COLLINGWOOD UTILITY SERVICES

COLLUS Power Corp
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August 15, 2008

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

Attn: Ms. Kirsten Walli, Board Secretary

Dear Ms. Walli

Re: COLLUS Power Corp
2009 Rate Application
OEB File No. EB-2009-0226

COLLUS Power Corp is submitting its 2009 Rate Application, in compliance with the OEB Filing Requirements for Transmission and Distribution Applications. The components of the application are as follows:

- Exhibit 1 – Administration
- Exhibit 2 – Rate Base
- Exhibit 3 – Operating Revenue
- Exhibit 4 – Operating Costs
- Exhibit 5 – Deferral and Variance Accounts
- Exhibit 6 – Cost of Capital and Rate of Return
- Exhibit 7 – Calculation of Revenue Deficiency or Surplus
- Exhibit 8 – Cost Allocation
- Exhibit 9 – Rate Design

Further to the Board's RESS filing guidelines, an electronic copy of our full application will be submitted through the OEB e-Filing Services. Two hard copies of the application are being sent by courier.

We would be pleased to provide any further information or details that you may require relative to this application.

Yours respectfully,

Mr. E. D. Houghton C.E.T. M.A.A.T.O.
President and CEO
COLLUS Power Corp

COLLUS POWER CORP

APPLICATION FOR APPROVAL OF ELECTRICITY DISTRIBUTION RATES

EFFECTIVE MAY 1, 2009

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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 COLLUS Power Corp 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 **COLLUS Power Corp** for an Order or Orders approving or fixing just and reasonable distribution rates and other charges, effective May 1, 2009.
Applicant's Name:	**COLLUS Power Corp**
Applicant's Address for Service:	43 Stewart Road PO Box 189 Collingwood ON L9Y 3Z4
	Attention: Mr. E. D. Houghton, CEO
	Telephone: 1-705-445-1800 Ext: 2222 Fax: 1-705-445-8267 E-mail: ehoughton@collus.com

APPLICATION

1. Introduction

(a) The Applicant is COLLUS Power Corp (referred to in this Application as the "Applicant" or "COLLUS Power Corp"). The Applicant is a corporation incorporated pursuant to the Ontario *Business Corporations Act* with its head office in the Town of Collingwood. The Applicant carries on the business of distributing electricity within the Town of Collingwood and the Towns of Thornbury, Stayner and Creemore.

(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 Exhibit 1, Tab1, Schedule 5 and then for ease of reference also as Appendix A attached to this summary and Exhibit 9, Tab 1, Schedule 7, and the material being filed in support of this Application sets out COLLUS Power Corp'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) there are no impacts to any of the 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; 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 Collingwood, Ontario, this 15th day of August, 2008.

APPENDIX A

SCHEDULE OF PROPOSED RATES AND CHARGES

Schedule of Proposed Tariff of Rates and Charges
Effective May 1, 2009

Monthly Rate and Charges

Residential

Service Charge	$	10.47
Distribution Volumetric Rate	$/kWh	0.0206
Deferral and Variance Account Rider	$/kWh	0.0000
Retail Transmission Rate – Network Service Rate	$/kWh	0.0047
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0029
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administrative Charge	$	0.25

General Service Less Than 50 kW

Service Charge	$	20.20
Distribution Volumetric Rate	$/kWh	0.0139
Deferral and Variance Account Rider	$/kWh	0.0000
Retail Transmission Rate – Network Service Rate	$/kWh	0.0043
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0026
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administrative Charge	$	0.25

General Service Greater Than 50 kW

Service Charge	$	93.23
Distribution Volumetric Rate	$/kW	2.6166
Deferral and Variance Account Rider	$/kW	0.0000
Retail Transmission Rate – Network Service Rate	$/kW	1.7399
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.0322
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administrative Charge (if applicable)	$	0.25

Large Use

Service Charge	$	5067.26
Distribution Volumetric Rate	$/kW	2.2132
Deferral and Variance Account Rider	$/kW	0.0000
Retail Transmission Rate – Network Service Rate - Interval Metered	$/kW	2.0461
Retail Transmission Rate – Line and Transformation Connection Service Rate - Interval Metered	$/kW	1.2940
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administrative Charge (if applicable)	$	0.25

Street Lighting

Service Charge (per connection)	$	1.9051
Distribution Volumetric Rate	$/kW	8.7319
Deferral and Variance Account Rider	$/kW	0.0000
Retail Transmission Rate – Network Service Rate	$/kW	1.3122
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.7979
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge (per customer)	$	0
Distribution Volumetric Rate	$/kW h	0.0458
Deferral and Variance Account Rider	$/kW h	0.0000
Retail Transmission Rate – Network Service Rate	$/kW	0.0043
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.0026
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administrative Charge (if applicable)	$	0.25

Specific Service Charges

Customer Administration		
Charge to certify cheque	$	15.00
Arrears certificate	$	15.00
Statement of account	$	15.00
Pulling post dated cheque	$	15.00
Duplicate invoice for previous billing	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Legal letter Charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	15.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Special meter reads	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	20.00
Collection of account charge – no disconnection - after regular hours	$	165.00
Disconnect/Reconnect Charge - At Meter during Regular Hours	$	40.00
Disconnect/Reconnect Charge - 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
Service call - after regular hours	$	165.00
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	(0.3500)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

Retail Service Charges (if applicable)

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing, charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction 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 Factor

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0750
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0397
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0643
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0340

DISTRIBUTOR LICENCE:

A copy of COLLUS Power Corp's Electricity Distribution Licence ED-2002-0518, issued on June 13, 2003, accompanies this Schedule as Appendix A hereto.

