detailed risk assessments and a thermo graphic survey completed at each location every three years. In Stations, each location is inspected monthly and a thermo graphic survey is conducted annually. Additionally, in Stations a detailed risk assessment is conducted every three years.

Secondly, "Work & Test" maintenance is performed periodically where a piece of equipment is test operated to verify its proper operation. Additionally equipment that requires calibration is re-verified and/or any required testing is performed for predictive purposes i.e. doble testing, furan analysis etc. In Lines, equipment like reclosers and switches are test operated and lubricated every 3 years, and reclosers verified every 6 years. In the Stations, transformers will receive dissolved gas in oil analysis along with other diagnostic testing annually. Breakers will be test operated/ lubricated and relays re-calibrated/verified every three years.

Corrective maintenance occurs only when the periodic maintenance activity has discovered a deficiency or defect. At that time, some corrective maintenance is scheduled like a part replacement, rebuild, or overhaul as deemed necessary to correct the problem discovered.

Thunder Bay Hydro is in the midst of implementing its maintenance program within its enterprise system where all periodic maintenance will be automatically generated. Additionally,

corrective maintenance and failures will be traced to various equipment types, as well as each specific piece of equipment. The automated system is expected to be operational in the summer of 2009.

The overall implementation plan for the maintenance program is to be as follows:

1. List all asset types;
2. Determine criticality and failure modes for each type;
3. Determine required reliability for each type;
4. Determine best or best combination of maintenance methods for each type;
5. Estimate required maintenance to achieve desired reliability for each type;
6. Estimate total maintenance cost for each type;
7. List each asset that will require maintenance;
8. Determine the total cost to maintain the distribution system;
9. Adjust the program or resources as required to match; and
10. Schedule start dates per priorities & last maintained.

Thunder Bay Hydro's Maintenance Program Strategy will be as follows:

1. Risk assessments will be performed on all assets every three years;
2. Infrared scans of all station assets to be performed annually and line assets to be performed every three years;
3. Low criticality equipment like line hardware, distribution transformers and cables will be maintained only with objective evidence of defect or failure;
4. Breakers, reclosers, line switches, relays, and most substation equipment will be periodically maintained with a work and test procedure;
5. The most costly and critical assets; power transformers maintained with a predictive methodology i.e. gas-in-oil, furan, doble testing as well as some periodic maintenance; and
6. A spare power transformer is to be secured for each unique transformer type.

Effective Work Execution Strategies

Recently, Thunder Bay Hydro has undergone several structure, strategy, and policy changes, as outlined below. This will lower costs and improve the overall efficiency of its capital programs,

as well as its operations and maintenance activities, which will help to keep the replacement costs as low as possible.

During 2006 and 2007 extensive efforts were undertaken to improve the efficiency of the Power System Division's organizational structure, planning, and execution of work. This included a re-structuring of the division along with the development of clear roles and responsibilities throughout. Processes were also developed for the execution of capital and maintenance programs. Also included in the improvement of efficiency were the development of departmental metrics and the posting of those metrics so that crews could take greater ownership and accountability for the work they perform. Additionally, utilization of HTE (our enterprise system) will be increased during 2008/9 allowing for a more structured approach to the planning of work and acquisition of the required resources, such as materials, equipment, and labour.

The development of a 20-year capital plan will allow Thunder Bay Hydro to accurately anticipate its short-term and long-term requirements due to the complete view being considered over a 20-year period. Additionally, the preliminary development of the plan has facilitated advancing the entire planning cycle to where the capital plan is supplied to the Lines & Operations groups in the prior year to the work being performed. This allows for more effective execution of projects due to improved planning.

In the long term it is expected that all designs will be completed by June of the year prior to the work being performed so that long lead items may be ordered and contracts negotiated early; ensuring best prices are secured and detailed designs are used for the budgeting process. This will ensure that greater coordination and improved planning are facilitated in the overall execution of capital work leading to improved efficiencies, as well as improved budgeting.

In 2006, a One Outage per Customer per Year Policy was introduced to facilitate work being undertaken while equipment is de-energized. This will improve worker and public safety while reducing the costs of construction and maintenance. Previously, work was done almost

exclusively under live-line conditions. This change will have a positive impact on the cost of replacing lines going forward with the plan.

Another philosophy change has been the reduction of the number of small like-for-like replacement projects with larger scale entire neighbourhood rebuilds. This is a requirement due to the condition of the system whereby small replacements are no longer effective in managing the assets and large scale rebuilds are required. This also allows for more effective capital utilization given the economies of scale and allows the option of voltage conversions during rebuilds whereby lower voltage networks can be eliminated along with the need for the substation. This reduces system losses and removes the liability of the substation.

Increased focus has been placed on the replacement of the overhead lines and underground cables to address the end of life infrastructure. Within substations there has been an increased focus on maintenance activities such that many of these assets can remain in service safely until they are no longer needed.

In 2005, ESA required that Thunder Bay Hydro must adhere to a set of engineered standards in compliance with CSA requirements. Thunder Bay Hydro's previous in-house standards did not comply with the new requirements. Initially, Thunder Bay Hydro acquired Enersource's Standards. While these standards allowed Thunder Bay Hydro to become compliant with our regulators they increased Thunder Bay Hydro's overall line construction costs significantly (approximately 25%) due to the requirement for non native soil backfilling, significantly higher poles, and substantially different construction practices than had been utilized previously.
In September of 2006, Thunder Bay Hydro became a member of the Utility Standards Forum (USF) and received approval for these standards in late 2006 for overhead and in early 2007 for underground. From these approval dates forward all released work will be in accordance with these standards. These standards coincide more closely with previous construction practices simplifying small like-for-like replacements and have lowered costs of large scale projects.

Lastly, Thunder Bay Hydro will be investigating the use of composite and steel poles that could extend the planning horizon to 80 years from the existing 40-year replacement cycle. This would align with the design life of conductors at 80 years and ultimately has the potential to reduce our overhead line replacement capital requirements should the installed costs be comparable to wood. However, the benefits would not be fully realized until all wood poles were replaced when the 40-year replacement cycle would then be increased and 80 years would then be realized. Presently, the cost of composite poles is declining while the cost of wood poles continues to escalate. It is anticipated that within the next 5 – 10 years the cost of the composite poles will be equivalent to that of wood.

All of these efforts have already and will continue to improve overall execution efficiency of Thunder Bay Hydro, having a positive impact on the required resources to accomplish its 20-year capital plan.

BUSINESS APPLICATIONS:

The Information Systems Department (ISD) personnel oversee the acquisition, installation, operation, maintenance, availability and security of the LDC's computer hardware, software, data and network resources. They provide support services to all departments for resources under the ISD scope of responsibility. ISD operates following generally accepted Information Technology industry standards. ISD is currently supporting over 200 users utilizing pc workstations, thin-clients, laptops and wireless devices to connect to the network resources. The ISD group actively pursues implementation of new technologies and services to support the LDC moving forward.

Software:

Support of computer operating systems, business applications, industry specific packages, design and geographic applications and standard integrated office products (deployment, installation, version upgrades, licensing, maintenance).

Customized departmental and LDC applications are developed, tested, implemented and supported using standard development tools.

Maintain and update current levels of virus protection, security software updates and email filtering for security/virus risks.

Direct and coordinate out of scope/expertise development to third party vendors.

Hardware:

Configure servers, pc workstations, thin-clients, laptops, printers and wireless devices to serve as or connect to network resources (deployment, firmware upgrades, licensing, maintenance).

Maintain system servers for primary and backup domain controllers, database applications, data repository and printer sharing and browser based business applications.

Business application and data file servers configured with real time data redundancy for fail over recovery and storage expansion.

Replacement/repair of failed devices or direct undeterminable hardware failures and problems to third party vendors.

Asset tracking and rationalization to ensure optimal deployment and viability.

Network Infrastructure:

Implement, manage and maintain network connectivity (routing, switches, firewall, cable/wireless).

Control network access (security, passwords, remote access), group and individual access.

LAN/WAN design, implementation and support of ethernet and fiber optic resources.

Data Management:

Maintain daily, weekly, and monthly data archives utilizing tape backup and other media for servers and other critical applications (off site storage for disaster recovery).

Ensure the integrity and security of the data by following industry standards and implementing legislated privacy regulation controls (user/user group data access restrictions).

Help Desk and Training:

Provides basic, intermediate and advanced levels of on-site support and trouble-shooting to end-users for any software, hardware and network resource connectivity issues under the ISD scope of responsibility.

Train employees on computer basics helping them to utilize the tools they have available through their office productivity software and customized in-house developed applications.

Cross training and knowledge transfer among ISD personnel to facilitate broad range support.

Research and Development:

Maintain a functional understanding of developments within the Information Technology industry and current trends in the LDC's operating environment.

Attend training and education forums in new technology and evaluate new products and services for LDC compatibility.

Plan to implement new technologies to ensure cost effective solutions are leveraged to support the corporate objectives.

Procurement/Disposal:

Responsible for setting standards, selecting specific products, detailing requisition specifications, engaging third party vendors, license management, maintenance contract management and invoice reconciliation for all technology purchase related activities within the LDC.

Lifecycle tracking for assets to determine end of life disposal.

CUSTOMER SERVICES:

Thunder Bay Hydro is "Committed to Customer Service." Its Customer Service & Conservation Division which delivers this service is made up of the following departments: Customer Service, Billing & Settlements and Conservation & Energy Services. The first two departments are responsible for overall daily operations of the company's CIS. In addition Customer Service is responsible for call centre operations, collections, customer account maintenance and meter readings which are outsourced to a non-affiliated third party under a service level agreement. The initial contract was a one year term with a provision for a further two 1 year extensions upon mutual agreement. Service levels are tracked monthly, and the contractor maintains a 99.5% accuracy rate and a 95% read rate. Thunder Bay Hydro's service area is challenged with access issues as approximately 20% of meters are inside residences. To mitigate this, Meter Readers leave mail cards for customers to complete and return, as well as the options to phone in or web enter their reads.

Customer Service is responsible for back office functions such as web inquiries; move in and out requests; new account setups; and call centre activities. Back office functions are performed in Thunder Bay by in-house staff. Customer Service handles over 55,000 inquires per year with additional outage calls being directed to System Control staff. With time-of-use billing and smart meter installations, Thunder Bay Hydro anticipates an increase in call volume activity and

as such is embarking on a smart meter training program for customer service representatives to ensure they are fully competent to discuss and answer customer inquiries.

To ensure customers are receiving quality service, activities are monitored and tracked. Overall statistical information of the customer service call centre shows that staff maintain an a SQI of answering 95% incoming calls within 30 seconds and less than 1.5% abandoned call rate. These statistics are reviewed with all call centre staff at regular staff meetings.

Collections involve a combination of activities, including the monitoring and collecting of overdue active accounts. With over 58,000 past due notices and 21,000 disconnection notices being issued annually, credit risk is a concern for Thunder Bay Hydro. The forecast for 2009 credit loss is $160,000 which is slightly less than 0.2% of 2009 Test Year gross billings of $90,847,000. In an effort to minimize credit losses, Thunder Bay 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. Thunder Bay Hydro does not perform field collections. Accounts that Thunder Bay Hydro staff are unsuccessful in collecting are turned over to a collection agency 90 days after the final due date.

Billing & Settlements is responsible for meter reading edits, bill production and wholesale and retail settlement interactions. With a mix of bi-monthly and monthly billing, Thunder Bay Hydro issues 330,000 invoices annually to customers. 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 7,000 retailer accounts; account adjustments; processing meter changes; and other various billing account related field service orders. Thunder Bay Hydro offers customers a number of billing and payment options including an equal payment plan; a preauthorized payment plan; local depots and mail-ins.

Conservation & Energy Services is responsible for key account management, consumer high bill management and conservation and demand management programming. Specifically they also support elementary schools by providing Electricity Safety and Conservation sessions for students. Conservation & Energy Services also promotes electrical safety through the provision

of public service bill inserts, as well as the use of public service announcements on local radio stations.

Building a conservation culture in Ontario continues to be an important objective for Thunder Bay Hydro and Conservation & Energy Services is very active in the community promoting conservation initiatives, attending a number of community events each year, distributing compact florescent light bulbs and promoting its conservation programs. It also continues to participate with the Ontario Power Authority in program delivery, however, activities over and above these programs are necessary to keep the conservation momentum building.

Public Relations:

The Communications and Events Coordinator is responsible for external communications to stakeholders and the community as well as the provision of internal communication for the organization's staff. The position administers the development and execution of the corporation's communication strategy.

The realm of responsibility externally includes media relations and marketing conservation initiatives, customer education about electricity-related issues and access to programs, community outreach for both safety and conservation-related topics, as well as support for, and organizing cooperation with other organizations who share similar goals. Internally, the position provides consultation for risk management issues, helps plan and implement Human Resources strategies, produces staff communications, and coordinates events focused on corporate responsibility.

The position is also responsible for the evolution and maintenance of the corporate website. The site features both informative and interactive modules that are kept current through in-house administration. Web content supports customer relations and education, automates administrative tasks for customers and contractors, and features current information on public announcements, conservation and safety programs and media releases

SAFETY AND HEALTH:

Thunder Bay Hydro is committed to creating and maintaining a Corporate Culture where Health and Safety are the utility's top priorities. The utility's 'Target Zero' program has been an unqualified success for the utility since its introduction and we have supported this program by ensuring awareness and competency regarding safe work practices in everything we do. Health and Safety objectives and strategies include:

- Maintaining the momentum of the 'Target Zero' program, ensuring the program remains fresh and its profile high within the utility.
- Achieving E&USA 'Effort Level' (Silver) certification of our Health & Safety Management program and continue to do the work required to progress along E&USA's Paths to Zero.
- Maintaining a Corporate Culture where Safety is of primary importance in decision making.
- Delivering programs to increase safety awareness at work and at home, and to promote employee wellness.
- Delivering a strong public safety program.

ADMINISTRATIVE AND GENERAL EXPENSES:

Administrative and general expenses include expenses incurred in connection with the general administration of the utility's operations. Within Thunder Bay 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:

- Members of the Executive Management Team;
- Executive Assistants of the Executive Management Team;
- Corporate Services, including Human Resources; and
- Financial Services, including Accounting, and Regulatory Services.

Executive Costs:

This team includes the President, the Vice Presidents of Customer Service & Conservation, Finance, Human Resources & Safety and Power Systems and the Executive Assistants.

Corporate Services:

The Human Resources & Safety Division is responsible for human resource management for the utility, including resource planning, employee recruitment and training, labour relations, and benefits administration. Additionally, it is responsible for ensuring a healthy and safe work environment for all employees, including the development and execution of the corporation's health and safety strategy, safety training and reporting.

The Health and Safety function exists at Thunder Bay Hydro to implement and maintain a Safety Management System that facilitates the achievement of the corporation's first priority, which is to secure the Health and Safety of our employees and the public.
Part of the success of our Safety Management System is due to our commitment to creating and maintaining a corporate culture where Health and Safety is the top priority for all employees at all levels. To date, this has been achieved through the implementation of "Target Zero" which is what we have internally branded as our Safety Management System. Target Zero has been an unqualified success for the utility since its introduction and we have supported this program by ensuring awareness and competency regarding safe work practices in everything we do.

Health and Safety Objectives and Strategies

The ultimate objective of our Health and Safety efforts is the pursuit of zero workplace incidents.

Long term goals to support this objective are:

- Zero lost time workplace incidents and an incidents performance trend which compares favourably with industry benchmarks.
- Maintaining the momentum of Target Zero and ensuring that the program remains fresh and its profile high within the utility.

- Maintaining a corporate culture where safety is of primary importance in decision making.
- Delivering programs to increase safety awareness at work and at home, and to promote employee wellness.
- Delivering a strong public safety program.

Short term goals to support this objective are:

- Achieving E&USA 'Effort Level' (Silver) certification of our Health & Safety Management System.
- Developing and implementing a Pandemic Plan.
- Completing a Fire and Life Safety Audit.
- Facilitating employee led wellness initiatives for 2008 and 2009.
- Leading corporate events to support North American Occupational Safety and Health Week (NAOSH).
- Delivering the Highline Hazards presentation to youth in the community.
- Developing and delivering a call before you dig campaign in the community.

2008 achievements to date which support this objective:

- Completed a risk assessment and hazard registry.
- Conducted an audit of our Internal Responsibility System (with EUSA) and developed a plan for implementing its recommendations.
- Completed the revision and roll out of the Emergency Evacuation Plan.
- Completed the revision and roll out of the Early and Safe Return to Work Program.
- Completed an Asbestos Audit and trained all affected employees.
- Completed all training initiatives for the year.

2007 achievements regarding Health and Safety:

- Zero injuries in the workplace.
    - Thunder Bay Hydro achieved Zero lost time incidents in 2007. At year end, utility staff had worked 630 days without a lost time incident. Although this is an exceptional

achievement, our commitment to Target Zero means never being satisfied with Safety performance. Continual effort is required to maintain this level of performance

- The utility has outperformed both the Canadian Electricity Association and relevant WSIB average indexes in 2006 and is likely to do so again in 2007 once finalized data is available.
    - The utility has been advised that it will receive a EUSA President's Award for achieving 250,000 hours without a lost time incident between May 1, 2006 and December 31, 2007
- Increased safety awareness at work and at home to promote employee wellness.

- Detailed reporting of our Safety Management System and the progress made with its programs and initiatives have been presented throughout the year to the Board. However, examples of significant supporting activities include: an emphasis on training, with 51 courses and workshops delivered; working toward our Effort Award (Silver) under E&USA's Paths to Zero program including the development of an Emergency Response Plan; updating our Hazard Registry; implementing a Human Resources Information System; and, focusing on employee wellness by training a new Ergonomic Change Team, as well as enhancing the delivery of our EAP program.

- A corporate culture where safety is of primary importance in decision making.
    - Significant continued emphasis was put on Target Zero as well as specific initiatives such as: celebration of milestone safety events; creating an updated New Hire Orientation Program, expanding our Job Planning and Hazard Identification Program; and increasing employee involvement in the Safety Management System.

    - A strong safety culture is evident in decision making throughout the corporate structure from regular discussion at the Board level to budget decisions which support a strong safety program to the impact of safety on work guidelines and job planning.

- Delivery of a strong Public Safety Program.
    - Examples of elements include: Thunder Bay Hydro led SMARTRISK Heroes event where over 5500 students from the region attended a young worker awareness program during NAOSH Week; helping to organize and supporting the Threads of Life Walk to kick off NAOSH Week; delivering a new Highline Hazard and Energy audiences such as Superior Science, St Joseph's Care Group and at Forum North; and a significant presence in external safety conferences/seminars (Forum North, IAPA, CSSE, AEUSP and the CEO Health & Safety Leadership Charter).

- Progressive relationship with the Ministry of Labour.
    - We continue to enjoy an excellent relationship due to ongoing efforts in strengthening our communication with the MOL. No orders or fines were levied on the utility in 2007.
- Maintain the momentum of Target Zero.
    - Maintaining the momentum of the Target Zero program takes a great deal of ongoing work. In addition to items identified above, which help support the program, celebrations are held to commemorate Safety milestones, and the Target Zero Committee meets regularly to evaluate the Safety Management System and improve its programs. Our efforts to achieve the E&USA Silver Award are key to strengthening our Safety Management System and, as a result, our Target Zero performance.

Environment

Thunder Bay Hydro is committed to being an environmental leader. We embrace our responsibility as a good corporate citizen in complying with environmental laws, standards and procedures. Therefore:

- We will meet our legal regulatory requirements and look for ways to continuously improve our environmental performance.

- We will identify, assess and manage environmental risks and integrate environmental considerations into our decisions.
- We will identify potential environment effects and undertake corrective action to prevent environmental incidents.
- We will ensure our employees and contractors understand their roles and responsibilities from an environmental perspective and have the necessary skills, training and knowledge to perform their duties.
- We will promote environmental awareness by working together with employees, contractors, suppliers, regulators, industry and the public.
- We will conserve natural resources and minimize environmental impact by practicing the three 'R's' – Reduce, Reuse and Recycle.
- We will measure and communicate the results of our environmental performance.

Outsourcing

With the exception of auditing and training, all areas of the Safety Management System are created and implemented in-house.

Auditing

To ensure an unbiased third party view, we outsource the auditing function on a regular basis to assist Thunder Bay Hydro in measuring progress, successes and to identify any gaps in the Safety Management System.

Training

Training is an integral part of the Safety Management System at Thunder Bay Hydro. Given the risks associated with our product, training is on-going to ensure that our employees are fully competent in identifying the hazards associated with their work and to implement the appropriate barriers to protect themselves, co-workers and the public.

Due to the complexity and specialization in the courses delivered, the majority of training is outsourced to specialists. However, as a part of our employee retention program, more and more

of our staff are being trained as trainers to deliver the more routine sessions. This also assists in our cost reduction strategy.

Human Resources

Ensuring the utility can continue to attract, develop and retain required Human Resources is a critical challenge. Meeting this challenge is becoming increasingly difficult and is becoming one of the greatest risks the utility faces.

Long term success will require that the utility provide a fulfilling, fair, and challenging work environment that allows us to attract, develop, engage and retain high quality staff. A wide range of initiatives contribute to meeting this challenge:

- Assessment of Internal Management Skills and Management Skills Training

  A regular assessment of internal management skills occurs. This assessment feeds a multi-year plan of management skills. The goal of this plan will be to ensure current and future utility management staff has the necessary operational, financial, supervisory and strategic skills to effectively contribute to the management of Thunder Bay Hydro.

- Succession Planning Strategy

  This includes an analysis of probable succession scenarios for supervisory, and non-supervisory, positions and the establishment of temporary and permanent succession plans.

- Employee Engagement Strategy

  Includes regular updates to staff through meetings and other communications; outlining the industry developments, challenges and overall Corporate Goals and Strategies. There is also a process of 'translating' Corporate Strategies into departmental action plans and specific objectives, and coordination of objectives across the company to avoid conflict. There is ongoing communication of departmental and individual objectives to those responsible, and a regular program of comparing requirements to results and updating staff of this progress.

- Formal Employee Satisfaction Assessment

  Yearly employee satisfaction surveys to receive feedback upon which to base new initiatives and modify existing programs.

- Compensation Strategy

  Establish a strategy for fairly balancing target compensation levels with retention risk for union and non-union staff.

- Institutional Relationships/Partnerships

  Promote relationships with post-secondary institutions that will help ensure the long term availability of specific skills required by the utility.

- Internal Promotional Program

  Establish a strategy promoting the benefits of working at the utility to increase retention.

Financial Services:

The Finance Division is responsible for the preparation of statutory, management and Board of Directors financial reporting; all daily accounting functions, including accounts payable, accounts receivable, compensation and payroll, including OMERS administration 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.

The Regulatory Services department within the Finance Division is responsible for all regulatory reporting and compliance with applicable codes and legislation governing Thunder Bay Hydro. The department handles all regulatory reporting including development and preparation of rate filings, performance reporting, and compliance.

In accordance with the OEB's APH, the following is a summary of the categories of expenditures that are included in administrative and general expenses:

1. Salaries and expenses for all employees working within the above noted functional areas including:

- Executive salaries and expenses;
- Management salaries and expenses; and
- General and administrative salaries and expenses.

Detailed information with respect to employee complement and compensation is provided as part of Table 3 in Exhibit 4, Tab 2, Schedule 4.

2. Outside services employed include, but are not limited to consulting and professional fees of accountants and auditors, actuaries, legal services, public relations counsel and tax consultants.

3. Office supplies and expenses specifically related to the administrative and general functional departments, as noted above.

4. Insurance premiums to protect the utility against losses and damages, including owned or leased property used in its utility operations, as well as injuries and damages claims of employees or others, losses not covered by insurance, and expenses incurred in the settlement of claims. Thunder Bay Hydro currently maintains prudent levels of Comprehensive General Liability insurance, including Enhanced Directors and Officers' Liability Insurance, as well as property and automobile insurance.

5. Annual expense for post-retirement benefits provided to eligible Thunder Bay Hydro employees in accordance with company policy and as provided in the collective bargaining agreement between Thunder Bay Hydro and its union. 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.

6. Regulatory 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.

OM&A DETAILED COSTS TABLE

Expense Description	2006 Board Approved	2006 Actual	Variance from 2006 Board Approved	2007 Actual	Variance from 2006 Actual	2008 Bridge	Variance from 2007 Actual	2009 Test	Variance from 2008 Bridge
Operation									
5005-Operation Supervision and Engineering	153,754	192,586	38,832	246,985	54,399	302,452	55,467	264,373	(38,078)
5010-Load Dispatching	638,180	639,060	880	720,682	81,622	769,838	49,156	816,699	46,861
5012-Station Buildings and Fixtures Expense	247,823	383,251	135,428	321,047	(62,204)	309,836	(11,210)	309,836	0
5014-Transformer Station Equipment - Operation Labour		0	0	0	0	0	0	0	0
5015-Transformer Station Equipment - Operation Supplies and Expenses		0	0	0	0	0	0	0	0
5016-Distribution Station Equipment - Operation Labour	37,333	0	(37,333)	0	0	0	0	0	0
5017-Distribution Station Equipment - Operation Supplies and Expenses	38,626	97,048	58,422	98,599	1,550	119,350	20,751	93,130	(26,220)
5020-Overhead Distribution Lines and Feeders - Operation Labour	60,549	155,176	94,627	127,636	(27,540)	122,284	(5,352)	106,084	(16,200)
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	310,733	387,412	76,679	406,105	18,693	406,621	516	414,815	8,194
5030-Overhead Subtransmission Feeders - Operation		0	0	0	0	0	0	0	0
5035-Overhead Distribution Transformers- Operation	118,951	117,182	(1,769)	212,752	95,569	88,703	(124,049)	341,548	252,845
5040-Underground Distribution Lines and Feeders - Operation Labour	8,991	23,410	14,419	18,655	(4,755)	23,202	4,547	10,287	(12,915)
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	4,828	8,114	3,286	5,391	(2,723)	11,653	6,262	5,809	(5,844)
5050-Underground Subtransmission Feeders - Operation			0		0		0		0
5055-Underground Distribution Transformers - Operation	62,468	106,220	43,752	87,393	(18,827)	91,227	3,834	71,865	(19,362)
5060-Street Lighting and Signal System Expense			0		0		0		0
5065-Meter Expense	243,191	563,268	320,077	490,640	(72,629)	485,380	(5,260)	544,081	58,701
5070-Customer Premises - Operation Labour	70,365	24,749	(45,616)	20,077	(4,673)	11,131	(8,946)	8,773	(2,358)
5075-Customer Premises - Materials and Expenses	13,101	16,045	2,944	28,825	12,780	11,172	(17,653)	37,465	26,293
5085-Miscellaneous Distribution Expense	859	0	(859)	0	0	0	0	0	0
5090-Underground Distribution Lines and Feeders - Rental Paid		0	0	0	0	0	0	0	0
5095-Overhead Distribution Lines and Feeders - Rental Paid	2,146		(2,146)		0		0		0
5096-Other Rent			0		0		0		0
Sub-Total	**2,011,898**	**2,713,521**	**701,623**	**2,784,785**	**71,264**	**2,752,849**	**(31,937)**	**3,024,765**	**271,917**

Expense Description	2006 Board Approved	2006 Actual	Variance from 2006 Board Approved	2007 Actual	Variance from 2006 Actual	2008 Bridge	Variance from 2007 Actual	2009 Test	Variance from 2008 Bridge
Maintenance									
5105-Maintenance Supervision and Engineering	854,467	754,276	(100,191)	654,477	(99,799)	654,104	(373)	548,396	(105,708)
5110-Maintenance of Buildings and Fixtures - Distribution Stations	4,923	26,784	21,861	12,499	(14,285)	12,499	0	12,499	0
5112-Maintenance of Transformer Station Equipment		0	0	0	0	0	0	0	0
5114-Maintenance of Distribution Station Equipment	114,633	70,870	(43,763)	154,114	83,244	192,696	38,582	286,238	93,542
5120-Maintenance of Poles, Towers and Fixtures	329,955	142,498	(187,458)	139,885	(2,613)	165,297	25,412	133,991	(31,306)
5125-Maintenance of Overhead Conductors and Devices	873,414	789,575	(83,839)	882,978	93,403	790,769	(92,209)	686,177	(104,592)
5130-Maintenance of Overhead Services	160,594	310,963	150,369	256,757	(54,206)	303,356	46,599	344,777	41,421
5135-Overhead Distribution Lines and Feeders - Right of Way	327,390	277,983	(49,407)	522,385	244,402	483,555	(38,830)	716,115	232,560
5145-Maintenance of Underground Conduit	20,634	34,853	14,219	31,271	(3,582)	17,606	(13,665)	17,669	63
5150-Maintenance of Underground Conductors and Devices	119,275	117,236	(2,039)	112,952	(4,284)	128,393	15,441	164,495	36,102
5155-Maintenance of Underground Services	73,409	67,987	(5,422)	96,140	28,153	146,536	50,396	74,510	(72,026)
5160-Maintenance of Line Transformers	98,039	56,493	(41,546)	407,165	350,672	101,256	(305,909)	64,866	(36,390)
5165-Maintenance of Street Lighting and Signal Systems		0	0	0	0	0	0	0	0
5170-Sentinel Lights - Labour		0	0	0	0	0	0	0	0
5172-Sentinel Lights - Materials and Expenses		0	0	0	0	0	0	0	0
5175-Maintenance of Meters	1,018	888	(130)	537	(351)	0	(537)	0	0
5178-Customer Installations Expenses- Leased Property		0	0	0	0	0	0	0	0
5185-Water Heater Rentals - Labour		0	0	0	0	0	0	0	0
5186-Water Heater Rentals - Materials and Expenses		0	0	0	0	0	0	0	0
5190-Water Heater Controls - Labour		0	0	0	0	0	0	0	0
5192-Water Heater Controls - Materials and Expenses		0	0	0	0	0	0	0	0
5195-Maintenance of Other Installations on Customer Premises		0	0	0	0	0	0	0	0
Sub-Total	**2,977,751**	**2,650,405**	**(327,346)**	**3,271,159**	**620,754**	**2,996,067**	**(275,091)**	**3,049,733**	**53,666**

Expense Description	2006 Board Approved	2006 Actual	Variance from 2006 Board Approved	2007 Actual	Variance from 2006 Actual	2008 Bridge	Variance from 2007 Actual	2009 Test	Variance from 2008 Bridge
Billing and Collections									
5305-Supervision	42,002	45,081	3,079	0	(45,081)	0	0	0	0
5310-Meter Reading Expense	436,092	418,282	(17,810)	425,989	7,707	275,059	(150,930)	281,316	6,257
5315-Customer Billing	1,186,499	1,141,557	(44,942)	1,138,862	(2,695)	1,290,662	151,800	1,271,382	(19,280)
5320-Collecting	621,640	573,514	(48,126)	641,092	67,578	688,412	47,320	679,308	(9,104)
5325-Collecting- Cash Over and Short		(10)	0	0	10	0	0	0	0
5330-Collection Charges			0		0		0		0
5335-Bad Debt Expense	146,686	105,590	(41,096)	80,362	(25,227)	160,000	79,638	160,000	0
5340-Miscellaneous Customer Accounts Expenses		0	0	0	0	0	0	0	0
Sub-Total	**2,432,919**	**2,284,014**	**(148,895)**	**2,286,306**	**2,292**	**2,414,133**	**127,827**	**2,392,006**	**(22,127)**
Community Relations									
5405-Supervision	13,583	15,027	1,444	0	(15,027)	0	0	0	0
5410-Community Relations - Sundry		0	0	0	0	0	0	0	0
5415-Energy Conservation	44,343	401,746	357,403	381,627	(20,119)	58,431	(323,196)	78,732	20,301
5420-Community Safety Program	3,350	8,030	4,680	14,646	6,617	14,600	(46)	14,892	292
5515-Advertising Expense	107,763	122,228	14,465	106,270	(15,958)	122,285	16,015	134,715	12,430
Sub-Total	**169,039**	**547,031**	**377,992**	**502,544**	**(44,487)**	**195,316**	**(307,228)**	**228,339**	**33,023**

Expense Description	2006 Board Approved	2006 Actual	Variance from 2006 Board Approved	2007 Actual	Variance from 2006 Actual	2008 Bridge	Variance from 2007 Actual	2009 Test	Variance from 2008 Bridge
Administrative and General Expenses									
5605-Executive Salaries and Expenses	566,779	582,547	15,768	815,595	233,047	977,940	162,345	966,552	(11,388)
5610-Management Salaries and Expenses	107,628	0	(107,628)	0	0	0	0	0	0
5615-General Administrative Salaries and Expenses	1,074,938	1,076,454	1,516	1,193,512	117,057	1,173,476	(20,036)	1,258,112	84,636
5620-Office Supplies and Expenses	210,361	182,881	(27,480)	169,123	(13,758)	193,042	23,919	191,768	(1,274)
5630-Outside Services Employed	180,930	237,678	56,748	181,373	(56,304)	226,700	45,327	239,149	12,449
5635-Property Insurance	34,277	30,818	(3,459)	31,255	437	37,874	6,619	32,550	(5,324)
5640-Injuries and Damages	206,659	170,407	(36,252)	208,509	38,103	297,604	89,095	315,652	18,048
5645-Employee Pensions and Benefits	19,303	0	(19,303)	0	0	0	0	0	0
5655-Regulatory Expenses	140,432	0	(140,432)	0	0	0	0	0	0
5665-Miscellaneous General Expenses	95,055	194,209	99,154	243,650	49,441	272,750	29,101	258,406	(14,344)
5670-Rent	229,658	275,609	0	272,114	(3,495)	303,512	31,398	308,288	4,776
5675-Maintenance of General Plant	45,110	62,666	17,556	91,710	29,044	78,218	(13,492)	75,643	(2,575)
5740-Amortization of Deferred charges	0	0	0	0	0	0		0	
Sub-Total	**2,911,130**	**2,813,268**	**(143,812)**	**3,206,840**	**393,572**	**3,561,117**	**354,276**	**3,646,120**	**85,004**
Total Operating, Maintenance and Administration Expenses	**10,502,737**	**11,008,239**	**459,561**	**12,051,634**	**1,043,395**	**11,919,481**	**(132,152)**	**12,340,964**	**421,483**
Amortization Expenses									
5705-Amortization Expense - Property, Plant, and Equipment	4,056,140	4,382,390	326,250	4,564,773	182,383	4,526,557	(38,216)	4,573,436	46,879
Sub-Total	**4,056,140**	**4,382,390**	**326,250**	**4,564,773**	**182,383**	**4,526,557**	**(38,216)**	**4,573,436**	**46,879**
Total Distribution Expense Before Income Taxes	14,558,877	15,390,629		16,616,407		16,446,038		16,914,400	
Variance Determined as 1% of Total Distribution Expense before Taxes	145,589	153,906		166,164		164,460		169,144	
Materiality		**153,906**							

VARIANCE ANALYSIS ON OM&A COSTS:

Thunder Bay Hydro has provided a detailed OM&A cost table covering the periods from 2006 Board Approved, 2006 Actual, 2007 Actual, 2008 Bridge Year and 2009 Test Year including the variances year over year in Exhibit 4, Tab 2, Schedule 2, above.

Variance Analysis:

As mentioned above, the variance that triggers the required analysis is $153,906, representing 1% of Thunder Bay Hydro's total distribution expenses before PILs. Thunder Bay Hydro has reviewed the total variance of each major group of accounts, as well as individual OEB USoA accounts in determining where explanations were necessary. The following Table 1 summarizes the accounts exceeding the variance amount and requiring explanations.

The summary on the following page provides an explanation for the 2009 Test Year increased OM&A costs over the 2006 Actuals in the amount of $1,523,771, which represents a 9.9% increase.

Summary of Cost Drivers of the OM&A Variance		
	Amount	% Increase
2009 Test Year OM&A	$ 16,914,400	
2006 Actual OM&A	$ 15,390,629	
Increase in OM&A Costs	$ 1,523,771	9.90%
Significant increases are all driven by Thunder Bay Hydro's **AMP** and include the following:		
Load Dispatching - Account 5010 and Maintenance of Distribution Station Equipment - Account 5114 - Skilled labour salary adjustment and the additional staff complement as discussed at Executive Compensation, Incentive Plan Expenses, Pension Expense and Post Retirement Benefits at Exhibit 4, Tab 2, Schedule 4.	$ 393,007	
O/H Distribution Transformers - Operations - Account 5035 - Main cost driver is the PCB work component of Thunder Bay Hydro's AMP as discussed in Exhibit 1, Tab 2, Schedule 3.	$ 224,366	
Supervision and Engineering - Accounts 5005 and 5105 - Cost driver of the reduction is mainly attributable to the increased capital work resulting in a large base to allocate the overheads.	$ (134,093)	
Maintenance of Distribution Station Equipment - Account 5114 - Cost driver being the increase maintenanced activity as addressed in Exhibit 4, Tab 2, Schedule 1 under Effective Work Execution Strategies. Specifically, within substations there has been an increased focus on maintenance activities such that many of these assets can remain in service safely until they are no longer needed.	$ 215,368	
O/H Distribution Lines and Feeders - Right of Way - Account 5135 - Cost driver is the forestry management program as discussed in Exhibit 1, Tab 2, Schedule 3.	$ 438,132	
Energy Conservation - Account 5415. Thunder Bay Hydro is now carrying out OPA funded CDM programs versus the OEB funded CDM programs which were carried out in 2006.	$ (323,014)	
Executive Salaries and Expenses - Account 5605 - As explained in detail at Exhibit 4, Tab 2, Schedule 2, Thunder Bay Hydro was not at full complement during 2006 combined with an Executive Team compensation adjustment in 2008 in recognition of the importance of retention and attraction of critical skills.	$ 384,005	
General Administrative Salaries and Expenses - Account 5615 - Staff complement was increased mid 2006 to address the workload in the Accounting/Regulatory departments; staff progressions and increased overhead allocation as a result of complement increase in Purchasing	$ 181,658	
Amortization Expense - Property, Plant and Equipment - Account 5705 - consistent with increasing infrastructure capital spending	$ 191,046	
All other variances	$ (37,704)	
	$ 1,532,771	
Other notable causes include the following:		
The 2006 actual costs for OMERS do not include the costs for the period January to April as they such was approved for a deferral account. The amount deferred for this time period amounted to $144,517.		
Staff complement increases that have not been seperately identified in the above accounts as explained in the Executive Compensation, Incentive Plan Expenses, Pension Expense and Post Retirement Benefits at Exhibit 4, Tab 2, Schedule 4. (Succession planning being the cost driver for these OM&A costs).		

Table 1
Summary of OM&A Variances Exceeding Variance Analysis Threshold

Expense Description	2006 Board Approved	2006 Actual	Variance from 2006 Board Approved	2007 Actual	Variance from 2006 Actual	2008 Bridge	Variance from 2007 Actual	2009 Test	Variance from 2008 Bridge
Operation									
5065-Meter Expense	243,191	563,268	320,077	490,640	(72,629)	485,380	(5,260)	544,081	58,701
Maintenance									
5120-Maintenance of Poles, Towers and Fixtures	329,955	142,498	(187,458)	139,885	(2,613)	165,297	25,412	133,991	(31,306)
5130-Maintenance of Overhead Services	160,594	310,963	150,369	256,757	(54,206)	303,356	46,599	344,777	41,421
5135-Overhead Distribution Lines and Feeders - Right of Way	327,390	277,983	(49,407)	522,385	244,402	483,555	(38,830)	716,115	232,560
5160-Maintenance of Line Transformers	98,039	56,493	(41,546)	407,165	350,672	101,256	(305,909)	64,866	(36,390)
Community Relations									
5415-Energy Conservation	44,343	401,746	357,403	381,627	(20,119)	58,431	(323,196)	78,732	20,301
Administrative and General Expenses									
5605-Executive Salaries and Expenses	566,779	582,547	15,768	815,595	233,047	977,940	162,345	966,552	(11,388)
Amortization Expenses									
5705-Amortization Expense - Property, Plant, and Equipment	4,056,140	4,382,390	326,250	4,564,773	182,383	4,526,557	(38,216)	4,573,436	46,879

OPERATION - METER EXPENSE VARIANCE – ACCOUNT #5065:

The variance for the 2006 Actual over the 2006 Board Approved is the result of a reconsideration of the Stores and Purchasing Department overhead costs burdened to the meter exchanges in the field. Prior to 2006, there were minimal overhead costs assigned to this activity. Considering that every meter that was issued to the field resulted in a return of a meter to stock, it was deemed more appropriate to charge the activities that drive the costs. As a result, an overhead was assigned to both issues and returns to the field. Variation in this account subsequent to 2006 has been below the materiality threshold.

MAINTENANCE – OVERHEAD POLES, TOWERS & FIXTURES VARIANCE – ACCOUNT #5120:

The 2006 Actual costs of $142,498 is a decrease of $187,458 from the 2006 Board Approved costs of $329,955. A review of cost comparators coupled with increased education and awareness of the APH resulted in improved tracking and classification of the smaller like-for-like replacements work Thunder Bay Hydro previously considered a maintenance expense. Additionally, overtime costs have been more aggressively managed resulting in reduced costs.

MAINTENANCE – OVERHEAD DISTRIBUTION LINES & FEEDERS VARIANCE – ACCOUNT #5135:

The 2007 Actual increased by $244,402 over the 2006 Actual and the 2009 Test Year of $716,115 is an increase of $232,560 over the 2008 Bridge year. The tree trimming costs are driving this increase. As was discussed in Exhibit 1, Tab 2, Schedule 3 under the Forestry Management, regular scheduled forestry practices for line clearing were downsized in the past resulting in vegetation growing relatively unchecked into the power lines causing many unscheduled power interruptions and increasing the safety risk to the public and power line workers.

Present levels of vegetation that are in proximity to overhead lines will require 10 years of intense management in order to reduce both hazardous situations and achieve a sustainable trimming cycle. The chart in Exhibit 1, Tab 2, Schedule 3, page 4 indicates estimated line

clearing costs of $7,667,120 are required to correct the situation and Thunder Bay Hydro's plan is to do this over a ten year period.

Once the current situation has been addressed, a sustainable trimming cycle of 7 years will be able to maintain vegetation levels to an acceptable level and prevent the current situation from repeating. The table in Exhibit 1, Tab 2, Schedule 3, page 5 estimates the total amount to maintain vegetation over a 7 year tree trimming cycle will be $3,624,644 resulting in approximately $518,000 annually.

MAINTENANCE – MAINTENANCE OF LINE TRANSFORMERS VARIANCE – ACCOUNT #5160:

The 2007 Actuals increased by $350,672 over the 2006 Actuals; the 2008 Bridge year is forecasting a reduction of $305,909 from the 2007 Actuals. During 2007, Thunder Bay Hydro incurred significant non-routine costs for PCB waste disposal in the amount of $317,773.

Due to pending PCB legislation introduced in early 2007 that was expected to become law later that year, Thunder Bay Hydro undertook to sample the remaining 2300 contaminated oil distribution transformers. This work required that all high level PCB contaminated oil and medium level PCB contaminated oil located in environmentally sensitive areas be removed from service by 2009. This legislation required that Thunder Bay Hydro quickly determine which transformers would need to be replaced. Thunder Bay Hydro was required to put a plan into place to accomplish this within the short time period from introduction of the legislation. The legislation is still pending at this time and it is unclear as to when it will be enacted. Thunder Bay Hydro has undertaken a due diligence approach of removing 15-20% of its PCB transformers annually.