APPENDIX A

COPY OF

COLLUS Power Corp

DISTRIBUTION LICENCE

CONTACT INFORMATION:

FOR COLLUS Power Corp:

Mr. T. (Tim) E. Fryer CHIEF FINANCIAL OFFICER:

1-705-445-1800 Ext. 2225 tfryer@collus.com

Mr. D. (Darius) Vaicunias DIRECTOR, REGULATORY COMPLIANCE AND GOVERNANCE:

1-705-445-1800 Ext. 2227 dvaicunias@collus.com

SPECIFIC APPROVALS REQUESTED:

In this proceeding, COLLUS Power Corp is requesting the following approvals:

- Approval to charge rates effective May 1, 2009 to recover a revenue requirement of $ **6,134,984** which includes a revenue deficiency of $ **976,701** as set out in Exhibit 7, Tab 1, Schedule 1. The schedule of proposed rates is set out in Exhibit 1 Tab 1 Schedule 2 Appendix A and Exhibit 9 Tab 1 Schedule 6. In the event that the OEB is unable to provide a Decision and Order in this Application for implementation by COLLUS Power Corp 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;

- Approval of the Applicant's proposed change in capital structure, decreasing the Applicant's deemed common equity component from 46.7% to 43.3% and increasing the deemed debt component from 53.33% to 52.7% for Long-Term and 4% for Short-Term, as set out in Exhibit 6, Tab 1, Schedule 4, consistent with Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors dated December 20, 2006;

- Approval of revised Low Voltage Rates as reviewed and described in Exhibit 9, Tab 1, Schedule 1;

- Approval to continue the Smart Meter Rate Adder of $0.26 per customer per month. Within this application COLLUS Power Corp is not seeking approval to adjust rates for implementation of smart meters.

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

- Approval of the proposed Transformer Allowance rate set out in Exhibit 9 Tab 1 Schedule 1;

- Approval to continue the Specific Service Charges approved in the OEB's Decision and Order in the matter of COLLUS Power Corp's 2006 distribution rates [RP-2005-0020/EB-2005-0353]

DRAFT ISSUES LIST:

COLLUS Power Corp 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 COLLUS Power Corp's proposed revenue requirement
- The reasonableness of the proposed electricity distribution rates.
- The on-going inability for COLLUS Power Corp to earn the regulated rate of return due to the loss of the largest distribution customer shortly after the 2006 EDR rate approval.
- The on-going inability for COLLUS Power Corp to earn the approved revenue requirement established through the 2006 EDR approval process and originally with the initial unbundling of distribution rates process.

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 June 13 2008, COLLUS Power Corp confirmed its' self-nomination request for rebasing in 2009. Previously, in Board File No. EB-2006-0330, the OEB issued its list of distributors that will be rebased in 2009 – the list included COLLUS Power Corp

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

ACCOUNTING ORDERS REQUESTED:

COLLUS Power Corp is not requesting Accounting Orders in this proceeding.

COMPLIANCE WITH UNIFORM SYSTEM OF ACCOUNTS:

COLLUS Power Corp 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:

COMMUNITIES SERVED:	Town of Collingwood Town of Thornbury Town of Stayner Town of Creemore
TOTAL SERVICE AREA:	57 sq km
RURAL SERVICE AREA:	0 sq km
DISTRIBUTION TYPE:	Electricity distribution
SERVICE AREA POPULATION:	23,600
MUNICIPAL POPULATION:	23,600

A map of the COLLUS Power Corp Distribution Service Territory accompanies this Schedule as Appendix A.

APPENDIX A

MAP OF DISTRIBUTION SERVICE TERRITORY

MAP OF DISTRIBUTION SERVICE TERRITORY

The outlined area represents the Town of Collingwood, the Towns of Thornbury, Stayner and Creemore of which each are a part of COLLUS Power Corp's service territory. The outlined area can be viewed in Appendix B with this schedule.

LIST OF NEIGHBOURING UTILITIES:

COLLUS POWER CORP is bounded by Hydro One Networks Inc. on all service territory boundaries.

EXPLANATION OF HOST or EMBEDDED UTILITY:

COLLUS Power Corp is a Fully Registered Market Participant for the purposes of settlement with the Independent Electricity System Operator. In a sense though COLLUS Power Corp is considered an “embedded” LDC because it receives electricity from Hydro One Networks Inc low voltage distribution system.

UTILITY ORGANIZATIONAL CHART:

Appendix A with this schedule is COLLUS Power Corp' Organizational Structure Chart.

CORPORATE ENTITIES RELATIONSHIPS CHART:

As indicated in the Appendix A provided with this schedule Collingwood Utility Services Corp is the parent company of COLLUS Power Corp (a local distribution company LDC), COLLUS Solutions Corp (the services company) and COLLUS Energy Corp (a non-operating retail company). This company structure was established at the outset of the former Collingwood Public Utilities Commission – Hydro Department, in order to comply with *The Electricity Act 1998* requirements.

COLLUS Power Corp purchases services under a Services Agreement from COLLUS Solutions Corp. Further explanation is provided in Exhibit 4, Tab 2, Schedule 4 in the Shared Services review. A copy of the current service agreement and applicable amendments is provided as Appendix B in this schedule.

For further clarification as noted above COLLUS Energy Corp was established in order to house any retail oriented operations that the company decided to enter into. Currently and in the years past there has been no business operations in this company.

PLANNED CHANGES IN CORPORATE AND OPERATIONAL STRUCTURE:

No changes to COLLUS Power Corp's corporate and operational structures are planned at the present time.

STATUS OF BOARD DIRECTIVES FROM PREVIOUS BOARD DECISIONS:

1. 2006 TIER 2 ADJUSTMENT – Substation Capital Investment & Maintenance Cost

As part of the 2006 EDR application process the OEB provided a mechanism for those LDC's that had previously been adversely impacted by the decision to set a "floor" of $0 net income for establishing an LDC's initial rate of return. COLLUS Power Corp is an LDC that had incurred a negative net income result for 1999 and the OEB's use of a "floor" mechanism resulted in approximately $1.4 M of return that had not been included in rates for revenue requirement. The 2006 EDR application submitted by COLLUS Power Corp included information to substantiate the overall impact and the financial hardship caused by the use of the "floor" mechanism.

In its 2006 EDR Decision (RP-2005-020 EB-2005-0353), the Ontario Energy Board approved a Tier 2 adjustment relating to construction of a new substation and plant maintenance for existing substations. The approved adjustment to rate base of $1,000,000 for substation capital investment and the addition of $200,000 in plant maintenance for existing substations has been subject to quarterly monitoring requirements to the audit department of the OEB. .

This new substation project is discussed in greater detail in Exhibit 2, Tab 3, Schedules 1 and 2 (Capital Budget by Project; Materiality Analysis on Capital Additions). As an overview the substation capital and remaining portion of operation and maintenance spending was undertaken and completed in 2007. The upgrade to the sub-station (Municipal Station #5) serves to alleviate concern about the load on the distribution system in the area as well as the system overall.

2. LOW VOLTAGE RATE RIDER AND VARIANCE ACCOUNT 1550

In its 2006 EDR Decision, the OEB provided for the collection of low voltage rates from COLLUS Power Corp customers. For the purposes of this rate application COLLUS Power Corp has reviewed and re-calculated the estimated rate requirement to fully recover expected costs of Low Voltage charges from HONI. This is dealt with in Exhibit 9 with full explanation of the rates that are being submitted with this 2009 Cost of Service application for approval.

COMPANY POLICIES AND REGULATIONS/SERVICE CHARGES:

A copy of COLLUS Power Corp's current Conditions of Service and Service charges has been provided as Appendix A to this Schedule.

APPENDIX A

COPY OF COLLUS Power Corp CONDITIONS OF SERVICE AND SERVICE CHARGES

PLANNED CHANGES IN CONDITIONS OF SERVICE:

COLLUS Power Corp developed their Conditions of Service document in conjunction with 16 members of the Cornerstone Hydro Electric Concepts (CHEC) group of LDC's. After a recent thorough review of the document with assistance from the staff of the OEB, a new updated version of the Conditions of Service has been published.

As per the OEB requirements and to allow an opportunity for customer comment, in May 2008 a copy of the General notice was used by the CHEC member LDC's within the service territory media base. It was also noted on the customer invoices that a copy of the updated Conditions of Service could be made available for scrutiny over a period of about 2 months. A copy of the form of notice utilized by COLLUS Power Corp is set out in Appendix A of this Schedule.

Following a 60 day review period and having received no comment from the public, the new Conditions of Service was adopted and the updated version 6.0 was filed.

APPENDIX A

Notice of Change to Conditions of Service Document

The Distribution System Code requires that every distributor produce its own "Conditions of Service" document. The purpose of this document is to provide a means of communicating the types and level of service available to the customers within the distributor's service territory.

The current version of the *Conditions of Service* was published in 2004. Since then, various changes to regulations and codes that govern Distributor activities have come into effect, which in turn require updates to the original document.

The revised document is available to view on our web site, *“Link to Web Site”.* Customers without internet access may obtain a copy of the revised *Conditions of Service* at our office at *“location”*

The public is invited to make written comments on the revisions. Comments will be accepted until Friday July 15, 2008. Please direct all written comments to:

“Utility Name”
Attn: Conditions of Service
Street Address
Town, ON X0X 0X0

Note on Bills:

“Your Utility” has revised our Conditions of Service document. The document is available on our web site or at the local office. Comments on the revised document will be accepted at the Utility office until Friday July 15, 2008.