COMMUNITY RELATIONS – ENERGY CONSERVATION VARIANCE – ACCOUNT #5705:

Total Community Relations Expense for 2006 Actual increased significantly over 2006 Board Approved by $357,403 and then subsequently decreased in the 2008 Bridge Year, by $323,196

the increase and subsequent decreases are a result of the implementation of Thunder Bay Hydro third tranche CDM plan as approved by the OEB in February 2005 for $1,606,665. The 2006 Actual Year was the first full year of the implementation of the CDM programs and the decrease in 2008 Bridge Year reflects the lower activity level associated with the delivery of OPA approved conservation programs versus the larger slate of third tranche programs.

ADMINISTRATIVE AND GENERAL EXPENSE –EXECUTIVE SALARIES AND EXPENSES VARIANCE – ACCOUNT #5605:

The cost increase of $233,047 in 2007 Actual over the 2006 Actual is driven by changes in the structure of, and the transition of staff within the Executive Management Team. The current President was promoted to that position from his previous position of Vice President Customer Service in July of 2003. Subsequently, the Vice President Customer Service was not filled. Rather the position was filled at the "Manager" level and as such, while the overall management complement did not change, the Executive Team complement was reduced by one position. In September of 2007, the incumbent Manager was promoted to Vice President Customer Service reflecting the increasing demands in this area. The Manager level position was not filled; therefore, although the Executive Management Team increased in complement, the overall management complement did not increase. In addition, the Vice President, Power Systems position was vacated by the incumbent in September 2006 and remained unfilled until July of 2007, temporarily reducing the Executive Management Team costs in 2007.

This cost shows a further increase of $162,345 in 2008 Bridge Year over the 2007 Actual. This is a combination of the vacancy for the Vice President, Power Systems for the first six months of 2007 coupled with a compensation increase for the Executive Management Team approved by the Board of Directors effective January 1, 2008. Over the course of 2007 and into 2008 the Board of Directors considered the issue of Executive compensation at the utility. To aid in its consideration, the Board used the industry management compensation information provided in the annual Management Salary Survey completed by the Mearie Group in addition to outside consultant expertise.

After review of the 2006 and 2007 survey data, the Board determined that the utility Executive Team, consisting of the President & CEO and the Vice Presidents were compensated at salary levels below the 25th percentile of comparable surveyed LDCs. The Board determined that this relatively low level of compensation was significantly increasing the risks associated with Executive level skill retention and recruitment. The Board concluded that the degree of competition in the LDC industry in Ontario for Executive level skills is becoming increasingly competitive. Further, the Board concluded that if it becomes necessary to recruit new Executive talent it is likely that a significant salary premium would be required to entice candidates to relocate to Thunder Bay if suitable internal candidates are not available. They concluded that the retention and attraction of critical talent is a significant priority for the utility and that the level of risk associated with potentially losing members of the current Executive Team members was excessive. In May of 2008 the Board determined that an Executive Compensation philosophy should be constructed which reduces the risk. The Board resolved that members of the Executive team should be compensated at levels consistent with the Mean of comparable surveyed LDC's. The resultant annual increase is approximately $75,000.

AMORTIZATION EXPENSE VARIANCE – ACCOUNT #5705:

The variance year over year in amortization expense is directly related to the fixed assets and additions to fixed assets.

SHARED SERVICES:

Thunder Bay Hydro Corporation is the parent company for four affiliates; Thunder Bay Renewable Power Incorporated (TBRPI), a generation company; Thunder Bay Hydro Energy Services Inc. (TBHESI), a water heater rental business; Thunder Bay Hydro Electricity Distribution Inc., (Thunder Bay Hydro) the distribution company; and Thunder Bay Hydro Utility Services Inc. (TBHUSI), a back office services company. Competitive meter service provider (MSP) services are also provided within TBHUSI to northern commercial and industrial customers. Thunder Bay Hydro provides certain services to its various affiliates. Because Thunder Bay Hydro is the provider of the services, there are no expenses related to shared services included. Thunder Bay Hydro recovers revenues from TBHESI and TBHUSI in respect of the services it provides, and these revenues are as per the Services Agreements in Exhibit 4, Tab 2, Schedule 3, Appendix A.

Related party transactions with the City of Thunder Bay include Thunder Bay Hydro's payment of property taxes, water and sewer charges, telephone charges and the City of Thunder Bay's payment to Thunder Bay Hydro for electricity bills. The foregoing involves non-discretionary transactions. Thunder Bay Hydro does not have a Services Agreement with the City of Thunder Bay.

Services Provided By Thunder Bay Hydro to TBHUSI

TBHUSI is a back office services company that provides wholesale settlement, EBT, meter reading, MV90, customer information system, bill production and mailing, after hours system control, related ISD services and conservation programming exclusively to the smaller LDC's in Northwestern Ontario. The services are provided to regional LDC's only and are not marketed or promoted to a larger group. The arrangements with the regional LDC's allows for overall efficiencies to be gained by sharing of expertise and excess capacity. Essentially, the smaller utilities contracts with TBHUSI for the primary reason of being remotely hosted on Thunder Bay Hydro's computer systems for their use of hardware and software for Customer Information Systems, Financials, remote meter reading, etc.

For the most part, the Northern Ontario utilities perform their own work with their own staff on the computer systems through remote access with minimal assistance from Thunder Bay Hydro staff. Thunder Bay Hydro staff monitors the MV90 and wholesale settlement systems to make sure utility meter data passes VEE rules prior to transmission to the billing system. Thunder Bay Hydro staff also process EBT transactions, print, stuff and mail customer bills, make billing collection calls, receive after hours outage calls on behalf of and for regional LDCs and provide ISD support related to the information systems being used.

TBHUSI is also registered as a Meter Service Provider with the IESO to provide metering related services to Northwestern Ontario commercial and industrial customers. TBHUSI contracts with Thunder Bay Hydro for staff and equipment to carry out this work.

Thunder Bay Hydro bills TBHUSI based on costs plus bank prime, adjusted quarterly as per the Services Agreement.

In light of the recent amendments to the Affiliate Relationships Code (ARC), Thunder Bay Hydro will be seeking to have external consultants review the existing Services Agreements in place and the method of cost allocation for compliance with all aspects of the ARC.

The following Table 1 summarizes the billings to TBHUSI by Thunder Bay Hydro for each of 2006 Actual, 2007 Actual, 2008 Bridge Year and 2009 Test Year.

Table 1

Services Provided to Affiliate Company- Thunder Bay Hydro Utility Services Inc.

	2006	**2007**	**2008**	**2009**
Services Billed to TBHUSI by Thunder Bay Hydro	117,608	72,752	63,000	63,000

Services Provided By Thunder Bay Hydro to TBHESI

TBHESI is a competitive gas and electric water heater rental company. Thunder Bay Hydro provides staff and ISD systems support for consumer site visits and general administration of the business.

TBHESI is currently in discussions with a potential purchaser of the rental water heaters and as such, does not anticipate any activity in the 2009 Test Year.

The following Table 2 summarizes the billings to TBHESI by Thunder Bay Hydro for each of 2006 Actual, 2007 Actual, 2008 Bridge Year and 2009 Test Year.

Table 2

Services Provided to Affiliate Company- Thunder Bay Hydro Energy Services Inc.

	2006	2007	2008	2009
Services Billed to TBHESI by Thunder Bay Hydro	207,852	114,703	130,000	0

Services Provided By Thunder Bay Hydro to TBRPI

TBRPI is a generation company that has carried our preparation work in partnership with the Corporation of the City of Thunder Bay for a landfill generation project.

Thunder Bay Hydro currently does not have a Services Agreement with TBRPI given the limited activity to date. It is anticipated that a Services Agreement will be put in place by the end of the 2008 Bridge Year. There have been no billings by Thunder Bay Hydro to TBRPI to date.

APPENDIX A

SERVICES AGREEMENTS

Thunder Bay Hydro Energy Services Inc.

Thunder Bay Hydro Utility Services Inc.

SERVICES AGREEMENT

THIS AGREEMENT made as of the 30th day of June 2006,

BETWEEN:

THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC., a corporation incorporated under the *Ontario Business Corporations Act*, R.S.O. 1990, c. B.18 (hereinafter referred to as "DISTRIBUTION")

OF THE FIRST PART

- and -

THUNDER BAY HYDRO ENERGY SERVICES INC., a corporation incorporated under the *Ontario Business Corporations Act*, R.S.O. 1990, c. B.18 (hereinafter referred to as "SERVICES")

OF THE SECOND PART

WHEREAS DISTRIBUTION is required by the Ontario Energy Board to enter a service agreement (hereinafter referred to as the "Agreement") with SERVICES under the Affiliate Relationships Code For Electricity Distributors and Transmitters (revised November 24, 2003 and as may be amended from time to time) (hereinafter referred to as the "Code");

AND WHEREAS the Code provides that DISTRIBUTION and any affiliate with which it shares services, shall do so in accordance with a Services Agreement;

AND WHEREAS DISTRIBUTION has agreed to share services of certain of its employees with SERVICES for a fee, subject to the terms and conditions set forth herein;

NOW THEREFORE THIS AGREEMENT WITNESSETH that in consideration of the premises and agreements herein contained, it is mutually declared, covenanted and agreed by and between the parties hereto as follows:

1. GENERAL AND ADMINISTRATIVE SERVICES

(a) DISTRIBUTION shall provide general and administrative services (hereinafter referred to as the "G&A Services") to SERVICES as SERVICES may reasonably require from time to time. The G&A Services shall consist of corporate administrative services normally required in the ordinary course of business, including accounting, financial reporting, corporate secretarial duties and other in-house services that are normally classified as general and administrative expenses. DISTRIBUTION shall not incur any third party costs in providing G&A Services to SERVICES without the prior written approval of SERVICES. DISTRIBUTION shall charge and SERVICES shall purchase such services for an annual fee of $16,000.00 per annum, settled monthly on the last day of the month in which the services are performed. The annual fee shall be adjusted annually based on the change in the Consumer Price Index for the City of Thunder Bay, as provided in paragraph 6 hereof.

(b) SERVICES shall pay DISTRIBUTION for maintenance labour provided as needed by SERVICES. SERVICES shall pay for the same on a cost recovery plus the prime rate of DISTRIBUTION'S Bank (Bank Prime Rate) adjusted quarterly. The current Prime Rate of DISTRIBUTION'S Bank is 6% per annum. Such interest shall be payable on the first day of each month commencing after such maintenance labour has been provided. SERVICES shall pay DISTRIBUTION the cost of wage costs plus benefits for clerical work provided by DISTRIBUTION to SERVICES. Clerical work shall be charged out for the first clerk at 50% of the annual wage plus benefits, for the second clerk at 25% of the annual wage plus benefits and for a third clerk at 20% of the annual wage plus benefits plus the prime rate charged by the Bank of DISTRIBUTION, which rate shall apply for three months and then be amended based on the new prime rate, if any, for the next three months and so on.

(c) SERVICES shall pay DISTRIBUTION the amount of $0.77 per bill, in consideration for supplies, printing and postage. This amount shall be reviewed by the parties on January 1st of each calendar year and the cost per bill will be based on arms length third party provider rates for similar services, such as Canada Post.

(d) In addition to any payments made under paragraph 1 (b), SERVICES shall reimburse DISTRIBUTION for any third party costs incurred by DISTRIBUTION in accordance with paragraph 1 (a). DISTRIBUTION shall, if requested by SERVICES, be required to submit an invoice or similar evidence of payment in respect of all third party costs for which it seeks reimbursement hereunder.

(e) All services, resources, and products sold according to paragraph 1 (b) and paragraph 1 (c) are to be sold at a minimum of the fair market value of the service, resource, or product.

(f) Where a fair market value is not available for any product, resource, or service provided under paragraph 1, DISTRIBUTION shall charge no less than a cost-based price, and shall pay no more than a cost-based price. A cost-based price shall reflect the costs of producing the service or product, including a return on invested capital. The return component shall be the higher of DISTRIBUTION's approved rate of return or the bank prime rate.

(g) DISTRIBUTION shall sell assets to SERVICES at a price no less than the net book value of the asset.

2. MANAGEMENT SERVICES and OVERHEAD

(a) Services shall consist of management services (hereinafter referred to as the "Management Services") to include supervision, customer contacts, settling customer complaints, co-ordinating purchasing, field services and customer interaction.

(b) SERVICES shall pay DISTRIBUTION the amount of $49,000.00 per annum, payable monthly, as consideration for the management services provided by DISTRIBUTION to SERVICES. DISTRIBUTION shall not incur any third party costs in providing Management Services to SERVICES without the prior written approval of SERVICES.

(c) In addition to any payments made under paragraph 2 (b), SERVICES shall reimburse DISTRIBUTION for any third party costs incurred by DISTRIBUTION in accordance with paragraph 2 (b). DISTRIBUTION shall, if requested by SERVICES, be required to submit an invoice or similar evidence of payment in respect of all third party costs for which it seeks reimbursement hereunder.

(d) All services, resources, and products sold under paragraph 2 (b) and paragraph 2 (c) are to be sold at a minimum of the fair market value of the service, resource, or product.

(e) Where a fair market value is not available for any product, resource, or service provided under Section 2, DISTRIBUTION shall charge no less than a cost-based price, and shall pay no more than a cost-based price. A cost-based price shall reflect the costs of producing the service or product, including a return on invested capital. The return component shall be the higher of DISTRIBUTION's approved rate of return or the bank prime rate.

(f) DISTRIBUTION shall sell assets to SERVICES at a price no less than the net book value of the asset.

3. LEASING SERVICES

(a) Leasing of real property by DISTRIBUTION shall consist of leasing DISTRIBUTION real property to SERVICES (hereinafter referred to as the "Leasing Services").

(b) SERVICES agrees to pay DISTRIBUTION for the use of the premises at DISTRIBUTION's leasing cost.

4. LIMITATION OF LIABILITY

All risk arising under this Agreement and extraneous to this Agreement is with SERVICES. DISTRIBUTION assumes no risk. In no event shall DISTRIBUTION be liable for damages arising from risks associated with the provision of services under this Agreement or otherwise.

5. DISPUTE RESOLUTION PROCESS

Any dispute arising between DISTRIBUTION and SERVICES under this Agreement or arising over the terms of the Agreement shall be resolved by arbitration under the Arbitrations Act, 1991, S.O. 1991, Chapter 17.

6. TERMINATION

The term of this Agreement is on a year-to-year basis commencing on the date hereof. This Agreement may be terminated by SERVICES by giving written notice to DISTRIBUTION, or by DISTRIBUTION by giving written notice to SERVICES, given at least six months prior to any anniversary of the date hereof. Any changes in the amounts payable under this Agreement, based on a change in the Consumer Price Index for the City of Thunder Bay, shall be changed as of January 1st in each year, based on the change, if any, in the Consumer Price Index for Thunder Bay as of the end of October for the prior year from the previous end of October.

7. ENTIRE AGREEMENT

This Agreement contains the entire agreement amongst DISTRIBUTION and SERVICES and no amendment hereof shall be binding upon DISTRIBUTION and SERVICES unless same is in writing and signed by DISTRIBUTION and SERVICES. Amendments to this Agreement come into effect on the anniversary of a six-month notice period.

8. PERSONAL SERVICES AGREEMENT

This Agreement is a personal services agreement and may not be assigned by either party hereto without the prior written consent of the other party.

9. CONFIDENTIALITY

(a) Information that becomes known through the relationship between DISTRIBUTION and SERVICES remains confidential, and neither DISTRIBUTION nor SERVICES may disclose said information to any third party.

(b) All confidential information that DISTRIBUTION shares with SERVICES under this Agreement is to be protected from access by SERVICES. Access to DISTRIBUTION's information services shall include appropriate computer data management and data access protocols as well as contractual provisions regarding the breach of any access protocols. Compliance with the access protocols and the Agreement shall be ensured as necessary, through a review which complies with the provisions of Section 5900 of the Canadian Institute of Chartered Accountants Handbook (hereinafter referred to as the "CICA Handbook"). The Ontario Energy Board (hereinafter referred to as the "Board") may provide direction regarding the terms of the Section 5900 review. The results of any review shall be made available to the Board.

(c) Services to be provided by DISTRIBUTION's employees under Sections 1 and 2 of this Agreement are subject to the provision that these employees are not directly involved in collecting, and do not have access to, confidential information.

(d) Services to be provided by DISTRIBUTION's employees under Sections 1 and 2 of this Agreement are subject to the provision that these employees do not carry out the day-to-day operation of DISTRIBUTION's transmission or distribution network.

(e) DISTRIBUTION shall not release to SERVICES confidential information relating to a consumer, retailer, or generator without the consent of that consumer, retailer, or generator.

(f) DISTRIBUTION shall not disclose confidential information to SERVICES without the consent in writing of the consumer, retailer, or generator, as the case may be, except where confidential information is required to be disclosed:

(i) for billing or market operation purposes;
(ii) for law enforcement purposes;
(iii) for the purpose of complying with a legal requirement; or
(iv) for the processing of past due accounts of the consumer which have been passed to a debt collection agency.

(g) Confidential information may be disclosed where the information has been sufficiently aggregated such that any individual consumer, retailer, or generator's information cannot reasonably be identified. If such information is aggregated it must be disclosed on a non-discriminatory basis to any party requesting the information.

10. QUALITY OF SERVICE

DISTRIBUTION shall meet its obligations to SERVICES under this Agreement by providing a quality of service at least equal to that which would be provided by an independent third party.

11. FORCE MAJEURE

"Force Majeure" means a strike, lockout, riot, insurrection, war, fire, tempest, flood, act of God, lack of materials or supply of service which results notwithstanding the diligent efforts of DISTRIBUTION. During the occurrence of an event of Force Majeure, the obligations of the party effected by such event of Force Majeure, to the extent that such obligations cannot be performed as a result of such event of Force Majeure, shall be suspended, and such a party shall not be considered to be in default hereunder, for the period of such occurrence, except that the occurrence of an event of Force Majeure affecting SERVICES (but not affecting the performance of DISTRIBUTION's obligations hereunder) shall not relieve it of its obligations to make payments to DISTRIBUTION hereunder. The non-performing party shall give the other party prompt written notice of the particulars of the event of Force Majeure and its expected duration and shall continue to furnish regular reports with respect thereto on a timely basis during the continuance of the event of Force Majeure and shall use its best efforts to remedy its inability to perform. The suspension of performance is to be of not greater scope and of no longer duration than is required by the Force Majeure condition. No obligations of either Party that arose before the Force Majeure causing the suspension of performance are excused as a result of the Force Majeure.

12. TIME

Time shall be of the essence herein.

13. PREVIOUS AGREEEMENTS

This Agreement terminates, cancels and supersedes any and all other written and verbal agreements between the parties relating to these issues herein.

14. INUREMENT

This Agreement shall bind DISTRIBUTION, SERVICES, and their respective legal representatives, executors, administrators, successors and permitted assigns.

15(1). DEFINITIONS

All words in the Agreement are defined under Sections 1.2 and 1.3 of the Affiliate Relationships Code for Electricity Distributors and Transmitters as of its revised date February 1, 2001 (hereinafter referred to as the "Code"), unless the context otherwise requires.

15(2) APPLICATION OF THE 'AFFILIATE RELATIONSHIPS CODE" TO THE AGREEMENT

All sections of the code apply to this Agreement and are incorporated by reference.

16. CONSTRUCTION

The Agreement herein shall, in all respects, be subject to and be interpreted, construed and enforced in accordance with the laws in effect in the Province of Ontario. Each party hereto accepts the jurisdiction of the courts of the Province of Ontario and all courts of appeal therefrom.

17. HEADINGS

The headings of clauses herein are inserted for convenience or reference only and shall not affect or be considered the construction of the provisions hereof.

IN WITNESS WHEREOF the parties hereto have executed this Agreement as of the date first above written.

THUNDER BAY HYDRO ELECTRICTY DISTRIBUTION INC.
Per: _____
Per: _____

THUNDER BAY HYDRO ENERGY SERVICES INC.
Per: _____
Per: _____

SERVICES AGREEMENT

THIS AGREEMENT made as of the 30th day of June 2006,

BETWEEN:

THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC., a corporation incorporated under the *Ontario Business Corporations Act*, R.S.O. 1990, c. B.18 (hereinafter referred to as "DISTRIBUTION")

OF THE FIRST PART

- and -

THUNDER BAY HYDRO UTILITY SERVICES INC., a corporation incorporated under the *Ontario Business Corporations Act*, R.S.O. 1990, c. B.18 (hereinafter referred to as "SERVICES")

OF THE SECOND PART

WHEREAS DISTRIBUTION is required by the Ontario Energy Board to enter a service agreement (hereinafter referred to as the "Agreement") with SERVICES under the Affiliate Relationships Code for Electricity Distributors and Transmitters (revised November 24, 2003 and as may be amended from time to time) (hereinafter referred to as the "Code");

AND WHEREAS the Code provides that DISTRIBUTION and any affiliate with which it shares services, shall do so in accordance with a Services Agreement

AND WHEREAS DISTRIBUTION has agreed to share services of certain of its employees with SERVICES for a fee, subject to the terms and conditions set forth herein;

NOW THEREFORE THIS AGREEMENT WITNESSETH that in consideration of the premises and agreements herein contained, it is mutually declared, covenanted and agreed by and between the parties hereto as follows:

1. SERVICES PROVIDED

(a) DISTRIBUTION shall provide meter services to SERVICES as SERVICES may reasonably require from time to time. The meter services shall consist of a contract employee to service customers of the meter service provider business, a qualified meter technician on an "as is required" basis and 364 square feet of office space. All such services shall be provided on a cost recovery plus the prime rate of DISTRIBUTION'S Bank (Bank Prime Rate) adjusted quarterly. The current Prime Rate of DISTRIBUTION'S Bank is 6% per annum.

(b) DISTRIBUTION shall provide utility billing services to SERVICES as SERVICES may reasonably require from time to time and this will include download meter reading data, wholesale settlement, electronic business transaction functions, remote meter reader function, information services, customer information services, accounting services and purchasing services. These shall be provided on a cost recovery plus Bank Prime Rate adjusted quarterly, which Bank Prime Rate is presently 6% per annum.

(c) In addition to any payments made under paragraphs 1 (a) and (b), SERVICES shall reimburse DISTRIBUTION for any third party costs incurred by DISTRIBUTION in accordance with paragraphs 1 (a) and (b). DISTRIBUTION shall, if requested by SERVICES, be required to submit an invoice or similar evidence of payment in respect of all third party costs for which it seeks reimbursement hereunder.

(d) All amounts owing by SERVICES will be settled as incurred, or at a minimum, on a monthly basis. Both DISTRIBUTION and SERVICES, will settle any amounts owing within three months following the year end of Distribution

(e) All services, resources, and products sold according to paragraph 1 (b) and paragraph 1 (c) are to be sold at a minimum of the fair market value of the service, resource, or product.

(f) Where a fair market value is not available for any product, resource, or service provided under paragraph 1, DISTRIBUTION shall charge no less than a cost-based price, and shall pay no more than a cost-based price. A cost-based price shall reflect the costs of producing the service or product, including a return on invested capital. The return component shall be the higher of DISTRIBUTION's approved rate of return or the bank prime rate.

(g) DISTRIBUTION shall sell assets to SERVICES at a price no less than the net book value of the asset.

2. LIMITATION OF LIABILITY

All risk arising under this Agreement and extraneous to this Agreement is with SERVICES. DISTRIBUTION assumes no risk. In no event shall DISTRIBUTION be liable for damages arising from risks associated with the provision of services under this Agreement or otherwise.

3. DISPUTE RESOLUTION PROCESS

Any dispute arising between DISTRIBUTION and SERVICES under this Agreement or arising over the terms of the Agreement shall be resolved by arbitration under the Arbitrations Act, 1991, S.O. 1991, Chapter 17.

4. TERMINATION

The term of this Agreement is on a year-to-year basis commencing on the date hereof. This Agreement may be terminated by SERVICES by giving written notice to DISTRIBUTION, or by DISTRIBUTION by giving written notice to SERVICES, given at least six months prior to any anniversary of the date hereof. Any changes in the amounts payable under this Agreement shall be changed as of January 1st in each year, based on the change, if any, in the Consumer Price Index for Thunder Bay as of the end of October for the prior year from the previous end of October.

5. ENTIRE AGREEMENT

This Agreement contains the entire agreement amongst DISTRIBUTION and SERVICES and no amendment hereof shall be binding upon DISTRIBUTION and SERVICES unless same is in writing and signed by DISTRIBUTION and SERVICES. Amendments to this Agreement come into effect on the anniversary of a six-month notice period.

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(a) Information that becomes known through the relationship between DISTRIBUTION and SERVICES remains confidential, and neither DISTRIBUTION nor SERVICES may disclose said information to any third party.

(b) All confidential information that DISTRIBUTION shares with SERVICES under this Agreement is to be protected from access by SERVICES. Access to DISTRIBUTION's information services shall include appropriate computer data management and data access protocols as well as contractual provisions regarding the breach of any access protocols. Compliance with the access protocols and the Agreement shall be ensured as necessary, through a review which complies with the provisions of Section 5900 of the Canadian Institute of Chartered Accountants Handbook (hereinafter referred to as the "CICA Handbook"). The Ontario Energy Board (hereinafter referred to as the "Board") may provide direction regarding the terms of the Section 5900 review. The results of any review shall be made available to the Board.

(c) Services to be provided by DISTRIBUTION's employees under Section 1 of this Agreement are subject to the provision that these employees are not directly involved in collecting, and do not have access to, confidential information.

(d) DISTRIBUTION shall not release to SERVICES confidential information relating to a consumer, retailer, or generator without the consent of that consumer, retailer, or generator.

(e) DISTRIBUTION shall not disclose confidential information to SERVICES without the consent in writing of the consumer, retailer, or generator, as the case may be, except where confidential information is required to be disclosed:

(i) for billing or market operation purposes;
(ii) for law enforcement purposes;
(iii) for the purpose of complying with a legal requirement; or
(iv) for the processing of past due accounts of the consumer which have been passed to a debt collection agency.

(f) Confidential information may be disclosed where the information has been sufficiently aggregated such that any individual consumer, retailer, or generator's information cannot reasonably be identified. If such information is aggregated it must be disclosed on a non-discriminatory basis to any party requesting the information.

8. QUALITY OF SERVICE

DISTRIBUTION shall meet its obligations to SERVICES under this Agreement by providing a quality of service at least equal to that which would be provided by an independent third party.

9. FORCE MAJEURE

"Force Majeure" means a strike, lockout, riot, insurrection, war, fire, tempest, flood, act of God, lack of materials or supply of service which results notwithstanding the diligent efforts of DISTRIBUTION. During the occurrence of an event of Force Majeure, the obligations of the party effected by such event of Force Majeure, to the extent that such obligations cannot be performed as a result of such event of Force Majeure, shall be suspended, and such a party shall not be considered to be in default hereunder, for the period of such occurrence, except that the occurrence of an event of Force Majeure affecting SERVICES (but not affecting the performance of DISTRIBUTION's obligations hereunder) shall not relieve it of its obligations to make payments to DISTRIBUTION hereunder. The non-performing party shall give the other party prompt written notice of the particulars of the event of Force Majeure and its expected duration and shall continue to furnish regular reports with respect thereto on a timely basis during the continuance of the event of Force Majeure and shall use its best efforts to remedy its inability to perform. The suspension of performance is to be of no greater scope and of no longer duration than is required by the Force Majeure condition. No obligations of either Party that arose before the Force Majeure causing the suspension of performance are excused as a result of the Force Majeure.

10. TIME

Time shall be of the essence herein.

11. PREVIOUS AGREEEMENTS

This Agreement terminates, cancels and supersedes any and all other written and verbal agreements between the parties relating to these issues herein.

12. INUREMENT

This Agreement shall bind DISTRIBUTION, SERVICES, and their respective legal representatives, executors, administrators, successors and permitted assigns.

13(1). DEFINITIONS

All words in the Agreement are defined under Sections 1.2 and 1.3 of the Affiliate Relationships Code for Electricity Distributors and Transmitters as of its revised date February 1, 2001 (hereinafter referred to as the "Code"), unless the context otherwise requires.

13(2) APPLICATION OF THE 'AFFILIATE RELATIONSHIPS CODE" TO THE AGREEMENT

All sections of the code apply to this Agreement and are incorporated by reference.

14. CONSTRUCTION

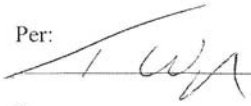
The Agreement herein shall, in all respects, be subject to and be interpreted, construed and enforced in accordance with the laws in effect in the Province of Ontario. Each party hereto accepts the jurisdiction of the courts of the Province of Ontario and all courts of appeal therefrom.

15. HEADINGS

The headings of clauses herein are inserted for convenience or reference only and shall not affect or be considered the construction of the provisions hereof.

IN WITNESS WHEREOF the parties hereto have executed this Agreement as of the date first above written.

THUNDER BAY HYDRO ELECTRICTY DISTRIBUTION INC.

Per: 

Per: _____

THUNDER BAY HYDRO UTILITY SERVICES INC.

Per: 

Per: _____

EMPLOYEE COMPENSATION, INCENTIVE PLAN EXPENSES, PENSION EXPENSE AND POST RETIREMENT BENEFITS:

Overview:

The table below summarizes Thunder Bay Hydro's head count for 2007, 2008 as well as our forecasted head count for 2009. Numbers of part-time, and temporary/seasonal staff employed at points throughout the year, are also provided.

Class	2007	2008	2009 (Forecast)
Executive	5	5	5
Management/Supervisory	18	18	18
Management/Non-Supervisory	11	11	13
Management/Part-time	2	2	2
Unionized	85	85	92
Unionized/Part-time	16	10	10
Unionized/Temporary/Seasonal	8	8	8
Total	**145**	**139**	**148**

Executive:

Executive complement is expected to remain constant throughout the period.

Management/Supervisory:

In 2007 we restructured our Information Systems Department and eliminated one Management/Supervisory position – the IT Support Supervisor.

In 2008 an additional supervisor was added to our supervisory complement in our Power Systems Division / Powerline Department. This addition was deemed necessary to assist with the organization, planning and completion of work related to the utility's on-going asset management and capital improvement plans, which have ramped-up considerably since 2006.

Additionally, it will be necessary to temporarily exceed complement in 2009 to prepare for upcoming retirements in this group to ensure that adequate training and skills transfer occurs. This overlap will vary in range from one to three months.

Management/Non-Supervisory:

Management/Non-Supervisory complement is expected to remain constant through 2008. Given that Thunder Bay Hydro's capital plan anticipates significant increased activity in 2009, it is expected that it will be necessary to add an additional person (Program Manager) to our complement in our Power Systems Division / Asset Management & Engineering Department. This is necessary to ensure sufficient resources to enable the completion of the utility's 20-year capital plan, as well as continuing to keep current with our existing maintenance planning.

Thunder Bay Hydro will also be increasing the complement in the Purchasing Department. The increased capital work; anticipated retirement of 2 of the 3 staff (the two senior positions) and the increasing contract administration workload are the driver for this cost increase.

Management/Part-time:

Management/Part-time complement is expected to remain constant throughout the period.

Unionized:

The unionized workforce is represented by the International Brotherhood of Electrical Workers, Local 339. The represented employees include tradespersons, technical, labour-intensive and administrative/clerical staff, sometimes referred to "inside" and "outside" staff.

We had both increases and decreases regarding unionized staff complement in 2007. The increase occurred in our Power Systems Division / Powerline Department with an increase of two Powerline Technician Apprentices. The decrease occurred in our Customer Service & Conservation Division / Meter Reading Department when the entire department was disbanded with the work being contracted out. Three of the five full-time complement were absorbed in

other departments within the utility, and the other two full-time staff were severed from the utility under different scenarios.

An increase in unionized positions between 2007 and 2008 is not noticeable due to the fact that we reduced complement by contracting out work in one area (Meter Reading = 2 overall) and increased complement in another area (Powerline = 2). The hirings in Powerline are related to Thunder Bay Hydro's apprenticeship/succession program whereby staff are hired and brought through their apprenticeship (4-5 years) in advance of pending retirements to ensure human resources are available to perform required work, as well as the increase 2008 capital construction activity.

For 2009, the majority of the increase in staff is related to the same demographic challenges referred to above. As well, an increase in staff is necessary to account for the increase in capital projects being taken on to ensure the reliability of our system. This is described as workforce planning.

The additional unionized staff for 2009 includes the following:

Position	Addition	Comments
Powerline Technician Apprentices	5	3 required to account for pending retirements; 2 to address increase in capital and maintenance
Meter Technician Apprentice	1	To account for pending retirements.
System Operator Apprentice	1	To account for pending retirement.

<u>Unionized Part-time:</u>

With the contracting out of our Meter Reading Department work, part-time staff in this Division have been eliminated.

Unionized/Temporary/Seasonal:

Unionized/Temporary/Seasonal complement is expected to remain constant throughout the period.

Thunder Bay Hydro's core business is the construction, operation and maintenance of the local distribution system. Skilled trades resources and technical staff are required in order to meet Thunder Bay Hydro's responsibilities to provide safe and reliable service to customers and to maintain the OEB Service Quality Levels.

Thunder Bay Hydro faces increases in workload for the following reasons:

- Thunder Bay Hydro has increased the amount of capital work it performs. Our AMP projects future increases in replacement of aged infrastructure will be required over the next 20 years.
- Demand work continues to increase as we strive to maintain our current system.

Thunder Bay Hydro's skilled work force is aging, and significant retirement levels are forecasted in the trades and trades supervision over the next 5 to 15 years. This is commonplace in our industry resulting in limited availability in required skills. This also raises the concern of existing staff obtaining employment elsewhere with the opportunities available to them.

To project staff numbers, Thunder Bay Hydro considers loss of personnel due to retirement, internal advancement, and opportunities with other employers. We also take into account the likelihood of attracting qualified staff as replacements.

Our demographics alone clearly demonstrate that Thunder Bay Hydro must plan on replacing significant numbers of trades staff over the coming years if it is to maintain sufficient skilled trades people to manage our workload. This is reflected in the table below:

Classification	Current Complement	Eligible to Retire in 5 years	Eligible to Retire in 10 years
Trades Supervisor	8	4	6
Powerline Tech	33	8	12
Metering Tech	3	2	3
System Control	6	1	2
Station Electrician	2	0	1
Service Electrician	1	1	1
Total	53	16	27

The last eleven powerline retirees retired at ages ranging from 48 to 56 with the average age being 52. Trades and technical staff such as the Metering Technicians, System Control Operators and Station Electricians work within small workgroups. The loss of a single staff member in these departments represents a significant percentage of that labour force which has a negative impact on workload and shift coverage.

One possible option for Thunder Bay Hydro to replenish and expand its trades staff workforce is to recruit, as required, fully qualified journeypersons and add them immediately to the workforce with modest amounts of orientation and/or training. The availability of fully qualified journeypersons in these fields is very limited. The last qualified journeyman PLT that Thunder Bay Hydro has been able to hire was in December of 2001. Since then, Thunder Bay Hydro has posted and hired twelve staff for the position of PLT – none of which was above the level of third-year apprentice at the time of hire. Therefore our ability to attract certified trades people, especially in our local market, is unlikely.

In response to the tight supply in the labour market and the operational requirements for additional staff, Thunder Bay Hydro has introduced strategic hiring in the areas impacted by the demographic challenges facing the electrical industry, through the use of apprentice programs and the strategic hiring of technical staff.

The advantages of hiring and training apprentices and new technical staff include; a typically younger workforce age, consistency in training, and learning and training on the system for

which they will ultimately be responsible. Other utilities in the province are experiencing similar challenges and have also come to the conclusion that the hiring and training of apprentices is the best option.

Besides the obvious benefit of revitalizing the workforce, new employees offer many intangible benefits including improved staff morale and improved labour relations through demonstrating an investment in the future of the workgroups within the company.

Apprentice Program Hiring:

To graduate from an apprentice program requires 5 years of on the job training and schooling. Apprentices therefore must be hired in advance of qualified tradesperson retirements/requirements to allow time for the apprentices to complete their training if Thunder Bay Hydro is to maintain the necessary level of qualified labour. This requirement, by default, results in increases to complement.

Powerline Technician Apprentices:

- In both 2007 and 2008, Thunder Bay Hydro hired two Powerline Technician Apprentices to address pending retirements and increased capital spending. Going forward, Thunder Bay Hydro plans to hire an additional five Powerline Technician apprentices in 2009 and another three in 2010.

Meter Technician Apprentices:

- One in 2009 to address pending retirements.

System Control Operator Apprentice:

- One to address pending retirement.

It should be noted that the numbers presented do not account for trades staff losses in addition to retirement.

Thunder Bay Hydro's Performance Management Program:

Management/Professional/Supervisory/Administrative Employees

Performance management is a shared process that includes input from the employee and the supervisor. It is the collaborative process that facilitates the link between the employee's job duties and expectations and the organization's mission, vision, values and corporate strategic objectives.

Thunder Bay Hydro's performance management program clarifies job responsibilities, performance and competency standards and objectives between the employee and supervisor; provides for regular feedback to employees about their performance; and establishes employee developmental needs and encourages continuous learning.

The performance management system aligns employee performance plans with the attainment of strategic business objectives and goals, as well as the opportunity to cultivate a system-wide, long-term view of the organization.

For managers, the performance management system improves operations in the department; facilitates communications with employees regarding performance strengths and weaknesses; facilitates the development of goals; aids decision making regarding promotions/reassignments and provides for training/development plans.

For employees, the performance management system provides an opportunity to receive feedback regarding their work performance. The system can assist employees in identifying where to concentrate self-development efforts and in learning about possible career paths that may be available to them in the organization. This feedback loop also improves productivity, quality of service to customers and enhances employee motivation and commitment.

Unionized Employees

All unionized employees have a formal performance review on an annual basis to discuss their performance with their supervisors.

Goals and objectives are agreed to for the next 6 to 12-month review period (dependent on the objectives and the expected deliverables) in areas that require improvement to meet job or performance targets.

Thunder Bay Hydro's Total Compensation System:

Introduction

Thunder Bay Hydro's total compensation system is comprised of a combination of fundamental elements - including both cash and non-cash rewards - designed to support the organization's compensation philosophy, motivate and reward performance aligned with critical business objectives, and provide a positive return on the significant dollars invested in compensation.

Merit Pay

As a performance driven organization, base salary is based on performance and tied directly to demonstrated behavioural competencies and Thunder Bay Hydro's values. At Thunder Bay Hydro, non-union employees achieve base line salary increases through goal setting and building behavioural competencies to improve individual skills to maximize potential and enhance their contribution to the business. The Performance Management System is a practical tool used to help both the employee and the organization achieve results. There is a partnership between the employee and supervisor to share in the responsibility of developing skills and abilities. It is the responsibility of the employee to take charge of their development while Thunder Bay Hydro provides them with the tools and coaching to achieve their development goals.

Merit pay is intended to provide a system to reward employee behaviours and values through increases to base pay. A merit increase is the amount of additional compensation added to current base salaries following a review of employee performance and is usually awarded in six-month increments until the incumbent has achieved the 100% salary for their respective position.

Thunder Bay Hydro has a formal and disciplined approach in awarding base line merit increases to individuals. Each Vice President reviews the performance of each non-union employee in

their department, taking into consideration the remarks and comments from the employee's direct supervisor who conducted the review prior to the recommendation of any merit increase. Final approval for merit increases resides with the Vice President, Human Resources & Safety who reviews all comments and recommendations to ensure such increases are warranted.

Incentive Based Pay

Thunder Bay Hydro seeks to encourage an incentive based performance culture by aligning employees' efforts with the corporate vision and the short and long-term goals of Thunder Bay Hydro. At present, incentive based pay systems exist only for the President and the Vice President, Power Systems. In the case of the President, the Board of Directors for Thunder Bay Hydro annually sets out strategic objectives that align to the organization's success and continued growth. With respect to the Vice President, Power Systems, the President sets the objectives to be met through discussions with the Vice President, Power Systems. Thunder Bay Hydro supports the Balanced Scorecard methodology in setting corporate and individual goals to foster continuous improvement and cost reductions that support a healthy balance sheet that provides value to customers by keeping rates reasonable.

The three pillars of Thunder Bay Hydro's goals focus on ensuring that the health & safety of our employees and the public is the utility's first priority; providing a reliable supply of electricity to the residents and businesses of Thunder Bay; and protecting and growing the value of the utility to our shareholder.

One of Thunder Bay Hydro's beliefs is that 'Our Customers are the reason we exist'. Both corporate and individual goals and Thunder Bay Hydro's are structured to deliver and reward on the results of this belief. Corporate results are shared regularly with the organization as Thunder Bay Hydro tracks its efforts against outputs.

Executive Pay

Thunder Bay Hydro.'s executive pay philosophy considers LDC compensation from throughout Ontario at other like-sized or similarly structured utilities, ensuring that executives are

compensated at levels consistent with the mean of comparable LDC's. Such compensation levels are reviewed on a regular basis.

Benefits

A comprehensive and competitive benefits package exists which includes medical and dental insurance, life insurance, vacation and leave policies and a company-sponsored retirement plan. The plans are designed to address the health and welfare needs of the employee population.

The benefit packages are consistent across the organization for 123 employees, including the executive team. The only inconsistencies are LTD coverage for a portion of the union group (grandfathered as the result of a merger and subsequent negotiating process); life insurance coverage (1.5 times current base salary for union employees versus 2 times for non-union employees); tiered health spending account (annual) amounts for non-union staff; and reduced, employee-funded partial benefits for participating part-time staff.

Employee Compensation and Benefits:

Thunder Bay Hydro's employee complement, compensation and benefits are set out in Table 3, below. Total compensation, for the purposes of this Table, is calculated as the total of the compensation components times the average number of employees in each classification.

Table 3
Thunder Bay Hydro Electricity Distribution Inc.'s
Employee Complement and Compensation

Number of Employees (FTEs)	**2006**	**2007**	**2008**	**2009**
Executive	3.77	5.00	5.00	5.00
Management	15.07	17.62	18.29	20.00
Non-Union	13.32	11.97	11.13	11.51
Union	98.65	92.71	93.26	101.23
Total	130.80	127.30	127.68	137.74
Number of Part Time Employees	**2006**	**2007**	**2008**	**2009**
Executive				
Management				
Non-Union	1	2	2	2
Union	27	27	26	21
Total	**28**	**29**	**28**	**23**
Total Compensation	**2006**	**2007**	**2008**	**2009**
Executive	520,384	683,497	847,029	870,379
Management	1,408,231	1,633,208	1,824,650	2,065,914
Non-Union	990,120	883,098	919,808	965,987
Union	7,312,259	7,027,978	7,142,464	7,591,269
Total	**10,230,993**	**10,227,782**	**10,733,951**	**11,493,549**
Compensation - Average Yearly Base Wages	**2006**	**2007**	**2008**	**2009**
Executive	106,649	105,544	128,421	132,731
Management	74,333	73,613	79,915	81,334
Non-Union	59,014	58,214	64,971	65,584
Union	53,748	54,923	56,394	56,414
Compensation - Average Yearly Overtime	**2006**	**2007**	**2008**	**2009**
Executive				
Management				
Non-Union				
Union	5,369	6,018	3,452	2,519
Compensation - Average Yearly Incentive	**2006**	**2007**	**2008**	**2009**
Executive	15,000	11,330	14,624	14,624
Management				
Non-Union				
Union				
Compensation - Average Yearly Benefits	**2006**	**2007**	**2008**	**2009**
Executive	27,476	26,623	35,136	35,496
Management	19,101	19,060	19,873	21,962
Non-Union	15,473	15,546	17,681	18,342
Union	15,008	14,868	16,313	16,061
	2006	**2007**	**2008**	**2009**
Total Salary, Wages & Benefits Charged to O&M	**5,741,097**	**5,980,160**	**5,939,265**	**6,169,535**

OMERS Pension Expense and Post Retiree Benefits:

OMERS Members

Thunder Bay Hydro employees are members of OMERS. Accordingly, Thunder Bay Hydro has provided the OMERS pension premium information for the 2006 Actual, 2007 Actual, 2008 Bridge Year and the 2009 Test Year in Table 4 below.