PRELIMINARY LIST OF WITNESSES

In that COLLUS Power Corp requests that this Application be disposed of by the way of a written hearing, if there is deemed to be a necessity for a technical conference or oral hearing, COLLUS Power Corp will provide information regarding potential witnesses as required.

SUMMARY OF THE APPLICATION:

Preamble

COLLUS Power Corp's mission statement is:

> "Our business provides people with the energy for success and the necessities of life."

COLLUS Power Corp is an electricity distribution company licensed by the Ontario Energy Board to provide electricity distribution services to customers within the Town of Collingwood and the Towns of Thornbury, Stayner and Creemore.

COLLUS Power Corp's priorities are defined in its Vision Statement:

> "Together we will grow, maximize opportunities and exceed customers' expectations."

Within its service territory, COLLUS Power Corp has partnered with local agencies and businesses to deliver innovative conservation and demand management programs.

COLLUS Power Corp has consistently exceeded the OEB's Service Quality Indicators and, as set out in Table 1.2.1-1 below, has targeted to maintain its performance above the OEB's standard and improve that performance where necessary, in the 2009 Test Year.

Table 1.2.1-1
COLLUS Power Corp SERVICE QUALITY INDICATORS
AVERAGE PERFORMANCE FOR 2007

Appointments Met – at the appointed time		
SQI Standard: 90% of the time		
2007	**2008 Target**	**2009 Target**
99.4%	99.00%	99.00%
Telephone Accessibility – answered in person within 30 seconds		
SQI Standard: 65% of the time		
2007	**2008 Target**	**2009 Target**
90.23%	90.00%	90.00%
Underground Cable Locates – within 5 working days		
SQI Standard: 90% of the time		
2007	**2008 Target**	**2009 Target**
100%%	99.00%	99.00%
Connection of New Services – Low Voltage within 5 working days		
SQI Standard: 90% of the time		
2007	**2008 Target**	**2009 Target**
100%	99.00%	99.00%
Connection of New Services – High Voltage within 10 working days		
SQI Standard: 90% of the time		
2007	**2008 Target**	**2009 Target**
100.00%	99.0%	99.00%
Emergency Response – Urban within 60 minutes		
SQI Standard: 90% of the time		
2007	**2008 Target**	**2009 Target**
100.00%	100.00%	100.00%
Written Responses to Inquiries – within 10 working days		
SQI Standard: 80% of the time		
2007	**2008 Target**	**2009 Target**
100.0%	99.00%	99.00%

A major goal is to pursue industry leadership in service reliability. COLLUS Power Corp continues to work to improve service reliability and reduce system losses by ensuring that its distribution system is maintained at a high level of quality. Its 2007 service reliability statistics with a System Average Interruption Duration Index ("SAIDI") of 2.23, System Average Interruption Frequency Index ("SAIFI") of 0.83 and Customer Average Interruption Duration Index ("CAIDI") of 2.69, are levels that are targeted to be improved upon with the programs that are proposed in this application. Within this application reduced system losses allows the proposed lowering of the Total Distribution Loss Factor applied to customers consumption, as it did in the 2006 EDR approval process.

COLLUS Power Corp will continue to work towards higher reliability results in future years.

Purpose and Need

COLLUS Power Corp's requested revenue requirement for 2009 includes the recovery of its costs to provide distribution services, its permitted Return on Equity ["ROE"] and the funds necessary to service its debt as it transitions to a 60%/40% debt equity ratio by 2010. Through this rate application, COLLUS Power Corp seeks the recovery through rates of its proposed 2009 base revenue requirement in the amount of **$ 5,808,984**.

When its forecasted results for 2009 are considered, COLLUS Power Corp estimates that its present rates will produce a deficiency in distribution revenue of $976,701 for the 2009 Test Year. Excluded from this estimate is the impact of energy costs.

Therefore, COLLUS Power Corp 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 COLLUS Power Corp's forecasted results for its 2009 Test Year. With the rates presently in effect, COLLUS Power Corp estimates that its revenue for 2009 would not be sufficient to provide a reasonable return. COLLUS Power Corp is also presenting the historical actual information for fiscal 2006, OEB-Approved data for 2006, actual information for fiscal 2007 as well as information for six months of actual and six months of forecast for the fiscal 2008 Bridge Year.

Timing

The financial information supporting the Test Year for this Application will be COLLUS Power Corp'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 COLLUS Power Corp as needed to enable it to earn the maximum return permitted by the OEB for the 2009 Test Year.

Customer Impact

In preparing this application, COLLUS Power Corp has considered the impacts on its customers, with a goal of minimizing those impacts. With respect to cost allocation, COLLUS Power Corp notes that for the majority of its customers, the revenue to cost ratio of each rate 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.