Post-Retirement Benefits - OMERS Members

Thunder Bay 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 Bridge Year and 2009 Test Year, in Table 5 below.

Post-Retirement Benefits Accounting Information

Thunder Bay Hydro pays certain health, dental and life insurance benefits, under unfunded defined benefit plans, on behalf of its retired employees.

Current Accounting Treatment of Post-Retirement Benefits

Employee future benefits are recorded on an accrual basis. The accrued benefit obligations and current service cost are calculated using the projected benefit method prorated on length of service and reflect management's best estimate of certain underlying assumptions. The current service cost is for a period equal to the actuarial present value of benefits attributed to that period in which employees rendered their services. Significant assumptions underlying the valuation include management's best estimate of the interest (discount) rate, salary escalation, the average retirement age of employees, employee turnover and expected health and dental care costs.

Treatment of Changes in Actuarial Value in Post-Retirement Benefits

Thunder Bay Hydro has adopted the following accounting policies with respect to the treatment of changes in actuarial value in post-retirement benefits:

- Actuarial gains (losses) are amortized into expense on a straight-line basis over the average remaining service period of active employees to full eligibility;
- Curtailment gains or losses are recognized in earnings in the year of the event, giving rise to the curtailment; and
- Settlement gains or losses are recognized in earnings for the period in which a settlement occurs.

1 **Table 4**

Pension Premium Information

Pension	2006 Actual	2007 Actual	2008 Projected	2009 Test Year
Pension Premiums	569,614	570,641	596,779	676,049
Adjustments				
Less: amount capitalized	125,084	124,102	129,787	147,027
Amount expensed in each year	444,530	446,539	466,992	529,022

Table 5

Post Retirement Benefit Information

Post Retirement Benefits	2006 Actual	2007 Actual	2008 Projected	2009 Test Year
Post Retirement Benefits Cost	234,589	478,686	403,887	415,756
Adjustments				
Less: Amount capitalized	52,193	104,104	87,837	90,418
	182,396	374,582	316,050	325,338

DEPRECIATION, AMORTIZATION AND DEPLETION:

Consistent with the CICA Handbook, the OEB's Accounting Procedures Handbook (the "APH") does not provide prescriptive guidance in terms of the amortization methods to be used, the asset categories, the estimated useful lives or amortization rates. Instead, it is expected that in the absence of an objective study to support changes to the current methods, lives or rates, utilities will continue to use methods, lives or rates consistent with past practice.

In contrast, the former Accounting for Municipal Electric Utilities in Ontario manual (section 5102—Fixed Assets Depreciation Rates for General Plant Assets and section 5103—Fixed Assets Depreciation Rates for Other Capital Assets) provided set schedules of asset types, estimated useful life, and depreciation rates based on the straight line method of depreciation.

Appendix B – "Amortization Rates" – of the 2006 Electricity Distribution Rate Handbook ("EDRH") provides rates based on the straight-line method of amortization.

Pursuant to the APH, electric utilities that were subject to reporting using the Accounting for Municipal Electric Utilities in Ontario manual as prescribed by the former Ontario Hydro will be expected to use these rates until a change can be supported by an objective study and the change has been authorized by the Board.

Thunder Bay Hydro confirms that it has complied with the APH with respect to the amortization of capital assets.

Amortization on capital assets is calculated as follows:

- Amortization calculated on a straight line basis over the estimated remaining useful life of the assets at the end of the previous year; plus:

- Amortization on capital additions during the current year - amortization commences in the month that the asset is capitalized.

In the Final Report of the Board on the 2006 EDRH, dated May 11, 2005, the OEB considered that the use of the average of the opening and closing balances for calculating amortization offered the most reliable figure without imposing an unreasonable burden on the distributor. In addition, the OEB noted (at page 23) that the "object is to arrive at a data set that is more representative of a typical year in the life of the distributor". Thunder Bay Hydro submits that its methodology for calculating amortization meets this objective.

Details of Thunder Bay Hydro's depreciation by asset group are provided in the Accumulated Depreciation Table at Exhibit 4, Tab 3, Schedule 3. Details of Thunder Bay Hydro's amortization and depletion by asset group are provided in the Fixed Asset Continuity Schedules at Exhibit 4, Tab 3, Schedule 3.

DETERMINATION OF LOSS ADJUSTMENT FACTORS:

Total Loss Factor:

Thunder Bay Hydro Electricity Distribution Inc. 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 2007. The calculations are summarized in Table 1 below.

Table 1
Total Loss Factor Calculations

Calculation for distribution loss adjustment factors

	Description	2002	2003	2004	2005	2006	2007	Total
A	"Wholesale" kWh IESO plus Embedded Gener	1,076,345,106	1,094,955,754	1,081,303,890	1,101,297,420	1,080,427,586	1,074,642,764	6,508,972,520
B	"Wholesale" kWh for Large Use customer(s)	66,598,584	61,582,912	48,566,752	26,801,264	2,277,520	0	205,827,031
C	Net "Wholesale" kWh (A)-(B)	1,009,746,522	1,033,372,842	1,032,737,138	1,074,496,156	1,078,150,066	1,074,642,764	6,303,145,489
D	"Retail" kWh (Distributor)	1,014,551,190	1,051,670,544	1,034,530,471	1,053,058,417	1,042,542,867	1,022,967,701	6,219,321,190
E	"Retail" kWh for Large Use Customer(s)	65,932,598	60,967,083	48,081,084	26,533,251	2,254,745	0	203,768,761
F	Net "Retail" kWh (D)-(E)	948,618,592	990,703,461	986,449,387	1,026,525,166	1,040,288,122	1,022,967,701	6,015,552,429
G	Loss Factor [(C)/(F)]	106.44%	104.31%	104.69%	104.67%	103.64%	105.05%	104.78%
H	Distribution Loss Adjustment Factor (5 year avg.)							**104.78%**
	Supply Facility Loss Factor		100.56%	100.61%	100.56%	100.51%	100.51%	100.55%
	Supply Facility Loss Adjustment Factor (3 year avg.)							**100.55%**
	Total Loss Factor							**1.053579322**

Based on the information on the foregoing table, Thunder Bay Hydro is increasing its Distribution Loss Factor from 4.57% to 4.78%.

Supply Facility Loss Factor:

The supply facility loss factor (the "SFLF") is calculated in Table 2 and represents the losses on supply to Thunder Bay 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 2
Supply Facility Loss Factor

Description	Full Year 2003	Full Year 2004	Full Year 2005	Full Year 2006	Full Year 2007	Total
"Wholesale" kWh IESO With Losse	1,094,230,750	1,080,356,450	1,098,964,000	1,078,983,080	1,072,448,510	5,424,982,790
"Wholesale" kWh IESO No Losses	1,088,127,000	1,073,807,000	1,092,816,000	1,073,499,000	1,067,018,000	5,395,267,000
Supply Facility Loss Factor	0.00561	0.00610	0.00563	0.00511	0.00509	0.00551

Total Loss Factor by Class:

Table 3 sets out the class-specific Loss Factors used by Thunder Bay Hydro in the calculation of commodity and other non-distribution charges.

Table 3

Total Loss Factor by Class

Total Utility Loss Adjustment Factor		LAF
Supply Facility Loss Factor		1.0055
Distribution Loss Factor		
Distribution Loss Factor - Secondary Metered Customer < 5,000kW		1.0478
Distribution Loss Factor - Primary Metered Customer < 5,000kW		1.0373
Total Loss Factor		
Total Loss Factor - Secondary Metered Customer < 5,000kW		1.0536
Total Loss Factor - Primary Metered Customer < 5,000kW		1.0430

Materiality Analysis on Distribution Losses:

Thunder Bay Hydro's total loss factor is 4.78%. Pursuant to the Filing Requirements, as the Total Loss Factor is less than 5%, Thunder Bay Hydro is not required to provide an explanation of, or justification for, its loss adjustment factor.

Income Tax, Large Corporation Tax and Ontario Capital Taxes:

Thunder Bay 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 1 below provides a summary of 2006 OEB Approved, 2006 Actual, 2007 Actual , 2008 Bridge and 2009 Test Year income taxes.

Table 1
Summary of Income Taxes

Description	2006 Board Approved	2006 Actual	2007 Actual	2008 Bridge	2009 Test
Income Taxes	1,092,369	1,109,218	737,431	655,911	800,672
Large Corporation Tax	21,095	0	0	0	0
Ontario Capital Tax	235,550	230,440	218,391	165,897	169,466
Total Taxes	1,349,014	1,339,658	955,822	821,808	970,138

Copies of Thunder Bay Hydro's Federal and Provincial PILS returns filed with the Ministry of Finance for the year ended December 31, 2007 have been provided at Exhibit 4, Tab 3, Schedule 4.

TAX CALCULATIONS:

Thunder Bay Hydro's detailed tax calculations are provided in the following Table 2.

Table 2
Tax Calculations

Description	2006 Board Approved	2008 Bridge	2009 Test
Determination of Taxable Income			
Utility Income Before Taxes	1,044,760	1,341,261	2,021,239
Book to Tax Adjustments			
Additions to Accounting Income:			
Depreciation and amortization	4,056,140	5,046,443	5,112,382
Employee Benefit Plans - accrued, not paid		63,686	124,437
Meals & entertainment / Mileage	9,000	5,783	6,707
Other Additions (Apprenticeship tax Credits)		40,000	59,524
Total Additions	**4,065,140**	**5,155,912**	**5,303,050**
Deductions from Accounting Income:			
Capital Cost Allowance	3,170,939	4,154,915	4,405,206
Cumulative eligible capital deduction	7,052	30,485	69,049
Amortization of Capitalized Depreciation		234,426	243,380
Total Deductions	**3,177,991**	**4,419,826**	**4,717,636**
Regulatory Taxable Income	**1,931,909**	**2,077,347**	**2,606,654**
Corporate Income Tax Rate	0.3612	0.3157	0.3072
Subtotal	**697,806**		
Less: R&D ITC (0.3)			
Regulatory Income Tax	**697,806**	**655,911**	**800,672**

Calculation of Utility Income Taxes			
Income Taxes	697,806	655,911	800,672
Large Corporation Tax	13,473	0	0
Ontario Capital Tax	235,550	165,897	169,466
Total Taxes	**946,829**	**821,808**	**970,138**
Tax Rates			
Federal Tax	0.2212	0.1950	0.1900000
Federal Surtax			
Provincial Tax	0.1400	0.1400	0.1400000
Apprenticeship Tax Credit		(0.0193)	(0.0228354)
Total Tax Rate	0.3612	0.3157	0.3071646
Calculation of Large Corporation Tax			
Total Rate Base	71,314,672	73,583,178	75,169,648
Less: Exemption	49,909,100		
Taxable Capital	**21,405,572**		
LCT Rate	0.0013	0.0000	0.0000
Subtotal	26,757	0	0
Federal Surtax	21,640	0	0
Large Corporation Tax	**13,473**	**0**	**0**
Calculation of Ontario Capital Tax			
Total Rate Base	88,516,821	88,731,808	90,318,279
Less Exemption	10,000,000	15,000,000	15,000,000
Taxable Capital /Deemed taxable capital	**78,516,821**	**73,731,808**	**75,318,279**
OCT Rate	0.0030	0.0023	0.0023
Ontario Capital Tax	**235,550**	**165,897**	**169,466**

INTEREST EXPENSE

Thunder Bay Hydro has calculated interest expense in accordance with the Filing Requirements in Exhibit 5, Tab 1, Schedule 3, based on Thunder Bay Hydro's deemed debt rate and deemed interest rate, and based on a 56.7/43.3 debt to equity ratio. Table 1 below summarizes the interest calculations.

Table 1
Deemed Interest Expense

	Deemed Interest Rate	2006 Board Approved	2006 Actual	2007 Actual	2008 Bridge Year	2009 Test Year
Long Term	0.21%	0	0	0	0	$ 82,220
Short Term	4.77%	-	-	-	-	134,403
Total		0	0	0	0	$ 216,623

CAPITAL COST ALLOWANCE:

Thunder Bay Hydro is providing Capital Cost Allowance continuity schedules for the 2008 Bridge Year and the 2009 Test Year on the following two pages.

2008 Bridge Year:

Class	Class Description	UCC Prior Year Ending Balance	Less: Non-Distribution Portion	Less: Disallowed FMV Increment	UCC Bridge Year Opening Balance	Additions	Dispositions	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	CCA	UCC Ending Balance
1	Distribution System - 1988 to 22-Feb-2005	58,888,037	0	0	58,888,037	0	0	58,888,037	0	58,888,037	4%	2,355,521	56,532,516
2	Distribution System - pre 1988		0	0	0	0	0	0	0	0	6%	0	0
4	Buildings	1,967,835			1,967,835	40000		2,007,835	20,000	1,987,835	6%	119,270	1,888,565
6	Buildings (No footings below ground)		0	0	0	0	0	0	0	0	10%	0	0
8	General Office/Stores Equip	607,854	0	0	607,854	208,408	0	816,262	104,204	712,058	20%	142,412	673,850
10	Computer Hardware/ Vehicles	1,068,920	0	0	1,068,920	353,126	0	1,422,046	176,563	1,245,483	30%	373,645	1,048,401
10.1	Certain Automobiles		0	0	0	0	0	0	0	0	30%	0	0
12	Computer Software	47,946	0	0	47,946	22,000	0	69,946	11,000	58,946	100%	58,946	11,000
13 1	Lease # 1		0	0	0	-	0	0	0	0	20%	0	0
13 2	Lease #2		0	0	0	0	0	0	0	0		0	0
13 3	Lease # 3		0	0	0	0	0	0	0	0		0	0
13 4	Lease # 4		0	0	0	0	0	0	0	0		0	0
14	Franchise		0	0	0	0	0	0	0	0		0	0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs		0	0	0	0	0	0	0	0	8%	0	0
43.1	Certain Energy-Efficient Electrical Generating Equipment		0	0	0	0	0	0	0	0	30%	0	0
45	Computers & Systems Hardware acq'd post Mar 22/04	87,522	0	0	87,522	0	0	87,522	0	87,522	45%	39,385	48,137
45.1	Computers & Systems Hardware acq'd post Mar 19/07		0	0	0	205,555	0	205,555	102,778	102,778	55%	56,528	149,027
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)		0	0	0	0	0	0	0	0	30%	0	0
47	Distribution System - post 22-Feb-2005	10,699,065			10,699,065	3,832,077	0	14,531,142	1,916,038	12,615,103	8%	1,009,208	13,521,933
	SUB-TOTAL - UCC	**73,367,179**	**0**	**0**	**73,367,179**	**4,661,166**	**0**	**78,028,345**	**2,330,583**	**75,697,762**		**4,154,915**	**73,873,430**

2009 Test Year:

Class	Class Description	UCC Prior Year Ending Balance	Less: Non-Distribution Portion	Less: Disallowed FMV Increment	UCC Bridge Year Opening Balance	Additions	Dispositions	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	CCA	UCC Ending Balance
1	Distribution System - 1988 to 22-Feb-2005	56,532,516	0	0	56,532,516	0	0	56,532,516	0	56,532,516	4%	2,261,301	54,271,215
2	Distribution System - pre 1988	0	0	0	0	0	0	0	0	0	6%	0	0
4	Buildings	1,888,565	0	0	1,888,565	95000	0	1,983,565	47,500	1,936,065	6%	116,164	1,867,401
6	Buildings (No footings below ground)	0	0	0	0	0	0	0	0	0	10%	0	0
8	General Office/Stores Equip	673,850	0	0	673,850	225,550	0	899,400	112,775	786,625	20%	157,325	742,075
10	Computer Hardware/ Vehicles	1,048,401	0	0	1,048,401	693,500	0	1,741,901	346,750	1,395,151	30%	418,545	1,323,356
10.1	Certain Automobiles	0	0	0	0	0	0	0	0	0	30%	0	0
12	Computer Software	11,000	0	0	11,000	37,850	0	48,850	18,925	29,925	100%	29,925	18,925
13 1	Lease # 1	0	0	0	0	0	0	0	0	0	20%	0	0
13 2	Lease #2	0	0	0	0	0	0	0	0	0		0	0
13 3	Lease # 3	0	0	0	0	0	0	0	0	0		0	0
13 4	Lease # 4	0	0	0	0	0	0	0	0	0		0	0
14	Franchise	0	0	0	0	0	0	0	0	0		0	0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	0	0	0	0	0	0	0	0	0	8%	0	0
43.1	Certain Energy-Efficient Electrical Generating Equipment	0	0	0	0	0	0	0	0	0	30%	0	0
45	Computers & Systems Hardware acq'd post Mar 22/04	48,137	0	0	48,137	0	0	48,137	0	48,137	45%	21,662	26,475
45.1	Computers & Systems Hardware acq'd post Mar 19/07	149,027	0	0	149,027	77,310	0	226,337	38,655	187,682	55%	103,225	123,112
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	0	0	0	0	0	0	0	0	0	30%	0	0
47	Distribution System - post 22-Feb-2005	13,521,933			13,521,933	5,382,617	0	18,904,550	2,691,308	16,213,242	8%	1,297,059	17,607,491
	SUB-TOTAL - UCC	**73,873,430**	**0**	**0**	**73,873,430**	**6,511,827**	**0**	**80,385,257**	**3,255,913**	**77,129,343**		**4,405,206**	**75,980,050**

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Thunder Bay Hydro Electricity Distribution Inc
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Canada Revenue Agency / Agence du revenu du Canada

T2 CORPORATION INCOME TAX RETURN

200

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

Parts, sections, subsections, and paragraphs mentioned on this return refer to the 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 services office or tax centre. You have to file the return within six months after the end of the corporation's tax year.

For more information see www.cra.gc.ca or the *T2 Corporation – Income Tax Guide* (T4012).

055 Do not use this area

CLIENT'S COPY

Identification

Business Number (BN) 001 89209 0614 RC0001

Corporation's name

002 Thunder Bay Hydro Electricity Distribution Inc.

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

If yes, do you have a copy of the articles of amendment? *(Do not submit)* 004 1 Yes ☐ 2 No ☐

Address of head office

Has this address changed since the last time you filed your T2 return? 010 1 Yes ☐ 2 No ☒

(If yes, complete lines 011 to 018)

011 34 N. Cumberland Street

012

City: 015 Thunder Bay

Province, territory, or state: 016 ON

Country (other than Canada): 017

Postal code/Zip code: 018 P7A 4L4

Mailing address (if different from head office address)

Has this address changed since the last time you filed your T2 return? 020 1 Yes ☐ 2 No ☒

(If yes, complete lines 021 to 028)

021 c/o

022

023

City: 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 ☒

(If yes, complete lines 031 to 038)

031 34 N. Cumberland Street

032

City: 035 Thunder Bay

Province, territory, or state: 036 ON

Country (other than Canada): 037

Postal code/Zip code: 038 P7A 4L4

040 Type of corporation at the end of the tax year

1 ☒ 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 2007-01-01 YYYY MM DD

Tax year-end: 061 2007-12-31 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 ☒

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 ☒

Is the corporation a professional corporation that is a member of a partnership? 067 1 Yes ☐ 2 No ☒

Is this the first year of filing after:

Incorporation? 070 1 Yes ☐ 2 No ☒

Amalgamation? 071 1 Yes ☐ 2 No ☒

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

Has there been a wind-up of a subsidiary under section 88 during the current tax year? 072 1 Yes ☐ 2 No ☒

If yes, complete and attach Schedule 24.

Is this the final tax year before amalgamation? 076 1 Yes ☐ 2 No ☒

Is this the final return up to dissolution? 078 1 Yes ☐ 2 No ☒

Is the corporation a resident of Canada? 080 1 Yes ☒ 2 No ☐ If no, give the country of residence on line 081 and complete and attach Schedule 97.

081

Is the non-resident corporation claiming an exemption under an income tax treaty? 082 1 Yes ☐ 2 No ☒

If yes, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:

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

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	X	8
Does the corporation have any property that is eligible capital property?	210	X	10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming reserves of any kind?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Was the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231		31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232		T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	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

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Attachments – continued from page 2

		Yes	Schedule
Is the corporation subject to Part XIII.1 tax?	255		92 *
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	X	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

*We do not print this schedule.

Additional information

Is the corporation inactive?	280	1 Yes	2 No X
Has the major business activity changed since the last return was filed? (enter yes for first-time filers)	281	1 Yes	2 No X
What is the corporation's major business activity? (Only complete if yes was entered at line 281)	282		
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	Electricty Distribu	285	97.000 %
286		287	%
288		289	%

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

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI	300	2,073,621	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")		2,073,621	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355		D
Taxable income (amount C **plus** amount D)	360	2,073,621	
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)		2,073,621	Z

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

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Small business deduction

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

Income from active business carried on in Canada from Schedule 7 ..... 400 2,073,621 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 2,073,621 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 2005 and in 2006 / Number of days in the tax year 365) = ... 1

400,000 x (Number of days in the tax year after 2006 365 / Number of days in the tax year 365) = ... 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 *** 244,120 / 11,250 D = ... 8,679,822 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 365 / 365) 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 / 365) 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 / 365) 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 2005 / Number of days in the tax year 365) x 3 % = I

Amount H x (Number of days in the tax year in 2006 / Number of days in the tax year 365) x 5 % = J

Amount H x (Number of days in the tax year in 2007 / Number of days in the tax year 365) x 7 % = K

Resource deduction – total of amounts I, J and K ..... 438 L
Enter amount L on line 10.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360						2,073,621	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")						2,073,621	I
Amount I	2,073,621 x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	365 / 365 x	7 %	=	145,153	J
Amount I	2,073,621 x	Number of days in the tax year after December 31, 2007 and before January 1, 2009 / Number of days in the tax year	x 365	8.5 %	=		K
Amount I	2,073,621 x	Number of days in the tax year after December 31, 2008 and before January 1, 2010 / Number of days in the tax year	x 365	9 %	=		K1
Amount I	2,073,621 x	Number of days in the tax year after December 31, 2009 and before January 1, 2011 / Number of days in the tax year	x 365	10 %	=		K2
General tax reduction for Canadian-controlled private corporations – total of amounts J, K, K1, and K2 Enter amount L on line 638.						145,153	L

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)							M
Amount Z1 from Part 9 of Schedule 27							N
Amount QQ from Part 13 of Schedule 27							O
Taxable resource income from line 435							P
Amount used to calculate the credit union deduction (from Schedule 17)							Q
Total of amounts N, O, P, and Q					▶		R
Amount M minus amount R (if negative, enter "0")							S
Amount S	x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	365 / 365 x	7 %	=		T
Amount S	x	Number of days in the tax year after December 31, 2007 and before January 1, 2009 / Number of days in the tax year	x 365	8.5 %	=		U
Amount S	x	Number of days in the tax year after December 31, 2008 and before January 1, 2010 / Number of days in the tax year	x 365	9 %	=		U1
Amount S	x	Number of days in the tax year after December 31, 2009 and before January 1, 2011 / Number of days in the tax year	x 365	10 %	=		U2
General tax reduction – total of amounts T, U, U1, and U2 Enter amount V on line 639.							V

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 2,073,621

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 = _____

▶ 2,073,621

x 26 2 / 3 % = 552,966 D

Part I tax payable minus investment tax credit refund (line 700 minus line 780) 458,686

Deduct: Corporate surtax from line 600 23,225

Net amount ..... 435,461 ▶ 435,461 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 % ..... 550 787,976 A

Corporate surtax calculation

Base amount from line A above	787,976	1
Deduct:		
10 % of taxable income (line 360 or amount Z, whichever applies)	207,362	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	207,362	7
Net amount (line 1 **minus** line 7)	580,614	8

Corporate surtax*

Line 8 580,614 × Number of days in the tax year before January 1, 2008 / Number of days in the tax year 365/365 × 4 % = 600 23,225 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	2,073,621		
Deduct:			
Amount from line 400, 405, 410, or 425, whichever is the least			
Net amount	2,073,621 ▶	2,073,621	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) 811,201 E

Deduct:

Small business deduction from line 430			9
Federal tax abatement	608	207,362	
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 L	638	145,153	
General tax reduction from amount V	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	352,515 ▶	352,515	F

Part I tax payable – Line E **minus** line F ..... 458,686 G
Enter amount G on line 700.

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Summary of tax and credits

Federal tax

Part I tax payable	700	458,686
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		458,686

Add provincial or territorial tax:

Provincial or territorial jurisdiction 750 Ontario
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Québec, Ontario, and Alberta)	760	
Provincial tax on large corporations (New Brunswick and Nova Scotia)	765	
Total tax payable	770	458,686 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	458,686
Total credits	890	458,686 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 Speziale (Last name in block letters) 951 Cindy (First name in block letters) 954 Vice President - Finance (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 2008-06-26 (Date (yyyy/mm/dd)) Cindy Speziale (Signature of the authorized signing officer of the corporation)

956 (807) 343-1118 (Telephone number)

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

958 (Name in block letters)

959 (Telephone number)

Language of correspondence – Langue de correspondance

990 Indicate your language of correspondence by entering 1 for English or 2 for French.
Indiquez votre langue de correspondance en inscrivant 1 pour anglais ou 2 pour français.

1 English / Anglais ☒ 2 Français / French ☐

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Thunder Bay Hydro Electricity Distribution Inc
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Schedule of Instalment Remittances

Name of corporation contact

Telephone number

Effective interest date	Description (instalment remittance, split payment, assessed credit)	Amount of credit
	Instalments	458,686
	Total amount of instalments claimed (carry the result to line 840 of the T2 Return)	458,686 A
	Total instalments credited to the taxation year per T9	458,686 B

Transfer

	Account number	Taxation year end	Amount	Effective interest date	Description
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					

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GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 100

Name of corporation	Business Number	Tax year end Year Month Day
Thunder Bay Hydro Electricity Distribution Inc.	89209 0614 RC0001	2007-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
Assets					
	Total current assets	1599	+	33,163,573	32,498,098
	Total tangible capital assets	2008	+	132,394,171	129,683,414
	Total accumulated amortization of tangible capital assets	2009	–	71,991,528	68,974,136
	Total intangible capital assets	2178	+		
	Total accumulated amortization of intangible capital assets	2179	–		
	Total long-term assets	2589	+	1,323,298	1,634,330
	*Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	94,889,514	94,841,706
Liabilities					
	Total current liabilities	3139	+	12,169,217	13,364,942
	Total long-term liabilities	3450	+	43,283,005	42,334,448
	*Subordinated debt	3460	+		
	*Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	55,452,222	55,699,390
Shareholder equity					
	Total shareholder equity (mandatory field)	3620	+	39,437,292	39,142,316
	Total liabilities and shareholder equity	3640	=	94,889,514	94,841,706
Retained earnings					
	Retained earnings/deficit – end (mandatory field)	3849	=	4,505,667	4,210,691

* Generic item

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GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 125

Name of corporation	Business Number	Tax year end Year Month Day
Thunder Bay Hydro Electricity Distribution Inc.	89209 0614 RC0001	2007-12-31

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	+	87,826,492	86,720,375
	Cost of sales	8518	–	71,841,094	70,895,278
	Gross profit/loss	8519	=	15,985,398	15,825,097
	Cost of sales	8518	+	71,841,094	70,895,278
	Total operating expenses	9367	+	17,329,148	16,209,911
	Total expenses (mandatory field)	9368	=	89,170,242	87,105,189
	Total revenue (mandatory field)	8299	+	90,075,217	88,864,598
	Total expenses (mandatory field)	9368	–	89,170,242	87,105,189
	Net non-farming income	9369	=	904,975	1,759,409
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	=	904,975	1,759,409
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	–	610,000	1,213,708
	Deferred income tax provision	9995	–		
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	294,975	545,701

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SCHEDULE 141

NOTES CHECKLIST

Corporation's name	Business Number	Tax year end Year Month Day
Thunder Bay Hydro Electricity Distribution Inc.	89209 0614 RC0001	2007-12-31

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

Part 1 – Accounting practitioner information

Does the accounting practitioner have a professional designation? ..... 095 1 Yes [X] 2 No [ ]

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

Part 2 – Type of involvement

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

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

Part 3 – Reservations

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

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

Part 4 – Other information

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 [ ]

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Thunder Bay Hydro Electricity Distribution Inc
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NET INCOME (LOSS) FOR INCOME TAX PURPOSES — SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
Thunder Bay Hydro Electricity Distribution Inc.	89209 0614 RC0001	2007-12-31

- 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				294,975 A
Add:				
Provision for income taxes – current		101	610,000	
Amortization of tangible assets		104	4,828,980	
Non-deductible meals and entertainment expenses		121	17,225	
	Subtotal of additions		5,456,205 ▶	5,456,205
Other additions:				
Miscellaneous other additions:				
601 Regulatory Asset Recovery		291	300,050	
602 Future Employee Benefits		292	236,117	
603.2 Ontario Specified Tax Credits	11,562			
	Total 11,562	293	11,562	
	Subtotal of other additions	199	547,729 ▶	547,729
	Total additions	500	6,003,934 ▶	6,003,934
Deduct:				
Gain on disposal of assets per financial statements		401	8,799	
Capital cost allowance from Schedule 8		403	4,035,544	
Cumulative eligible capital deduction from Schedule 10		405	6,099	
	Subtotal of deductions		4,050,442 ▶	4,050,442
Other deductions:				
Miscellaneous other deductions:				
701 Regulatory Asset Deductions		391	174,846	
	Total	394		
	Subtotal of other deductions	499	174,846 ▶	174,846
	Total deductions	510	4,225,288 ▶	4,225,288
Net income (loss) for income tax purposes – enter on line 300 of the T2 return				2,073,621

* For reference purposes only

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Thunder Bay Hydro Electricity Distribution Inc.
89209 0614 RC0001

SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
Thunder Bay Hydro Electricity Distribution Inc.	89209 0614 RC0001	2007-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under regulation 1101(5q)? **101** 1 Yes ☐ 2 No ☒

	1 Class number 200	Description	2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year) 201	3 Cost of acquisitions during the year (new property must be available for use)* 203	4 Net adjustments** 205	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** 211	7 Reduced undepreciated capital cost	8 CCA rate % 212	9 Recapture of capital cost allowance (line 107 of Schedule 1) 213	10 Terminal loss (line 404 of Schedule 1) 215	11 Capital cost allowance (column 7 multiplied by column 8; or a lower amount) (line 403 of Schedule 1)**** 217	12 Undepreciated capital cost at the end of the year (column 6 plus column 7 minus column 11) 220
1	10	Rolling Stock/Comp	1,303,598	192,756		8,755	92,001	1,395,598	30	0	0	418,679	1,068,920
2	8	Office/Other Equip	594,456	146,988		0	73,494	667,950	20	0	0	133,590	607,854
3	4	Building	2,093,442			0		2,093,442	6	0	0	125,607	1,967,835
4	47	Distribution Equipment Post Feb	7,524,724	3,933,666		0	1,966,833	9,491,557	8	0	0	759,325	10,699,065
5	12	Computer Software	42,544	95,892		0	47,946	90,490	100	0	0	90,490	47,946
6	45	Computer Equipment acquired at	99,118	42,633		44	21,295	120,412	45	0	0	54,185	87,522
7	1	Distribution Equipment	61,341,705			0		61,341,705	4	0	0	2,453,668	58,888,037
		Total	72,999,587	4,411,935		8,799	2,201,569	75,201,154				4,035,544	73,367,179

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see Regulation 1100(2) and (2.2).
** Include amounts transferred under section 85, or on amalgamation and winding-up of a subsidiary. See the *T2 Corporation Income Tax Guide* for other examples of adjustments to include in column 4.
*** The net cost of acquisitions is the cost of acquisitions (column 3) plus or minus certain adjustments from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.
**** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

T2 SCH 8 (06)

Canada

THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.
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Exhibit 4
Tab 3
Schedule 4
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SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
Thunder Bay Hydro Electricity Distribution Inc.	89209 0614 RC0001	2007-12-31

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	Thunder Bay Hydro Corporation		86523 2995 RC0001	1	1,000	100.000			34,931,625
2	Thunder Bay Renewable Power Incc		86170 7461 RC0001	3					
3	Thunder Bay Hydro Utility Services I		86189 1059 RC0001	3					
4	Thunder Bay Hydro Energy Ser		86512 8656 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.

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SCHEDULE 10

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year end Year Month Day
Thunder Bay Hydro Electricity Distribution Inc.	89209 0614 RC0001	2007-12-31

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide*.
- A separate cumulative eligible capital account must be kept for each business.

Part 1 – Calculation of current year deduction and carry-forward

Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter "0") 200 87,134 A

Add:
- Cost of eligible capital property acquired during the taxation year 222
- Other adjustments 226
- Subtotal (line 222 plus line 226) x 3 / 4 = B
- Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002 228 x 1 / 2 = C
- amount B minus amount C (if negative, enter "0") ▶ D
- Amount transferred on amalgamation or wind-up of subsidiary 224 E
- Subtotal (add amounts A, D, and E) 230 87,134 F

Deduct:
- Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year 242 G
- The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7) 244 H
- Other adjustments 246 I
- (add amounts G, H, and I) x 3 / 4 = 248 J

Cumulative eligible capital balance (amount F minus amount J) (if amount K is negative, enter "0" at line M and proceed to Part 2) 87,134 K

Cumulative eligible capital for a property no longer owned after ceasing to carry on that business 249

amount K 87,134
less amount from line 249

Current year deduction 87,134 x 7.00 % = 250 6,099 *
(line 249 plus line 250) (enter this amount at line 405 of Schedule 1) 6,099 ▶ 6,099 L

Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0") 300 81,035 M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

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Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

Amount from line K (show as positive amount)				N
Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988	400		1	
Total of all amounts which reduced CEC in the current or prior years under subsection 80(7)	401		2	
Total of CEC deductions claimed for taxation years beginning before July 1, 1988	402		3	
Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988	408		4	
Line 3 minus line 4 (if negative, enter "0")		▶	5	
Total of lines 1, 2 and 5			6	
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400			7	
Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000			8	
Subtotal (line 7 plus line 8)	409	▶	9	
Line 6 minus line 9 (if negative, enter "0")		▶		O
Line N minus line O (if negative, enter "0")				P
Line 5 _____ x 1 / 2 =				Q
Line P minus line Q (if negative, enter "0")				R
Amount R _____ x 2 / 3 =				S
Amount N or amount O, whichever is less				T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)	410			

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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 2007

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 ☒

	1 Names of associated corporations 100	2 Business Number of associated corporations 200	3 Asso-ciation code 300	4 Business limit for the year (before the allocation) $	5 Percentage of the business limit % 350	6 Business limit allocated* $ 400
1	Thunder Bay Hydro Electricity Distribution Inc.	89209 0614 RC0001	1	400,000	100.0000	400,000
2	Thunder Bay Hydro Corporation	86523 2995 RC0001	1	400,000		
3	Thunder Bay Renewable Power Incorporated	86170 7461 RC0001	1	400,000		
4	Thunder Bay Hydro Utility Services Inc.	86189 1059 RC0001	1	400,000		
5	Thunder Bay Hydro Energy Ser	86512 8656 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.

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SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
Thunder Bay Hydro Electricity Distribution Inc.	89209 0614 RC0001	2007-12-31

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) 100	Provide only one number per shareholder: Business Number 200	Social Insurance number 300	Trust number 350	Percentage common shares 400	Percentage preferred shares 500
1	Thunder Bay Hydro Corporation	86523 2995 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

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SCHEDULE 53

GENERAL RATE INCOME POOL (GRIP) CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
Thunder Bay Hydro Electricity Distribution Inc.	89209 0614 RC0001	2007-12-31

On: 2007-12-31

- If you are a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC), use this schedule to determine the general rate income pool (GRIP).
- When an eligible dividend was paid in the tax year, file a completed copy of this schedule with your *T2 Corporation Income Tax Return*. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- Subsections referred to in this schedule are from the *Income Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool, and low rate income pool.

Eligibility for the various additions

Answer the following questions to determine the corporation's eligibility for the various additions:

2006 addition

1. Is this the corporation's first taxation year that includes January 1, 2006? ☐ Yes ☒ No
2. If not, what is the date of the taxation year end of the corporation's first year that includes January 1, 2006? Enter the date and go directly to question 4 — 2006-12-31
3. During that first year, was the corporation a CCPC or would it have been a CCPC if not for the election of subsection 89(11) ITA? ☒ Yes ☐ No
   If the answer to question 3 is yes, complete Part 5.

Change in the type of corporation

4. Was the corporation a CCPC during its preceding taxation year? ☒ Yes ☐ No
5. Corporations that become a CCPC or a DIC ☐ Yes ☒ No
   If the answer to question 5 is yes, complete Part 4.

Amalgamation (first year of filing after amalgamation)

6. Corporations that were formed as a result of an amalgamation ☐ Yes ☒ No
   If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to question 9.
7. Was one or more of the predecessor corporations neither a CCPC nor a DIC? ☐ Yes ☐ No
   If the answer to question 7 is yes, complete Part 4.
8. Was one or more of the predecessor corporation a CCPC or a DIC during the taxation year that ended immediately before amalgamation? ☐ Yes ☐ No
   If the answer to question 8 is yes, complete Part 3.

Winding-up

9. Corporations that wound-up a subsidiary ☐ Yes ☒ No
   If the answer to question 9 is yes, answer questions 10 and 11. If the answer is no, go to Part 1.
10. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? ☐ Yes ☐ No
    If the answer to question 10 is yes, complete Part 4.
11. Was the subsidiary a CCPC or a DIC during its last taxation year? ☐ Yes ☐ No
    If the answer to question 11 is yes, complete Part 3.

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Thunder Bay Hydro Electricity Distribution Inc
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Part 1 – Calculation of general rate income pool (GRIP)

If the corporation's tax year includes January 1, 2006, complete "Part 5 – GRIP addition for 2006" and then line 050. Otherwise, complete line 100.

GRIP addition for 2006 (the greater of amount QQ from Part 5 or "0")	050		A
GRIP at the end of the previous tax year	100	4,400,133	B
Taxable income for the year (DICs enter "0")*	110	2,073,621	C
Income for the credit union deduction* (amount E in Part 3 of Schedule 17)	120		
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less*	130		
For a CCPC, the lesser of aggregate investment income (line 440 of the T2 return) and taxable income*	140		
Subtotal (add lines 120, 130, and 140)			D
Income taxable at the general corporate rate (line C minus line D)	150	2,073,621	
After-tax income (line 150 multiplied by 68 %)	190	1,410,062	E
Eligible dividends received in the tax year	200		
Dividends deductible under section 113 received in the tax year	210		
Subtotal (add lines 200 and 210)			F
GRIP addition:			
Becoming a CCPC (line PP from Part 4)	220		
Post-amalgamation (total of lines EE from Part 3 and lines PP from Part 4)	230		
Post-wind-up (total of lines EE from Part 3 and lines PP from Part 4)	240		
Subtotal (add lines 220, 230, and 240)	290		G
Subtotal (add lines A or B (as applicable), E, F, and G)		5,810,195	H
Eligible dividends paid in the previous tax year	300		
Excessive eligible dividend designations made in the previous tax year	310		
Note: If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310.			
Subtotal (line 300 minus line 310)			I
GRIP before adjustment for specified future tax consequences (line H minus line I) (amount can be negative)	490	5,810,195	
Total GRIP adjustment for specified future tax consequences to previous tax years (amount Y from Part 2)	560		
GRIP at the end of the year (line 490 minus line 560) Enter this amount on line 160 on Schedule 55.	590	5,810,195	

* **Note:** For lines 110, 120, 130, and 140, the income amount is the amount before considering specified future tax consequences. This phrase is defined in subsection 248(1). It includes the deduction of a loss carryback from subsequent tax years, a reduction of Canadian exploration expenses and Canadian development expenses that were renounced in subsequent tax years (e.g., flow-through share renunciations), reversals of income inclusions where an option is exercised in subsequent tax years, and the effect of certain foreign tax credit adjustments.

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560 of page 1 or leave it blank.

First previous tax year 2006-12-31

Taxable income before specified future tax consequences from the current tax year	3,070,926	J1	
Enter the following amounts before specified future tax consequences from the current tax year:			
Income for the credit union deduction (amount E in Part 3 of Schedule 17)		K1	
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less		L1	
Aggregate investment income (line 440 of the T2 return)		M1	
Subtotal (add lines K1, L1, and M1)			O1
Subtotal (line J1 minus line O1) (if negative, enter "0")	3,070,926		3,070,926 P1

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences Q1

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . R1

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less S1

Aggregate investment income (line 440 of the T2 return) T1

Subtotal (add lines R1, S1, and T1) ▶ V1

Subtotal (line Q1 minus line V1) (if negative, enter "0") ▶ W1

Subtotal (line P1 minus line W1) (if negative, enter "0") X1

GRIP adjustment for specified future tax consequences to first previous tax year (line X1 multiplied by 68 %) . . . 500

Second previous tax year 2005-12-31

Taxable income before specified future tax consequences from the current tax year 3,669,687 J2

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . K2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less L2

Aggregate investment income (line 440 of the T2 return) M2

Accelerated tax reduction (line 637 of T2 return)* **multiplied by 100/7** N2

Subtotal (add lines K2, L2, M2, and N2) ▶ O2

Subtotal (line J2 minus line O2) (if negative, enter "0") 3,669,687 ▶ 3,669,687 P2

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences Q2

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . R2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less S2

Aggregate investment income (line 440 of the T2 return) T2

Accelerated tax reduction (line 637 of T2 return)* **multiplied by 100/7** U2

Subtotal (add lines R2, S2, T2, and U2) ▶ V2

Subtotal (line Q2 minus line V2) (if negative, enter "0") ▶ W2

Subtotal (line P2 minus line W2) (if negative, enter "0") X2

GRIP adjustment for specified future tax consequences to second previous tax year (line X2 multiplied by 68 %) 520

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Third previous tax year 2004-12-31

Taxable income before specified future tax consequences from the current tax year J3

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . K3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less L3

Aggregate investment income (line 440 of the T2 return) M3

Accelerated tax reduction (line 637 of T2 return)* **multiplied by 100/7** N3

Subtotal (**add** lines K3, L3, M3, and N3) ▶ O3

Subtotal (line J3 **minus** line O3) (if negative, enter "0") ▶ P3

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences Q3

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . R3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less S3

Aggregate investment income (line 440 of the T2 return) T3

Accelerated tax reduction (line 637 of T2 return)* **multiplied by 100/7** U3

Subtotal (**add** lines R3, S3, T3, and U3) ▶ V3

Subtotal (line Q3 **minus** line V3) (if negative, enter "0") ▶ W3

Subtotal (line P3 **minus** line W3) (if negative, enter "0") X3

GRIP adjustment for specified future tax consequences to third previous tax year (line X3 **multiplied by** 68 %) . . . 540

Total GRIP adjustment for specified future tax consequences to previous tax years: (**add** lines 500, 520, and 540) (if negative, enter "0") . . . . . Y

Enter amount Y on line 560.