Customer impacts are provided showing the percentage average Total Bill Impact and Average Dollar Impact, which include distribution rates [monthly service charge and volumetric rates], and revised low voltage rates. This is provided in detail in Exhibit 9 as Appendix A.

For reference though the following Table 1.2.1-2 provides the projected monthly impact on an average customer in regards to the total charges for the provision and use of electricity.

Table 1.2.1-2
AVERAGE MONTHLY TOTAL CHARGES IMPACT – PERCENT & DOLLAR

Class Average Monthly Total Charges Impact		Average Total Charges Impact %	Average Dollar Impact
Residential		2.50%	$ 2.66
General Service <50 kW		3.60%	$ 10.36
General Service >50 kW		3.83%	$ 271.01
Large Use		0.08%	$ 204.15
Street Lighting		40.00%	$ 2,551.44
Unmetered Scattered Load		32.00%	$ 16.60

Smart Meters

In this application COLLUS Power Corp requests approval to continue with the Smart Meter adder provided in the 2008 EDR (EB-2007-0856) approved rates. Sometime in the near future further application will be made to the Ontario Energy Board for adjustment based on the outcome of the determination process of selecting an approved technology solution for COLLUS Power Corp.

COLLUS Power Corp is currently working with a portion of the CHEC group of LDC's to obtain estimated costs through a combined Request for Proposal process. The RFP is for system operation, meter pricing and installation services.

COLLUS Power Corp has recently completed the first stage of their Smart Meter selection process by participating with proper authority in the Ministry of Energy London Hydro Request for Proposal process.

Major Issues

The issues to be reviewed in this case, as COLLUS Power Corp sees them, are discussed in Exhibit 1, Tab Schedule 6 (Draft Issues List).

COLLUS Power Corp also offers comments on the following matters:

- **Capital Structure**

COLLUS Power Corp is requesting a change in its deemed capital structure. Specifically, COLLUS Power Corp is requesting a decrease in the deemed equity ratio from 46.7% to 43.3% consistent with the second year of the phase-in of the shift in COLLUS Power Corp's capital structure from 50% to 40% equity as outlined in the Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario Electricity Distributors dated December 20, 2006 (the "Cost of Capital Report").

- **Return on Equity**

COLLUS Power Corp has assumed a return on equity of 8.57% consistent with the methodology outlined in Appendix B of the Cost of Capital Report. COLLUS Power Corp understands the OEB will be finalizing the return on equity for 2009 rates based on January 2009 market interest rate information.

- **Capital Expenditures**

COLLUS Power Corp continues to expand and reinforce its distribution system in order to meet the demand of new and existing customers in its service territory. This increase in demand comes both from expansion of the COLLUS Power Corp distribution system into currently non-serviced areas and distribution system upgrades needed in existing areas.

- **Operating and Maintenance Costs**

Operating and maintenance costs have been updated to reflect the impact of inflation and expected changes in costs, including services fees from its service provider.

Based on the OEB's *Comparison of Ontario Electricity Distributors Costs [EB-2006-0268]*, as updated with 2007 Data issued on June 24, 2008, COLLUS Power Corp's OM&A costs per customer compare favorably with its "Mid-Size Southern Medium-High Undergrounding" cohort. As reported, the five (5) year average OM&A cost per customer for the cohort was $208.00 while COLLUS Power Corp's average cost was $211.00.

Information of the calculations supporting this analysis are included in Table 1.2.1-3 below.

Table 1.2.1-3
SUMMARY OF THE APPLICATION

COMPARISON OF COLLUS Power Corp OM&A COSTS TO
"Mid-Size Southern Medium-High Undergrounding" COHORT GROUPING

Cohort Groupings	Total OM&A	
LDC	5 Year Average	2007
E.L.K. Energy Inc.	$ 155.00	$ 182.00
Wasaga Distribution Inc.	$ 157.00	$ 159.00
Chatham-Kent Hydro Inc.	$ 162.00	$ 164.00
Peterborough Distribution Incorporated	$ 181.00	$ 192.00
Festival Hydro Inc.	$ 182.00	$ 185.00
Welland Hydro-Electric Systems Corp.	$ 183.00	$ 209.00
Kingston Electricity Distribution Limited	$ 189.00	$ 182.00
Westario Power Inc.	$ 203.00	$ 196.00
COLLUS Power Corp.	**$ 211.00**	**$ 225.00**
St. Thomas Energy Inc.	$ 216.00	$ 214.00
Essex Powerlines Corporation	$ 221.00	$ 206.00
Woodstock Hydro Services Inc.	$ 223.00	$ 228.00
Niagara Falls Hydro Inc.	$ 247.00	$ 255.00
Bluewater Power Distribution Corporation	$ 261.00	$ 256.00
Erie Thames Powerlines Corporation	$ 329.00	$ 356.00
Average for Cohort Group	**$ 208.00**	**$ 214.00**

SOURCE: Comparison of Ontario Electricity Distributors Costs [EB-2006-0268], updated with 2007 Data Issued June 24, 2008.

This table is part of the PEG report that is part of the comparative data analysis development that is ongoing for the Ontario distribution utilities as part of the OEB's Performance Based Regulation Program. COLLUS Power Corp relies strongly upon comparative analysis to peer LDC's as a measurement tool when it examines its efficiency and effectiveness. The PEG report data is still only a general comparison tool as it is still trying to establish the exact parameters to be used in completing comparative analysis. For instance this is only comparing OM&A expenses and needs to incorporate capital spending data as well to achieve a final completely accurate comparison tool.
Still as noted earlier it is a useful general tool that can be utilized on a relative basis to determine the comparison results.

BUDGET DIRECTIVES:

COLLUS Power Corp 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

COLLUS Power Corp'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 and revenue forecast at existing rates for fiscal 2008 and 2009. The forecast is weather normalized as outlined in Exhibit 3, Tab 2, Schedule 1 and considers such factors as new customer additions and load profiles for all classes of customers.

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. Each item is reviewed account by account, where applicable in regards to materiality levels, for each of the forecast years with indirect costs allocated to direct costs for budget presentation.

Capital Budget

The capital budget forecast is prepared over a 2-year period and is influenced, among other factors, by COLLUS Power Corp's capacity to finance capital projects. 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:

COLLUS Power Corp is not requesting any changes in methodology in the current proceeding.

Calculation of Revenue Deficiency or Surplus

	2009 Test Existing Rates	2009 Test Proposed Rates
Revenue		
Suff/ Def From Below.		$976,701
Distribution Revenue	$4,832,283	$4,832,283
Other Operating Revenue (Net)	$326,000	$326,000
Total Revenue	$5,158,283	$6,134,984
Distribution Costs		
Operation, Maintenance, and Administration	$3,806,764	$3,806,764
Depreciation & Amortization	$983,056	$983,056
Capital Taxes	$2,174	$2,174
Interest- Deemed Interest	$515,894	$515,894
Total Costs and Expenses	$5,307,887	$5,307,887
Utility Income Before Income Taxes	-$149,604	$827,097
Net Adjustments per 2008 Pils	-$116,104	-$116,104
Taxable Income	-$265,708	$710,993
Income Tax (Tax Rate 33.0%)	-$87,684	$234,628
Utility Income	-$61,920	$592,469
Rate Base	$15,966,037	$15,966,037
Equity	43.30%	43.30%
Equity Component Rate Base	$6,913,294	$6,913,294
Income / Equity Rate Base %	-0.896%	8.57%
Target Return -Equity on Rate Base	8.57%	8.57%
Return- Equity on Rate Base	$592,469	$592,469
Revenue Deficiency	$654,390	
Revenue Deficiency (Gross-up)	$976,701	

1

CAUSES OF REVENUE DEFICIENCY:

COLLUS Power Corp's net revenue deficiency is calculated as $ **654,390** and when grossed up for PILs, the revenue deficiency is $ **976,701**. COLLUS Power Corp's calculation of its 2009 revenue deficiency is provided in Exhibit 1, Tab 2, Schedule 4 and Exhibit 7, Tab 1, Schedule 1.

The revenue deficiency is primarily the result of:

- The largest customer ALCOA Wheel Products of COLLUS Power Corp ceased operation in 2007. The negative impact on distribution service revenue associated with ALCOA Wheel Products ceasing operations is approximately half of the noted revenue deficiency.

- 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 and, as a result the rate base on which the rate of return is based, as discussed further in Exhibit 2 Tab 1 ((Rate Base Overview) and Tab 2 (Gross Assets – Property, Plant and Equipment)

FINANCIAL STATEMENTS – 2006 and 2007:

The COLLUS Power Corp Audited 2006 and 2007 Financial Statements accompany this Schedule as Appendix A.

APPENDIX A

COPY OF AUDITED FINANCIAL STATEMENTS FOR 2006 AND 2007

COPY OF 2007 T2 AND CT23 CORPORATION TAX RETURNS

PRO FORMA FINANCIAL STATEMENTS - 2008 AND 2009:

The COLLUS Power Corp 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 COLLUS Power Corp 2008 PRO FORMA STATEMENTS

APPENDIX B

COPY OF COLLUS Power Corp 2009 PRO FORMA STATEMENTS

RECONCILIATION BETWEEN FINANCIAL STATEMENTS AND FINANCIAL RESULTS FILED:

COLLUS Power Corp advises that because the 2006 and 2007 Audited Financial Statements do not vary from the regulatory financial results filed in this Application, a reconciliation between financial statements and financial results filed has not been provided.

PROPOSED ACCOUNTING TREATMENT FOR PROJECTS WITH A PROJECT LIFE CYCLE GREATER THAN ONE YEAR:

In accordance with the guidelines set out in the Accounting Procedures Handbook and COLLUS Power Corp Capitalization Policy , when required capital costs of any constructed assets will include an appropriate allowance for use of funds during construction. COLLUS Power Corp Capitalization Policy is provided in Exhibit 2, Tab 3, Schedule 4. At this time there does not appear to be any projects that will qualify for this accounting treatment.