***Note:** The accelerated tax reduction was available for 2001 to 2004 tax years.

Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or DIC in its last tax year)

nb. 1 Post amalgamation . . . ☐ Post wind-up . . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary corporation was a CCPC or DIC in its last tax year. In the calculation below, **corporation** means a predecessor or a subsidiary. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for each predecessor and each subsidiary that was a CCPC or DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Corporation's GRIP at the end of its last tax year . . . . . AA

Eligible dividends paid by the corporation in its last tax year . . . . . BB

Excessive eligible dividend designations made by the corporation in its last tax year CC

Subtotal (line BB **minus** line CC) ▶ DD

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or DIC in its last tax year) (line AA **minus** line DD) . . . . . EE

After you complete this calculation for each predecessor and each subsidiary, calculate the total of all the EE lines. Enter this total amount on:

- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or DIC in its last tax year), or the corporation is becoming a CCPC

nb. 1 Corporation becoming a CCPC ☐ Post amalgamation ☐ Post wind-up ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or DIC in its last tax year. Also, use this part for a corporation becoming a CCPC. In the calculation below, **corporation** means a corporation becoming a CCPC, a predecessor, or a subsidiary.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was not a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of its previous/last tax year		FF
The corporation's money on hand immediately before the end of its previous/last tax year		GG
Unused and unexpired losses at the end of the corporation's previous/last tax year:		
Non-capital losses		
Net capital losses		
Farm losses		
Restricted farm losses		
Limited partnership losses		
Subtotal	▶	HH
Subtotal (add lines FF, GG, and HH)		II
All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year		JJ
Paid up capital of all the corporation's issued and outstanding shares of capital stock immediately before the end of its previous/last tax year		KK
All the corporation's reserves deducted in its previous/last tax year		LL
The corporation's capital dividend account immediately before the end of its previous/last tax year		MM
The corporation's low rate income pool immediately before the end of its previous/last tax year		NN
Subtotal (add lines JJ, KK, LL, MM, and NN)	▶	OO
GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or DIC in its last tax year), or the corporation is becoming a CCPC (line II **minus** line OO) (if negative, enter "0")		PP

After you complete this worksheet for each predecessor and each subsidiary, calculate the total of all the PP lines. Enter this total amount on:

- line 220 for a corporation becoming a CCPC;
- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Ontario

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

2007 CT23 Corporations Tax and Annual Return

For taxation years commencing after December 31, 2004

Corporations Tax Act – Ministry of Finance (MOF)
Corporations Information Act – Ministry of Government Services (MGS)

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

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

MGS Annual Return Required? *(Not required if already filed or Annual Return exempt. Refer to Guide)* [X] Yes [ ] No **Page 1 of 20**

Ministry Use

Corporation's Legal Name *(Including punctuation)*
Thunder Bay Hydro Electricity Distribution Inc.

Ontario Corporations Tax Account No. (MOF)
1800284

Mailing Address
34 N. Cumberland Street
Thunder Bay
ON CA P7A 4L4

This Return covers the Taxation Year
Start: year month day 2007-01-01
End: year month day 2007-12-31

Has the mailing address changed since last filed CT23 Return? [ ] Yes | Date of Change: year month day

Date of Incorporation or Amalgamation
year month day 2000-10-26

Registered/Head Office Address
34 N. Cumberland Street
Thunder Bay
ON CA P7A 4L4

Ontario Corporation No. (MGS)
1446795

Location of Books and Records
34 N. Cumberland Street
Thunder Bay
ON CA P7A 4L4

Canada Revenue Agency Business No.
If applicable enter
89209 0614 RC0001

Name of person to contact regarding this CT23 Return	Telephone No.	Fax No.
Cindy Speziale	(807) 343-1118	

Jurisdiction Incorporated
Ontario

Address of Principal Office in Ontario *(Extra-Provincial Corporations only)* (MGS)
Ontario Canada

If not incorporated in Ontario, indicate the date Ontario business activity commenced and ceased:
Commenced: year month day
Ceased: year month day
[X] *Not Applicable*

Former Corporation Name *(Extra-Provincial Corporations only)* [X] *Not Applicable* (MGS)

Information on Directors/Officers/Administrators must be completed on MGS Schedule A or K as appropriate. If additional space is required for Schedule A, only this schedule may be photocopied. State number submitted (MGS). ▶ No. of Schedule(s)

If there is no change to the Directors'/Officers'/Administrators' information previously submitted to MGS, please check (X) this box. Schedule(s) A and K are not required (MGS). ▶ [ ] No Change

Preferred Language / *Langue de préférence*
[X] English *anglais* [ ] French *français*

Ministry Use

Certification (MGS)

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

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

Title D [ ] Director O [ ] Officer P [X] Other individuals having knowledge of the Corporation's business activities

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

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Thunder Bay Hydro Electricity Distribution Ir	1800284	2007-12-31

CT23 Corporations Tax Return

Identification continued (for CT23 filers only)

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

Type of corporation

1

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

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

2

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

- [ ] This is the first year filing after incorporation or an amalgamation (If checked, attach Ontario Schedule 24.)
- [ ] Amended Return
- [ ] Taxation year end change – Canada Revenue Agency approval required
- [ ] Final taxation year up to dissolution *(Note: for discontinued businesses, see guide.)*
- [ ] Final taxation year before amalgamation
- [ ] The corporation has a floating fiscal year end
- [ ] There has been a transfer or receipt of asset(s) involving a corporation having a Canadian permanent establishment outside Ontario
- [ ] There was an acquisition of control to which subsection 249(4) of the federal *Income Tax Act* (ITA) applies since the previous taxation year

If checked, date control was acquired year ____ month ____ day ____

- [ ] The corporation was involved in a transaction where all or substantially all (90% or more) of the assets of a non-arm's length corporation were received in the taxation year and subsection 85(1) or 85(2) of the federal ITA applied to the transaction (If checked, attach Ontario Schedule 44.)
- [ ] First year filing of a parent corporation after winding-up a subsidiary corporation(s) under section 88 of the federal ITA during the taxation year. (If checked, attach Ontario Schedule 24.)
- [ ] Section 83.1 of the CTA applies (redirection of payments for certain electricity corporations)

Yes	No	
[ ]	[X]	Was the corporation inactive throughout the taxation year?
[X]	[ ]	Has the corporation's Federal T2 Return been filed with the Canada Revenue Agency?

Are you requesting a refund due to:

[ ]	[X]	the Carry-back of a Loss?
[X]	[ ]	an Overpayment?
[ ]	[X]	a Specified Refundable Tax Credit?
[ ]	[X]	Are you a member of a Partnership or Joint Venture?

Complete if applicable

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

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

Specify major business activity

Income Tax

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

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Net income (loss) for Ontario purposes (per reconciliation schedule, page 15)	±	From 690	2,073,621
Subtract: Charitable donations	–	1	
Subtract: Gifts to Her Majesty in right of Canada or a province and gifts of cultural property *(Attach schedule 2)*	–	2	
Subtract: Taxable dividends deductible, per federal Schedule 3	–	3	
Subtract: Ontario political contributions *(Attach Schedule 2A)* (Int.B. 3002R)	–	4	
Subtract: Federal Part VI.1 tax _____ x 3	–	5	
Subtract: Prior years' losses applied – Non-capital losses From 715	–	From 704	
Net capital losses (page 16) _____ x inclusion rate 50.000000 % =	–	714	
Farm losses	–	From 724	
Restricted farm losses	–	From 734	
Limited partnership losses	–	From 754	
Taxable Income (Non-capital loss)	=	10	2,073,621
Addition to taxable income for unused foreign tax deduction for federal purposes	+	11	
Adjusted Taxable Income 10 + 11 (if 10 is negative, enter 11)	=	20	2,073,621

Taxable Income

Number of Days in Taxation Year

From 10 (or 20 if applicable) 2,073,621 x 30 100.0000 % (Ontario Allocation) x 12.5 % x (Days after Dec. 31, 2002 and before Jan. 1, 2004 33 ÷ Total Days 73 365) = + 29

From 10 (or 20 if applicable) 2,073,621 x 30 100.0000 % (Ontario Allocation) x 4.14 % x (Days after Dec. 31, 2003 34 365 ÷ Total Days 73 365) = + 32 290,307

Income Tax Payable (before deduction of tax credits) 29 + 32 = 40 290,307

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

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

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

* Income from active business carried on in Canada for federal purposes (fed.s.125(1)(a))		50	2,073,621
Federal taxable income, less adjustment for foreign tax credit (fed.s.125(1)(b))	+ 51	2,073,621	
Add: Losses of other years deducted for federal purposes (fed.s.111)	+ 52		
Subtract: Losses of other years deducted for Ontario purposes (s.34)	– 53		
	= 2,073,621	54	2,073,621
Federal Business limit (line 410 of the T2 Return) for the year before the application of fed.s.125(5.1)		55	400,000

Ontario Business Limit Calculation

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

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

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

Income eligible for the IDSBC From 30 100.0000 % (***Ontario Allocation) x 56 400,000 = 60 400,000 (Least of 50, 54 or 45)

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

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

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

continued on Page 5

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Thunder Bay Hydro Electricity Distribution Ir	1800284	2007-12-31

Income Tax *continued from Page 4*

Calculation of IDSBC Rate 7.% x (Days after Dec. 31, 2002 and before Jan. 1, 2004: 31 ÷ Total Days: 73 365) = + 89

8.5% x (Days after Dec. 31, 2003: 34 365 ÷ Total Days: 73 365) = + 90 8.5000

IDSBC Rate for Taxation Year 89 + 90 = 78 8.5000

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

Corporations claiming the IDSBC must complete the Surtax section below if the corporation's taxable income (or if associated, the associated group's taxable income) is greater than the amount 400,000 in 114 below.

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

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

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

***Taxable Income of the corporation** From 10 (or 20 if applicable) + 80 2,073,621 .

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

Name of associated corporation (Canadian & foreign) *(if insufficient space, attach schedule)*	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End	* Taxable Income (if loss, enter nil)
See schedule			+ 82 .
			+ 83 .
			+ 84 .

Aggregate Taxable Income 80 + 82 + 83 + 84 , etc. = 85 2,073,621 .

320,000 x (Days after Dec. 31, 2002 and before Jan. 1, 2004: 31 ÷ Total Days: 73 365) = + 115 .

400,000 x (Days after Dec. 31, 2003: 34 365 ÷ Total Days: 73 365) = + 116 400,000 .

115 + 116 = 400,000 . – 114 400,000 .

(If negative, enter nil) = 86 1,673,621 .

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

From 86 1,673,621 . x From 97 4.6670 % = 87 78,108 .

From 87 78,108 . x From 60 400,000 . ÷ From 114 400,000 . = 88 78,108 .

Surtax Lesser of 70 or 88 = 100 34,000

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

continued on Page 6

Income Tax *continued from Page 5*

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Additional Deduction for Credit Unions (s.51(4)) *(Attach schedule 17)* — 110

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

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

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

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

Eligible Canadian Profits + 120

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

Add: Adjustment for Surtax on Canadian-controlled private corporations

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

Lesser of 56 or 121 + 122 400,000

120 − 56 + 122 = 130

Taxable Income + From 10 2,073,621

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

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

Subtract: Taxable Income 10 2,073,621 X Allocation % to jurisdictions outside Canada − 140

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

10 − 56 + 122 − 140 − 141 = 142 2,073,621

Claim

Number of Days in Taxation Year

143 Lesser of 130 or 142 X From 30 100.0000% Ontario Allocation X 15% X (Days after Dec. 31, 2002 and before Jan. 1, 2004: 33 ÷ Total Days 73 365) = + 154

143 Lesser of 130 or 142 X From 30 100.0000% Ontario Allocation X 22% X (Days after Dec. 31, 2003: 34 365 ÷ Total Days 73 365) = + 156

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

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

Manufacturing and Processing Profits Credit for Electrical Generating Corporations = 161

Manufacturing and Processing Profits Credit for Corporations that Produce and Sell Steam for uses other than the Generation of Electricity = 162

Credit for Foreign Taxes Paid (s.40)

Applies if you paid tax to a jurisdiction outside Canada on foreign investment income (Int.B. 3001R). *(Attach schedule)* 170

Credit for Investment in Small Business Development Corporations (SBDC)

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

Eligible Credit 175 Credit Claimed 180

Subtotal of Income Tax 40 − 70 + 100 − 110 − 160 − 161 − 162 − 170 − 180 = 190 290,307

continued on Page 7

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Thunder Bay Hydro Electricity Distribution Ir	1800284	2007-12-31

DOLLARS ONLY

Income Tax *continued from Page 6*

Specified Tax Credits *(Refer to Guide)*

Ontario Innovation Tax Credit (OITC) (s.43.3) *Applies* to scientific research and experimental development in Ontario.
Eligible Credit From 5620 OITC Claim Form *(Attach original Claim Form)* + 191

Co-operative Education Tax Credit (CETC) (s.43.4) *Applies* to employment of eligible students.
Eligible Credit From 5798 CT23 Schedule 113 *(Attach Schedule 113)* + 192

Ontario Film & Television Tax Credit (OFTTC) (s.43.5)
Applies to qualifying Ontario labour expenditures for eligible Canadian content film and television productions. Name of Production 204
Eligible Credit From 5850 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC)
(Attach the original Certificate of Eligibility) + 193

Graduate Transitions Tax Credit (GTTC) (s.43.6)
Applies to employment of eligible unemployed post secondary graduates, for employment commencing prior to July 6, 2004 and expenditures incurred prior to January 1, 2005. No. of Graduates From 6596 194
Eligible Credit From 6598 CT23 Schedule 115 *(Attach Schedule 115)* + 195

Ontario Book Publishing Tax Credit (OBPTC) (s.43.7)
Applies to qualifying expenditures in respect of eligible literary works by eligible Canadian authors.
Eligible Credit From 6900 OBPTC Claim Form *(Attach both the original Claim Form and the Certificate of Eligibility)* + 196

Ontario Computer Animation and Special Effects Tax Credit (OCASE) (s.43.8)
Applies to labour relating to computer animation and special effects on an eligible production.
Eligible Credit From 6700 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC)
(Attach the original Certificate of Eligibility) + 197

Ontario Business-Research Institute Tax Credit (OBRITC) (s.43.9)
Applies to qualifying R&D expenditures under an eligible research institute contract.
Eligible Credit From 7100 OBRITC Claim Form *(Attach original Claim Form)* + 198

Ontario Production Services Tax Credit (OPSTC) (s.43.10)
Applies to qualifying Ontario labour expenditures for eligible productions where the OFTTC has not been claimed.
Eligible Credit From 7300 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC)
(Attach the original Certificate of Eligibility) + 199

Ontario Interactive Digital Media Tax Credit (OIDMTC) (s.43.11)
Applies to qualifying labour expenditures of eligible products for the taxation year.
Eligible Credit From 7400 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC)
(Attach the original Certificate of Eligibility) + 200

Ontario Sound Recording Tax Credit (OSRTC) (s.43.12)
Applies to qualifying expenditures in respect of eligible Canadian sound recordings.
Eligible Credit From 7500 OSRTC Claim Form *(Attach both the original Claim Form and the Certificate of Eligibility)* + 201

Apprenticeship Training Tax Credit (ATTC) (s.43.13)
Applies to employment of eligible apprentices. No. of Apprentices From 5896 202 4
Eligible Credit From 5898 CT23 Schedule 114 *(Attach Schedule 114)* + 203 11,562

Other (specify) _____ + 203.1 _____

Total Specified Tax Credits 191 + 192 + 193 + 195 + 196 + 197 + 198 + 199 + 200 + 201 + 203 + 203.1 = 220 11,562

Specified Tax Credits *Applied to reduce Income Tax* = 225 11,562

Income Tax 190 – 225 **OR Enter NIL if reporting Non-Capital Loss** *(amount cannot be negative)* = 230 278,745

To determine if the Corporate Minimum Tax (CMT) is applicable to your Corporation, see **Determination of Applicability** section for the CMT on **Page 8**. If CMT is not applicable, transfer amount in 230 to Income Tax in **Summary** section on **Page 17**.

OR

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

Corporate Minimum Tax (CMT)

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DOLLARS ONLY

Total Assets of the corporation	+ 240	94,889,514
Total Revenue of the corporation	+ 241	90,075,217

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

If you are a member of an associated group (X) 242 ☐ (Yes)

Name of associated corporation (Canadian & foreign) *(if insufficient space attach schedule)*	Ontario Corporations Tax Account No. (MOF) (If applicable)	Taxation Year End	Total Assets	Total Revenue
			+ 243	+ 244
			+ 245	+ 246
			+ 247	+ 248
Aggregate Total Assets 240 + 243 + 245 + 247, etc.			= 249 94,889,514	
Aggregate Total Revenue 241 + 244 + 246 + 248, etc.				= 250 90,075,217

Determination of Applicability

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

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

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

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

Calculation: CMT *(Attach Schedule 101.)*

Gross CMT Payable – CMT Base From Schedule 101 2136 904,575 (If negative, enter zero) × From 30 100.0000 % (Ontario Allocation) X 4% = 276 36,199

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

Subtract: Income Tax – From 190 290,307

Net CMT Payable (If negative, enter Nil on Page 17.) = 280 -254,108

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

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

If 280 is greater than or equal to zero, transfer 230 to **Page 17** and transfer 280 to **Page 17, and to Part 4 of Schedule 101: Continuity of CMT Credit Carryovers.**

CMT Credit Carryover available From Schedule 101 From 2333

Application of CMT Credit Carryovers

A. Income Tax (before deduction of specified credits) + From 190 290,307

Gross CMT Payable + From 276 36,199

Subtract: Foreign Tax Credit for CMT purposes – From 277

If 276 – 277 is negative, enter NIL in 290 = 36,199 – 290 36,199

Income Tax eligible for CMT Credit = 300 254,108

B. Income Tax (after deduction of specified credits) + From 230 278,745

Subtract: CMT credit used to reduce income taxes – 310

Income Tax = 320 278,745

Transfer to page 17

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

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

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End	CT23 Page 9 of 20
Thunder Bay Hydro Electricity Distribution Ir	1800284	2007-12-31	DOLLARS ONLY

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

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

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

Members of a partnership (limited or general) or a joint venture, must attach all financial statements of each partnership or joint venture of which they are a member. The Paid-up Capital of each corporate partner must include its share of liabilities that would otherwise be included if the partnership were a corporation. If Investment Allowance is claimed, Total Assets must be adjusted by adding the corporation's share of the partnership's Total Assets and by deducting investments in the partnership as it appears on the corporation's balance sheet, in addition to any other required adjustments (s.61(5)). Special rules apply to limited partnerships (Int.B. 3017R).

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

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

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

Paid-up Capital

Paid-up capital stock (Int.B. 3012R and 3015R)	+	350	34,931,[illegible]
Retained earnings (if deficit, deduct) (Int.B. 3012R)	±	351	4,50[illegible]
Capital and other surpluses, excluding appraisal surplus (Int.B,3012R)	+	352	
Loans and advances *(Attach schedule)* (Int.B. 3013R)	+	353	33,498,[illegible]
Bank loans (Int.B. 3013R)	+	354	
Bankers acceptances (Int.B. 3013R)	+	355	
Bonds and debentures payable (Int.B. 3013R)	+	356	
Mortgages payable (Int.B. 3013R)	+	357	
Lien notes payable (Int.B. 3013R)	+	358	
Deferred credits (including income tax reserves, and deferred revenue where it would also be included in paid-up capital for the purposes of the large corporations tax) (Int.B. 3013R)	+	359	5,945,[illegible]
Contingent, investment, inventory and similar reserves (Int.B. 3012R)	+	360	
Other reserves not allowed as deductions for income tax purposes *(Attach schedule)* (Int.B. 3012R)	+	361	9,880,[illegible]
Share of partnership(s) or joint venture(s) paid-up capital *(Attach schedule(s))* (Int.B. 3017R)	+	362	
Subtotal	=	370	88,763,[illegible]
Subtract: Amounts deducted for income tax purposes in excess of amounts booked *(Retain calculations. Do not submit.)* (Int.B. 3012R)	–	371	
Deductible R & D expenditures and ONTTI costs deferred for income tax if not already deducted for book purposes (Int.B. 3015R)	–	372	
Total Paid-up Capital	=	380	88,763,[illegible]
Subtract: Deferred mining exploration and development expenses (s.62(1)(d)) (Int.B. 3015R)	–	381	
Electrical Generating Corporations Only – All amounts with respect to electrical generating assets, except to the extent that they have been deducted by the corporation in computing its income for income tax purposes for the current or any prior taxation year, that are deductible by the corporation under clause 11(10)(a) of the *Corporations Tax Act*, and the assets are used both in generating electricity from a renewable or alternative energy source and are qualifying property as prescribed by regulation	–	382	
Net Paid-up Capital	=	390	88,763,046

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

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

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

continued on Page 10

Capital Tax *continued from Page 9*

Total Assets (Int.B. 3015R) *DOLLARS ONLY*

Total Assets per balance sheet	+	420	94,889,514
Mortgages or other liabilities deducted from assets	+	421	
Share of partnership(s)/joint venture(s) total assets *(Attach schedule)*	+	422	
Subtract: Investment in partnership(s)/joint venture(s)	–	423	
Total Assets as adjusted	=	430	94,889,514
Amounts in 360 and 361 (if deducted from assets)	+	440	
Subtract: Amounts in 371, 372 and 381	–	441	
Subtract: Appraisal surplus if booked	–	442	
Add or Subtract: Other adjustments (specify on an attached schedule)	±	443	
Total Assets	=	450	94,889,514

Investment Allowance (410 ÷ 450) x 390 — Not to exceed 410 = 460

Taxable Capital 390 – 460 = 470 88,763,046

Gross Revenue (as adjusted to include the share of any partnership(s)/joint venture(s) Gross Revenue) 480 90,075,217

Total Assets (as adjusted) From 430 94,889,514

Calculation of Capital Tax for all Corporations except Financial Institutions

Note: This version (2007) of the CT23 may only be used for a taxation year that commenced after December 31, 2004.

Financial Institutions use calculations on page 13.

Important: If the corporation is a family farm corporation, family fishing corporation or a credit union that is not a Financial Institution, complete only Section A below.

OR If the corporation is not a member of an associated group and/or partnership, complete Section B below, then review only the Capital Tax calculations in Section C on page 11, selecting and completing the one specific subsection (e.g. C3) that applies to the corporation.

OR If the corporation is a member of an associated group and/or partnership, complete Section B below and Section D on page 11, and if applicable, complete Section E or Section F on page 12. Note: If the corporation is a member of a connected partnership, please refer to the CT23 Guide for additional instructions before completing the Capital Tax section.

SECTION A

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

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

SECTION B

B1. Calculation of Taxable Capital Deduction (TCD)

Number of Days in Taxation Year

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

Taxable Capital Deduction (TCD) 501 + 502 + 504 + 505 = 503 12,500,000

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

Calculation of Capital Tax Rate

Number of Days in Taxation Year

0.3 %	x	Days before Jan. 1, 2007: 556	÷	Total Days: 73 / 365	= +	511		%
0.285 %	x	Days after Dec. 31, 2006 and before Jan. 1, 2009: 557 365	÷	Total Days: 73 / 365	= +	512	0.2850	%

Capital Tax Rate 511 + 512 = 516 0.2850 %

continued on Page 11

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Thunder Bay Hydro Electricity Distribution Ir	1800284	2007-12-31

DOLLARS ONLY

Capital Tax Calculation

continued from Page 10

SECTION C

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

C1. If 430 and 480 on page 10 are both $3,000,000 or less, enter NIL in 550 on page 12 and complete the return from that point.

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

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

\+ From 470 _____
− From 503 _____
= 471 _____ × From 30 100.0000 % (Ontario Allocation) × From 516 0.2850 % (Capital Tax Rate) × Days in taxation year 555 365 / 365 (366 if leap year) *If floating taxation year, refer to Guide.* = + 523 _____ *Transfer to 543 on page 12 and complete the return from that point*

SECTION D

This section applies ONLY to a corporation that is a member of an associated group (excluding Financial Institutions and corporations exempt from Capital Tax) and/or partnership. You must check either 509 or 524 and complete this section before you can calculate your Capital Tax Calculation under either Section E or Section F.

D1. ☐ 509 (X if applicable) — All corporations that you are associated with do **not** have a permanent establishment in Canada.

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

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

D2. ☒ 524 (X if applicable) — One or more of the corporations that you are associated with maintains a permanent establishment in Canada.

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

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

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

D2. Calculation is on next page

continued on Page 12

Capital Tax Calculation *continued from Page 11*

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DOLLARS ONLY

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

Taxable Capital From 470 on page 10 + From 470 88,763,046.

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

Names of associated corporations (excluding Financial Institutions and corporations exempt from Capital Tax) having a permanent establishment in Canada *(if insufficient space, attach schedule)*	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End	Taxable Capital
See schedule			+ 531 2,672,123.
			+ 532 .
			+ 533 .
Aggregate Taxable Capital 470 + 531 + 532 + 533, etc.			= 540 91,435,169.

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

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

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

From 470 88,763,046. ÷ From 540 91,435,169. × From 503 12,500,000. = 541 12,134,697.

Transfer to 542 in Section E below

Ss.69(2.1) Election Filed

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

SECTION E

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

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

+	From 470	88,763,046.									
−	542	12,134,697.									
=	471	76,628,349.	×	From 30	100.0000 %	×	From 516	0.2850 %	×	555 365 / 365 (366 if leap year)	= + 523 218,391.
					Ontario Allocation			Capital Tax Rate		Days in taxation year	Total Capital Tax for the taxation year

Transfer to 543 and complete the return from that point

SECTION F

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

+ From 470 . × From 30 100.0000 % (Ontario Allocation) × From 516 0.2850 % (Capital Tax Rate) = + 561 .

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

= 562 .

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

Transfer to 543 and complete the return from that point

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

Capital Tax before application of specified credits	= 543	218,391.
Subtract: Specified Tax Credits applied to reduce capital tax payable *(Refer to Guide)*	− 546	.
Capital Tax 543 − 546 *(amount cannot be negative)*	= 550	218,391.

Transfer to Page 17

continued on Page 13

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Thunder Bay Hydro Electricity Distribution Ir	1800284	2007-12-31

DOLLARS ONLY

Capital Tax *continued from Page 12*

Calculation of Capital Tax for Financial Institutions

1.1 Credit Unions only

For taxation years commencing after May 4, 1999 enter NIL in 550 on page 12, and complete the return from that point.

1.2 Other than Credit Unions

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

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

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

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

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

2. Small Business Investment Tax Credit

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

Allowable Credit for Eligible Investments – 585 _____

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

Capital Tax - Financial Institutions 575 – 585 = 586 _____

Transfer to 543 on Page 12

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

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

(2) Unlicensed Insurance (enter premium tax payable in 588 and attach a detailed schedule of calculations. If subject to tax under (1) above, add both taxes together and enter total tax in 588.)
Applies to Insurance Brokers and other persons placing insurance for persons resident or property situated in Ontario with unlicensed insurers.

Deduct: Specified Tax Credits applied to reduce premium tax *(Refer to Guide)* – 589 _____

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

DOLLARS ONLY

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

Net income (loss) for federal income tax purposes, per federal T2 Schedule 1 ± 600 2,073,621
Transfer to Page 15

Add:

Federal capital cost allowance	+ 601	4,035,544
Federal cumulative eligible capital deduction	+ 602	6,099
Ontario taxable capital gain	+ 603	
Federal non-allowable reserves. Balance beginning of year	+ 604	
Federal allowable reserves. Balance end of year	+ 605	
Ontario non-allowable reserves. Balance end of year	+ 606	
Ontario allowable reserves. Balance beginning of year	+ 607	
Federal exploration expenses (e.g. CEDE, CEE, CDE, COGPE)	+ 608	
Federal resource allowance *(Refer to Guide)*	+ 609	
Federal depletion allowance	+ 610	
Federal foreign exploration and development expenses	+ 611	
Crown charges, royalties, rentals, etc. deducted for Federal purposes *(Refer to Guide)*	+ 617	

Management fees, rents, royalties and similar payments to non-arms' length non-residents

Number of Days in Taxation Year

		Days after Dec. 31, 2002 and before Jan. 1, 2004	Total Days		
612	× 5 / 12.5 ×	33	÷ 73	365	=+ 633
612	× 5 / 14 ×	Days after Dec. 31, 2003: 34	365	÷ 73 Total Days 365	=+ 634

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

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

Add any negative amount in 473 from Ont. CT23 Schedule 161 + 616

Federal allowable business investment loss + 620

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

Total of Additions 601 to 611 + 617 + 613 + 615 + 616 + 620 + 614 = 4,041,643 ▶ 640 4,041,643
Transfer to Page 15

Deduct:

Ontario capital cost allowance (excludes amounts deducted under 675)	+ 650	4,035,544
Ontario cumulative eligible capital deduction	+ 651	6,099
Federal taxable capital gain	+ 652	
Ontario non-allowable reserves. Balance beginning of year	+ 653	
Ontario allowable reserves. Balance end of year	+ 654	
Federal non-allowable reserves. Balance end of year	+ 655	
Federal allowable reserves. Balance beginning of year	+ 656	
Ontario exploration expenses (e.g. CEDE, CEE, CDE, COGPE) *(Retain calculations. Do not submit.)*	+ 657	
Ontario depletion allowance	+ 658	
Ontario resource allowance *(Refer to Guide)*	+ 659	
Ontario current cost adjustment *(Attach schedule)*	+ 661	
CCA on assets used to generate electricity from natural gas, alternative or renewable resources.	+ 675	

Subtotal of deductions for this page 650 to 659 + 661 + 675 681 4,041,643
Transfer to Page 15

continued on Page 15

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Thunder Bay Hydro Electricity Distribution Ir	1800284	2007-12-31

DOLLARS ONLY

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

continued from Page 14

Net Income (loss) for federal income tax purposes, per federal Schedule 1 — From ± 600 2,073,621.

Total of Additions on page 14 — From = 640 4,041,643.

Sub Total of deductions on page 14 — From = 681 4,041,643.

Deduct:

Ontario New Technology Tax Incentive (ONTTI) Gross-up
(*Applies* only to those corporations whose Ontario allocation is less than 100% in the current taxation year.)

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

ONTTI Gross-up deduction calculation:

Gross-up of CCA: From 662 × 100 / From 30 100.0000 (Ontario Allocation) − From 662 = 663

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

Qualifying expenditures: 665 × 30% × 100 / From 30 100.0000 (Ontario allocation) = 666

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

Qualifying expenditures: 667 × 100% × 100 / From 30 100.0000 (Ontario allocation) = 668

Number of Employees accommodated 669

Ontario School Bus Safety Tax Incentive (OSBSTI)
(*Applies* to the eligible acquisition of school buses purchased after May 4, 1999 and before January 1, 2006.) *(Refer to Guide)*

Qualifying expenditures: 670 × 30% × 100 / From 30 100.0000 (Ontario allocation) = 671

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

Qualifying expenditures: 672 × 15% × 100 / From 30 100.0000 (Ontario allocation) = 673

Ontario allowable business investment loss	+ 678	
Ontario Scientific Research Expenses claimed in year in 477 from Ont. CT23 Schedule 161	+ 679	
Amount added to income federally for an amount that was negative on federal form T661, line 454 or 455 (if filed after June 30, 2003)	+ 677	
Total of other deductions allowed by Ontario *(Attach schedule)*	+ 664	

Total of Deductions 681 + 663 + 666 + 668 + 671 + 673 + 678 + 679 + 677 + 664 = 4,041,643. ▶ 680 4,041,643.

Net income (loss) for Ontario Purposes 600 + 640 − 680 = 690 2,073,621.
Transfer to Page 4

Continuity of Losses Carried Forward

DOLLARS ONLY

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

Analysis of Balance at End of Year by Year of Origin

Year of Origin (oldest year first) year month day	Non-Capital Losses	Non-Capital Losses of Predecessor Corporations	Total Capital Losses from Listed Personal Property only	Farm Losses	Restricted Farm Losses
800 10th preceding taxation year 1998 12 31	817 (9)	860 (9)		850	870
801 9th preceding taxation year 1999 12 31	818 (9)	861 (9)		851	871
802 8th preceding taxation year 2000 12 31	819 (9)	862 (9)		852	872
803 7th preceding taxation year 2001 12 31	820	830	840	853	873
804 6th preceding taxation year 2002 12 31	821	831	841	854	874
805 5th preceding taxation year 2003 12 31	822	832	842	855	875
806 4th preceding taxation year 2004 12 31	823	833	843	856	876
807 3rd preceding taxation year 2005 12 31	824	834	844	857	877
808 2nd preceding taxation year 2006 12 31	825	835	845	858	878
809 Current taxation year 2007 12 31	826	836	846	859	879
Total	829	839	849	869	889

Notes:

(1) Non-capital losses include allowable business investment losses, fed.s.111(8)(b), as made applicable by s.34.

(2) Where acquisition of control of the corporation has occurred, the utilization of losses can be restricted. See fed.s.111(4) through 111(5.5), as made applicable by s.34.

(3) Includes losses on amalgamation (fed.s.87(2.1) and s.87(2.11)) and/or wind-up (fed.s.88(1.1) and 88(1.2)), as made applicable by s.34.

(4) To the extent of applicable gains/income/at-risk amount only.

(5) Generally a three year carry-back applies. See fed.s.111(1) and fed.s.41(2)(b), as made applicable by s.34.

(6) Where a limited partner has limited partnership losses, attach loss calculations for each partnership.

(7) Include amount from 11 if taxable income is adjusted to claim unused foreign tax credit for federal purposes.

(8) Amount in 709 must equal total of 829 + 839.

(9) Include non-capital losses incurred in taxation years ending after March 22, 2004.

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Thunder Bay Hydro Electricity Distribution Ir	1800284	2007-12-31

DOLLARS ONLY

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

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

- If, after applying a loss carry-back to one or more previous years, there is a balance of loss available to carry forward to a future year, it is the corporation's responsibility to claim such a balance for those years following the year of loss within the limitations of fed.s.111, as made applicable by s.34.
- Where control of a corporation has been acquired by a person or group of persons, certain restrictions apply to the carry-forward and carry-back provisions of losses under fed.s.111(4) through 111(5.5), as made applicable by s.34.
- Refunds arising from the loss carry-back adjustment may be applied by the Minister of Finance to amounts owing under any Act administered by the Ministry of Finance.
- Any late filing penalty applicable to the return for which the loss is being applied will not be reduced by the loss carry-back.
- The application of a loss carry-back will be available for interest calculation purposes on the day that is the latest of the following:
  1) the first day of the taxation year after the loss year,
  2) the day on which the corporation's return for the loss year is delivered to the Minister, or
  3) the day on which the Minister receives a request in writing from the corporation to reassess the particular taxation year to take into account the deduction of the loss.
- If a loss is being carried back to a predecessor corporation, enter the predecessor corporation's account number and taxation year end in the spaces provided under Application of Losses below.

Application of Losses

	Predecessor Ontario Corporation's Tax Account No. (MOF)	Taxation Year Ending year month day	Non-Capital Losses	Total Capital Losses	Farm Losses	Restricted Farm Losses
Total amount of loss			910	920	930	940
Deduct: Loss to be carried back to preceding taxation years and applied to reduce taxable income						
i) 3rd preceding	901	2004-12-31	911	921	931	941
ii) 2nd preceding	902	2005-12-31	912	922	932	942
iii) 1st preceding	903	2006-12-31	913	923	933	943
Total loss to be carried back			From 706	From 716	From 726	From 736
Balance of loss available for carry-forward			919	929	939	949

Summary

Income Tax	+ From 230 or 320		278,745
Corporate Minimum Tax	+ From 280		
Capital Tax	+ From 550		218,391
Premium Tax	+ From 590		
Total Tax Payable	= 950		497,136
Subtract: Payments	– 960		882,541
Capital Gains Refund (s.48)	– 965		
Qualifying Environmental Trust Tax Credit *(Refer to Guide)*	– 985		
Specified Tax Credits *(Refer to Guide)*	– 955		
Other, specify _____	–		
Balance	= 970		-385,405
If payment due	Enclosed * 990		
If overpayment: Refund *(Refer to Guide)*	= 975		385,405
Apply to (year month day) 2008-12-31	980		*(includes credit interest)*

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

Certification

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

Name *(please print)*

Cindy Speziale

Title

Vice President - Finance

Full Residence Address

Signature: Cindy Speziale

Date: 2008-06-26

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

Corporate Minimum Tax (CMT)
CT23 Schedule 101

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Thunder Bay Hydro Electricity Distribution Inc.	1800284	2007-12-31

Part 1: Calculation of CMT Base

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

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

Net Income/Loss (unconsolidated, determined in accordance with GAAP)		± 2100	294,975
Subtract (to the extent reflected in net income/loss):			
Provision for recovery of income taxes / benefit of current income taxes	+ 2101		
Provision for deferred income taxes (credits) / benefit of future income taxes	+ 2102		
Equity income from corporations	+ 2103		
Share of partnership(s)/joint venture(s) income	+ 2104		
Dividends received/receivable deductible under fed.s.112	+ 2105		
Dividends received/receivable deductible under fed.s.113	+ 2106		
Dividends received/receivable deductible under fed.s.83(2)	+ 2107		
Dividends received/receivable deductible under fed.s.138(6)	+ 2108		
Federal Part VI.1 tax paid on dividends declared and paid, under fed.s.191.1(1)	x 3 + 2109		
Subtotal	=	– 2110	
Add (to extent reflected in net income/loss):			
Provision for current taxes / cost of current income taxes	+ 2111	610,000	
Provision for deferred income taxes (debits) / cost of future income taxes	+ 2112		
Equity losses from corporations	+ 2113		
Share of partnership(s)/joint venture(s) losses	+ 2114		
Dividends that have been deducted to arrive at net income per Financial Statements s.57.4(1.1) (excluding dividends under fed.s.137(4.1))	+ 2115		
Subtotal	= 610,000	+ 2116	610,000
Add/Subtract:			
Amounts relating to s.57.9 election/regulations for disposals etc. of property for current/prior years			
** Fed.s.85	+ 2117	or – 2118	
** Fed.s.85.1	+ 2119	or – 2120	
** Fed.s.97	+ 2121	or – 2122	
** Amounts relating to amalgamations (fed.s.87) as prescribed in regulations for current/prior years	+ 2123	or – 2124	
** Amounts relating to wind-ups (fed.s.88) as prescribed in regulations for current/prior years	+ 2125	or – 2126	
** Amounts relating to s.57.10 election/ regulations for replacement re fed.s13(4), 14(6) and 44 for current/prior years	+ 2127	or – 2128	
Interest allowable under ss.20(1)(c) or (d) of ITA to the extent not otherwise deducted in determining CMT adjusted net income		– 2150	
Capital gains on eligible donations of publicly-listed securities and ecologically sensitive land made after May 1, 2006 (to the extent reflected in net income/loss)		– 2155	
Subtotal (Additions)	=		+ 2129
Subtotal (Subtractions)	=		– 2130
** Other adjustments			± 2131
Subtotal ± 2100 – 2110 + 2116 + 2129 – 2130 ± 2131			= 2132 904,975
** Share of partnership(s)/joint venture(s) adjusted net income/loss			± 2133
Adjusted net income (loss) (if loss, transfer to 2202 in *Part 2: Continuity of CMT Losses Carried Forward.*)			= 2134 904,975
Deduct: * CMT losses: pre-1994 Loss	+ From 2210		
* CMT losses: other eligible losses	+ 2211		
	=		– 2135

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

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

CMT Base = 2136 904,975

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

Corporate Minimum Tax (CMT)

CT23 Schedule 101

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Thunder Bay Hydro Electricity Distribution Inc.	1800284	2007-12-31

Part 2: Continuity of CMT Losses Carried Forward

Balance at Beginning of year NOTES (1), (2)			+ 2201
Add: Current year's losses	+ 2202		
Losses from predecessor corporations on amalgamation NOTE (3)	+ 2203		
Losses from predecessor corporations on wind-up NOTE (3)	+ 2204		
Amalgamation (X) 2205 ☐ Yes Wind-up (X) 2206 ☐ Yes			
Subtotal	=	▶	+ 2207
Adjustments (attach schedule)			± 2208
CMT losses available 2201 + 2207 ± 2208			= 2209
Subtract: Pre-1994 loss utilized during the year to reduce adjusted net income	+ 2210		
Other eligible losses utilized during the year to reduce adjusted net income NOTE (4)	+ 2211		
Losses expired during the year	+ 2212		
Subtotal	=	▶	– 2213
Balances at End of Year NOTE (5) 2209 – 2213			= 2214

Notes:

(1) Pre-1994 CMT loss (see s.57.1(1)) should be included in the balance at beginning of the year. Attach schedule showing computation of pre-1994 CMT loss.

(2) Where acquisition of control of the corporation has occurred, the utilization of CMT losses can be restricted. (see s.57.5(3) and a 57.5(7))

(3) Include and indicate whether CMT losses are a result of an amalgamation to which fed.s.87 applies and/or a wind-up to which fed.s.88(1) applies. (see s.57.5(8) and s.57.5(9))

(4) CMT losses must be used to the extent of the lesser of the adjusted net income 2134 and CMT losses available 2209.

(5) Amount in 2214 must equal sum of 2270 + 2290.

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

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

	Year of Origin (oldest year first) year month day	CMT Losses of Corporation	CMT Losses of Predecessor Corporations
2240	9th preceding taxation year 1998-12-31	2260	2280
2241	8th preceding taxation year 1999-12-31	2261	2281
2242	7th preceding taxation year 2000-12-31	2262	2282
2243	6th preceding taxation year 2001-12-31	2263	2283
2244	5th preceding taxation year 2002-12-31	2264	2284
2245	4th preceding taxation year 2003-12-31	2265	2285
2246	3rd preceding taxation year 2004-12-31	2266	2286
2247	2nd preceding taxation year 2005-12-31	2267	2287
2248	1st preceding taxation year 2006-12-31	2268	2288
2249	Current taxation year 2007-12-31	2269	2289
Totals		2270	2290

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

Corporate Minimum Tax (CMT)
CT23 Schedule 101

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Thunder Bay Hydro Electricity Distribution Inc.	1800284	2007-12-31

Part 4: Continuity of CMT Credit Carryovers

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

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

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

Subtract Income Tax (190 on page 6 of the CT23 or page 4 of the CT8) ..... – From 190

Subtotal (If negative, enter NIL) ... = ▶ – 2305

Current year's CMT credit (If negative, enter NIL) 280 or 347 – 2305 ... = ▶ + 2310

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

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

Subtotal 2301 + 2310 + 2325 ..... = 2330

Adjustments *(Attach schedule)* ..... ± 2332

CMT Credit Carryover available 2330 ± 2332 ..... = 2333

Transfer to Page 8 of the CT23 or Page 5 of the CT8

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

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

Subtotal ..... = ▶ – 2335

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

Notes:

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

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

(3) Include and indicate whether CMT credits are a result of an amalgamation to which fed.s.87 applies and/or a wind-up to which fed.s.88(1) applies. (see s.43.1(4))

(4) Amount in 2336 must equal sum of 2370 + 2390.