INFORMATION ON PARENT AND SUBSIDIARIES

The COLLUS Power Corp 2007 Annual Report is part of the 2008-2010 Collingwood Utility Services Corp Business plan. The Financial Statements for 2007 have been previously provided as Appendix A in Exhibit 1, Tab 3, Schedule 1. For further information the business plan can be accessed through the website located at www.collus.com.

A detailed description of COLLUS Power Corp and the associated group of companies is set out in Exhibit 1, Tab 1, Schedule 14 (Corporate Entities Relationships Chart).

Information on COLLUS Power Corp Organizational Chart is provided at Exhibit 1, Tab1, Schedule 13.

COLLUS Power Corp advises that it does not prepare a Management Discussion and Analysis (“MD&A”) Report

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Ontario Energy Board
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2300 Yonge Street
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Toronto ON M4P 1E4
Telephone: (416) 481-1967
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2300, rue Yonge
26e étage
Toronto ON M4P 1E4
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Ontario

Licensing & Applications Branch

June 13, 2003

Mr. Darius Vaiciunas
Load Management & Regulatory Coordinator
COLLUS Power Corp.
Box 189
Collingwood, ON
L9Y 3Z5

Dear Mr. Vaiciunas:

Re: Application for Renewal Electricity Distribution Licence
Board File No. RP-2002-0189/EB-2002-0518

In the subject application, one party, Hydro One Networks Inc. responded to the Notice of Proposal to renew the Electricity Distribution Licence. After considering the application and the written submissions by Hydro One Networks Inc., I have decided to issue the Electricity Distribution Licence for COLLUS Power Corp. under Part V of the *Ontario Energy Board Act, 1998* ("the Act").

Attached to this letter is the Electricity Distribution Licence for COLLUS Power Corp.

Under section 76 of the Act, the Board may suspend or revoke this licence if: the licensee does not comply with the Act or the *Electricity Act, 1998* or a regulation under those Acts; is in breach of any condition of the licence; is no longer in a position to operate in conformity with the Act and the Electricity Act and the conditions of its licence; has been negligent in carrying on the activity authorized by the licence; or has made fraudulent misrepresentations in carrying on its business.

If you have any questions regarding these matters, please contact Elaine Wong, Licensing Advisor at 416 440-7638.

Sincerely,

M. Garner

Mark Garner
Director of Licensing

Enc.

cc. Mr. Glen MacDonald, Hydro One Networks Inc.

Ontario

Electricity Distribution Licence

ED-2002-0518

Collus Power Corporation

Valid Until

March 31, 2023

M. C. Garner

Mark C. Garner
Director of Licensing
Ontario Energy Board

Date of Issuance: June 13, 2002

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

Electricity Distribution Licence 2

1 Definitions 3

In this Licence: 4

"**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; 5

"**Act**" means the Ontario Energy Board Act, 1998, S.O. 1998, c. 15, Schedule B, as amended; 6

"**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; 7

"**Board**"means the Ontario Energy Board; 8

"**Director**" means the Director of Licensing appointed under section 5 of the*Act*; 9

"**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; 10

"**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; 11

"**Electricity Act**" means the *Electricity Act, 1998*, S.O. 1998, c. 15, Schedule A, as amended; 12

"**Licensee**" means Collus Power Corporation; 13

"**Market Rules**" means the rules made under section 32 of the *Electricity Act*; 14

"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*; 15

"Rate Order" means an Order or Orders of the Board establishing rates the Licensee is permitted to charge; 16

"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; 17

"service area" with respect to a distributor, means the area in which the distributor is authorized by its licence to distribute electricity; 18

"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*; 19

"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. 20

2 Interpretation 21

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. 22

3 Authorization Granted under this Licence 23

3.1 The Licensee is authorized, under Part V of the *Act* and subject to the terms and conditions set out in this Licence: 24

a) To own and operate a distribution system in the service area described in Schedule 1 of this Licence; 25

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 , 26

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*. 27

4 Obligation to Comply with Legislation, Regulations and Market Rules 28

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. 29

4.2 The Licensee shall comply with all applicable Market Rules. 30

5 Obligation to Comply with Codes 31

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 to this requirement are set out in Schedule 3 of this Licence: 32

a) the Affiliate Relationships Code for Electricity Distributors and Transmitters; 33

b) the Distribution System Code; 34

c) the Retail Settlement Code, and; 35

d) the Standard Supply Service Code. 36

5.2 The Licensee shall: 37

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; 38

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. 39

6 Obligation to Provide Non-discriminatory Access 40

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. 41

7 Obligation to Connect 42

7.1 The Licensee shall connect a building to its distribution system if: 43

a) The building lies along any of the lines of the distributor's distribution system, and 44

b) The owner, occupant or other person in charge of the building requests the connection in writing. 45

7.2 The Licensee shall make an offer to connect a building to its distribution system if: 46

a) The building is within the Licensee's service area as described in Schedule 1, and 47

b) The owner, occupant or other person in charge of the building requests the connection in writing. 48