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

	Year of Origin (oldest year first) year month day	CMT Credit Carryovers of Corporation	CMT Credit Carryovers of Predecessor Corporation(s)
2340	9th preceding taxation year 1998-12-31	2360	2380
2341	8th preceding taxation year 1999-12-31	2361	2381
2342	7th preceding taxation year 2000-12-31	2362	2382
2343	6th preceding taxation year 2001-12-31	2363	2383
2344	5th preceding taxation year 2002-12-31	2364	2384
2345	4th preceding taxation year 2003-12-31	2365	2385
2346	3rd preceding taxation year 2004-12-31	2366	2386
2347	2nd preceding taxation year 2005-12-31	2367	2387
2348	1st preceding taxation year 2006-12-31	2368	2388
2349	Current taxation year 2007-12-31	2369	2389
Totals		2370	2390

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

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

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Thunder Bay Hydro Electricity Distribution Inc.	1800284	2007-12-31

CMT Losses Carried Forward Workchart

(i) Continuity of Pre-1994 CMT Losses

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

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

	Year of Origin YYYY/MM/DD	Opening Balance	Adjustment	Deduction	Expired	Closing Balance
10th Prior Year	1997-12-31					
9th Prior Year	1998-12-31					
8th Prior Year	1999-12-31					
7th Prior Year	2000-12-31					
6th Prior Year	2001-12-31					
5th Prior Year	2002-12-31					
4th Prior Year	2003-12-31					
3rd Prior Year	2004-12-31					
2nd Prior Year	2005-12-31					
1st Prior Year	2006-12-31					
	Total					

Predecessor Corporations Only – Amalgamation

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

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
1997-12-31						
1998-12-31						
1999-12-31						
2000-12-31						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
2006-12-31						
Total						

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

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Thunder Bay Hydro Electricity Distribution Inc.	1800284	2007-12-31

CMT Losses Carried Forward Workchart (continued)

Predecessor Corporations Only – Wind-Up

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

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
1997-12-31						
1998-12-31						
1999-12-31						
2000-12-31						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
2006-12-31						
Total						

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

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Thunder Bay Hydro Electricity Distribution Inc.	1800284	2007-12-31

CMT Credit Carryovers Workchart

Filing Corporation

	Year of Origin YYYY/MM/DD	Opening Balance	Adjustment	Deduction	Expired	Closing Balance
10th Prior Year	1997-12-31					
9th Prior Year	1998-12-31					
8th Prior Year	1999-12-31					
7th Prior Year	2000-12-31					
6th Prior Year	2001-12-31					
5th Prior Year	2002-12-31					
4th Prior Year	2003-12-31					
3rd Prior Year	2004-12-31					
2nd Prior Year	2005-12-31					
1st Prior Year	2006-12-31					
	Total					

Predecessor Corporations Only – Amalgamation

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

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
1997-12-31						
1998-12-31						
1999-12-31						
2000-12-31						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
2006-12-31						
Total						

Predecessor Corporations Only – Wind-Up

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

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
1997-12-31						
1998-12-31						
1999-12-31						
2000-12-31						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
2006-12-31						
Total						

Ontario

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

Surtax on Canadian-Controlled Private Corporations

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Thunder Bay Hydro Electricity Distribution Inc.	1800284	2007-12-31

Name of Associated Corporation (Canadian and Foreign)	Corporations Tax Number	Taxation Year End	Taxation Income (if loss, enter nil)
Thunder Bay Hydro Corporation	7318179	2007-12-31	+
Thunder Bay Renewable Power Incorporated	8247610	2007-12-31	+
Thunder Bay Hydro Utility Services Inc.	8247622	2007-12-31	+
Thunder Bay Hydro Energy Ser	8159029	2007-12-31	+
			+
			+
			+
			+
			+
			+
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			+
			+
		Total	
		Transfer to 85 of the CT23	=

Ontario

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Corporations Tax
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Oshawa ON L1H 8E9

Paid-Up Capital: Loans and Advances

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Thunder Bay Hydro Electricity Distribution Inc.	1800284	2007-12-31

Loans or Advances Credited or Advanced to Corporation
(includes accounts payable to related parties outstanding at the taxation year end for 120 days or more, and accounts payable to non-related parties outstanding for 365 days or more at the taxation year end)

Corporation of the City of Thunder Bay	+	33,490,500
IBM	+	9,385
	+	
	+	
	+

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

Ontario Capital Cost Allowance
Schedule 8

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Thunder Bay Hydro Electricity Distribution Inc.	1800284	2007-12-31

Is the corporation electing under regulation 1101(5q)? 1 ☐ Yes 2 ☒ No

1 Class number	2 Ontario undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of the prior year's CCA schedule)	3 Cost of acquisitions during the year (new property must be available for use) See note 1 below	4 Net adjustments (show negative amounts in brackets)	5 Proceeds of dispositions during the year (amount not to exceed the capital cost)	6 Ontario undepreciated capital cost (column 2 plus column 3 or minus column 4 minus column 5)	7 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5) See note 2 below	8 Reduced undepreciated capital cost (column 6 minus column 7)	9 CCA rate %	10 Recapture of capital cost allowance	11 Terminal loss	12 Ontario capital cost allowance (column 8 multiplied by column 9; or a lower amount)	13 Ontario undepreciated capital cost at the end of the year (column 6 minus column 12)
10	1,303,598	192,756		8,755	1,487,599	92,001	1,395,598	30	0	0	418,679	1,068,920
8	594,456	146,988		0	741,444	73,494	667,950	20	0	0	133,590	607,854
4	2,093,442			0	2,093,442		2,093,442	6	0	0	125,607	1,967,835
47	7,524,724	3,933,666		0	11,458,390	1,966,833	9,491,557	8	0	0	759,325	10,699,065
12	42,544	95,892		0	138,436	47,946	90,490	100	0	0	90,490	47,946
45	99,118	42,633		44	141,707	21,295	120,412	45	0	0	54,185	87,522
1	61,341,705			0	61,341,705		61,341,705	4	0	0	2,453,668	58,888,037
Totals	72,999,587	4,411,935		8,799	77,402,723	2,201,569	75,201,154					73,367,179

Enter in boxes 650 . . . . 650 . . . . 650 on the CT23. 4,035,544

Note 1. Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule. See Regulation 1100(2) and (2.2) of the *Income Tax Act* (Canada).

Note 2. The net cost of acquisitions is the cost of acquisitions plus or minus certain adjustments from column 4.

Note 3. If the taxation year is shorter than 365 days, prorate the CCA claim.

Note 4. Ontario recapture should be included in net income after deducting the federal recapture and the Ontario terminal loss is deducted from net income after including the federal terminal loss.

Ontario

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Corporations Tax
33 King Street West
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Ontario Cumulative Eligible Capital Deduction

Schedule 10 Page 1 of 2

For taxation years 2002 and later

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Thunder Bay Hydro Electricity Distribution Inc.	1800284	2007-12-31

- **For use by a corporation that has eligible capital property.**
- **A separate cumulative eligible capital account must be kept for each business.**

Part 1 – Calculation of current year deduction and carry-forward

Ontario Cumulative eligible capital – balance at end of preceding taxation year *(if negative, enter zero)* = + 87,134 A

Add: Cost of eligible capital property acquired during the taxation year + B

Other adjustments + C

B + C = x 3 / 4 = D

Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002 x 1 / 2 = – E

D minus E *(if negative, enter zero)* = ▷ + F

Amount transferred on amalgamation or wind-up of subsidiary + G

Subtotal A + F + G = 87,134 H

Deduct: Ontario proceeds of sales (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year + I

The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7) of the *Income Tax Act* (Canada) + J

Other adjustments + K

I + J + K = x 3 / 4 = – L

Ontario cumulative eligible capital balance H minus L = 87,134 M

If M is negative, enter zero at line Q and proceed to Part 2, page 2.

Cumulative eligible capital for a property no longer owned after ceasing to carry on that business N

From M 87,134

From N –

Current year deduction M minus N = 87,134 x 7 % = + 6,099 O

N + O = 6,099 ▷ – 6,099 P

Enter amount in box 651 of the CT23

Note: *The maximum current year deduction is 7%. Any amount up to the maximum deduction of 7% may be claimed. For taxation years starting after December 21, 2000, the deduction may not exceed the maximum amount prorated for the number of days in the taxation year divided by 365 or 366 days.*

Ontario cumulative eligible capital - closing balance M minus P *(if negative, enter zero)* = 81,035 Q

See page 2 - Part 2

Ontario Cumulative Eligible Capital Deduction
Schedule 10 Page 2 of 2

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Thunder Bay Hydro Electricity Distribution Inc.	1800284	2007-12-31

Part 2 – Amount to be included in income arising from disposition

Complete this part only if the amount at line M is negative.

Amount from line M above. *Show this as a positive amount; not negative.* _____ R

Total cumulative eligible capital deductions from income for taxation years beginning after June 30, 1988 + _____ 1

Total of all amounts which reduced cumulative eligible capital in the current or prior years under subsection 80(7) of the ITA + _____ 2

Total of cumulative eligible capital deductions claimed for taxation years beginning before July 1, 1988 + _____ 3

Negative balances in the cumulative eligible capital account that were included in income for taxation years beginning before July 1, 1988 – _____ 4

Deduct line 4 from line 3 *(if negative, enter zero)* = _____ ▷ + _____ 5

Total lines 1 + 2 + 5 = _____ 6

Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 1 _____ 7

Amounts at **Line Z** from Ontario Schedule 10 of previous taxation years ending after February 27, 2000 *(This will be Line T in earlier versions of this schedule.)* + _____ 8

Total lines 7 + 8 = _____ ▷ – _____ 9

Deduct line 9 from line 6 *(if negative, enter zero)* = _____ ▷ – _____ S

R minus S *(if negative, enter zero)* = _____ T

From Line 5 _____ × 1 / 2 = – _____ U

T minus U *(if negative, enter zero)* = _____ V

From V _____ × 2 / 3 = _____ W

Lesser of R and S = + _____ Z

Amount to be included in income W + Z = _____

Exhibit	Tab	Schedule	Appendix	Contents
5– Cost of Capital and Rate of Return				
	1	1		Overview
		2		Capital Structure
		3		Cost of Long Term Debt

OVERVIEW:

The purpose of this evidence is to summarize the method and cost of financing Thunder Bay Hydro's capital requirements for the 2009 test year.

Capital Structure:

Thunder Bay Hydro has a current deemed structure of 53.3% debt, 46.7% equity with, and a deemed return on equity of 2.93%. This differs from the capital structure and return specified in the OEB's Decision in RP-2005-0020/EB-2005-0419/EB-2007-0580/EB-2007-0067, dated 21st April, 2006. Thunder Bay Hydro has used the OEB Board prescribed deemed capital structure of 56.70% debt and 43.30% equity for purposes of the 2009 Rate Application.

The deemed capital structure and associated return on equity used in this application complies with the Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario Electricity Distributors dated August 15, 2006. That Report requires all licensed Ontario electricity distributors to move toward a 60% debt/40% equity ratio. Details are provided in Exhibit 5, Tab 1, Schedule 2. Thunder Bay Hydro believes the requested capital structure and equity return will provide continued access to long-term debt at reasonable rates.

Return on Equity:

Thunder Bay Hydro is requesting an equity return for the 2009 Test year of 3.75% in accordance with the shareholder direction for rate minimization. It is acknowledged that this is still well below the maximum allowed rate of return on equity of 8.57% approved for the 2008 cost of service rate applications and should be well below the maximum allowed rate of return on equity approved for the 2009 cost of service rate applications. Thunder Bay Hydro's shareholder does not require dividend payments, allowing Thunder Bay Hydro to limit increase in rates sufficient to fund capital and operating needs while continuing to comply with our debt covenants. Thunder Bay Hydro's use of an ROE of 3.75% is without prejudice to any revised ROE that may be adopted by the OEB in early 2009.

Cost of Debt: Long Term

Exhibit 5, Tab 1, Schedule 3 provides the detail of Thunder Bay Hydro's forecast long-term debt cost of 0.21% for 2009. Long-term debt cost information for the 2006 Board Approved, 2006 Actual, 2007 Actual, 2008 Bridge Year and 2009 Test Year periods are also filed at Exhibit 5, Tab 1, Schedule 2

Cost of Debt: Short Term

In the application Thunder Bay Hydro has assumed a return on Short Term Debt for the 2009 Test year of 4.47% in accordance with the Cost of Capital Parameter Updates for 2008 Cost of Service Applications issued by the OEB on March 7, 2008. Thunder Bay Hydro understands that the OEB will be finalizing the return on short term debt for 2009 rates based on January 2009 market interest rate information.

CAPITAL STRUCTURE

2006 Board Approved

Elements	Deemed Amount $Million	Deemed Proportion	Cost Rate (%)	Return (%).
Long-term debt	35,664,999		50%	0%
Unfunded short-term debt				
Common equity	35,664,999		50%	2.93%
Total	71,329,997		100%	1.47%

2006 Actual

Elements	Deemed	Cost Rate (%)	Return (%)
Long-term debt	35,889,268	50%	0%
Unfunded short-term debt			
Common equity	35,889,268	50%	2.93%
Total	71,778,537	100%	1.47%

2007 Actual

Elements	Deemed	Cost Rate (%)	Return (%)
Long-term debt	36,627,009	50%	0%
Unfunded short-term debt			
Common equity	36,627,009	50%	2.93%
Total	73,254,018	100%	1.47%

2008 Bridge

Elements	Deemed	Cost Rate (%)	Return (%)
Long-term debt	39,219,834	53.30%	0%
Unfunded short-term debt			
Common equity	39,219,834	46.70%	2.93%
Total	73,583,178	100%	1.37%

1

2009 Test

Elements	**Deemed**	**Cost Rate (%)**	**Return (%)**
Long-term debt	39,614,405	52.70%	.21%
Unfunded short-term debt	3,006,786	4.0%	4.47%
Common equity	32,548,458	43.30%	3.75%
Total	75,169,648	100%	1.91%

COST OF LONG TERM DEBT

	2006 Board Approved			2006 Actual			2007 Actual			2008 Bridge			2009 Test Year		
	Principal	**Carrying Costs**	**Calculated Cost Rate**	**Principal**	**Carrying Costs**	**Calculated Cost Rate**	**Principal**	**Carrying Costs**	**Calculated Cost Rate**	**Principal**	**Carrying Costs**	**Calculated Cost Rate**	**Principal**	**Carrying Costs**	**Calculated Cost Rate**
Long Term Debt															
Note Payable to Shareholder	33,490,500	0	0%	33,490,500	0	0%	33,490,500	0	0%	33,490,500	0	0%	33,490,500	0	0%
Capital Lease Obligation				46,209	2,025	3.13%	9,385	908	3.13%	0	48	3.13%			
2009 Capital Funding													1,153,142	72,000	6.0%
TOTAL	33,490,500	0	0%	33,536,709	2,025	0%	33,499,885	908	0%	33,490,500	48	0%	34,643,642	72,000	.21%

Exhibit	Tab	Schedule	Appendix	Contents
6 – Calculation of Revenue Deficiency or Surplus				
	1	1		Revenue Deficiency - Overview

REVENUE DEFICIENCY - OVERVIEW:

Thunder Bay Hydro has provided detailed calculations supporting its 2009 revenue deficiency. The net revenue deficiency is calculated as $979,722 and when grossed up for PILs Thunder Bay Hydro's revenue deficiency is $1,414,077. The Table on the following page provides the revenue deficiency calculations for the 2009 Test Year at Existing 2008 OEB-approved rates and the 2009 Test Year Revenue Requirement.

1 **Calculation of Revenue Deficiency**

Calculation of Revenue Deficiency or Surplus		
	2009 Test Existing Rates	2009 Test Proposed Rates
Revenue		
Suff/ Def From Below.		$1,414,077
Distribution Revenue	$16,104,861	$16,104,861
Other Operating Revenue (Net)	$1,802,790	$1,802,790
Total Revenue	$17,907,651	$19,321,728
Distribution Costs		
Operation, Maintenance, and Administration	$12,340,964	$12,340,964
Depreciation & Amortization	$4,573,436	$4,573,436
Property & Capital Taxes	$169,466	$169,466
Interest- Deemed Interest	$216,623	$216,623
Total Costs and Expenses	$17,300,489	$17,300,489
Utility Income Before Income Taxes	$607,162	$2,021,239
Net Adjustments per 2009 Pils	$585,415	$585,415
Taxable Income	$1,192,577	$2,606,654
Income Tax (Tax Rate 30.72%)	$366,317	$800,672
Utility Income	$240,845	$1,220,567
Rate Base	$75,169,648	$75,169,648
Equity	43.30%	43.30%
Equity Component Rate Base	$32,548,458	$32,548,458
Income / Equity Rate Base %	0.74%	3.75%
Target Return -Equity on Rate Base	3.75%	3.75%
Return- Equity on Rate Base	$1,220,567	$1,220,567
Revenue Deficiency	$979,722	
Revenue Deficiency (Gross-up)	$1,414,077	

Exhibit	Tab	Schedule	Appendix	Contents
7 – Cost Allocation				
	1	1		Cost Allocation Overview
		2		Summary of Results and Proposed Changes
		3		Amended 2006 Cost Allocation Information Filing

COST ALLOCATION OVERVIEW:

Introduction:

On September 29, 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. Thunder Bay Hydro prepared a cost allocation information filing consistent with Thunder Bay Hydro's understanding of the Directions, the Guidelines, the Model and the Instructions. Thunder Bay Hydro submitted this filing to the OEB on February 28, 2007.

One of the main objectives of the filing was to provide information on any apparent cross-subsidization among a distributor's rate classifications. It was felt that this would give an indication of cross-subsidization from one class to another and this information would be useful as a tool in future rate applications.

SUMMARY OF RESULTS AND PROPOSED CHANGES:

INITIAL COST ALLOCATION STUDY RESULTS:

The data used in the Cost Allocation Model was consistent with Thunder Bay Hydro's cost data that supported its 2006 OEB-approved distribution rates. Consistent with the Guidelines, Thunder Bay 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 were developed from the best data available to Thunder Bay Hydro, its engineering records, and its customer and financial information systems.

As noted above, 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.

The following Table 1 outlines the revenue to cost ratios from the Cost Allocation Informational Filing submitted by Thunder Bay Hydro on February 28, 2007. The calculations are based on Thunder Bay Hydro's OEB-approved 2006 electricity distribution rates.

Table 1
Revenue to Cost Ratios as Filed in Thunder Bay Hydro's
Initial Cost Allocation Informational Filing

Rate Classification	Revenue (A)	Allocated Cost (B)	Revenue to Cost Ratio (A)/(B)
Residential	$11,526,142	$10,006,572	115.19%
GS <50 kW	$3,034,508	$2,781,142	109.11%
GS 50 to 999 kW	$1,973,558	$3,002,815	65.72%
GS 1,000 to 4,999 kW	$1,250,520	$1,968,554	63.52%
Street Lighting	$63,229	$106,089	59.60%
Sentinel Lighting	$13,515	$15,923	84.88%
Unmetered Scattered Load	$56,510	$36,887	153.20%
Total	**$17,917,982**	**$17,917,982**	**100.00**

UPDATED COST ALLOCATION STUDY RESULTS:

In preparing for this rate application a review of the initial cost allocation filing was conducted and it was discovered that the number of "customers" versus the number of "connections" for streetlights and unmetered scattered load were entered into the initial model. In addition, in the initial model the approved streetlighting revenue was entered in the unmetered scattered load category and approved ummetered scattered load revenue was entered in for streetlighting revenue. As a result, for the purposes of this application, the cost allocation model was updated to correct for these oversights. A copy of the updated cost allocation is provided in Appendix A. The revenue to cost ratios for updated study is provided in Table 2 below:

Table 2
Revenue to Cost Ratios from Thunder Bay Hydro's
Updated Cost Allocation Information Filing

Rate Classification	Revenue (A)	Allocated Cost (B)	Revenue to Cost Ratio (A)/(B)
Residential	$11,485,811	$9,110,134	126.08%
General Service <50 kW	$3,025,787	$2,663,297	113.61%
General Service 50 to 999 kW	$1,974,050	$2,992,953	65.96%
General Service 1,000 to 4,999 kW	$1,219,955	$2,027,511	60.17%
Street Light	$143,401	$1,061,468	13.51%
Sentinel	$12,366	$11,754	105.21%
Unmetered Scattered Load	$56,838	$51,091	111.25%
Total	**$17,918,208**	**$17,918,208**	**100.00%**

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 which are summarized in Table 3 below. Table 3 also provides Thunder Bay Hydro's proposed 2009 revenue to cost ratios. The proposed revenue to cost ratios reflects adjustments to revenue to address cross subsidization.

Table 3
Thunder Bay Hydro's Proposed Revenue to Cost Ratios

Customer Class	OEB Low	OEB High	Thunder Bay Hydro Updated Cost Allocation Filing Results	Thunder Bay Hydro Proposed 2009 Revenue to Cost Ratios
Residential	85%	115%	126.08%	119.13%
General Service <50 kW	80%	120%	113.61%	113.61%
General Service 50 to 999 kW	80%	180%	65.96%	72.98%
General Service 1,000 to 4,999 kW	80%	180%	60.17%	70.09%
Street Light	70%	120%	13.51%	41.75%
Sentinel	70%	120%	105.21%	105.21%
Unmetered Scattered Load	80%	120%	111.25%	111.25%

Thunder Bay 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 re-alignment will move those classes, which are under contributing, to approximately 50% between their current ratio and target ratio. For example the current revenue to cost ratio for street lights is 13.51% moving the ratio to 41.75% means the proposed ratio is half way between 13.51% and 70%. The 70% being the low end of the OEB target range.

The additional revenue from the under contributing class will be distributed to those classes that are over contributing with the highest share being applied to the Residential class since this is the class that has the highest level of over contribution.

The following table outlines the revenue splits required to achieve the proposed revenue to cost ratios

Table 4

Revenue Split by Rate Class to Achieve Proposed Revenue to Cost Ratios

Rate Classification	Revenue Split to Achieve Proposed Revenue Cost Ratio
Residential	61.76%
General Service <50 kW	16.85%
General Service 50 to 999 kW	12.55%
General Service 1,000 to 4,999 kW	6.11%
Street Light	2.26%
Sentinel	0.09%
Unmetered Scattered Load	0.38%
Total	100.00%

Cost Allocation Summary:

The discussion and tables above support Thunder Bay 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. Thunder Bay 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;
- When necessary partial reallocation provides time for further refinement of the cost allocation model and movement between classes.

AMENDED 2006 COST ALLOCATION FILING:

Thunder Bay Hydro's Amended 2006 Cost Allocation Filing is provided on the following pages.

Ontario Energy Board

2006 Cost Allocation Information Filing

Sheet I1 Utility Information Sheet

Name of LDC:	Thunder Bay Hydro Electricity Distribution Inc.
License Number:	ED-2002-0529
EDR 2006 EB Number:	EB-2005-0419
Cost Allocation EB Number:	EB-2007-0001 ← drop-down menu
Date of Submission:	February 28, 2007
Version:	1.2

Contact Information

Name:	C Thomas Wright
Title:	Vice President Finance
Phone Number:	807-343-1118
E-Mail Address:	Twright@Tbhydro.on.ca

1. GENERAL

I1 General

2. LDC INPUT - Rate Classes

I2 Rate Classes Declaration

3. LDC INPUT - Financial Data

I3 Trial Balance Data → I4 Break Out Assets

Load Shapes

4. LDC INPUT - Customer Data and Operating Stats

I5 Misc. Data | I6 Rate Class Stats | I7.1 Meter Capital | I7.2 Meter Reading | I8 Demand Data | I9 Direct Allocation

5. MODEL PROCESS - Categorization - OEB Defaults

E1 Categorization

6. MODEL PROCESS - Allocators calculated from 4.

E2 Allocators | E3 PLCC

7. MODEL PROCESS - Detail Cost Elements by Rate Class

E4 Trial Balance Allocation Details | E5 Reconciliation

8. MODEL OUTPUT- Summaries by Rate Class

O1 Rev - Cost Ratios | O2 Fixed Charges Floor & Ceiling | O2.1 Line Transformer PLCC Adjustment | O2.2 Primary Cost PLCC Adjustment | O2.3 Secondary Cost PLCC Adjustment

O3.1 Line Tran Unit Cost | O3.2 Substat Tran Unit Cost | O3.3 Primary Cost Pool | O3.4 Secondary Cost Pool | O3.5 USL Metering Credit

O4 Summary by Class & Accounts | O5 Details by Class & Accounts | O6 Source Data for E2 | O7 Amortization

Ontario

2006 Cost Allocation Information Filing
Thunder Bay Hydro Electricity Distribution Inc.
EB-2005-0419 EB-2007-0001
February 28, 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	Residential	YES
2	GS <50	GS <50	YES
3	GS>50-Regular	General Service 50 to 999	YES
4	GS> 50-TOU		NO
5	GS >50-Intermediate	General Service 1000 to 4999	YES
6	Large Use >5MW		NO
7	Street Light	Street Light	YES
8	Sentinel	Sentinel	YES
9	Unmetered Scattered Load	Unmetered Scattered Load	YES
10	Embedded Distributor		NO
11	Back-up/Standby Power		NO
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

Ontario

2006 Cost Allocation Information Filing

Thunder Bay Hydro Electricity Distribution Inc.

EB-2005-0419 EB-2007-0001

February 28, 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

Approved Target Net Income ($)	$1,044,984			
Approved PILs ($)	$1,349,014			
Approved Interest ($)	$3,566			
Approved Specific Service Charges ($)	$656,412			
Approved Transformer Ownership Allowance ($)	$413,327			
Approved Low Voltage Wheeling Adjustment ($)	$0			
Approved Revenue Requirement ($)	$17,504,880	From this Sheet	Differences?	
Revenue Requirement to be Used in this model ($)	$17,918,207	$17,918,207	Rev Req Matches	
Approved Rate Base ($)	$71,302,279			
Rate Base to be Used in this model ($)	$71,364,278	$71,364,278	Rate Base Matches	

2006 Cost Allocation Information Filing
Thunder Bay Hydro Electricity Distribution Inc.
EB-2005-0419 EB-2007-0001
February 28, 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	$59,142,638

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	$274,500		-	274,500					274,500				
1805	Land	$133,038		($133,038)	-									
1805-1	Land Station >50 kV			$0	-					-				
1805-2	Land Station <50 kV		100.00%	$133,038	133,038					133,038				
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	$3,894,355		($3,894,355)	-									
1808-1	Buildings and Fixtures > 50 kV			$0	-					-				
1808-2	Buildings and Fixtures < 50 KV		100.00%	$3,894,355	3,894,355					3,894,355	$68,665			
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	$7,814,045		($7,814,045)	-					-				
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)		10.00%	$781,404	781,404					781,404				
1820-2	Distribution Station Equipment - Normally Primary below 50 kV Primary)			$0	-					-				
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)		90.00%	$7,032,640	7,032,640					7,032,640	$161,591			
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	$14,980,471		($14,980,471)	-									
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery			$0	-					-				
1830-4	Poles, Towers and Fixtures - Primary		70.00%	$10,486,330	10,486,330	($394,829)	$14,961	$ (6,221,811)	$ (14,961)	3,869,690	$859,837			
1830-5	Poles, Towers and Fixtures - Secondary		30.00%	$4,494,141	4,494,141	($169,212)	$6,412	$ (2,666,490)	$ (6,412)	1,658,439	$368,501			
1835	Overhead Conductors and Devices	$18,420,815		($18,420,815)	-									
1835-3	Overhead Conductors and Devices Subtransmission Bulk Delivery			$0	-					-				
1835-4	Overhead Conductors and Devices Primary		70.00%	$12,894,570	12,894,570	($485,504)	$18,396	$ (7,650,682)	$ (18,396)	4,758,384	$102,070			
1835-5	Overhead Conductors and Devices Secondary		30.00%	$5,526,244	5,526,244	($208,073)	$7,884	$ (3,278,864)	$ (7,884)	2,039,307	$43,744			
1840	Underground Conduit	$10,498,393		($10,498,393)	-									
1840-3	Underground Conduit - Bulk Delivery			$0	-					-				
1840-4	Underground Conduit - Primary		60.00%	$6,299,036	6,299,036	($237,170)	$8,987	$ (3,737,381)	$ (8,987)	2,324,485	$551,069			
1840-5	Underground Conduit - Secondary		40.00%	$4,199,357	4,199,357	($158,113)	$5,991	$ (2,491,587)	$ (5,991)	1,549,657	$367,377			
1845	Underground Conductors and Devices	$12,350,995		($12,350,995)	-									

2006 Cost Allocation Information Filing
Thunder Bay Hydro Electricity Distribution Inc.
EB-2005-0419 EB-2007-0001
February 28, 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	$69,142,538

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 - 2106 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
1845-3	Underground Conductors and Devices - Bulk Delivery			$0	-					-				
1845-4	Underground Conductors and Devices - Primary		60.00%	$7,410,597	7,410,597	($279,022)	$10,872	$ (4,396,869)	$ (10,872)	2,734,676	$87,076			
1845-5	Underground Conductors and Devices - Secondary		40.00%	$4,940,398	4,940,398	$186,015	$7,248	$ (2,931,246)	$ (7,248)	1,823,117	$44,716			
1850	Line Transformers	$20,471,040		$0	20,471,040	($770,771)	$29,356	$ (12,145,697)	$ (29,356)	7,554,272	$581,634			
1855	Services	$15,326,215		$0	15,326,215	$577,060	21,695	$ (9,093,440)	$ (21,695)	5,655,715	$72,415			
1860	Meters	$6,082,872		$0	6,082,872	($229,032)	$8,679	$ (3,609,124)	$ (8,679)	2,244,716	$261,581			
	Total	$110,246,737		$0	$110,246,737	($3,694,801)	$140,000	($58,223,641)	($140,000)	48,328,395	$3,530,469	$0	$0	$0
	SUB TOTAL from I3	$110,246,737												

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Sheet I4 Break Out Worksheet - Second Run

Instructions:
This is an input sheet for the Break Out of Distribution Assets, Contributed Capital, Amortization, and Amortization Expenses.
Please see Handbook for detailed instructions

Enter Net Fixed Assets from approved EDR, Sheet 3-1, cell F12	$59,142,538

RATE BASE AND DISTRIBUTION ASSETS

Account	Description	BALANCE SHEET ITEMS										EXPENSE ITEMS					
												5705	5710	5715	5720		
		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		
General Plant		Break out Functions				Contributed Capital - 1995	Accumulated Depreciation - 2105 Capital Contribution	Accumulated Depreciation - 2105 Fixed Assets Only	Accumulated Depreciation - 2120	Net Asset		5705 Amortization Expense - Property, Plant, and Equipment	5710 Amortization of Limited Term Electric Plant	5715 Amortization of Intangibles and Other Electric Plant	5720 Amortization of Electric Plant Acquisition Adjustments		
1905	Land	$0			-					$ -							
1906	Land Rights	$0			-					$ -							
1908	Buildings and Fixtures	$0			-					$ -							
1910	Leasehold Improvements	$0			-					$ -							
1915	Office Furniture and Equipment	$1,152,446			1,152,446					$ 1,152,446		28,687					
1920	Computer Equipment - Hardware	$2,275,356			2,275,356					$ 2,275,356		139,533					
1925	Computer Software	$330,517			330,517					$ 330,517		66,107					
1930	Transportation Equipment	$4,309,873			4,309,873					$ 4,309,873		240,325					
1935	Stores Equipment	$63,417			63,417					$ 63,417		181					
1940	Tools, Shop and Garage Equipment	$2,062,957			2,062,957					$ 2,062,957							
1945	Measurement and Testing Equipment	$80,771			80,771					$ 80,771							
1950	Power Operated Equipment	$3,583			3,583					$ 3,583							
1955	Communication Equipment	$162,056			162,056					$ 162,056							
1960	Miscellaneous Equipment	$0			-					$ -		1,566					
1970	Load Management Controls - Customer Premises	$0			-					$ -							
1975	Load Management Controls - Utility Premises	$0			-					$ -							
1980	System Supervisory Equipment	$373,170			373,170					$ 373,170							
1990	Other Tangible Property	$0			-					$ -							
2005	Property Under Capital Leases	$0			-					$ -							
2010	Electric Plant Purchased or Sold	$0			-					$ -							
	Total	$10,814,143		$0	$10,814,143	$0	$0	$0	$0	$10,814,143		$485,671	$0	$0	$0		
	SUB TOTAL from I3	$10,814,143															
	I3 Directly Allocated	$0															
	Grand Total	$121,060,880		$0	$121,060,880	($3,694,601)	$140,000	($58,223,541)	($140,000)	$59,142,538		$4,016,140	$0	$0	$0		
						$3,694,601	Balanced	$58,083,541	Balanced	$140,000	Balanced						
												($4,016,140)	Balanced				
													$0	Balanced			
														$0	Balanced		

To be Prorated

1995	Contributed Capital - 1995	($3,694,601)
2105	Accumulated Depreciation - 2105	($58,083,541)
2120	Accumulated Depreciation - 2120	($140,000)
	Total	**($61,918,342)**
	Net Assets	**$59,142,538**

Net Fixed Assets Match EDR

Amortization Expenses

5705	Amortization Expense - Property, Plant, and Equipment	$4,016,140
5710	Amortization of Limited Term Electric Plant	$0
5715	Amortization of Intangibles and Other Electric Plant	$0

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Sheet I4 Break Out Worksheet - Second Run

Instructions:
This is an input sheet for the Break Out of Distribution Assets, Contributed Capital, Amortization, and Amortization Expenses.
Please see Handbook for detailed instructions

Enter Net Fixed Assets from approved EDR, Sheet 3-1, cell F12	$59,142,538

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
5720	Amortization of Electric Plant Acquisition Adjustments	$0												$0
	Total Amortization Expense	$4,016,140												

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Sheet I5 Miscellaneous Data Worksheet - Second Run

kMs of Roads in Service Area Where Distribution Lines Exist	1041
Deemed Equity Component of Rate Base (%)	50%

	1	2	3	5	7	8	9
	Residential	GS <50	General Service 50 to 999	General Service 1000 to 4999	Street Light	Sentinel	Unmetered Scattered Load
Step 3: Insert Approved Monthly Service Charge (Please refer to Approved EDR Sheet 8-5 column W)	11.15	17.22	185.29	1,622.25	0.34	6.07	8.45
Step 4: Insert Smart Meter Adder Included in Approved Monthly Service Charge (Please refer to Approved EDR Sheet 8-5 column T)	0.27	0.27	0.27	0.27			

Instructions (Cont'd):

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Sheet I6 Customer Data Worksheet - Second Run

Total kWhs	994,634,344
Total kWs	1,303,347
Total Approved Distribution Revenue ($)	$16,551,155

			1	2	3	5	7	8	9
	ID	Total	Residential	GS <50	General Service 50 to 999	General Service 1000 to 4999	Street Light	Sentinel	Unmetered Scattered Load
Billing Data									
kWh from approved EDR model, Sheet 7-1, Col M	CEN	994,634,344	356,604,252	147,826,584	294,465,063	181,786,271	10,787,529	130,673	3,033,972
kW from approved EDR model, Sheet 7-1, Col S	CDEM	1,303,347			719,611	553,018	30,411	307	
kW, included in CDEM, from customers with line transformer allowance from approved EDR model, Sheet 6-3, Col P		627,299			73,092	554,207			
Optional - kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-							
KWh excluding KWh from Wholesale Market Participants	CEN EWMP	994,634,344	356,604,252	147,826,584	294,465,063	181,786,271	10,787,529	130,673	3,033,972
kWh - 30 year weather normalized amount		1,037,944,183	356,201,229	147,094,432	303,713,497	217,070,698	10,745,284	133,840	2,985,202
Approved Distribution Rev from approved EDR, Sheet 7-1, Col AK + Sheet 7-3 Col H	CREV	$16,551,155	$10,663,900	$2,740,846	$1,806,182	$1,158,847	$114,938	$11,709	$54,733
Bad Debt 3 Year Historical Average from Approved EDR Model	BDHA	$134,423	$79,889		$54,534	$0	$0	$0	$0

Late Payment 3 Year Historical Average	LPHA	$254,938	$179,199	$43,970	$26,686	$4,722	$18	$344	
Weighting Factor - Services			1.0	2.0	10.0	10.0	1.0	1.0	1.0
Weighting Factor - Billings			1.0	2.0	7.0	7.0	1.0	0.1	5.0
Number of Bills	CNB	329,780	268,467	55,233	5,580	218	35	163	84
Number of Connections (Unmetered)	CCON	13,340					12,769	140	431
Total Number of Customer from Approved EDR, Sheet 7-1, Col H excluding connections	CCA	49,466	44,167	4,495	471	19	3	140	171
Bulk Customer Base	CCB	-							
Primary Customer Base	CCP	49,152	44,167	4,495	471	19			
Line Transformer Customer Base	CCLT	49,152	44,167	4,495	471	19			
Secondary Customer Base	CCS	49,110	44,167	4,495	441	7			
Weighted - Services	CWCS	70,977	44,167	8,990	4,410	70	12,769	140	431
Weighted Meter -Capital	CWMC	4,595,585	3,150,670	418,415	998,900	27,600	-	-	-
Weighted Meter Reading	CWMR	550,950	385,067	128,066	27,233	10,584	-	-	-
Weighted Bills	CWNB	419,990	268,467	110,466	39,060	1,526	35	16	420
Data Mismatch Analysis									
Revenue with 30 year weather normalized kWh		16,806,140	10,651,848	2,727,271	1,862,910	1,383,777	114,488	11,993	53,853

Weather Normalized Data from Hydro

	Total	Residential	GS <50	General Service 50 to 999	General Service 1000 to 4999	Street Light	Sentinel	Unmetered Scattered Load
kWh - 30 year weather normalized amount	1,085,378,232	**372,479,625**	153,816,648	317,593,204	226,990,829	11,236,344	139,956	3,121,626
2006 EDR Distribution Loss Factor		**1.0457**	1.0457	1.0457	1.0457	1.0457	1.0457	1.0457
								-

Bad Debt Data from EDR 2006

Sheet ADJ5 rows 26 - 32, column E	157,441	45,442	578	111,421	-			
Sheet ADJ5 rows 26 - 32, column F	138,307	98,546	32,187	7,574	-			
Sheet ADJ5 rows 26 - 32, column G	146,686	95,679	6,400	44,607				
Three-year average	**147,478**	**79,889**	**13,055**	**54,534**	-	-	-	-

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		Residential			GS <50			General Service 50 to 999			General Service 1000 to 4999			TOTAL		
		1	2	3	1	2	3	1	2	3	1	2	3	1	2	3
		Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs (2)
	Allocation Percentage Weighted Factor			68.56%			9%			22%			1%			100%
	Cost Relative to Residential Average Cost			1.00			1.65			27.98			31.50			1.34
	Total	43155	3150670	73.00922616	3477	418415	120.337935	489	998900	2042.740286	12	27600	2300	47133	4595585	97.50245295
Meter Types	**Cost per Meter (installed)**															
Single Phase 200 Amp - Urban	50	35,196	1759800		2,191	109550			0		0		37,387	1869350		
Single Phase 200 Amp - Rural	150	5,337	800550		307	46050			0		0		5,644	846600		
Central Meter	250		0			0			0		0		0	0		
Network Meter (Costs to be updated)	225	2,808	586800		277	62325			0		0		2,885	649125		
Three-phase - No demand	210	12	2520		516	108990			0		0		531	111510		
Smart Meters	300		0			0			0		0		0	0		
Demand without IT (usually three-phase)	500	2	1000		180	91500		66	33000		0		251	125500		
Demand with IT	2,100		0			0		345	720300		0		343	720300		
Demand with IT and Interval																
Capability - Secondary Demand with IT and Interval	2,300		0			0		72	165600		12	27600	84	193200		
Capability - Primary Demand with IT and Interval	10,000		0			0		8	80000		0		8	80000		
Capability -Special (WMP)	40,000		0			0			0		0		0	0		
LDC Specific 1			0			0			0		0		0	0		
LDC Specific 2			0			0			0		0		0	0		
LDC Specific 3			0			0			0		0		0	0		

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Sheet I7.2 Meter Reading Worksheet - Second Run

Description		1 Residential			2 GS <50			3 General Service 50 to 999			5 General Service 1000 to 4999			TOTAL		
		Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs
	Allocation Percentage Weighted Factor			69.89%			23.24%			4.94%			1.92%			100.00%
	Cost Relative to Residential Average Cost			1.00			1.63			3.19			33.98			39.80
	Total	266,998	385,067	1.44	54,496	128,066	2.35	5,916	27,233	4.60	216	10,584	49.00	327,626	550,950	57
	Factor															
Residential - Urban - Outside	1.00	183,792	183,792			0			0			0		183,792	183,792	
Residential - Urban - Outside with other services	1.00		0			0			0			0		-	-	
Residential - Urban - Inside	2.00	48,300	96,600			0			0			0		48,300	96,600	
Residential - Urban - Inside - with other services	1.00		0			0			0			0		-	-	
Residential - Rural - Outside	3.00	34,764	104,292			0			0			0		34,764	104,292	
Residential - Rural - Outside with other services	2.00		0			0			0			0		-	-	
Residential - Rural Inside	2.70	142	383			0			0			0		142	383	
LDC Specific 2			0			0			0			0		-	-	
GS - Walking	2.00		0			0			0			0		-	-	
GS - Walking - with other services	3.00		0			0			0			0		-	-	
GS - Vehicle with other services — TOU Read	3.00		0			0			0			0		-	-	
GS - Vehicle with other services	3.00		0			0			0			0		-	-	
GS Vehicle	2.35		0		54,496	128,066			0			0		54,496	128,066	
LDC Specific 4	0.00		0			0			0			0		-	-	
Interval	49.00		0			0		180	8,820		216	10,584		396	19,404	
GS Vehicle	3.21		0			0		5,736	18,413			0		5,736	18,413	
LDC Specific 6			0			0			0			0		-	-	

Meter Reading Costs

Model Defaults

Based on Contractor Pricing
August 2005 Data

Description	Combined Relativity	Relativity	Winter Relativity	Relativity	Recalculated
Residential - Urban - Outside	1.00	1.00	1.00	1.00	1.00
Residential - Urban - Outside With Wire	0.74				1.00
Residential - Urban - Inside	1.32	2.10	1.97	1.77	2.00
Residential - Urban - Inside - With Wire	1.05				1.00
Residential - Rural - Outside	3.08	3.43	3.26		3.00
Residential - Rural - Outside With Wire	1.97				2.00
Residential with vehicle				2.87	3.00
GS - Walking	1.53				2.00
GS - Walking - With Water	1.26	3.57	3.14		3.00
GS - Vehicle	3.21				3.00
GS - Vehicle With Water	2.63			3.33	3.00
Interval	49.00				49.00
Time of Use Read – Ignore		3.57	3.38		3.00
Special Reads – Ignore	let misc charges pick up the difference			8.14	8.14

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Sheet I8 Demand Data Worksheet - Second Run

This is an input sheet for demand allocators.

CP TEST RESULTS	12 CP
NCP TEST RESULTS	4 NCP

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

			1	2	3	5	7	8	9
Customer Classes		Total	Residential	GS <50	General Service 50 to 999	General Service 1000 to 4999	Street Light	Sentinel	Unmetered Scattered Load
CO-INCIDENT PEAK									
1 CP									
Transformation CP	TCP1	187,838	66,647	28,923	56,569	35,368	-		331
Bulk Delivery CP	BCP1	187,838	66,647	28,923	56,569	35,368	-		331
Total Sytem CP	DCP1	187,838	66,647	28,923	56,569	35,368	-	-	331
4 CP									
Transformation CP	TCP4	727,371	273,825	103,217	204,967	138,544	5,323	66	1,429
Bulk Delivery CP	BCP4	727,371	273,825	103,217	204,967	138,544	5,323	66	1,429
Total Sytem CP	DCP4	727,371	273,825	103,217	204,967	138,544	5,323	66	1,429
12 CP									
Transformation CP	TCP12	1,931,051	654,949	281,919	539,427	443,141	7,508	94	4,013
Bulk Delivery CP	BCP12	1,931,051	654,949	281,919	539,427	443,141	7,508	94	4,013
Total Sytem CP	DCP12	1,931,051	654,949	281,919	539,427	443,141	7,508	94	4,013
NON CO_INCIDENT PEAK									
1 NCP									
Classification NCP from Load Data Provider	DNCP1	225,487	81,462	33,544	57,615	49,623	2,777	35	431
Primary NCP	PNCP1	225,487	81,462	33,544	57,615	49,623	2,777	35	431
Line Transformer NCP	LTNCP1	225,487	81,462	33,544	57,615	49,623	2,777	35	431
Secondary NCP	SNCP1	223,696	81,462	33,544	56,653	48,794	2,777	35	431
4 NCP									
Classification NCP from Load Data Provider	DNCP4	858,343	315,337	129,708	214,042	186,654	10,802	135	1,665
Primary NCP	PNCP4	858,343	315,337	129,708	214,042	186,654	10,802	135	1,665
Line Transformer NCP	LTNCP4	858,343	315,337	129,708	214,042	186,654	10,802	135	1,665
Secondary NCP	SNCP4	851,651	315,337	129,708	210,467	183,537	10,802	135	1,665
12 NCP									
Classification NCP from Load Data Provider	DNCP12	2,248,650	769,697	350,537	574,058	517,551	31,644	394	4,769
Primary NCP	PNCP12	2,248,650	769,697	350,537	574,058	517,551	31,644	394	4,769
Line Transformer NCP	LTNCP12	2,248,650	769,697	350,537	574,058	517,551	31,644	394	4,769
Secondary NCP	SNCP12	2,230,420	769,697	350,537	564,471	508,908	31,644	394	4,769

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Sheet I9 Direct Allocation Worksheet - Second Run

USoA Account #	Accounts	Direct Allocation	Total Allocated to Rate Classifications?	1 Residential	2 GS <50	3 General Service 50 to 999	5 General Service 1000 to 4999
1995	Contributions and Grants - Credit	$0	Yes				
1805	Land	$0	Yes				
1806	Land Rights	$0	Yes				
1808	Buildings and Fixtures	$0	Yes				
1810	Leasehold Improvements	$0	Yes				
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	Yes				
1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	Yes				
1825	Storage Battery Equipment	$0	Yes				
1830	Poles, Towers and Fixtures	$0	Yes				
1835	Overhead Conductors and Devices	$0	Yes				
1840	Underground Conduit	$0	Yes				
1845	Underground Conductors and Devices	$0	Yes				
1850	Line Transformers	$0	Yes				
1855	Services	$0	Yes				
1860	Meters	$0	Yes				
1905	Land	$0	Yes				
1906	Land Rights	$0	Yes				
1908	Buildings and Fixtures	$0	Yes				
1910	Leasehold Improvements	$0	Yes				
1915	Office Furniture and Equipment	$0	Yes				
1920	Computer Equipment - Hardware	$0	Yes				
1925	Computer Software	$0	Yes				
1930	Transportation Equipment	$0	Yes				
1935	Stores Equipment	$0	Yes				
1940	Tools, Shop and Garage Equipment	$0	Yes				
1945	Measurement and Testing Equipment	$0	Yes				
1950	Power Operated Equipment	$0	Yes				
1955	Communication Equipment	$0	Yes				
1960	Miscellaneous Equipment	$0	Yes				
1970	Load Management Controls - Customer Premises	$0	Yes				
1975	Load Management Controls - Utility Premises	$0	Yes				
1980	System Supervisory Equipment	$0	Yes				
1990	Other Tangible Property	$0	Yes				
2005	Property Under Capital Leases	$0	Yes				
2010	Electric Plant Purchased or Sold	$0	Yes				
2050	Completed Construction Not Classified--Electric	$0	Yes				
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	$0	Yes				
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	$0	Yes				
	Directly Allocated Net Fixed Assets			$0	$0	$0	$0
5005	Operation Supervision and Engineering	$0	Yes				
5010	Load Dispatching	$0	Yes				
5012	Station Buildings and Fixtures Expense	$0	Yes				
5014	Transformer Station Equipment - Operation Labour	$0	Yes				
5015	Transformer Station Equipment - Operation Supplies and Expenses	$0	Yes				
5016	Distribution Station Equipment - Operation Labour	$0	Yes				

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Sheet I9 Direct Allocation Worksheet - Second Run

USoA Account #	Accounts	Direct Allocation	Total Allocated to Rate Classifications?	1 Residential	2 GS <50	3 General Service 50 to 999	5 General Service 1000 to 4999
5017	Distribution Station Equipment - Operation Supplies and Expenses	$0	Yes				
5020	Overhead Distribution Lines and Feeders - Operation Labour	$0	Yes				
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$0	Yes				
5030	Overhead Subtransmission Feeders - Operation	$0	Yes				
5035	Overhead Distribution Transformers- Operation	$0	Yes				
5040	Underground Distribution Lines and Feeders - Operation Labour	$0	Yes				
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$0	Yes				
5050	Underground Subtransmission Feeders - Operation	$0	Yes				
5055	Underground Distribution Transformers - Operation	$0	Yes				
5065	Meter Expense	$0	Yes				
5070	Customer Premises - Operation Labour	$0	Yes				
5075	Customer Premises - Materials and Expenses	$0	Yes				
5085	Miscellaneous Distribution Expense	$0	Yes				
5090	Underground Distribution Lines and Feeders - Rental Paid	$0	Yes				
5095	Overhead Distribution Lines and Feeders - Rental Paid	$0	Yes				
5096	Other Rent	$0	Yes				
5105	Maintenance Supervision and Engineering	$0	Yes				
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$0	Yes				
5112	Maintenance of Transformer Station Equipment	$0	Yes				
5114	Maintenance of Distribution Station Equipment	$0	Yes				
5120	Maintenance of Poles, Towers and Fixtures	$0	Yes				
5125	Maintenance of Overhead Conductors and Devices	$0	Yes				
5130	Maintenance of Overhead Services	$0	Yes				
5135	Overhead Distribution Lines and Feeders - Right of Way	$0	Yes				
5145	Maintenance of Underground Conduit	$0	Yes				
5150	Maintenance of Underground Conductors and Devices	$0	Yes				
5155	Maintenance of Underground Services	$0	Yes				
5160	Maintenance of Line Transformers	$0	Yes				
5175	Maintenance of Meters	$0	Yes				
5305	Supervision	$0	Yes				
5310	Meter Reading Expense	$7,484	Yes	$5,484	$1,000	$1,000	
5315	Customer Billing	$0	Yes				
5320	Collecting	$0	Yes				
5325	Collecting- Cash Over and Short	$0	Yes				
5330	Collection Charges	$0	Yes				
5335	Bad Debt Expense	$0	Yes				
5340	Miscellaneous Customer Accounts Expenses	$0	Yes				
5405	Supervision	$0	Yes				

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Sheet I9 Direct Allocation Worksheet - Second Run

USoA Account #	Accounts	Direct Allocation	Total Allocated to Rate Classifications?	1 Residential	2 GS <50	3 General Service 50 to 999	5 General Service 1000 to 4999
5410	Community Relations - Sundry	$0	Yes				
5415	Energy Conservation	$0	Yes				
5420	Community Safety Program	$0	Yes				
5425	Miscellaneous Customer Service and Informational Expenses	$0	Yes				
5505	Supervision	$0	Yes				
5510	Demonstrating and Selling Expense	$0	Yes				
5515	Advertising Expense	$0	Yes				
5520	Miscellaneous Sales Expense	$0	Yes				
5605	Executive Salaries and Expenses	$0	Yes				
5610	Management Salaries and Expenses	$0	Yes				
5615	General Administrative Salaries and Expenses	$0	Yes				
5620	Office Supplies and Expenses	$0	Yes				
5625	Administrative Expense Transferred Credit	$0	Yes				
5630	Outside Services Employed	$0	Yes				
5635	Property Insurance	$0	Yes				
5640	Injuries and Damages	$0	Yes				
5645	Employee Pensions and Benefits	$0	Yes				
5650	Franchise Requirements	$0	Yes				
5655	Regulatory Expenses	$0	Yes				
5660	General Advertising Expenses	$0	Yes				
5665	Miscellaneous General Expenses	$0	Yes				
5670	Rent	$0	Yes				
5675	Maintenance of General Plant	$0	Yes				
5680	Electrical Safety Authority Fees	$0	Yes				
5705	Amortization Expense - Property, Plant, and Equipment	$0	Yes				
5710	Amortization of Limited Term Electric Plant	$0	Yes				
5715	Amortization of Intangibles and Other Electric Plant	$0	Yes				
5720	Amortization of Electric Plant Acquisition Adjustments	$0	Yes				
6105	Taxes Other Than Income Taxes	$0	Yes				
6205	Donations	$0	Yes				
6210	Life Insurance	$0	Yes				
6215	Penalties	$0	Yes				
6225	Other Deductions	$0	Yes				
	Total Expenses			$5,484	$1,000	$1,000	$0
	Depreciation Expense			$0	$0	$0	$0

Total Net Fixed Assets Excluding Gen Plant	$110,246,737	Allocated	Residential	GS <50	General Service 50 to 999	General Service 1000 to 4999
Approved Total PILs	$1,349,014	$0	$0	$0	$0	$0
Approved Total Return on Debt	$3,566	$0	$0	$0	$0	$0
Approved Total Return on Equity	$1,044,984	$0	$0	$0	$0	$0
		Total	$5,484	$1,000	$1,000	$0

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Sheet O1 Revenue to Cost Summary Worksheet - Second Run

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	1 Residential	2 GS <50	3 General Service 50 to 999	4 GS> 50-TOU	5 General Service 1000 to 4999	6 Large Use >5MW	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
crev	Distribution Revenue (sale)	$16,551,155	$10,663,900	$2,740,846	$1,806,182	$0	$1,158,847	$0	$114,938	$11,709	$54,733
mi	Miscellaneous Revenue (mi)	$1,367,052	$821,911	$284,941	$167,868	$0	$61,108	$0	$28,463	$657	$2,105
	Total Revenue	$17,918,207	$11,485,811	$3,025,787	$1,974,050	$0	$1,219,955	$0	$143,401	$12,366	$56,838
	Expenses										
di	Distribution Costs (di)	$5,075,301	$2,335,614	$659,589	$918,490	$0	$758,226	$0	$381,837	$4,190	$17,355
cu	Customer Related Costs (cu)	$2,753,110	$1,793,507	$615,668	$308,150	$0	$15,848	$0	$17,212	$260	$2,464
ad	General and Administration (ad)	$3,628,607	$1,881,197	$571,324	$586,998	$0	$380,307	$0	$196,873	$2,189	$9,719
dep	Depreciation and Amortization (dep)	$4,056,140	$1,964,029	$506,003	$726,990	$0	$547,829	$0	$294,847	$3,237	$13,306
INPUT	PILs (INPUT)	$1,349,014	$635,976	$174,263	$253,999	$0	$183,033	$0	$96,046	$1,056	$4,640
INT	Interest	$3,566	$1,681	$461	$672	$0	$484	$0	$254	$3	$12
	Total Expenses	$16,865,738	$8,612,004	$2,527,308	$2,795,198	$0	$1,885,728	$0	$987,068	$10,936	$47,497
	Direct Allocation	$7,484	$5,484	$1,000	$1,000	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$1,044,984	$492,645	$134,989	$196,755	$0	$141,783	$0	$74,400	$818	$3,594
	Revenue Requirement (includes NI	$17,918,207	$9,110,134	$2,663,297	$2,992,953	$0	$2,027,511	$0	$1,061,468	$11,754	$51,091
		Revenue Requirement input equals Output									
	Rate Base Calculation										
	Net Assets										
dp	Distribution Plant - Gross	$110,246,737	$54,393,517	$13,853,546	$18,728,024	$0	$13,637,980	$0	$9,137,678	$100,308	$395,485
gp	General Plant - Gross	$10,814,143	$5,128,204	$1,392,139	$2,010,964	$0	$1,450,880	$0	$785,919	$8,642	$37,397
accum dep	Accumulated Depreciation	($58,223,541)	($29,723,458)	($7,156,436)	($9,053,955)	$0	($6,658,286)	$0	($5,357,088)	($58,735)	($215,582)
co	Capital Contribution	($3,694,801)	($1,886,218)	($454,139)	($574,554)	$0	($422,527)	$0	($339,955)	($3,727)	($13,681)
	Total Net Plant	$59,142,538	$27,912,045	$7,635,109	$11,110,479	$0	$8,008,046	$0	$4,226,753	$46,487	$203,619
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$70,013,765	$25,101,895	$10,405,729	$20,727,826	$0	$12,796,201	$0	$759,350	$9,198	$213,566
	OM&A Expenses	$11,457,018	$6,010,318	$1,846,581	$1,813,637	$0	$1,154,382	$0	$595,922	$6,640	$29,539
	Directly Allocated Expenses	$7,484	$5,484	$1,000	$1,000	$0	$0	$0	$0	$0	$0
	Subtotal	$81,478,267	$31,117,696	$12,253,310	$22,542,463	$0	$13,950,583	$0	$1,355,272	$15,838	$243,104
	Working Capital	$12,221,740	$4,667,654	$1,837,997	$3,381,369	$0	$2,092,587	$0	$203,291	$2,376	$36,466
	Total Rate Base	$71,364,278	$32,579,699	$9,473,105	$14,491,849	$0	$10,100,634	$0	$4,430,044	$48,862	$240,085
		Rate Base Input equals Output									
	Equity Component of Rate Base	$35,682,139	$16,289,850	$4,736,553	$7,245,924	$0	$5,050,317	$0	$2,215,022	$24,431	$120,042
	Net Income on Allocated Assets	$1,044,985	$2,868,323	$497,479	($822,148)	$0	($665,773)	$0	($843,668)	$1,430	$9,341
	Net Income on Direct Allocation As	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Net Income	$1,044,985	$2,868,323	$497,479	($822,148)	$0	($665,773)	$0	($843,668)	$1,430	$9,341
	RATIOS ANALYSIS										
	REVENUE TO EXPENSES %	100.00%	126.08%	113.61%	65.96%	0.00%	60.17%	0.00%	13.51%	105.21%	111.25%
	EXISTING REVENUE MINUS ALLOC	$0	$2,375,678	$362,490	($1,018,903)	$0	($807,556)	$0	($918,067)	$612	$5,747
	RETURN ON EQUITY COMPONENT	2.93%	17.61%	10.50%	-11.35%	0.00%	-13.18%	0.00%	-38.09%	5.85%	7.78%
	Acceptable Ranges		85% to 115%	80% to 120%	80% to 180%		80% to 180%		70% to 120%	70% to 120%	80% to 120%
	Quantification of $ impact to move 50% within boundary		($504,579)	movement requir	$210,156	$0	$201,027	$0	$299,814	movement requir	($10,537)
	Number of customers		44,635		511		19		1		107
	$ Impact per customer		($11)		$411	#DIV/0!	$10,580	#DIV/0!	$299,814		($98)

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Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - Second Run

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1	2	3	5	7	8	9
	Residential	**GS <50**	**General Service 50 to 999**	**General Service 1000 to 4999**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
Customer Unit Cost per month - Avoided Cost	$3.49	$10.95	$51.52	$58.10	$0.11	-$0.04	$0.45
Customer Unit Cost per month - Directly Related	$4.99	$16.04	$73.87	$93.04	$0.17	$0.04	$0.68
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$10.15	$20.64	$110.97	$332.62	$6.86	$6.71	$6.15
Fixed Charge per approved 2006 EDR	$11.15	$17.22	$185.29	$1,622.25	$0.34	$6.07	$8.45

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Sheet O3.1 Line Transformers Unit Cost Worksheet - Second Run

ALLOCATION BY RATE CLASSIFICATION

Description	Total	1 Residential	2 GS <50	3 General Service 50 to 999	5 General Service 1000 to 4999	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
Depreciation on Acct 1850 Line Transformer	$561,634	$266,122	$69,911	$95,270	$81,947	$45,904	$503	$1,977
Depreciation on General Plant Assigned to Line Transformer	$75,944	$36,183	$9,417	$12,718	$10,953	$6,334	$69	$269
Acct 5035 - Overhead Distribution Transformers- Operatio	$294,883	$139,726	$36,707	$50,021	$43,026	$24,101	$264	$1,038
Acct 5055 - Underground Distribution Transformers - Operatio	$154,860	$73,378	$19,277	$26,269	$22,595	$12,657	$139	$545
Acct 5160 - Maintenance of Line Transformer	$243,042	$115,162	$30,253	$41,227	$35,462	$19,864	$218	$856
Allocation of General Expense	$340,723	$146,374	$44,717	$67,250	$60,375	$20,787	$228	$993
Admin and General Assigned to Line Transformer	$323,526	$149,555	$38,635	$56,237	$49,662	$27,935	$305	$1,196
PILs on Line Transformers	$210,866	$99,916	$26,248	$35,769	$30,767	$17,235	$189	$742
Debt Return on Line Transformer	$557	$264	$69	$95	$81	$46	$0	$2
Equity Return on Line Transformer	$163,343	$77,398	$20,333	$27,708	$23,833	$13,350	$146	$575
Less: Transformer Ownership Allowance Credi	($413,327)	($187,826)	($53,260)	($75,696)	($65,323)	($29,559)	($324)	($1,339)
Total	**$1,956,051**	**$916,252**	**$242,306**	**$336,868**	**$293,378**	**$158,653**	**$1,739**	**$6,855**
Billed kW without Line Transformer Allowance		0	0	646,519	-1,189	30,411	307	0
Billed kWh without Line Transformer Allowance		356,604,252	147,826,584	294,465,063	181,786,271	10,787,529	130,673	3,033,972
Line Transformation Unit Cost ($/kW		**$0.0000**	**$0.0000**	**$0.5210**	**-$246.6603**	**$5.2170**	**$5.6631**	**$0.0000**
Line Transformation Unit Cost ($/kWh		**$0.0026**	**$0.0016**	**$0.0011**	**$0.0016**	**$0.0147**	**$0.0133**	**$0.0023**
General Plant - Gross Asset	$10,814,143	$5,128,204	$1,392,139	$2,010,964	$1,450,880	$785,919	$8,642	$37,397
General Plant - Accumulated Depreciatior	$0	$0	$0	$0	$0	$0	$0	$0
General Plant - Net Fixed Asset	$10,814,143	$5,128,204	$1,392,139	$2,010,964	$1,450,880	$785,919	$8,642	$37,397
General Plant - Depreciatior	$485,671	$230,311	$62,522	$90,314	$65,160	$35,296	$388	$1,680
Total Net Fixed Assets Excluding General Plan	**$48,328,395**	**$22,783,841**	**$6,242,970**	**$9,099,515**	**$6,557,167**	**$3,440,834**	**$37,845**	**$166,222**
Total Administration and General Expens	**$3,628,607**	**$1,881,197**	**$571,324**	**$586,998**	**$380,307**	**$196,873**	**$2,189**	**$9,719**
Total O&M	**$7,828,411**	**$4,129,121**	**$1,275,257**	**$1,226,639**	**$774,075**	**$399,049**	**$4,451**	**$19,819**
Line Transformer Rate Base								
Acct 1850 - Line Transformers - Gross Asset	$20,471,040	$9,699,896	$2,548,198	$3,472,512	$2,986,876	$1,673,140	$18,344	$72,073
Line Transformers - Accumulated Depreciatior	($12,916,768)	($6,120,417)	($1,607,856)	($2,191,077)	($1,884,652)	($1,055,714)	($11,575)	($45,476)
Line Transformers - Net Fixed Asset	$7,554,272	$3,579,479	$940,342	$1,281,435	$1,102,224	$617,426	$6,769	$26,596
General Plant Assigned to Line Transformers - NF/	$1,690,995	$805,672	$209,690	$283,193	$243,885	$141,026	$1,546	$5,984
Line Transformer Net Fixed Assets Including General Plar	$9,245,266	$4,385,150	$1,150,032	$1,564,628	$1,346,109	$758,452	$8,315	$32,580
General Expenses								
Acct 5005 - Operation Supervision and Engineerin	$153,754	$68,612	$20,748	$29,352	$23,867	$10,562	$116	$497
Acct 5010 - Load Dispatching	$638,180	$284,786	$86,117	$121,830	$99,063	$43,840	$481	$2,062
Acct 5065 - Miscellaneous Distribution Expens	$859	$383	$116	$164	$133	$59	$1	$3
Acct 5105 - Maintenance Supervision and Engineerin	$854,467	$381,303	$115,304	$163,120	$132,637	$58,698	$644	$2,761
Total	**$1,647,260**	**$735,084**	**$222,285**	**$314,466**	**$255,701**	**$113,160**	**$1,242**	**$5,323**
Acct 1850 - Line Transformers - Gross Asset	$20,471,040	$9,699,896	$2,548,198	$3,472,512	$2,986,876	$1,673,140	$18,344	$72,073
Acct 1815 - 1855	$99,861,972	$48,712,438	$12,667,032	$16,237,808	$12,650,092	$9,108,226	$99,955	$386,420

Exhibit	Tab	Schedule	Appendix	Contents
8 – Rate Design				
	1	1		Rate Design Overview
		2		Rate Mitigation
		3		Proposed Retail Transmission Rate Adjustment
		4		Existing Rate Classes
		5		Existing Rate Schedule
		6		Proposed Rate Classes
		7		Schedule of Proposed Rates and Charges
		8		Reconciliation of Rate Class Revenue
		9		Rate and Bill Impacts
			A	Table of Rate and Bill Impacts
		10		Recovery of LRAM and SSM Amounts

RATE DESIGN OVERVIEW:

This Exhibit documents the calculation of Thunder Bay Hydro's proposed distribution rates by rate class for the 2009 test year, based on the rate design as proposed in this Exhibit.

Thunder Bay Hydro has determined its total 2009 service revenue requirement to be $19,321,728. The total revenue offsets in the amount of $1,802,790 reduce Thunder Bay Hydro's total service revenue requirement to a base revenue requirement to $17,518,938, which is used to determine the proposed distribution rates. The base revenue requirement is derived from Thunder Bay Hydro's 2009 capital and operating forecasts, weather normalized usage, forecasted customer counts, and regulated return on rate base. The revenue requirement is summarized in the table below:

Calculation of Base Revenue Requirement

Table 1(a)

OM&A Expenses	12,340,964
Amortization Expenses	4,573,436
Total Distribution Expenses	**16,914,400**
Regulated Return On Capital	1,437,190
PILs	970,138
Service Revenue Requirement	**19,321,728**
Less: Revenue Offsets	(1,802,790)
Base Revenue Requirement	**17,518,938**

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.

Summarized below is a comparison of the Service Revenue Requirement between the 2006 EDR approved and the 2009 Test Year.

Comparison of Service Revenue Requirement

Table 1(b)

		As per 2006 EDR Approved	2009 Test Year
Rate Base		$ 71,329,997	$ 75,169,648
Return on Rate Base @ 1.47% for	at 1.47%	$ 1,048,551	$ 1,437,190
	at 1.91%		
Distribution Expenses		$ 15,107,315	$ 16,914,400
Revenue Requirement Before PILS		$ 16,155,866	$ 18,351,590
PILS		$ 1,349,014	$ 970,138
SERVICE REVENUE REQUIREMENT		**$ 17,504,880**	**$ 19,321,728**

Proposed Apportionment of Revenue to Rate Classes

Table 2

Rate Classification	Proposed Revenue Split
Residential	61.76%
General Service Less Than 50 kW	16.85%
General Service Greater Than 50 kW	12.55%
General Service 1,000 to 4,999 kW	6.11%
Street Lights	2.26%
Sentinel Lights	0.09%
Unmetered Scattered Load	0.38%
Total	100.00%

The following table outlines the results of this allocation.

Allocation of Outstanding Base Revenue Requirement

Table 3

Rate Classification	Proposed Revenue
Residential	$10,819,715
General Service Less Than 50 kW	2,952,080
General Service 50 to 999 kW	2,198,802
General Service 1,000 to 4,999 kW	1,069,706
Street Lights	395,840
Sentinel Lights	16,239
Unmetered Scattered Load	66,556
Total	$17,518,938

Determination of Monthly Fixed Charges:

Thunder Bay Hydro's current OEB-approved monthly fixed charges based on its 2008 IRM application by customer class are summarized in the table below.

Current Monthly Fixed Charges

Table 4

Rate Class	Current Monthly Fixed Charge
Residential	$10.95
General Service Less Than 50 kW	17.06
General Service 50 to 999 kW	186.25
General Service 1,000 to 4,999 kW	1,632.83
Street Lights	0.34
Sentinel Lights	6.12
Unmetered Scattered Load	8.51

Using the existing approved fixed charges applied to the forecasted number of customers for 2009, the following table outlines the current split between fixed and variable distribution revenue.

Table 5

Rate Class	Fixed Revenue Proportion	Variable Revenue Proportion
Residential	55.72%	44.28%
General Service Less Than 50 kW	33.69%	66.31%
General Service 50 to 999 kW	62.49%	37.51%
General Service 1,000 to 4,999 kW	44.10%	55.90%
Street Lights	45.36%	54.64%
Sentinel Lights	86.77%	13.23%
Unmetered Scattered Load	72.94%	27.06%

Thunder Bay Hydro submits that it is appropriate for 2009 to maintain the same fixed/variable proportions assumed in the current rates to all customer classifications.

In its November 28, 2007 Report on Application of Cost Allocation for Electricity Distributors, 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. At 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". Thunder Bay Hydro's MSCs exceed that floor amount by rate class. 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-2008-0031). 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.

Until the OEB's Rate Review proceeding (EB-2008-0031) is completed and consistent with Norfolk Power Distribution Inc. 2008 Rate Decision (EB-2007-0753), it is Thunder Bay Hydro's view that a MSC ceiling has not been established and it is appropriate for the purposes of setting rates in this application to maintain the current fixed and variable proportions of its rates.

Changes in MSCs are due solely to changes in the total base revenue requirement attributable to each customer class. The following Table 6 provides Thunder Bay Hydro's calculations of its proposed monthly fixed distribution charges for the 2009 Test Year assuming the fixed/variable split supporting the current approved rates.

Proposed Monthly Service Charge

Table 6

Customer Class	Total Base Revenue Requirement	Fixed Revenue Proportion	2009 Test Year Customers/ Connections	Proposed Fixed Distribution Charge
Residential	$10,819,715	55.72%	44,635	$11.26
General Service Less Than 50 kW	2,952,080	33.69%	4,466	18.56
General Service 50 to 999 kW	2,198,802	62.49%	511	224.18
General Service 1,000 to 4,999 kW	1,069,706	44.10%	19	2,069.12
Street Lights	395,840	45.36%	13,091	1.14
Sentinel Lights	16,239	86.77%	176	6.66
Unmetered Scattered Load	66,556	72.94%	437	9.26
Total	$17,518,938		63,335	

Proposed Volumetric Charges:

The variable distribution charge is calculated by dividing the variable distribution portion of the base revenue requirement by the appropriate 2009 Test Year usage, kWh or kW, as the class charge determinant.

The following Table provides Thunder Bay Hydro's calculations of its proposed variable distribution charges for the 2009 Test Year assuming the same fixed/variable split used in designing the current approved rates.

Variable Distribution Charge Calculation

Table 7

Customer Class	Total Base Revenue Requirement	Variable Revenue Proportion	2009 Test Volumetric Billing Determinant		Proposed Volumetric Distribution Charge
Residential	$10,819,715	44.28%	337,772,229	kWh	$0.0142
General Service Less Than 50 kW	2,952,080	66.31%	143,961,424	kWh	0.0136
General Service 50 to 999 kW	2,198,802	37.51%	717,262	kW	1.2583
General Service 1,000 to 4,999 kW	1,069,706	55.90%	560,145	kW	1.6615
Street Lights	395,840	54.64%	31,276	kW	6.9151
Sentinel Lights	16,239	13.23%	402	kW	5.3435
Unmetered Scattered Load	66,556	27.06%	1,335,240	kWh	0.0135
Total	$17,518,938				

Proposed Adjustment to Transformer Allowance:

Currently, Thunder Bay Hydro provides a Transformer Allowance to those customers that own their transformation facilities. Thunder Bay 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.

The amount of Transformer Allowance expected to be provided to those General Service 50 to 999 kW and General Service 999 to 4,999 kW customers that own their transformers has been included in the volumetric charge for these classes. This means the General Service 50 to 999 kW volumetric charge has been increased by $0.1083 per kW to a total of $1.2583 per kW to recover the amount of the Transformer Allowance over all kWs in the General Service 50 to 999 kW rate class. In the case of the General Service 999 to 4,999 kW rate class, the volumetric charge has been increased by $0.594 per kW to a total of $1.6615 per kW to recover the amount of the Transformer Allowance over all kWs in this rate class.

Proposed Distribution Rates:

The following table sets out Thunder Bay Hydro's proposed 2009 electricity distribution rates based on the foregoing calculations, including adjustments for the recovery of transformer allowance.

Table 8

Customer Class	Proposed Monthly Service Charge	UOM	Proposed Volumetric Distribution Charge
Residential	$11.26	kWh	$0.0142
General Service <50 kW	18.56	kWh	$0.0136
General Service 50 to 999 kW	224.18	kW	$1.2583
General Service 1,000 to 4,999 kW	2,069.12	kW	$1.6615
Street Light	1.14	kW	$6.9151
Sentinel	6.66	kW	$5.3435
Unmetered Scattered Load	9.26	kWh	$0.0135

Smart Meter Rate Adder:

In this application Thunder Bay Hydro is proposing a smart meter adder of $1.25. Thunder Bay Hydro has used the Smart Meter Rate Addendum Model as provided by the OEB updated for the existing tax, deemed debt/equity capital structure, etc. for the current year to arrive at the amount for the smart meter rate adder. The model is provided on the following pages. Additional information supporting Thunder Bay Hydro's smart meter plan is addressed in Exhibit 2, Tab 3, Schedule 1.

2009 EDR Smart Meter Rate Calculation Model

Sheet 1 Utility Information Sheet

Legend:	Input Cell	Pull-Down Menu Option	Output Cell
	From Another Sheet	To The 2007 IRM Model	To Another Sheet

Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.

Name of LDC:	Thunder Bay Hydro Electricity Distribution Inc.		
Licence Number:	ED-2002-0529	Smart Meter Grouping:	Inactive
IRM 2007 EB Number:	EB-2007-0580		
EDR 2006 RP Number:	RP-2005-0020	EDR 2006 EB Number:	EB-2005-0419
Date of Submission:	August 29, 2008	Revision:	0
Version:	1.0		

Contact Information

Name:	
Title:	
Phone Number:	
E-Mail Address:	

1

RATE ADDER:

CURRENT SMART METER RATE ADDER:	**$ 0.27**
REVISED SMART METER RATE ADDER:	**$ 1.25**

2007 EDR Smart Meter Rate Calculation Model

Thunder Bay Hydro Electricity Distribution Inc.

EB-2007-0580

Friday, August 29, 2008

The original 2007 EDR Smart Meter Rate Calculation Model has been unlocked by the OEB and amended by Thunder Bay Hydro ***ONLY*** for the purposes of a working document for 2008 rate submission. It is not an official working file sanctionned by the OEB. **IKH Aug 11/08**

Sheet 2. Smart Meter Capital Cost and Operational Expense Data

Smart Meter Unit Installation Plan: *(From Smart Meter Plan filed December 15, 2006)*

assume calendar year installation	2006	2007	2008	2009	2010	Total
Planned number of Residential smart meters to be installed	-			44,635		44,635
Planned number of General Service Less Than 50 kW smart meters	-			4,466		4,466
Planned Meter Installation (Residential and Less Than 50 kW only)	-	-	-	49,101	-	49,101
Planned Meter Installation Completed before January 1, 2010		-		49,101		

Smart Meter Unit Cost

	Per Unit	
Smart Meter Unit Cost *Enter the invoiced cost per smart meter purchased* *Please provide details in Manager's Summary*	$ 112.32	A
Smart Meter Other Unit Cost *Enter the invoiced other costs per smart meter unit purchased* *Please provide details in Manager's Summary*	$ 5.01	B
Smart Meter Installation Cost per Unit *Enter the time and material cost per smart meter unit installed* *Please provide details in Manager's Summary*	$ 32.03	C
Smart Meter Other Cost per Unit *Enter the other cost per smart meter unit installed* *Please provide details in Manager's Summary*	$ 7.54	D
Total Unit cost per Smart Meter	**$ 156.90**	E = A + B + C + D

3. LDC Assumptions and Data

AMI Capital Cost

	2006	2007	2008	2009	2010	Total
AMI Computer Hardware Costs *Enter the estimated capital costs for AMI related Computer Hardware* *Please provide details in Manager's Summary*	$ -			$ 157,879	$ -	$ 157,879
			3. LDC Assumptions and Data			
	2006	2007	2008	2009	2010	
AMI Computer Software Costs *Enter the estimated capital costs for AMI related Computer Software* *Please provide details in Manager's Summary*	$ -		$ -	$ 56,659	$ -	$ 56,659
			3. LDC Assumptions and Data			
Total AMI Capital Cost	**$ -**	**$ -**	**$ -**	**$ 214,538**	**$ -**	**$ 214,538**

Other Capital Cost

	2006	2007	2008	2009	2010	Total
Other Computer Hardware Costs	$ -	$ -	$ -	$ -	$ -	$ -
Enter the estimated capital costs for other related Computer Hardware			*3. LDC Assumptions and Data*			
Please provide details in Manager's Summary						
Other Computer Software Costs	$ -	$ -	$ -	$ -	$ -	$ -
Enter the estimated capital costs for other related Computer Software			*3. LDC Assumptions and Data*			
Please provide details in Manager's Summary						
Total Other Capital Cost	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

Incremental AMI Operational Expenses

	2006	2007	2008	2009	2010
Incremental AMI O&M Expenses	$ -			$ 231,403	$ 231,403
Enter the estimated incremental AMI related O&M expenses			*3. LDC Assumptions and Data*		
Please provide details in Manager's Summary					
Incremental AMI Admin Expenses	$ -	$ -		$ 851	$ 851
Enter the estimated incremental AMI related Admin expenses			*3. LDC Assumptions and Data*		
Please provide details in Manager's Summary					
Total Incremental AMI Operation Expenses	**$ -**	**$ -**	**$ -**	**$ 232,253**	**$ 232,253**

Incremental Other Operational Expenses

	2006	2007	2008	2009	2010	Total
Incremental Other O&M Expenses	$ -			$ 28,350	$ 28,350	$ 56,700
Enter the estimated incremental Other related O&M expenses			*3. LDC Assumptions and Data*			
Please provide details in Manager's Summary						
Incremental Other Admin Expenses	$ -	$ -	$ -	$ -	$ -	$ -
Enter the estimated incremental Other related Admin expenses			*3. LDC Assumptions and Data*			
Please provide details in Manager's Summary						
Total Incremental Other Operation Expenses	**$ -**	**$ -**	**$ -**	**$ 28,350**	**$ 28,350**	**$ 56,700**

2007 EDR Smart Meter Rate Calculation Model

Thunder Bay Hydro Electricity Distribution Inc.

EB-2007-0580

Friday, August 29, 2008

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

Deemed Debt (from 2006 EDR Sheet "3-2 COST OF CAPITAL (Input)" Cell C 18)	57%	*4. Smart Meter Rate Calc*
Deemed Equity (from 2006 EDR Sheet "3-2 COST OF CAPITAL (Input)" Cell C 19)	43%	*4. Smart Meter Rate Calc*
Weighted Debt Rate (from 2006 EDR Sheet "3-2 COST OF CAPITAL (Input)" Cell C 25)	6.00%	*4. Smart Meter Rate Calc*
Proposed ROE (from 2006 EDR Sheet "3-2 COST OF CAPITAL (Input)" Cell E 32)	3.75%	*4. Smart Meter Rate Calc*
Weighted Average Cost of Capital	5.03%	

2006 EDR Total Metered Customers

Sum of Residential, General Service, and Large User *from 2006 EDR Sheet "7-1 ALLOCATION - Base Rev. Req." Cells H16 thru H93*	49,631	*4. Smart Meter Rate Calc*

2006 EDR Tax Rate

Corporate Income Tax Rate *(from 2006 PILs Sheet "Test Year PILs,Tax Provision" Cell D 14)*	33.00%	*5. PILs*

Capital Data:

	2006	2007	2008	2009	2010	Total
Smart meter including installation ($156.901073200436 times Planned Meters Installed)	$ -	$ -	$ -	$ 7,704,000	$ -	$ 7,704,000
Computer Hardware Costs *2. Smart Meter Data; AMI (F) plus Other (I)*	$ -	$ -	$ -	$ 157,879	$ -	$ 157,879
Computer Software Costs *2. Smart Meter Data; AMI (G) plus Other (J)*	$ -	$ -	$ -	$ 56,659	$ -	$ 56,659
Total Computer Costs *2. Smart Meter Data; AMI (H) plus Other (K)*	$ -	$ -	$ -	$ 7,918,538	$ -	$ 7,918,538

6. SM Avg Net Fixed Assets &UCC

LDC Amortization Policy:

Smart Meter Amortization Rate *Enter Amortization Policy*	15	Years	*6. SM Avg Net Fixed Assets &UCC*
Computer Hardware Amortization Rate *Enter Amortization Policy*	5	Years	*6. SM Avg Net Fixed Assets &UCC*
Computer Software Amortization Rate *Enter Amortization Policy*	3	Years	*6. SM Avg Net Fixed Assets &UCC*

Operating Expense Data:

	2006	2007	2008	2009	2010	Total
Incremental O&M Expenses *2. Smart Meter Data; AMI (L) plus Other (O)*	$ -	$ -	$ -	$ 259,753	$ 259,753	$ 519,505
Incremental Admin Expenses *2. Smart Meter Data; AMI (M) plus Other (P)*	$ -	$ -	$ -	$ 851	$ 851	$ 1,701
Total Incremental Operating Expense *2. Smart Meter Data; AMI (N) plus Other (Q)*	$ -	$ -	$ -	$ 260,603	$ 260,603	$ 521,206

4. Smart Meter Rate Calc

Per Meter Cost Split:

	Per Meter	Installed	Investment	% of Invest
Smart meter including installation	$ 156.90	49,101	$ 7,704,000	91%
Computer Hardware Costs	$ 3.22	49,101	$ 157,879	0%
Computer Software Costs	$ 1.15	49,101	$ 56,659	0%
Smart meter incremental operating expenses	$ 10.61	49,101	$ 521,206	0%
Total Smart Meter Capital Costs per meter	$ 171.89		$ 8,439,744	91%

2007 EDR Smart Meter Rate Calculation Model
Thunder Bay Hydro Electricity Distribution Inc.
EB-2007-0580
Friday, August 29, 2008
Sheet 4. Smart Meter Rate Calc

Smart Meter Rate Calculation

	2009		
Average Asset Values			
Net Fixed Assets Smart Meters *(6. SM Avg Net Fixed Assets &UCC)*	$ 3,723,600		
Net Fixed Assets Computer Hardware *(6. SM Avg Net Fixed Assets &UCC)*	$ 71,046		
Net Fixed Assets Computer Software *(6. SM Avg Net Fixed Assets &UCC)*	$ 23,608		
Total Net Fixed Assets	$ 3,818,253	$ 3,818,253	
Working Capital			
Operation Expense	$ 260,603		
15 % Working Capital	$ 39,090	$ 39,090	
Smart Meters included in Rate Base		$ 3,857,344	
Return on Rate Base			
Deemed Debt *(3. LDC Assumptions and Data)*	56.7%	$ 2,187,114	
Deemed Equity *(3. LDC Assumptions and Data)*	43.3%	$ 1,670,230	
		$ 3,857,344	
Weighted Debt Rate *(3. LDC Assumptions and Data)*	6.0%	$ 131,227	
Proposed ROE *(3. LDC Assumptions and Data)*	3.8%	$ 62,634	
Return on Rate Base		$ 193,860	$ 193,860
Operating Expenses			
Incremental Operating Expenses *(3. LDC Assumptions and Data)*			$ 260,603
Amortization Expenses			
Amortization Expenses - Smart Meters *(6. SM Avg Net Fixed Assets &UCC)*		$ 256,800	
Amortization Expenses - Computer Hardware *(6. SM Avg Net Fixed Assets &UCC)*		$ 15,788	
Amortization Expenses - Computer Software *(6. SM Avg Net Fixed Assets &UCC)*		$ 9,443	
Total Amortization Expenses			$ 282,031
Revenue Requirement Before PILs			$ 736,495
Calculation of Taxable Income			
Incremental Operating Expenses			-$ 260,603
Depreciation Expenses			-$ 282,031
Interest Expense			-$ 131,227
Taxable Income For PILs			$ 62,634
Grossed up PILs *(5. PILs)*			$ 6,103
Revenue Requirement Before PILs			$ 736,495
Grossed up PILs *(5. PILs)*			$ 6,103
Revenue Requirement for Smart Meters			**$ 742,598**
2007 Smart Meter Rate Adder			
Revenue Requirement for Smart Meters			$ 742,598
2006 EDR Total Metered Customers *(3. LDC Assumptions and Data)*			49,631
Annualized amount required per metered customer			$ 14.96
Number of months in year			12
2007 Smart Meter Rate Adder			**$ 1.25**

2007 EDR Smart Meter Rate Calculation Model

Thunder Bay Hydro Electricity Distribution Inc.

EB-2007-0580

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Sheet 5. PILs

PILs Calculation

INCOME TAX	
Net Income *(4. Smart Meter Rate Calc)*	$ 62,634
Amortization *(4. Smart Meter Rate Calc)*	$ 282,031
CCA - Class 47 (8%) Smart Meters *(6. SM Avg Net Fixed Assets &UCC)*	-$ 308,160
CCA - Class 45 (45%) Computers *(6. SM Avg Net Fixed Assets &UCC)*	-$ 58,998
Change in taxable income	-$ 22,493
Tax Rate *(3. LDC Assumptions and Data)*	33.00%
Income Taxes Payable	-$ 7,423
ONTARIO CAPITAL TAX	
Smart Meters *(6. SM Avg Net Fixed Assets &UCC)*	$ 7,447,200
Computer Hardware *(6. SM Avg Net Fixed Assets &UCC)*	$ 142,091
Computer Software *(6. SM Avg Net Fixed Assets &UCC)*	$ 47,216
Rate Base	$ 7,636,507
Less: Exemption	$ -
Deemed Taxable Capital	$ 7,636,507
Ontario Capital Tax Rate	0.225%
Net Amount (Taxable Capital x Rate)	$ 17,182

Gross Up

	PILs Payable	Gross Up	Grossed Up PILs
Change in Income Taxes Payable	-$ 7,423	33.00%	-$ 11,079
Change in OCT	$ 17,182		$ 17,182
PIL's	$ 9,759		**$ 6,103**

2007 EDR Smart Meter Rate Calculation Model

Thunder Bay Hydro Electricity Distribution Inc.

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Sheet 6. SM Avg Net Fixed Assets &UCC

Smart Meter Average Net Fixed Assets

Net Fixed Assets - Smart Meters

	2008	2009
Opening Capital Investment	$ -	$ -
Capital Investment Year 1 *(3. LDC Assumptions and Data)*	$ -	
Capital Investment Year 2 *(3. LDC Assumptions and Data)*		$ 7,704,000
Closing Capital Investment	$ -	$ 7,704,000
Opening Accumulated Amortization	$ -	$ -
Amortization Year 1 (15 Years Straight Line)	$ -	$ -
Amortization Year 2 (15 Years Straight Line)		$ 256,800
Closing Accumulated Amortization	$ -	$ 256,800
Opening Net Fixed Assets	$ -	$ -
Closing Net Fixed Assets	$ -	$ 7,447,200
Average Net Fixed Assets	$ -	$ 3,723,600

Net Fixed Assets - Computer Hardware

	2008	2009
Opening Capital Investment	$ -	$ -
Capital Investment Year 1 *(3. LDC Assumptions and Data)*	$ -	
Capital Investment Year 2 *(3. LDC Assumptions and Data)*		$ 157,879
Closing Capital Investment	$ -	$ 157,879
Opening Accumulated Amortization	$ -	$ -
Amortization Year 1 (5 Years Straight Line)	$ -	$ -
Amortization Year 2 (5 Years Straight Line)		$ 15,788
Closing Accumulated Amortization	$ -	$ 15,788
Opening Net Fixed Assets	$ -	$ -
Closing Net Fixed Assets	$ -	$ 142,091
Average Net Fixed Assets	$ -	$ 71,046

Net Fixed Assets - Computer Software

	2008	2009
Opening Capital Investment	$ -	$ -
Capital Investment Year 1 *(3. LDC Assumptions and Data)*	$ -	
Capital Investment Year 2 *(3. LDC Assumptions and Data)*		$ 56,659
Closing Capital Investment	$ -	$ 56,659
Opening Accumulated Amortization	$ -	$ -
Amortization Year 1 (3 Years Straight Line)	$ -	$ -
Amortization Year 2 (3 Years Straight Line)		$ 9,443
Closing Accumulated Amortization	$ -	$ 9,443
Opening Net Fixed Assets	$ -	$ -
Closing Net Fixed Assets	$ -	$ 47,216
Average Net Fixed Assets	$ -	$ 23,608

For PILs Calculation

UCC - Smart Meters

CCA Class 47 (8%)	2008	2009
Opening UCC	$ -	$ -
Capital Additions	$ -	$ 7,704,000
UCC Before Half Year Rule	$ -	$ 7,704,000
Half Year Rule (1/2 Additions - Disposals)	$ -	$ 3,852,000
Reduced UCC	$ -	$ 3,852,000
CCA Rate Class 47	8%	8%
CCA	$ -	$ 308,160
Closing UCC	$ -	$ 7,395,840

UCC - Computer Equipment

CCA Class 45.1 (55%)	2008	2009
Opening UCC	$ -	$ -
Capital Additions Hardware	$ -	$ 157,879
Capital Additions Software	$ -	$ 56,659
UCC Before Half Year Rule	$ -	$ 214,538
Half Year Rule (1/2 Additions - Disposals)	$ -	$ 107,269
Reduced UCC	$ -	$ 107,269
CCA Rate Class 55	55%	55%
CCA	$ -	$ 58,998
Closing UCC	$ -	$ 155,540

RATE MITIGATION:

Thunder Bay Hydro submits that the bill impacts of its proposed 2009 electricity distribution rates for all rate classes except Street Light and Unmetered Scattered Load are under 10% and therefore do not require rate mitigation.

The Street Light class has total bill impacts over 10% due to the adjustment resulting from the recent cost allocation study. Thunder Bay Hydro has proposed to move this customer class significantly closer to the OEB's target range of acceptable Revenue to Cost ratio. As a result, it is expected these classes would experience higher increases than the other customer classes.

The total bill impact for the Unmetered Scattered Load class is over 10%. This is due to the collection of LRAM and SSM resulting from CDM programs targeted to this rate class which is discussed in more detail at Schedule 10.

PROPOSED RETAIL TRANSMISSION RATE ADJUSTMENT:

Given that Hydro One has an application before the OEB for an increase in their Transmission Rates and the fact that the adjustment that was implemented with the 2006 EDR process resulted in significant under-collection, Thunder Bay Hydro is proposing to increase its existing Retail Transmission Network and Connection rates for its customer classes based on the proposed increases by Hydro One.

Calculation of Proposed Revised Rates:

Thunder Bay Hydro has reviewed its Retail Transmission Rates – both Network and Connection and recalculated those rates to reflect the impacts of Hydro One's Ontario Uniform Transmission Rate Order [EB-2008-0113] on Uniform Transmission Rate Adjustment Application as set out in the OEB's letter dated June 20, 2008.

The rate schedule for the recovery of the revenue requirements of all Ontario electricity transmitters will change. Hydro One is requesting the approved rates to be in effect from May 1, 2009. The August 28th, 2008 OEB Decision resulted in changes in Transmission rates as follows:

		Monthly Rate ($ per kW)
Transmission Rates	**Starting 2009/05/01**	**Ending 2009/04/30**
Network Service Rate	**2.57**	2.31
Line Connection Service Rate	**0.70**	0.59
Transformation Connection Service Rate	**1.62**	1.61

Thunder Bay Hydro, from market opening, had been over collecting on the Retail Transmission and Network Connection charges and hence opted to correct for such charges during the 2006 EDR process. However, the mechanics of the 2006 EDR Model actually resulted in an overcorrection of Thunder Bay Hydro's Transmission and Network Connection Charges billed to customers (refer to copy of worksheet 8-6 of the Thunder Bay Hydro's 2006 EDR filing which compares the actual data as filed compared to what should have been entered into the model). As

can be seen, the resulting retail rates are substantially lower than they should have been since May 1, 2006. The adjustment to the Retail Transmission and Network Connection charges as directed by the OEB effective with Thunder Bay Hydro's May 1, 2008 rates further compounded this error.

Information Used for the Calculation:

- The 2006 EDR as filed by Thunder Bay Hydro supporting the Rate Order Arising From the Decision On The Motion of June 21, 2007; specifically worksheet 8-6 of the model ;

- The 2008 Incentive Rate Mechanism Adjustment Model; specifically Sheet 9A – 2008 RTS Rate Change;

- The sum of the IESO Network Service Charges compared to billing revenues by month from January 2006 to June 2008; and

- The sum of the IESO Line Connection Service Charges compared to billing revenues by month from January 2006 to June 2008.

Determining Retail Transmission Rates:

To calculate the Retail Transmission Rates, Thunder Bay Hydro simply corrected the 2006 EDR calculation as shown in Table 3 and 4 below. Table 3 represents what was in the 2006 EDR approved Model. The revenue and cost figures incorrectly included RSVA adjustments resulting in a lower cost to revenue ratio. Table 4 represents the 2006 EDR Model with the actual RTS costs and revenue exclusive of RSVA adjustments. The RTS rates resulting in Table 4 were then populated in Table 2, in the column called "2008 RTS Rates as per Table 4". For example, the network rate for the residential class is 0.0057 (Table 4, Retail Transmission Rate $/kWh) less 0.0009 (Table 4, Increment $/kWh) or 0.0048 in Table 2. Finally, Table 1 below adjusts the resulting 2008 RTS rates by the OEB approved Hydro One costs increases. The resulting change to the 2008 existing RTS rates are as shown in the following Table 2 (i.e. the Residential increase

to the Network Service Rate is 1.0285 and the Line and Transformation Connection Service Rate is 1.3237).

To review for reasonableness of the results, Thunder Bay Hydro compared the Cost to Billings ratios for the period from June 2006 (the Hydro One rate reductions occurred May 1, 2006) to June 2008 as summarized in Table 4 with detail provided in Table 5. The average of the sum of the IESO Network Services Charges divided by the sum of the Network billing revenues for the period June 2006 to June 2008 was 1.0277. The average of the sum of the IESO Transformation Connection Service Charges divided by the Connection billing revenues for the period June 2006 to June 2008 was 1.4307.

Thunder Bay Hydro concludes that the simplistic approach results in reasonable estimates of the rate and that the rates are consistent with the majority of LDCs in the province.

Table 1

#N/A

Thunder Bay Hydro Electricity Distribution Inc.

EB-2007-XXXX, EB-2007-0580, EB-2005-0419
October 31 2007

Sheet 9A - 2008 RTS Rate Change

Instruction: The applicant may input the % value which will applied equally to to all rate classes or enter individual rates.

Retail Transmission Rates - Network Service Rate Adjustment	(Enter % amount here:)	11.25%	
Retail Transmission Rates - Line and Transformation Connection Service Rate Adjustment		5.00%	

		2008 Revised Rates per Table 2	2009 Proposed Rates	% Change
Residential				
Retail Transmission Rate – Network Service Rate	**$/kWh**	0.0039	0.0043	11.2500%
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kWh**	0.0032	0.0034	5.0000%
General Service Less Than 50 kW				
Retail Transmission Rate – Network Service Rate	**$/kWh**	0.0036	0.0040	11.2500%
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kWh**	0.0029	0.0030	5.0000%
General Service 50 to 999 kW				
Retail Transmission Rate – Network Service Rate	**$/kW**	1.4549	1.6186	11.2500%
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kW**	1.1362	1.1930	5.0000%
Retail Transmission Rate – Network Service Rate - Interval Metered	**$/kW**	1.5433	1.7169	11.2500%
Retail Transmission Rate – Line and Transformation Connection Service Rate - Interv	**$/kW**	1.2557	1.3185	5.0000%
General Service 1,000 to 4,999 kW				
Retail Transmission Rate – Network Service Rate	**$/kW**	1.5433	1.7169	11.2500%
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kW**	1.2557	1.3185	5.0000%
Retail Transmission Rate – Network Service Rate (if applicable)	**$/kW**	0.0000	0.0000	0.0000%
Retail Transmission Rate – Line and Transformation Connection Service Rate (if app	**$/kW**	0.0000	0.0000	0.0000%
Retail Transmission Rate – Network Service Rate (if applicable)	**$/kW**	0.0000	0.0000	0.0000%
Retail Transmission Rate – Line and Transformation Connection Service Rate (if app	**$/kW**	0.0000	0.0000	0.0000%
Unmetered Scattered Load				
Retail Transmission Rate – Network Service Rate	**$/kWh**	0.0036	0.0040	11.2500%
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kWh**	0.0029	0.0030	5.0000%
Sentinel Lighting				
Retail Transmission Rate – Network Service Rate	**$/kW**	1.1028	1.2269	11.2500%
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kW**	0.8967	0.9415	5.0000%
Street Lighting				
Retail Transmission Rate – Network Service Rate	**$/kW**	1.0972	1.2206	11.2500%
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kW**	0.8783	0.9222	5.0000%

Table 2

#N/A

Thunder Bay Hydro Electricity Distribution Inc.

EB-2007-XXXX, EB-2007-0580, EB-2005-0419
October 31 2007

Sheet 9A - 2008 RTS Rate Change

Instruction: The applicant may input the % value which will applied equally to to all rate classes or enter individual rates.

Retail Transmission Rates - Network Service Rate Adjustment	(Enter % amount here:)	-18.0%	
Retail Transmission Rates - Line and Transformation Connection Service Rate Adjustment		-5.0%	

		2008 RTS Rates as per Table 4	2008 RTS Adjusted for Hydro One Cost Reduction	% Change	2008 Current RTS Rates	% Change
Residential						
Retail Transmission Rate – Network Service Rate	**$/kWh**	0.0048	0.0039	-18.0000%	0.0038	102.85%
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kWh**	0.0033	0.0032	-5.0000%	0.0024	132.37%
General Service Less Than 50 kW						
Retail Transmission Rate – Network Service Rate	**$/kWh**	0.0043	0.0036	-18.0000%	0.0034	104.87%
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kWh**	0.0030	0.0029	-5.0000%	0.0022	129.96%
General Service 50 to 999 kW						
Retail Transmission Rate – Network Service Rate	**$/kW**	1.7742	1.4549	-18.0000%	1.3979	104.07%
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kW**	1.1960	1.1362	-5.0000%	0.8540	133.04%
Retail Transmission Rate – Network Service Rate - Interval Metered	**$/kW**	1.8821	1.5433	-18.0000%	1.4828	104.08%
Retail Transmission Rate – Line and Transformation Connection Service Rate - Inter	**$/kW**	1.3218	1.2557	-5.0000%	0.9437	133.06%
General Service 1,000 to 4,999 kW						
Retail Transmission Rate – Network Service Rate	**$/kW**	1.8821	1.5433	-18.0000%	1.4828	104.08%
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kW**	1.3218	1.2557	-5.0000%	0.9437	133.06%
Unmetered Scattered Load						
Retail Transmission Rate – Network Service Rate	**$/kWh**	0.0043	0.0036	-18.0000%	0.0034	104.87%
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kWh**	0.0030	0.0029	-5.0000%	0.0022	129.96%
Sentinel Lighting						
Retail Transmission Rate – Network Service Rate	**$/kW**	1.3448	1.1028	-18.0000%	1.0595	104.08%
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kW**	0.9439	0.8967	-5.0000%	0.6739	133.06%
Street Lighting						
Retail Transmission Rate – Network Service Rate	**$/kW**	1.3381	1.0972	-18.0000%	1.0542	104.08%
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kW**	0.9246	0.8783	-5.0000%	0.6602	133.04%

Table 3

Next TRANSMISSION RATES (Input)

THIS REPRESENTS WORKSHEET 8-6 OF THE 2006 EDR RATE APPLICATION

Show Top

	Retail Transmission Rate per kWh						Retail Transmission Rate per kW					
	Retail Tranmission Rate $/kWh			Increment $/kWh		Adjusted Retail Tranmission Rate $	Retail Tranmission Rate $/kW			Increment $		Adjusted Retail Tranmission Rate $
	Network	Connection	Total	Network	Connection	per KWh	Network	Connection	Total	Network	Connection	per KW
RESIDENTIAL												
Regular	0.0057	0.0050	0.0107	(0.0011)	(0.0025)	0.0071						
GENERAL SERVICE												
Less than 50 kW	0.0052	0.0045	0.0097	(0.0010)	(0.0022)	0.0064						
Greater than 50 kW Time of Use							2.2535	1.9603	4.2138	(0.4430)	(0.9749)	2.7959
Other > 50 kW (specify) .>50kW<1000kW							2.1218	1.7882	3.9100	(0.4171)	(0.8893)	2.6035
Other > 50 kW (specify) .>1000kW<5000kW							2.2508	1.9763	4.2271	(0.4425)	(0.9829)	2.8017
Large Use (> 5000 kW)							2.4952	2.2417	4.7369	(0.4905)	(1.1149)	3.1315
Unmetered Scattered Load												
Sentinel Lighting							1.6083	1.4113	3.0196	(0.3162)	(0.7019)	2.0015
Street Lighting							1.6002	1.3824	2.9826	(0.3146)	(0.6875)	1.9805

	Network	Connection	
Total 2004 Cost	$ 4,123,346	$ 1,841,520	This represents the cost for the year less the closing variance balance plus the opening variance balance.
			$5,149,905-2,352,208+1,325,749=$4,123,346 Network & $3,679,199-4,677,118+2,839,439=$1,841,520 Connecton
Total 2004 Revenue	$ 5,132,353	$ 3,663,478	This represents the revenue for the year after being reduced for the variance adjustment.
Variance	**$ (1,009,007)**	**$ (1,821,958)**	
Cost / Revenue Ratio	0.80	0.50	

Table 4

	THE FOLLOWING REPRESENTS WHAT SHOULD HAVE BEEN THE CALCULATION		
	Network	**Connection**	
Total 2004 Cost	$ 5,149,905	$ 3,679,199	This represents the cost for the year
Total 2004 Revenue	$ 6,158,812	$ 5,501,157	This represents the revenue for the year
			$5,132,353+2,352,208-1,325,749=$6,158,812 Network & $3,663,478+4,677,118-2,839,439=$5,501,157 Connecton
Variance	**$ (1,008,907)**	**$ (1,821,958)**	
Cost / Revenue Ratio	0.84	0.67	

	Retail Transmission Rate per kWh						Retail Transmission Rate per kW					
	Retail Tranmission Rate $/kWh			Increment $/kWh		Adjusted Retail Tranmission Rate $	Retail Tranmission Rate $/kW			Increment $		Adjusted Retail Tranmission Rate $
	Network	Connection	Total	Network	Connection	per KWh	Network	Connection	Total	Network	Connection	per KW
RESIDENTIAL												
Regular	0.0057	0.0050	0.0107	(0.0009)	(0.0017)	0.0081						
GENERAL SERVICE												
Less than 50 kW	0.0052	0.0045	0.0097	(0.0009)	(0.0015)	0.0074						
Greater than 50 kW Time of Use							2.2535	1.9603	4.2138	(0.3692)	(0.6492)	3.1954
Other > 50 kW (specify) .>50kW<1000kW							2.1218	1.7882	3.9100	(0.3476)	(0.5922)	2.9702
Other > 50 kW (specify) .>1000kW<5000kW							2.2508	1.9763	4.2271	(0.3687)	(0.6545)	3.2038
Large Use (> 5000 kW)							2.4952	2.2417	4.7369	(0.4088)	(0.7424)	3.5857
Unmetered Scattered Load												
Sentinel Lighting							1.6083	1.4113	3.0196	(0.2635)	(0.4674)	2.2887
Street Lighting							1.6002	1.3824	2.9826	(0.2621)	(0.4578)	2.2626

Table 5

Thunder Bay Hydro
Net Connection & Network Variances
Period January 1, 2006 to June 30, 2008

	NW Cost/Rev Ratio	Cnxn Cost/Rev Ratio
Jan 2006	0.84	0.66
Feb 2006	0.94	0.72
Mar 2006	0.82	0.70
Apr 2006	0.97	0.77
May 2006	0.71	0.62
Jun 2006	1.06	1.20
July 2006	1.03	1.34
Aug 2006	1.07	1.47
Sep 2006	1.21	1.60
Oct 2006	1.07	1.48
Nov 2006	1.04	1.33
Dec 2006	1.22	1.64
Jan 2007	1.05	1.33
Feb 2007	1.19	1.53
Mar 2007	0.94	1.30
Apr 2007	1.26	1.54
May 2007	0.92	1.29
Jun 2007	1.06	1.42
July 2007	1.00	1.41
Aug 2007	1.25	1.60
Sep 2007	1.35	1.85
Oct 2007	0.96	1.27
Nov 2007	1.00	1.35
Dec 2007	1.03	1.64
Jan 2008	0.80	1.25
Feb 2008	0.97	1.52
Mar 2008	0.94	1.55
Apr 2008	0.66	1.24
May 2008	0.74	1.30
Jun 2008	0.88	1.30
Average of June 2006 to June 2008	**1.0277**	**1.4307**

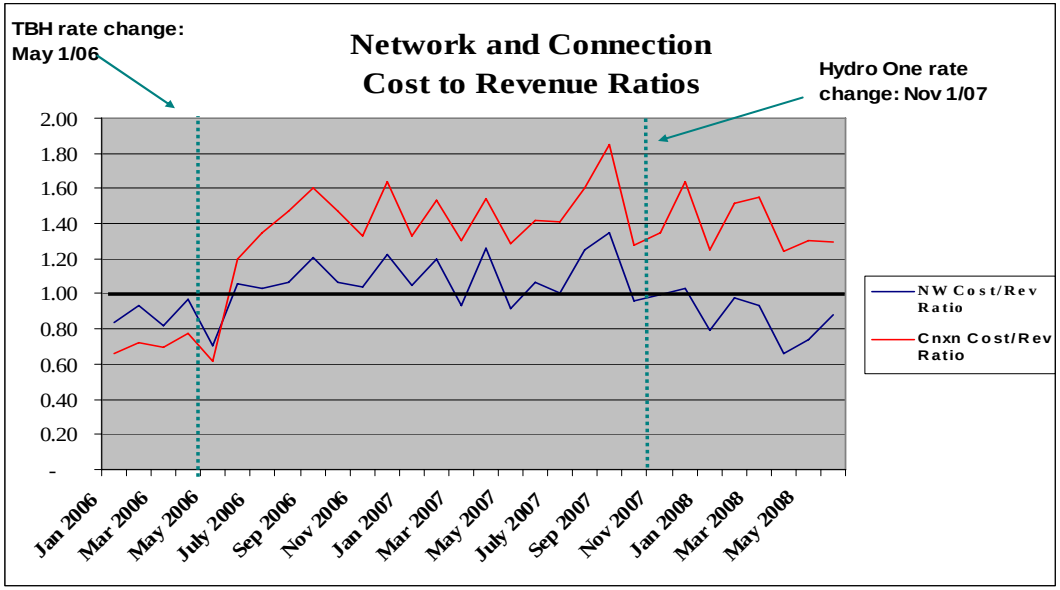


Table 6

Thunder Bay Hydro
Net Connection & Network Cost to Revenue Ratios
Period January 1, 2006 to June 30, 2008

	Network			Connection		
HISTORY	Revenue	Cost - paid to IESO	Cost/Rev Ratio	Revenue	Cost - paid to IESO	Cost/Rev Ratio
Jan 2006	621,467	521,521	0.84	543,093	359,878	0.66
Feb 2006	497,304	466,033	0.94	432,839	312,362	0.72
Mar 2006	567,462	466,344	0.82	492,747	343,269	0.70
Apr 2006	457,986	443,651	0.97	398,155	307,407	0.77
May 2006	539,568	380,431	0.71	464,844	288,305	0.62
Jun 2006	409,547	433,381	1.06	256,847	306,993	1.20
July 2006	350,914	362,486	1.03	195,681	263,131	1.34
Aug 2006	426,491	454,325	1.07	231,803	340,919	1.47
Sep 2006	368,366	444,887	1.21	200,386	320,816	1.60
Oct 2006	392,348	418,761	1.07	212,764	313,976	1.48
Nov 2006	398,954	415,665	1.04	216,046	287,149	1.33
Dec 2006	375,355	459,068	1.22	204,933	336,477	1.64
Jan 2007	477,853	501,470	1.05	259,077	344,646	1.33
Feb 2007	407,853	487,018	1.19	221,033	338,924	1.53
Mar 2007	510,207	478,406	0.94	276,352	360,639	1.30
Apr 2007	383,083	481,960	1.26	209,225	323,236	1.54
May 2007	461,264	424,175	0.92	250,233	322,112	1.29
Jun 2007	364,507	387,209	1.06	198,192	280,510	1.42
July 2007	394,413	395,340	1.00	213,715	302,016	1.41
Aug 2007	367,668	458,488	1.25	199,526	319,716	1.60
Sep 2007	339,227	456,943	1.35	183,842	340,652	1.85
Oct 2007	398,057	382,944	0.96	215,728	274,685	1.27
Nov 2007	384,277	383,601	1.00	208,323	281,212	1.35
Dec 2007	370,345	382,012	1.03	201,394	329,480	1.64
Jan 2008	500,802	398,286	0.80	271,040	338,806	1.25
Feb 2008	420,632	409,718	0.97	228,047	346,571	1.52
Mar 2008	396,307	370,970	0.94	214,836	333,531	1.55
Apr 2008	445,209	293,785	0.66	244,085	303,824	1.24
May 2008	395,482	294,377	0.74	215,489	280,232	1.30
Jun 2008	339,488	297,637	0.88	204,374	265,407	1.30

Proposed Revised Retail Transmission Service Rates:

The following Table sets out Thunder Bay Hydro's proposed Retail Transmission Service Rates for the 2009 Test Year:

Table 7

Rate Classification	Metric	RTR – Network	RTR – Line and Transformation
Residential	kWh	0.0043	0.0034
General Service Less Than 50 kW	kWh	0.0040	0.0030
General Service Greater Than 50 kW	kW	1.6186	1.1930
General Service Greater Than 50 kW (Interval Metered)		1.7169	1.3185
General Service Greater Than 1,000 kw to 4,999 kw	kW	1.7169	1.3185
Street Lights	kW	1.2206	.9222
Sentinel Lights	kW	1.2269	.9415
Unmetered Scattered Load	kWh	0.0040	0.0030

The balances in Thunder Bay Hydro's related Deferral Variance Accounts are expected to be disposed of through a separate proceeding as indicated by the OEB.

EXISTING RATE CLASSES:

Residential:

This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers.

General Service Less Than 50kW:

This classification refers to a non residential account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW. This class includes small commercial services such as small stores, small service stations, restaurants, churches, small offices and other establishments with similar loads.

General Service Greater Than 50 kW:

This classification refers to a non-residential account whose monthly average peak demand is greater than, or is forecast to be greater than, 50 kW but less than 1,000 kW. This class includes medium and large-size commercial buildings, apartment buildings, condominiums, trailer courts, industrial plants, as well as large stores, shopping centers, hospitals, manufacturing or processing plants, garages, storage buildings, restaurants, office buildings, hotels, motels, schools, colleges, arenas and other comparable premises.

Unmetered Scattered Load:

This classification refers to an account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, private sentinel lighting, etc. The customer will provide

detailed manufacturer information/documentation with regard to electrical demand/ consumption of the proposed unmetered load.

Sentinel Lighting:

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

Street Lighting:

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

EXISTING RATE SCHEDULE:

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2007-0880

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

AND IN THE MATTER OF an Application by Thunder Bay Hydro Electricity Distribution Inc. pursuant to section 78 of the Ontario Energy Board Act seeking approval to amend electricity distribution rates.

BEFORE: Paul Vlahos
Presiding Member

Paul Sommerville
Member

RATE ORDER

Thunder Bay Hydro Electricity Distribution Inc. ("Thunder Bay") is a licensed distributor of electricity providing service to consumers within its licensed service area. Thunder Bay filed an application with the Ontario Energy Board (the "Board") for an order or orders approving or fixing just and reasonable rates for the distribution of electricity and other charges, to be effective May 1, 2008.

On March 19, 2008, the Board issued its Decision (the "Decision") regarding Thunder Bay's application.

The Board directed that Thunder Bay file with the Board a proposed Tariff of Rates and Charges reflecting the Board's Decision, within 7 days of the date of the Decision.

Thunder Bay has provided the Board with a proposed Tariff of Rates and Charges.
The Board is satisfied that the document accurately reflects the Decision.

For completeness of the regulated charges, the Board has included in the Tariff of Rates and Charges the charges pertaining to services provided to retailers or consumers regarding the supply of competitive electricity, which are referenced in Chapter 12 of the 2006 Electricity Distribution Rate Handbook.

THE BOARD ORDERS THAT:

1. The Tariff of Rates and Charges set out in Appendix "A" of this Rate Order is approved, effective May 1, 2008, for electricity consumed or estimated to have been consumed on and after May 1, 2008.

2. The Tariff of Rates and Charges set out in Appendix "A" of this Order supersedes all previous distribution rate schedules approved by the Board for Thunder Bay and is final in all respects.

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

DATED at Toronto, April 15, 2008.

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Appendix "A"

The Tariff of Rates and Charges

To The Rate Order Arising from Decision

Thunder Bay Hydro Electricity Distribution Inc.

EB-2007-0880

April 15, 2008

Thunder Bay Hydro Electricity Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective May 1, 2008

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

EB-2007-0880

APPLICATION

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

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
SPECIFIC SERVICE CHARGES – May 1, 2008 for all charges incurred by customers on or after that date.
RETAIL SERVICE CHARGES – May 1, 2008 for all charges incurred by retailers or customers on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2008 unless the distributor is not capable of prorating changed loss factors jointly with distribution rates. In that case, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

SERVICE CLASSIFICATIONS

Residential

This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers.

General Service Less Than 50 kW

This classification refers to a non residential account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW. This class includes small commercial services such as small stores, small service stations, restaurants, churches, small offices and other establishments with similar loads.

General Service 50 to 999 kW

This classification refers to a non residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 1,000 kW. This class includes medium and large-size commercial buildings, apartment buildings, condominiums, trailer courts, industrial plants, as well as large stores, shopping centers, hospitals, manufacturing or processing plants, garages, storage buildings, hotels, motels, schools, colleges, arenas and other comparable premises. Note that for the application of the Retail Transmission Rate – Network Service Rate and the Retail Transmission Rate – Line and Transformation Connection Service Rate the following sub-classifications apply:

General Service 50 to 1,000 kW non-interval metered
General Service 50 to 1,000 kW interval metered.

General Service 1,000 to 4,999 kW

This classification refers to a non residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 1,000 kW but less than 5,000 kW.

Unmetered Scattered Load

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

Sentinel Lighting

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

Street Lighting

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

Thunder Bay Hydro Electricity Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective May 1, 2008

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

EB-2007-0880

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	11.22
Distribution Volumetric Rate	$/kWh	0.0138
Retail Transmission Rate – Network Service Rate	$/kWh	0.0038
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0024
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	$	17.33
Distribution Volumetric Rate	$/kWh	0.0125
Retail Transmission Rate – Network Service Rate	$/kWh	0.0034
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0022
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 999 kW

Service Charge	$	186.52
Distribution Volumetric Rate	$/kW	1.0637
Retail Transmission Rate – Network Service Rate	$/kW	1.3979
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.8540
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	1.4828
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	0.9437
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 1,000 to 4,999 kW

Service Charge	$	1,633.10
Distribution Volumetric Rate	$/kW	1.4364
Retail Transmission Rate – Network Service Rate	$/kW	1.4828
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.9437
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)	$	8.51
Distribution Volumetric Rate	$/kWh	0.0124
Retail Transmission Rate – Network Service Rate	$/kWh	0.0034
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0022
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Thunder Bay Hydro Electricity Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective May 1, 2008

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

EB-2007-0880

Sentinel Lighting		
Service Charge (per connection)	$	6.12
Distribution Volumetric Rate	$/kW	4.9122
Retail Transmission Rate – Network Service Rate	$/kW	1.0595
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.6739
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)	$	0.34
Distribution Volumetric Rate	$/kW	2.0569
Retail Transmission Rate – Network Service Rate	$/kW	1.0542
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.6602
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
Easement letter	$	15.00
Account history	$	15.00
Returned cheque charge (plus bank charges)	$	25.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Disconnect/Reconnect charge - At Meter – during regular hours	$	65.00
Disconnect/Reconnect charge - At Meter – after regular hours	$	185.00
Disconnect/Reconnect charge - At Pole - during regular hours	$	185.00
Disconnect/Reconnect charge - At Pole - after regular hours	$	415.00
Install/Remove load control device - during regular hours	$	65.00
Install/Remove load control device - after regular hours	$	185.00
Service call – customer owned equipment	$	30.00
Service call – after regular hours	$	165.00
Temporary Service – Install & remove – overhead – no transformer	$	500.00
Temporary Service – Install & remove – underground – no transformer	$	300.00
Temporary Service – Install & remove – overhead – with transformer	$	1000.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35
Allowances		
Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

Thunder Bay Hydro Electricity Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective May 1, 2008

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

EB-2007-0880

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 Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per 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 FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0457
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0145
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0352
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0045

PROPOSED RATE CLASSES:

Thunder Bay Hydro is not requesting any changes to the existing rate classes

SCHEDULE OF PROPOSED RATES AND CHARGES:

Thunder Bay Hydro Electricity Distribution Inc.

SCHEDULE OF PROPOSED RATES AND CHARGES
Effective May 1, 2009

MONTHLY RATES AND CHARGES

Residential		
Service Charge	**$**	11.26
Distribution Volumetric Rate	**$/kWh**	0.0142
LRAM and SSM Rate Rider	**$kWh**	0.0005
Smart Meter Rate Rider	**$month**	1.2500
Regulatory Assets Rate Rider	**$kWh**	0.0000
Retail Transmission Rate – Network Service Rate	**$/kWh**	0.0043
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kWh**	0.0034
Wholesale Market Service Rate	**$/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	**$**	18.56
Distribution Volumetric Rate	**$/kWh**	0.0136
LRAM and SSM Rate Rider	**$kWh**	0.0000
Smart Meter Rate Rider	**$month**	1.2500
Regulatory Assets Rate Rider	**$kWh**	0.0000
Retail Transmission Rate – Network Service Rate	**$/kWh**	0.0040
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kWh**	0.0030
Wholesale Market Service Rate	**$/kWh**	0.0052
Rural Rate Protection Charge	**$/kWh**	0.0010
Standard Supply Service – Administrative Charge (if applicable)	**$**	0.25
General Service 50 to 999 kW		
Service Charge	**$**	224.18
Distribution Volumetric Rate	**$/kW**	1.2583
LRAM and SSM Rate Rider	**$kWh**	0.0021
Smart Meter Rate Rider	**$month**	1.2500
Regulatory Assets Rate Rider	**$kWh**	0.0000
Retail Transmission Rate – Network Service Rate	**$/kW**	1.6186
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kW**	1.1930
Retail Transmission Rate – Network Service Rate - Interval Metered	**$/kW**	1.7169
Retail Transmission Rate – Line and Transformation Connection Service Rate - I	**$/kW**	1.3185
Wholesale Market Service Rate	**$/kWh**	0.0052
Rural Rate Protection Charge	**$/kWh**	0.0010
Standard Supply Service – Administrative Charge (if applicable)	**$**	0.25

General Service 1,000 to 4,999 kW

Service Charge	**$**	2,069.12
Distribution Volumetric Rate	**$/kW**	1.6615
LRAM and SSM Rate Rider	**$kW**	0.0027
Smart Meter Rate Rider	**$month**	1.2500
Regulatory Assets Rate Rider	**$kW**	0.0000
Retail Transmission Rate – Network Service Rate	**$/kW**	1.7169
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kW**	1.3185
Wholesale Market Service Rate	**$/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)	**$**	9.26
Distribution Volumetric Rate	**$/kWh**	0.0135
LRAM and SSM Rate Rider	**$/kWh**	0.0184
Regulatory Assets Rate Rider	**$kWh**	0.0000
Retail Transmission Rate – Network Service Rate	**$/kWh**	0.0040
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kWh**	0.0030
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)	**$**	6.66
Distribution Volumetric Rate	**$/kW**	5.3435
Regulatory Assets Rate Rider	**$kW**	0.0000
Retail Transmission Rate – Network Service Rate	**$/kW**	1.2269
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kW**	0.9415
Wholesale Market Service Rate	**$/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)	**$**	1.14
Distribution Volumetric Rate	**$/kW**	6.9151
Regulatory Assets Rate Rider	**$kW**	0.0000
Retail Transmission Rate – Network Service Rate	**$/kW**	1.2206
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kW**	0.9222
Wholesale Market Service Rate	**$/kWh**	0.0052
Rural Rate Protection Charge	**$/kWh**	0.0010

Specific Service Charges

Customer Administration

Arrears certificate	**$**	15.00
Statement of account	**$**	15.00
Easement letter	**$**	15.00
Account history	**$**	15.00
Returned cheque charge (plus bank charges)	**$**	25.00
Legal letter charge	**$**	15.00
Account set up charge/change of occupancy charge (plus credit agency cos	**$**	30.00
Special meter reads	**$**	30.00
Meter dispute charge plus Measurement Canada fees (if meter found corre	**$**	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	**$**	65.00
Disconnect/Reconnect at meter - after regular hours	**$**	185.00
Disconnect/Reconnect at pole - during regular hours	**$**	185.00
Disconnect/Reconnect at pole - after regular hours	**$**	415.00
Install/Remove load control device - during regular hours	**$**	65.00
Install/Remove load control device - after regular hours	**$**	185.00
Service call - customer-owned equipment	**$**	30.00
Service call - after regular hours	**$**	165.00
Specific Charge for Access to the Power Poles $/pole/year	**$**	22.35
Allowances		
Transformer Allowance for Ownership -per kW/kva of billing demand/month	**$/kW**	(0.60)
Primary Metering Allowance for transformer losses - applied to measured demand and energy	**%**	(1.00)

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0478
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0145
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0373
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0045

The following table provides a reconciliation between the 2009 distribution rate calculations based on the 2009 Proposed Rates and the total base revenue required. The reconciliation yields an acceptable difference.

RECONCILIATION OF RATE CLASS REVENUE:

Table 1

Customer Class	Fixed Distribution Revenue	Variable Distribution Revenue	Transformer Allowance Credit	Total Distribution Revenue	Expected
Residential	$ 6,031,047	$ 4,796,366		$ 10,827,413	$ 10,819,714
GS <50 kW	$ 994,668	$ 1,957,875		$ 2,952,543	$ 2,952,080
GS>50 kW	$ 1,373,995	$ 902,531	($77,679)	$ 2,198,846	$ 2,198,802
GS 1,000 to 4,999 kW	$ 471,759	$ 930,681	($332,726)	$ 1,069,714	$ 1,069,706
Street Light	$ 179,556	$ 216,277		$ 395,833	$ 395,840
Sentinel	$ 14,091	$ 2,148		$ 16,239	$ 16,239
Unmetered Scattered Load	$ 48,545	$ 18,026		$ 66,570	$ 66,556
Back-up/Standby Power	$ -			$ -	$ -
Total	**$ 9,113,661**	**$ 8,823,903**	**($410,406)**	**$ 17,527,159**	**$ 17,518,938**
				Difference Due to Rate Roundin	
				-$ 8,221	

RATE AND BILL IMPACTS:

Appendix A to this Schedule presents the results of the assessment of customer total bill impacts by level of consumption by customer per rate class and per the total customer class.

Impacts are derived using the applicable May 1, 2008 rates and the proposed 2009 distribution rates, including Rate Rider for the recovery of LRAM/SSM and Smart Meter Rates.

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

TABLE OF RATE AND BILL IMPACTS

TABLE OF RATE AND BILL IMPACTS

RESIDENTIAL

		2008 BILL			2009 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Consumption	Monthly Service Charge			10.95			11.26	0.31	2.83%	1.45%
100 kWh	Distribution (kWh)	100	0.0138	1.38	100	0.0142	1.42	0.04	2.90%	0.19%
	Smart Meter Rider (per month)			0.27			1.25	0.98	362.96%	4.58%
	LRAM & SSM Rider (kWh)	100			100	0.0005	0.05	0.05	#DIV/0!	0.23%
	Regulatory Assets (kWh)	100	0.0000	0.00	100	0.0000	0.00	0.00	#DIV/0!	0.00%
	Sub-Total			**12.60**			**13.98**	**1.38**	**10.95%**	**6.45%**
	Other Charges (kWh)	105	0.0194	2.03	105	0.0209	2.19	0.16	7.95%	0.75%
	Cost of Power Commodity (kWh)	105	0.0500	5.23	105	0.0500	5.24	0.01	0.20%	0.05%
	Total Bill			**19.86**			**21.41**	**1.55**	**7.81%**	**7.25%**

RESIDENTIAL

		2008 BILL			2009 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge			10.95			11.26	0.31	2.83%	0.89%
250 kWh	Distribution (kWh)	250	0.0138	3.45	250	0.0142	3.55	0.10	2.90%	0.29%
	Smart Meter Rider (per month)			0.27			1.25	0.98	362.96%	2.82%
	LRAM & SSM Rider (kWh)	250			250	0.0005	0.13	0.13	#DIV/0!	0.36%
	Regulatory Assets (kWh)	250	0.0000	0.00	250	0.0000	0.00	0.00	#DIV/0!	0.00%
	Sub-Total			**14.67**			**16.19**	**1.52**	**10.33%**	**4.36%**
	Other Charges (kWh)	261	0.0194	5.07	262	0.0209	5.47	0.40	7.95%	1.16%
	Cost of Power Commodity (kWh)	261	0.0500	13.07	262	0.0500	13.10	0.03	0.20%	0.08%
	Total Bill			**32.81**			**34.76**	**1.94**	**5.93%**	**5.59%**

RESIDENTIAL

Consumption 500 kWh		2008 BILL			2009 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
	Monthly Service Charge			10.95			11.26	0.31	2.83%	0.54%
	Distribution (kWh)	500	0.0138	6.90	500	0.0142	7.10	0.20	2.90%	0.35%
	Smart Meter Rider (per month)			0.27			1.25	0.98	362.96%	1.72%
	LRAM & SSM Rider (kWh)	500			500	0.0005	0.25	0.25	#DIV/0!	0.44%
	Regulatory Assets (kWh)	500	0.0000	0.00	500	0.0000	0.00	0.00	#DIV/0!	0.00%
	Sub-Total			**18.12**			**19.86**	**1.74**	**9.60%**	**3.05%**
	Other Charges (kWh)	523	0.0194	10.14	524	0.0209	10.95	0.81	7.95%	1.41%
	Cost of Power Commodity (kWh)	523	0.0500	26.14	524	0.0500	26.20	0.05	0.20%	0.09%
	Total Bill			**54.41**			**57.00**	**2.60**	**4.78%**	**4.56%**

RESIDENTIAL

Consumption 750 kWh		2008 BILL			2009 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
	Monthly Service Charge			10.95			11.26	0.31	2.83%	0.38%
	Distribution (kWh)	750	0.0138	10.35	750	0.0142	10.65	0.30	2.90%	0.37%
	Smart Meter Rider (per month)			0.27			1.25	0.98	362.96%	1.21%
	LRAM & SSM Rider (kWh)	750			750	0.0005	0.38	0.38	#DIV/0!	0.46%
	Regulatory Assets (kWh)	750	0.0000	0.00	750	0.0000	0.00	0.00	#DIV/0!	0.00%
	Sub-Total			**21.57**			**23.54**	**1.97**	**9.11%**	**2.43%**
	Other Charges (kWh)	784	0.0194	15.21	786	0.0209	16.42	1.21	7.95%	1.49%
	Cost of Power Commodity (kWh)	600	0.0500	30.00	600	0.0500	30.00	0.00	0.00%	0.00%
	Cost of Power Commodity (kWh)	184	0.0590	10.87	186	0.0590	10.97	0.09	0.85%	0.11%
	Total Bill			**77.66**			**80.92**	**3.27**	**4.21%**	**4.04%**

RESIDENTIAL

Consumption		2008 BILL			2009 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
1,000 kWh	Monthly Service Charge			10.95			11.26	0.31	2.83%	0.29%
	Distribution (kWh)	1,000	0.0138	13.80	1,000	0.0142	14.20	0.40	2.90%	0.38%
	Smart Meter Rider (per month)			0.27			1.25	0.98	362.96%	0.93%
	LRAM & SSM Rider (kWh)	1,000			1,000	0.0005	0.50	0.50	#DIV/0!	0.47%
	Regulatory Assets (kWh)	1,000	0.0000	0.00	1,000	0.0000	0.00	0.00	#DIV/0!	0.00%
	Sub-Total			**25.02**			**27.21**	**2.19**	**8.75%**	**2.08%**
	Other Charges (kWh)	1,046	0.0194	20.29	1,048	0.0209	21.90	1.61	7.95%	1.53%
	Cost of Power Commodity (kWh)	600	0.0500	30.00	600	0.0500	30.00	0.00	0.00%	0.00%
	Cost of Power Commodity (kWh)	446	0.0590	26.30	448	0.0590	26.42	0.12	0.47%	0.12%
	Total Bill			**101.60**			**105.53**	**3.93**	**3.86%**	**3.72%**

RESIDENTIAL

Consumption		2008 BILL			2009 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
1,500 kWh	Monthly Service Charge			10.95			11.26	0.31	2.83%	0.20%
	Distribution (kWh)	1,500	0.0138	20.70	1,500	0.0142	21.30	0.60	2.90%	0.39%
	Smart Meter Rider (per month)			0.27			1.25	0.98	362.96%	0.63%
	LRAM & SSM Rider (kWh)	1,500			1,500	0.0005	0.75	0.75	#DIV/0!	0.48%
	Regulatory Assets (kWh)	1,500	0.0000	0.00	1,500	0.0000	0.00	0.00	#DIV/0!	0.00%
	Sub-Total			**31.92**			**34.56**	**2.64**	**8.27%**	**1.71%**
	Other Charges (kWh)	1,569	0.0194	30.43	1,572	0.0209	32.85	2.42	7.95%	1.56%
	Cost of Power Commodity (kWh)	600	0.0500	30.00	600	0.0500	30.00	0.00	0.00%	0.00%
	Cost of Power Commodity (kWh)	969	0.0590	57.14	972	0.0590	57.33	0.19	0.33%	0.12%
	Total Bill			**149.49**			**154.74**	**5.24**	**3.51%**	**3.39%**

RESIDENTIAL

		2008 BILL			2009 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge			10.95			11.26	0.31	2.83%	0.15%
2,000 kWh	Distribution (kWh)	2,000	0.0138	27.60	2,000	0.0142	28.40	0.80	2.90%	0.39%
	Smart Meter Rider (per month)			0.27			1.25	0.98	362.96%	0.48%
	LRAM & SSM Rider (kWh)	2,000			2,000	0.0005	1.00	1.00	#DIV/0!	0.49%
	Regulatory Assets (kWh)	2,000	0.0000	0.00	2,000	0.0000	0.00	0.00	#DIV/0!	0.00%
	Sub-Total			**38.82**			**41.91**	**3.09**	**7.96%**	**1.52%**
	Other Charges (kWh)	2,091	0.0194	40.57	2,096	0.0209	43.80	3.22	7.95%	1.58%
	Cost of Power Commodity (kWh)	600	0.0500	30.00	600	0.0500	30.00	0.00	0.00%	0.00%
	Cost of Power Commodity (kWh)	1,491	0.0590	87.99	1,496	0.0590	88.24	0.25	0.28%	0.12%
	Total Bill			**197.39**			**203.95**	**6.56**	**3.32%**	**3.22%**

GENERAL SERVICE < 50 kW

		2008 BILL			2009 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Consumption	Monthly Service Charge			17.06			18.56	1.50	8.79%	1.37%
1,000 kWh	Distribution (kWh)	1,000	0.0125	12.50	1,000	0.0136	13.60	1.10	8.80%	1.00%
	Smart Meter Rider (per month)			0.27			1.25	0.98	362.96%	0.89%
	LRAM & SSM Rider (kWh)	1,000			1,000	0.0000	0.00	0.00	#DIV/0!	0.00%
	Regulatory Assets (kWh)	1,000	0.0000	0.00	1,000	0.0000	0.00	0.00	#DIV/0!	0.00%
	Sub-Total			**29.83**			**33.41**	**3.58**	**12.00%**	**3.27%**
	Other Charges (kWh)	1,046	0.0188	19.66	1,048	0.0202	21.17	1.51	7.66%	1.37%
	Cost of Power Commodity (kWh)	750	0.0500	37.50	750	0.0500	37.50	0.00	0.00%	0.00%
	Cost of Power Commodity (kWh)	296	0.0590	17.45	298	0.0590	17.57	0.12	0.71%	0.11%
	Total Bill			**104.44**			**109.65**	**5.21**	**4.99%**	**4.75%**

GENERAL SERVICE < 50 kW

Consumption		2008 BILL			2009 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
2,000 kWh	Monthly Service Charge			17.06			18.56	1.50	8.79%	0.73%
	Distribution (kWh)	2,000	0.0125	25.00	2,000	0.0136	27.20	2.20	8.80%	1.07%
	Smart Meter Rider (per month)			0.27			1.25	0.98	362.96%	0.48%
	LRAM & SSM Rider (kWh)	2,000			2,000	0.0000	0.00	0.00	#DIV/0!	0.00%
	Regulatory Assets (kWh)	2,000	0.0000	0.00	2,000	0.0000	0.00	0.00	#DIV/0!	0.00%
	Sub-Total			**42.33**			**47.01**	**4.68**	**11.06%**	**2.27%**
	Other Charges (kWh)	2,091	0.0188	39.32	2,096	0.0202	42.33	3.01	7.66%	1.46%
	Cost of Power Commodity (kWh)	750	0.0500	37.50	750	0.0500	37.50	0.00	0.00%	0.00%
	Cost of Power Commodity (kWh)	1,341	0.0590	79.14	1,346	0.0590	79.39	0.25	0.31%	0.12%
	Total Bill			**198.29**			**206.23**	**7.94**	**4.00%**	**3.85%**

GENERAL SERVICE < 50 kW

Consumption		2008 BILL			2009 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
5,000 kWh	Monthly Service Charge			17.06			18.56	1.50	8.79%	0.30%
	Distribution (kWh)	5,000	0.0125	62.50	5,000	0.0136	68.00	5.50	8.80%	1.11%
	Smart Meter Rider (per month)			0.27			1.25	0.98	362.96%	0.20%
	LRAM & SSM Rider (kWh)	5,000			5,000	0.0000	0.00	0.00	#DIV/0!	0.00%
	Regulatory Assets (kWh)	5,000	0.0000	0.00	5,000	0.0000	0.00	0.00	#DIV/0!	0.00%
	Sub-Total			**79.83**			**87.81**	**7.98**	**10.00%**	**1.61%**
	Other Charges (kWh)	5,229	0.0188	98.30	5,239	0.0202	105.83	7.53	7.66%	1.52%
	Cost of Power Commodity (kWh)	750	0.0500	37.50	750	0.0500	37.50	0.00	0.00%	0.00%
	Cost of Power Commodity (kWh)	4,479	0.0590	264.23	4,489	0.0590	264.85	0.62	0.23%	0.12%
	Total Bill			**479.86**			**495.99**	**16.13**	**3.36%**	**3.25%**

GENERAL SERVICE < 50 kW

Consumption		2008 BILL			2009 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
10,000 kWh	Monthly Service Charge			17.06			18.56	1.50	8.79%	0.15%
	Distribution (kWh)	10,000	0.0125	125.00	10,000	0.0136	136.00	11.00	8.80%	1.12%
	Smart Meter Rider (per month)			0.27			1.25	0.98	362.96%	0.10%
	LRAM & SSM Rider (kWh)	10,000			10,000	0.0000	0.00	0.00	#DIV/0!	0.00%
	Regulatory Assets (kWh)	10,000	0.0000	0.00	10,000	0.0000	0.00	0.00	#DIV/0!	0.00%
	Sub-Total			**142.33**			**155.81**	**13.48**	**9.47%**	**1.38%**
	Other Charges (kWh)	10,457	0.0188	196.59	10,478	0.0202	211.66	15.06	7.66%	1.54%
	Cost of Power Commodity (kWh)	750	0.0500	37.50	750	0.0500	37.50	0.00	0.00%	0.00%
	Cost of Power Commodity (kWh)	9,707	0.0590	572.71	9,728	0.0590	573.95	1.24	0.22%	0.13%
	Total Bill			**949.13**			**978.92**	**29.78**	**3.14%**	**3.04%**

GENERAL SERVICE < 50 kW

Consumption		2008 BILL			2009 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
15,000 kWh	Monthly Service Charge			17.06			18.56	1.50	8.79%	0.10%
	Distribution (kWh)	15,000	0.0125	187.50	15,000	0.0136	204.00	16.50	8.80%	1.13%
	Smart Meter Rider (per month)			0.27			1.25	0.98	362.96%	0.07%
	LRAM & SSM Rider (kWh)	15,000			15,000	0.0000	0.00	0.00	#DIV/0!	0.00%
	Regulatory Assets (kWh)	15,000	0.0000	0.00	15,000	0.0000	0.00	0.00	#DIV/0!	0.00%
	Sub-Total			**204.83**			**223.81**	**18.98**	**9.27%**	**1.30%**
	Other Charges (kWh)	15,686	0.0188	294.89	15,717	0.0202	317.48	22.60	7.66%	1.55%
	Cost of Power Commodity (kWh)	750	0.0500	37.50	750	0.0500	37.50	0.00	0.00%	0.00%
	Cost of Power Commodity (kWh)	14,936	0.0590	881.19	14,967	0.0590	883.05	1.86	0.21%	0.13%
	Total Bill			**1,418.41**			**1,461.85**	**43.43**	**3.06%**	**2.97%**

GENERAL SERVICE > 50 kW

Consumption		2008 BILL			2009 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
15,000 kWh	Monthly Service Charge			186.25			224.18	37.93	20.37%	2.37%
60 kW	Distribution (kWh)	15,000	0.0000	0.00	15,000	0.0000	0.00	0.00	#DIV/0!	0.00%
	Distribution (kW)	60	1.0637	63.82	60	1.2583	75.50	11.68	18.29%	0.73%
	Smart Meter Rider (per month)			0.27			1.25	0.98	362.96%	0.06%
	LRAM & SSM Rider (kWh)	60			60	0.0021	0.13	0.13	#DIV/0!	0.01%
	Regulatory Assets (kW)	60	0.0000	0.00	60	0.0000	0.00	0.00	#DIV/0!	0.00%
	Sub-Total			**250.34**			**301.05**	**50.71**	**20.26%**	**3.17%**
	Other Charges (kWh)	15,686	0.0132	207.05	15,717	0.0132	207.46	0.42	0.20%	0.03%
	Other Charges (kW)	60	2.2519	135.11	60	2.8116	168.70	33.58	24.85%	2.10%
	Cost of Power Commodity (kWh)	750	0.0500	37.50	750	0.0500	37.50	0.00	0.00%	0.00%
	Cost of Power Commodity (kWh)	14,936	0.0590	881.19	14,967	0.0590	883.05	1.86	0.21%	0.12%
	Total Bill			**1,511.20**			**1,597.77**	**86.57**	**5.73%**	**5.42%**

GENERAL SERVICE > 50 kW

Consumption		2008 BILL			2009 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
40,000 kWh	Monthly Service Charge			186.25			224.18	37.93	20.37%	1.02%
100 kW	Distribution (kWh)	40,000	0.0000	0.00	40,000	0.0000	0.00	0.00	#DIV/0!	0.00%
	Distribution (kW)	100	1.0637	106.37	100	1.2583	125.83	19.46	18.29%	0.52%
	Smart Meter Rider (per month)			0.27			1.25	0.98	362.96%	0.03%
	LRAM & SSM Rider (kWh)	100			100	0.0021	0.21	0.21	#DIV/0!	0.01%
	Regulatory Assets (kW)	100	0.0000	0.00	100	0.0000	0.00	0.00	#DIV/0!	0.00%
	Sub-Total			**292.89**			**351.47**	**58.58**	**20.00%**	**1.57%**
	Other Charges (kWh)	41,828	0.0132	552.13	41,912	0.0132	553.24	1.11	0.20%	0.03%
	Other Charges (kW)	100	2.2519	225.19	100	2.8116	281.16	55.97	24.85%	1.50%
	Cost of Power Commodity (kWh)	0	0.0607	0.00	0	0.0607	0.00	0.00	#DIV/0!	0.00%
	Cost of Power Commodity (kWh)	41,828	0.0607	2,539.80	41,912	0.0607	2,544.90	5.10	0.20%	0.14%
	Total Bill			**3,610.01**			**3,730.77**	**120.76**	**3.35%**	**3.24%**

GENERAL SERVICE > 50 kW

Consumption		2008 BILL			2009 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
100,000 kWh	Monthly Service Charge			186.25			224.18	37.93	20.37%	0.40%
350 kW	Distribution (kWh)	100,000	0.0000	0.00	100,000	0.0000	0.00	0.00	#DIV/0!	0.00%
	Distribution (kW)	350	1.0637	372.30	350	1.2583	440.41	68.11	18.29%	0.72%
	Smart Meter Rider (per month)			0.27			1.25	0.98	362.96%	0.01%
	LRAM & SSM Rider (kWh)	350			350	0.0021	0.74	0.74	#DIV/0!	0.01%
	Regulatory Assets (kW)	350	0.0000	0.00	350	0.0000	0.00	0.00	#DIV/0!	0.00%
	Sub-Total			**558.82**			**666.57**	**107.76**	**19.28%**	**1.15%**
	Other Charges (kWh)	104,570	0.0132	1,380.32	104,780	0.0132	1,383.10	2.77	0.20%	0.03%
	Other Charges (kW)	350	2.2519	788.17	350	2.8116	984.06	195.90	24.85%	2.08%
	Cost of Power Commodity (kWh)	0	0.0607	0.00	0	0.0607	0.00	0.00	#DIV/0!	0.00%
	Cost of Power Commodity (kWh)	104,570	0.0607	6,349.49	104,780	0.0607	6,362.24	12.75	0.20%	0.14%
	Total Bill			**9,076.79**			**9,395.97**	**319.17**	**3.52%**	**3.40%**

GENERAL SERVICE > 50 kW

Consumption		2008 BILL			2009 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
400,000 kWh	Monthly Service Charge			186.25			224.18	37.93	20.37%	0.10%
1,400 kW	Distribution (kWh)	400,000	0.0000	0.00	400,000	0.0000	0.00	0.00	#DIV/0!	0.00%
	Distribution (kW)	1,400	1.0637	1,489.18	1,400	1.2583	1,761.62	272.44	18.29%	0.74%
	Smart Meter Rider (per month)			0.27			1.25	0.98	362.96%	0.00%
	LRAM & SSM Rider (kWh)	1,400			1,400	0.0021	2.94	2.94	#DIV/0!	0.01%
	Regulatory Assets (kW)	1,400	0.0000	0.00	1,400	0.0000	0.00	0.00	#DIV/0!	0.00%
	Sub-Total			**1,675.70**			**1,989.99**	**314.29**	**18.76%**	**0.85%**
	Other Charges (kWh)	418,280	0.0132	5,521.30	419,120	0.0132	5,532.38	11.09	0.20%	0.03%
	Other Charges (kW)	1,400	2.2519	3,152.66	1,400	2.8116	3,936.24	783.58	24.85%	2.12%
	Cost of Power Commodity (kWh)	0	0.0607	0.00	0	0.0607	0.00	0.00	#DIV/0!	0.00%
	Cost of Power Commodity (kWh)	418,280	0.0607	25,397.96	419,120	0.0607	25,448.97	51.00	0.20%	0.14%
	Total Bill			**35,747.62**			**36,907.58**	**1,159.96**	**3.24%**	**3.14%**

GS (1,000 to 4,999 kW)

Consumption		2008 BILL			2009 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
585,000 kWh	Monthly Service Charge			1,632.83			2,069.12	436.29	26.72%	0.69%
3,500 kW	Distribution (kWh)	585,000	0.0000	0.00	585,000	0.0000	0.00	0.00	#DIV/0!	0.00%
	Distribution (kW)	3,500	1.4364	5,027.40	3,500	1.6615	5,815.25	787.85	15.67%	1.24%
	Smart Meter Rider (per month)			0.27			1.25	0.98	362.96%	0.00%
	LRAM & SSM Rider (kWh)	3,500			3,500	0.0027	9.45	9.45	#DIV/0!	0.03%
	Regulatory Assets (kW)	3,500	0.0000	0.00	3,500	0.0000	0.00	0.00	#DIV/0!	0.00%
	Sub-Total			**6,660.50**			**7,895.07**	**1,234.57**	**18.54%**	**1.95%**
	Other Charges (kWh)	605,617	0.0132	7,994.15	606,833	0.0132	8,010.20	16.05	0.20%	0.03%
	Other Charges (kW)	3,500	2.4265	8,492.75	3,500	3.0354	10,623.90	2,131.15	25.09%	3.36%
	Cost of Power Commodity (kWh)	0	0.0607	0.00	0	0.0607	0.00	0.00	#DIV/0!	0.00%
	Cost of Power Commodity (kWh)	605,617	0.0607	36,773.07	606,833	0.0607	36,846.92	73.85	0.20%	0.12%
	Total Bill			**59,920.47**			**63,376.09**	**3,455.62**	**5.77%**	**5.45%**

Street Lighting

Billing Determinants		2008 BILL			2009 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
13,000 Connections	Monthly Service Charge	13,000	0.3400	4,420.00	13,000	1.1430	14,859.00	10,439.00	236.18%	9.70%
905,000 kWh	Distribution (kWh)	905,000	0.0000	0.00	905,000	0.0000	0.00	0.00	#DIV/0!	0.00%
2,500 kW	Distribution (kW)	2,500	2.0569	5,142.25	2,500	6.9151	17,287.75	12,145.50	236.19%	11.29%
	Regulatory Assets (kW)	2,500	0.0000	0.00	2,500	0.0000	0.00	0.00	#DIV/0!	0.00%
	Sub-Total			**9,562.25**			**32,146.75**	**22,584.50**	**236.18%**	**20.99%**
	Other Charges (kWh)	946,359	0.0132	12,491.93	948,259	0.0132	12,517.02	25.09	0.20%	0.02%
	Other Charges (kW)	2,500	1.7144	4,286.00	2,500	2.1428	5,357.00	1,071.00	24.99%	1.00%
	Cost of Power Commodity (kWh)	750	0.0607	45.54	750	0.0607	45.54	0.00	0.00%	0.00%
	Cost of Power Commodity (kWh)	945,609	0.0607	57,417.35	947,509	0.0607	57,532.75	115.40	0.20%	0.11%
	Total Bill			**83,803.07**			**107,599.06**	**23,795.98**	**28.40%**	**22.12%**

Street Lighting

Billing Determinants		2008 BILL			2009 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
15,000 Connections	Monthly Service Charge	15,000	0.3400	5,100.00	15,000	1.1430	17,145.00	12,045.00	236.18%	11.50%
850,000 kWh	Distribution (kWh)	850,000	0.0000	0.00	850,000	0.0000	0.00	0.00	#DIV/0!	0.00%
2,400 kW	Distribution (kW)	2,400	2.0569	4,936.56	2,400	6.9151	16,596.24	11,659.68	236.19%	11.13%
	Regulatory Assets (kW)	2,400	0.0000	0.00	2,400	0.0000	0.00	0.00	#DIV/0!	0.00%
	Sub-Total			**10,036.56**			**33,741.24**	**23,704.68**	**236.18%**	**22.64%**
	Other Charges (kWh)	888,845	0.0132	11,732.75	890,630	0.0132	11,756.32	23.56	0.20%	0.02%
	Other Charges (kW)	2,400	1.7144	4,114.56	2,400	2.1428	5,142.72	1,028.16	24.99%	0.98%
	Cost of Power Commodity (kWh)	750	0.0607	45.54	750	0.0607	45.54	0.00	0.00%	0.00%
	Cost of Power Commodity (kWh)	888,095	0.0607	53,925.13	889,880	0.0607	54,033.51	108.39	0.20%	0.10%
	Total Bill			**79,854.54**			**104,719.33**	**24,864.79**	**31.14%**	**23.74%**

Sentinel Lighting

		2008 BILL			2009 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Billing Determinants	Monthly Service Charge	2	6.1200	12.24	2	6.6574	13.31	1.07	8.78%	5.65%
2 Connections	Distribution (kWh)	25	0.0000	0.00	25	0.0000	0.00	0.00	#DIV/0!	0.00%
25 kWh	Distribution (kW)	1	4.9122	2.46	1	5.3435	2.67	0.22	8.78%	1.13%
1 kW	Regulatory Assets (kW)	1	0.0000	0.00	1	0.0000	0.00	0.00	#DIV/0!	0.00%
	Sub-Total			**14.70**			**15.99**	**1.29**	**8.78%**	**6.79%**
	Other Charges (kWh)	26	0.0132	0.35	26	0.0132	0.35	0.00	0.20%	0.00%
	Other Charges (kW)	1	1.7334	0.87	1	2.1684	1.08	0.22	25.10%	1.14%
	Cost of Power Commodity (kWh)	26	0.0607	1.59	26	0.0607	1.59	0.00	0.20%	0.02%
	Cost of Power Commodity (kWh)	0	0.0607	0.00	0	0.0607	0.00	0.00	#DIV/0!	0.00%
	Total Bill			**17.50**			**19.01**	**1.51**	**8.64%**	**7.95%**

Sentinel Lighting

		2008 BILL			2009 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Billing Determinants	Monthly Service Charge	3	6.1200	18.36	3	6.6574	19.97	1.61	8.78%	5.47%
3 Connections	Distribution (kWh)	50	0.0000	0.00	50	0.0000	0.00	0.00	#DIV/0!	0.00%
50 kWh	Distribution (kW)	1	4.9122	3.68	1	5.3435	4.01	0.32	8.78%	1.10%
1 kW	Regulatory Assets (kW)	1	0.0000	0.00	1	0.0000	0.00	0.00	#DIV/0!	0.00%
	Sub-Total			**22.04**			**23.98**	**1.94**	**8.78%**	**6.57%**
	Other Charges (kWh)	52	0.0132	0.69	52	0.0132	0.69	0.00	0.20%	0.00%
	Other Charges (kW)	1	1.7334	1.30	1	2.1684	1.63	0.33	25.10%	1.11%
	Cost of Power Commodity (kWh)	52	0.0607	3.17	52	0.0607	3.18	0.01	0.20%	0.02%
	Cost of Power Commodity (kWh)	0	0.0607	0.00	0	0.0607	0.00	0.00	#DIV/0!	0.00%
	Total Bill			**27.21**			**29.48**	**2.27**	**8.34%**	**7.70%**

Unmetered Scattered Load

Consumption		2008 BILL			2009 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
1 Connection	Monthly Service Charge			8.51			9.26	0.75	8.78%	1.94%
250 kWh	Distribution (kWh)	250	0.0124	3.10	250	0.0135	3.38	0.28	8.87%	0.72%
	LRAM & SSM Rider (kWh)	250		0.00	250	0.0184	4.60	4.60	#DIV/0!	11.97%
	Regulatory Assets (kWh)	250	0.0000	0.00	250	0.0000	0.00	0.00	#DIV/0!	0.00%
	Sub-Total			**11.61**			**17.23**	**5.62**	**48.43%**	**14.63%**
	Other Charges (kWh)	261	0.0188	4.91	262	0.0202	5.29	0.38	7.66%	0.98%
	Cost of Power Commodity (kWh)	261	0.0607	15.87	262	0.0607	15.91	0.03	0.20%	0.08%
	Total Bill			**32.40**			**38.43**	**6.03**	**18.61%**	**15.69%**

Unmetered Scattered Load

Consumption		2008 BILL			2009 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
1 Connection	Monthly Service Charge			8.51			9.26	0.75	8.78%	1.11%
500 kWh	Distribution (kWh)	1	0.0124	0.01	1	0.0135	6.75	0.55	8.87%	0.81%
	LRAM & SSM Rider (kWh)	1	0.0000		1	0.0184	0.02	0.02	#DIV/0!	13.61%
	Regulatory Assets (kWh)	1	0.0000	0.00	1	0.0000	0.00	0.00	#DIV/0!	0.00%
	Sub-Total			**8.52**			**25.21**	**10.50**	**71.36%**	**15.53%**
	Other Charges (kWh)	1	0.0188	0.02	1	0.0202	0.02	0.00	7.66%	1.11%
	Cost of Power Commodity (kWh)	1	0.0607	0.06	1	0.0607	0.06	0.00	0.20%	0.09%
	Total Bill			**8.61**			**67.60**	**11.31**	**20.10%**	**16.74%**

RECOVERY OF LRAM AND SSM AMOUNTS:

Overview:

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 CDM initiatives. The CDM Plans of Thunder Bay Hydro were approved by the OEB.

"As prescribed in the Board's RP-2004-0203 decision of December 2004, and outlined in the subsequent 2006 EDR Report of the Board, a distributor will be expected to calculate the energy savings by customer class and to value those energy savings using the Board-approved variable distribution charge appropriate to the class. The resulting amount will be entered into a deferral account and may be claimed in a subsequent rate year as compensation for lost revenue.

Lost revenue will be calculated using the variable distribution rate (kW or kWh) for each affected class and would not include any Regulatory Asset Recovery rate riders, as these funds have their own independent true-up process in place. In addition, lost revenues are only accruable until new rates (new revenue requirement and load forecast) are set by the Board, as the savings would be assumed to be incorporated in the load forecast at that time.

Information required when filing the application for LRAM should include:

- kW or kWh impacts (both gross and net of free riders) of each program and for each class;

- A calculation of the impact of the CDM program on distribution revenues in each class;

- Verification of the participation levels;

- Where savings information is not provided in the TRC Guide, the distributor must comply with the requirements set out in the TRC Guide respecting custom projects; and

- Duration of the program in years or months.

All information filed for the LRAM proposal should correspond to program information used in the calculation of the cost/benefit analysis.

For the purpose of making an SSM claim, all of the information requirements listed above are required. SSM applies only to customer focused initiatives that reduce the demand for electricity and/or reduce the amount of energy used and only where the costs of the initiatives are expensed. The distributor must calculate the net benefits of a program using the TRC test. Under the SSM regime, a distributor may recover 5% of the net benefits created by the approved CDM portfolio, through a rate rider.

These instructions respecting SSM replace those that were posted to the Board's website on April 28, 2005."

Thunder Bay Hydro's CDM programs have resulted in decreases in kWh consumption and kW demand and subsequent 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 2005 and 2006 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).

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% 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 Report, Thunder Bay Hydro's LRAM/SSM request includes only customer-side activities. Thunder Bay Hydro has calculated energy savings by customer class and valued those savings by the OEB-approved distribution charge 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 this Application, the Filing Requirements contain provisions relating to applications for LRAM and SSM adjustments, and Thunder Bay Hydro submits that it has relied on and complied with the LRAM/SSM provisions of the Report, the OEB's TRC Guide and the Filing Requirements in preparing this request for LRAM/SSM adjustments for the years 2005 and 2006.

SUMMARY OF LRAM/SSM REQUEST:

Thunder Bay Hydro seeks approval for a cumulative recovery of 2005, 2006 and 2007 LRAM and single year SSM amounts as part of this Application. The LRAM request is cumulative since Thunder Bay Hydro has not previously requested approval, yet in the years subsequent to the delivery of conservation programming has had to bear the consumption and load impacts. For example with respect to the 2005 rate year Thunder Bay Hydro is requesting LRAM for 2005, 2006, 2007 and 2008. The calculation is simply the LRAM for 2005 multiplied by a factor of four. For the 2006 rate year the factor is three and for 2007 it is two. Recovery is to be based on a volumetric rate rider commencing May 1, 2009. Thunder Bay Hydro is proposing a three year recovery period in order to mitigate customer rate impacts, therefore the rate rider would remain in effect until April 30, 2012.

The LRAM calculations are based on the kWh or kW load reduction for each of the years times the applicable variable distribution rate for that rate class. The LRAM calculation, in the amount of $468,321, includes an adjustment for "free ridership" in accordance with the TRC Guide and the Toronto Hydro Decision.

The SSM calculation, in the amount of $106,024, 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. In accordance with the Toronto Hydro Decision, Thunder Bay Hydro has not grossed up the SSM amount for taxes and as such the SSM amount proposed for recovery is a pre-tax value. As with the LRAM calculation, the SSM calculation includes an adjustment for "free ridership" in accordance with the TRC Guide and the Toronto Hydro Decision.

The total combined LRAM and SSM amount for recovery is $574,346. The LRAM and SSM amounts and corresponding rate riders are set out by rate class in Table 1 (LRAM and SSM Total Amounts and Rate Riders by Class), below. Thunder Bay Hydro proposes a single rate rider for recovery of the total LRAM and SSM.

Details specific for each program are available on a separate diskette, provided with this filing.

Table 1

ANNUAL LRAM/SSM SAVINGS SUMMARY

Rate Class/Program	2005 LRAM	SSM	Total Revenue	2006 LRAM	SSM	Total Revenue	2007 LRAM	SSM	Total Revenue	Grand Total
Residential										
Seasonal LEDs	$197.24	$382.93	$580.17	$139.85	$516.82	$656.67	$102.01	$750.00	$852.01	$2,088.85
Energy Star Appliance Rebates	$1,025.10	$2,609.26	$3,634.36	$634.34	$1,825.47	$2,459.81	$477.72	$1,785.00	$2,262.72	$8,356.89
Secondary Fridge Retirement Program	$3,561.63	$5,494.61	$9,056.24	$2,027.04	$2,609.02	$4,636.06	n/a	n/a	n/a	$13,692.31
Water Heater Fuel Conversion	n/a	-$57.75	-$57.75	$549.33	$2,399.35	$2,948.68	n/a	n/a	n/a	$2,890.93
Compact Fluorescent Bulbs	$2,457.05	$2,047.57	$4,504.63	$1,720.51	$1,550.75	$3,271.26	$2,637.14	$2,470.00	$5,107.14	$12,883.03
Home Energy Saver Kits	n/a	-$85.01	-$85.01	$2,867.52	$2,129.47	$4,996.99	n/a	n/a	n/a	$4,911.99
One Change CFL Initiative	n/a	n/a	n/a	n/a	n/a	n/a	$52,742.88	$45,980.00	$98,722.88	$98,722.88
OPA Fridge Bounty	n/a	n/a	n/a	n/a	n/a	n/a	$10,934.04	n/a	$10,934.04	$10,934.04
OPA ERIP	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
OPA Summer Savings	n/a	n/a	n/a	n/a	n/a	n/a	$23,336.22	n/a	$23,336.22	$23,336.22
Conservation Bureau EKC Coupons	n/a	n/a	n/a	$23,005.39	n/a	$23,005.39	$58,504.15	n/a	$58,504.15	$81,509.55
Unmetered Scattered Load										
Traffic Light LEDs	$5,669.65	$15,066.87	$20,736.52	$5,591.62	$8,027.49	$13,619.11	$2,876.46	$5,361.40	$8,237.86	$42,593.48
General Service >50kW										
Parking Lot Winter Plug In Controls	n/a	n/a	n/a	$300.19	$661.55	$961.74	$896.41	$1,171.54	$2,067.96	$3,029.70
General Service >1MW										
Commercial Lighting Incentive	n/a	n/a	n/a	$385.70	$3,328.06	$3,713.75	n/a	n/a	n/a	$3,713.75
Cumulative LRAM plus single SSM			$77,101			$134,712			$362,532	
GRAND TOTAL										$574,346

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.

In accordance with the Toronto Hydro Decision, Thunder Bay Hydro has reduced the calculated load reduction for free ridership. Free ridership is the percentage of participants that would have undertaken a particular measure regardless of a particular program being offered. Table 2 below summarizes the CDM load impacts by program and customer class.

Table 2
CDM Load Impacts by Program and Class

Rate Class/Program	2005		2006		2007	
	kWh	kW	kWh	kW	kWh	kW
Residential						
Seasonal LEDs	15,085	2.88	10,183	4.44	7,269	4.00
Energy Star Appliance Rebates	78,402	4.72	46,190	3.31	34,042	3.00
Secondary Fridge Retirement Program	272,400	65.30	147,600	35.38	n/a	n/a
Water Heater Fuel Conversion	n/a	n/a	40,000	7.01	n/a	n/a
Compact Fluorescent Bulbs	187,920	40.50	125,280	27.00	187,920	40.50
Home Energy Saver Kits	n/a	n/a	208,800	45.00	n/a	n/a
One Change CFL Initiative	n/a	n/a	n/a	n/a	3,758,400	810.00
OPA Fridge Bounty	n/a	n/a	n/a	n/a	779,148	186.00
OPA ERIP	n/a	n/a	n/a	n/a	n/a	n/a
OPA Summer Savings	n/a	n/a	n/a	n/a	1,662,914	1,117.55
Conservation Bureau EKC Coupons	n/a	n/a	1,675,150	999.90	4,168,942	933.68
Unmetered Scattered Load						
Traffic Light LEDs	469,536	53.60	449,728	40.74	225,900	25.79
General Service >50kW						
Parking Lot Winter Plug In Controls	n/a	n/a	17,363	23.85	46,520	63.90
General Service >1MW						
Commercial Lighting Incentive	n/a	n/a	109,616	22.34	n/a	n/a
Total	1,023,343	167.00	2,829,910	1,208.97	10,871,055	3,184.42

The reduction in distribution revenue is calculated on the forgone volumes resulting from CDM activities by class and at the variable distribution rate applicable to that class and year.

Thunder Bay Hydro is not requesting the recovery of carrying costs on the forgone distribution revenue in this Application.

The following Table 3 summarizes the forgone revenue by customer class:

Table 3

Forgone Revenue by Class

Rate Class/Program	2005 kWh	Kw	Rate 1	Rate 2	Lost Revenue	2006 kWh	Kw	Rate 1	Rate 2	Lost Revenue	2007 kWh	Kw	Rate 1	Rate 2	Lost Revenue
Residential															
Seasonal LEDs	15,085	2.88	$0.0109	$0.0138	$197.24	10,183	4.44	$0.0138	$0.0137	$139.85	7,269	4.00	$0.0137	$0.0142	$102.01
Energy Star Appliance Rebates	78,402	4.72	$0.0109	$0.0138	$1,025.10	46,190	3.31	$0.0138	$0.0137	$634.34	34,042	3.00	$0.0137	$0.0142	$477.72
Secondary Fridge Retirement Program	272,400	65.30	$0.0109	$0.0138	$3,561.63	147,600	35.38	$0.0138	$0.0137	$2,027.04	n/a	n/a	$0.0137	$0.0142	n/a
Water Heater Fuel Conversion	n/a	n/a	$0.0109	$0.0138	n/a	40,000	7.01	$0.0138	$0.0137	$549.33	n/a	n/a	$0.0137	$0.0142	n/a
Compact Fluorescent Bulbs	187,920	40.50	$0.0109	$0.0138	$2,457.05	125,280	27.00	$0.0138	$0.0137	$1,720.51	187,920	40.50	$0.0137	$0.0142	$2,637.14
Home Energy Saver Kits	n/a	n/a	n/a	$0.0138	n/a	208,800	45.00	$0.0138	$0.0137	$2,867.52	n/a	n/a	$0.0137	$0.0142	n/a
One Change CFL Initiative	n/a	n/a	n/a	$0.0138	n/a	n/a	n/a	$0.0138	$0.0137	n/a	3,758,400	810.00	$0.0137	$0.0142	$52,742.88
OPA Fridge Bounty	n/a	n/a	n/a	$0.0138	n/a	n/a	n/a	$0.0138	$0.0137	n/a	779,148	186.00	$0.0137	$0.0142	$10,934.04
OPA ERIP	n/a	n/a	n/a	$0.0138	n/a	n/a	n/a	$0.0138	$0.0137	n/a	n/a	n/a	$0.0137	$0.0142	n/a
OPA Summer Savings	n/a	n/a	n/a	$0.0138	n/a	n/a	n/a	$0.0138	$0.0137	n/a	1,662,914	1,117.55	$0.0137	$0.0142	$23,336.22
Conservation Bureau EKC Coupons	n/a	n/a	n/a	$0.0138	n/a	1,675,150	999.90	$0.0138	$0.0137	$23,005.39	4,168,942	933.68	$0.0137	$0.0142	$58,504.15
General Service <50Kw															
Traffic Light LEDs	469,536	53.60	$0.0108	$0.0125	$5,669.65	449,728	40.74	$0.0125	$0.0124	$5,591.62	225,900	25.79	$0.0124	$0.0129	$2,876.46
Unmetered Scattered Load															
Parking Lot Winter Plug In Controls	n/a	n/a	n/a	n/a	n/a	17,363	23.85	$1.0332	$1.0567	$300.19	46,520	63.90	$1.0567	$1.2252	$896.41
General Service >1MW															
Commercial Lighting Incentive	n/a	n/a	n/a	n/a	n/a	109,616	22.34	$1.4626	$1.4268	$385.70	n/a	n/a	$1.4268	$1.3801	n/a
Total	1,023,343	167.00			$12,911	2,829,910	1,208.97			$37,221	10,871,055	3,184.42			$152,507
Cumulative					$51,643					$111,664					$305,014
Grand Total															$468,321

Thunder Bay Hydro proposes to allocate the forgone distribution revenue from each class to that class for recovery through a rate adder to be applied to the variable distribution rate component for each class. As noted above, Thunder Bay Hydro proposes to implement the rate adder over a three year period, from May 1, 2009 to April 30, 2012, in order to mitigate potential customer impacts.

SHARED SAVINGS MECHANISM (SSM):

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 are 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 Thunder Bay Hydro's CDM programs. Where a CDM program has resulted in net costs as opposed to net benefits, the total SSM claim has been reduced by the NPV of the costs.

Thunder Bay 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, Thunder Bay Hydro is only making application for customer-focused initiatives that reduce the demand for electricity.

Certain CDM programs were jointly sponsored with the OPA and One Change (Project Porchlight) and in these cases Thunder Bay Hydro did not apply for SSM. Thunder Bay Hydro

apportioned the savings in accordance with the TRC Guide and the OEB's EB-2005-0523 Decision.

As noted above, Thunder Bay Hydro has calculated the SSM recovery as 5% of the NPV of the net benefits (less the NPV of the net costs), for each program, in accordance with the TRC Guide.

Table 4 below summarizes the SSM calculations by program and by customer class.

Table 4

CALCULATION OF ANNUAL ALLOWABLE SSM

Rate Class/Program	2005 Wh	kW	Net Benefit (NPV)	Allowable SSM @ 5% of NPV	2006 kWh	kW	Net Benefit (NPV)	Allowable SSM @ 5% of NPV	2007 kWh	kW	Net Benefit (NPV)	Allowable SSM @ 5% of NPV
Residential												
Seasonal LEDs	15,085	2.88	$7,658.55	$382.93	10,183	4.44	$10,336.45	$516.82	7,269	4.00	$15,000.00	$750.00
Energy Star Appliance Rebates	78,402	4.72	$52,185.16	$2,609.26	46,190	3.31	$36,509.37	$1,825.47	34,042	3.00	$35,700.00	$1,785.00
Secondary Fridge Retirement Program	272,400	65.30	$109,892.29	$5,494.61	147,600	35.38	$52,180.46	$2,609.02	n/a	n/a	n/a	n/a
Water Heater Fuel Conversion	n/a	n/a	-$1,155.05	-$57.75	40,000	7.01	$47,986.99	$2,399.35	n/a	n/a	n/a	n/a
Compact Fluorescent Bulbs	187,920	40.50	$40,951.44	$2,047.57	125,280	27.00	$31,014.93	$1,550.75	187,920	40.50	$49,400.00	$2,470.00
Home Energy Saver Kits	n/a	n/a	-1,700.14	-$85.01	208,800	45.00	$42,589.49	$2,129.47	n/a	n/a	n/a	n/a
One Change CFL Initiative	n/a	n/a		n/a	n/a	n/a	n/a	n/a	3,758,400	810.00	$919,600.00	$45,980.00
OPA Fridge Bounty	n/a	n/a		n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
OPA ERIP	n/a	n/a		n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
OPA Summer Savings	n/a	n/a		n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Conservation Bureau EKC Coupons	n/a	n/a		n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
General Service <50kW												
Traffic Light LEDs	469,536	53.60	$301,337.36	$15,066.87	449,728	40.74	$160,549.83	$8,027.49	225,900	25.79	$107,228.00	$5,361.40
Unmetered Scattered Load												
Parking Lot Winter Plug In Controls	n/a	n/a		n/a	17,363	23.85	$13,231.04	$661.55	46,520	63.90	$23,430.88	$1,171.54
General Service >1MW												
Commercial Lighting Incentive	n/a	n/a		n/a	109,616	22.34	$66,561.16	$3,328.06	n/a	n/a	n/a	n/a
Total	1,023,343	167.00		$25,458	1,154,760	209.07		$23,048	4,260,051	947.19		$57,518
GRAND TOTAL												$106,024

As with the LRAM adjustment, Thunder Bay 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, Thunder Bay Hydro proposes to implement the variable distribution rate rider over three years to mitigate potential customer impacts.

RELIEF REQUESTED:

Thunder Bay Hydro proposes that the LRAM and SSM rate riders be combined into, and recovered through a single distribution rate rider as provided in Table 5 and that the total LRAM and SSM rate rider be implemented effective May 1, 2009 for a period of three years ending April 30, 2012.

Thunder Bay 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." Thunder Bay Hydro submits that its claim for LRAM and SSM in the amount of $574,345, calculated by staff using the EnerSpectrum TRC software, represents only 0.88% of its distribution revenue requirement and therefore does not have a material impact on distribution rates, and that any such impact has been mitigated by recovering the LRAM/SSM over three rate years. This can be seen in the discussion of bill impacts below. In light of the foregoing, Thunder Bay Hydro requests approval of its proposed LRAM and SSM without being subject to a further review.

TABLE 5

2009 TEST YEAR – LRAM AND SSM RIDER

	Amounts (2005 to 2007)		Billing Units (2009)		Rate Riders			Two Year Rate Rider	Three Year Rate Rider	Number of Years to Use	Rate Ride 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 (kW or kW)
Residential	419,264	72,407	337,772,229	kWh	0.0012	0.0002	0.0015	0.0007	0.0005		0.0005
GS <50 kW				kWh							0.0000
GS>50 kW	2,693	1,833	717,262	kW	0.0038	0.0026	0.0063	0.0032	0.0021		0.0021
GS 1,000 to 4,999 kW	1,157	3,328	560,145	kW	0.0021	0.0059	0.0080	0.0040	0.0027		0.0027
Street Light				kW							0.0000
Sentinel				kW							0.0000
Unmetered Scattered Load	45,206	28,455	1,335,240	kWh	0.0339	0.0213	0.0552	0.0276	0.0184		0.0184
Total	468,321	106,024									

BILL IMPACTS:

Thunder Bay Hydro proposes that the LRAM and SSM amounts be recovered over three years through rate riders effective May 1, 2009 until April 30, 2012. The Table of Rate and Bill Impacts as referenced in Schedule 9, Appendix A of this Exhibit, 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 rate class.