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. 49

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 any Codes to which the Licensee is obligated to comply with as a condition of this Licence. 50

8 Obligation to Sell Electricity 51

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. 52

9 Obligation to Maintain System Integrity 53

9.1 The Licensee shall maintain its distribution system to the standards established in the Distribution System Code, Market Rules and have regard to any other recognized industry operating or planning standards adopted by the Board. 54

10 Market Power Mitigation Rebates 55

10.1 The Licensee shall comply with the pass through of Ontario Power Generation rebate conditions set out in Appendix A of this Licence. 56

11 Distribution Rates 57

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. 58

12 Separation of Business Activities 59

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. 60

13 Expansion of Distribution System 61

13.1 The Licensee shall not construct, expand or reinforce an electricity distribution system or make and interconnection except in accordance with the *Act* and Regulations, the Distribution System Code and applicable provisions of the Market Rules. 62

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. 63

14 Provision of Information to the Board and Director of Licensing 64

14.1 The Licensee shall maintain records of and provide, in the manner and form determined by the Board or the Director, such information as the Board or the Director may require from time to time. 65

14.2 Without limiting the generality of condition 14.1 the Licensee shall notify the Director 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. 66

15 Restrictions on Provision of Information 67

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. 68

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: 69

a) to comply with any legislative or regulatory requirements, including the conditions of this Licence; 70

b) for billing, settlement or market operations purposes; 71

c) for law enforcement purposes; or 72

d) to a debt collection agency for the processing of past due accounts of the consumer, retailer, wholesaler or generator. 73

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. 74

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. 75

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. 76

16 Customer Complaint and Dispute Resolution 77

16.1 The Licensee shall: 78

a) have a process for resolving disputes with customers that deals with disputes in a fair, reasonable and timely manner; 79

b) publish information which will make its customers aware of and help them to use its dispute resolution process; 80

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; 81

d) give or send free of charge a copy of the process to any person who reasonably requests it; and 82

e) refer unresolved complaints and subscribe 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 Director. The Director will provide reasonable notice to the Licensee of the date this condition becomes effective. 83

17 Term of Licence 84

17.1 This Licence shall take effect on June 13, 2003 and terminate on March 31, 2023. 85

18 Transfer of Licence 86

18.1 In accordance with subsection 18(2) of the *Act*, this Licence is not transferable or assignable without leave of the Board. 87

19 Amendment of Licence 88

19.1 The Board may amend this Licence in accordance with section 74 of the *Act* or section 38 of the *Electricity Act.* 89

20 Fees and Assessments 90

20.1 The Licensee shall pay all fees charged and amounts assessed by the Board. 91

21 Communication 92

21.1 The Licensee shall designate a person that will act as a primary contact with the Director of Licensing on matters related to this Licence. The Licensee shall notify the Director promptly should the contact details change. 93

21.2 All official communication relating to this Licence shall be in writing. 94

21.3 All written communication is to be regarded as having been given by the sender and received by the addressee: 95

a) when delivered in person to the addressee by hand, by registered mail or by courier; 96

b) seven (7) business days after the date of posting if the communication is sent by regular mail; and, 97

c) when received by facsimile transmission by the addressee, according to the sender's transmission report. 98

22 Copies of the Licence 99

22.1 The Licensee shall: 100

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; 101

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. 102

Schedule 1 Definition of Distribution Service Area 103

This Schedule specifies the area in which the Licensee is authorized to distribute and sell electricity in accordance with condition 8 of this Licence. 104

1 The Town of Collingwood as established on January 1, 1993, following the annexation of a part of Nottawasaga Township. 105

2 The Town of Thornbury as of December 31, 1997, preceding the formation of the Town of the Blue Mountains. 106

3 The Village of Creemore as of December 31, 1992, preceding the formation of the Township of Clearview. 107

4 The Town of Stayner as of December 31, 1992, preceding the formation of the Township of Clearview. 108

Schedule 2 Provision of Standard Supply Service 109

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*. 110

The Licensee is authorized to retail electricity directly to consumers within its service area in accordance with condition 8 of this Licence, any applicable exemptions to this Licence, and at the rates set out in the Rate Orders. 111

Schedule 3 List of Code Exemptions 112

This Schedule specifies any specific Code requirements from which the Licensee has been exempt. 113

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. 114

Appendix A Market Power Mitigation Rebates 115

1 Definitions and Interpretation 116

In this Licence, 117

"embedded distributor" means a distributor who is not a market participant and to whom a host distributor distributes electricity; 118

"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; 119

"host distributor" means a distributor who is a market participant and who distributes electricity to another distributor who is not a market participant. 120

In this Licence, a reference to the payment of a rebate amount by the IMO includes interim payments made by the IMO. 121

2 Information Given to IMO 122

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: 123

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and 124

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.* 125

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 126 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 127

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*. 128

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. 129

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. 130

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. 131

3 Pass Through of Rebate 132

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: 133

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; 134

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 135

c embedded distributors to whom the distributor distributes electricity. 136

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. 137

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: 138

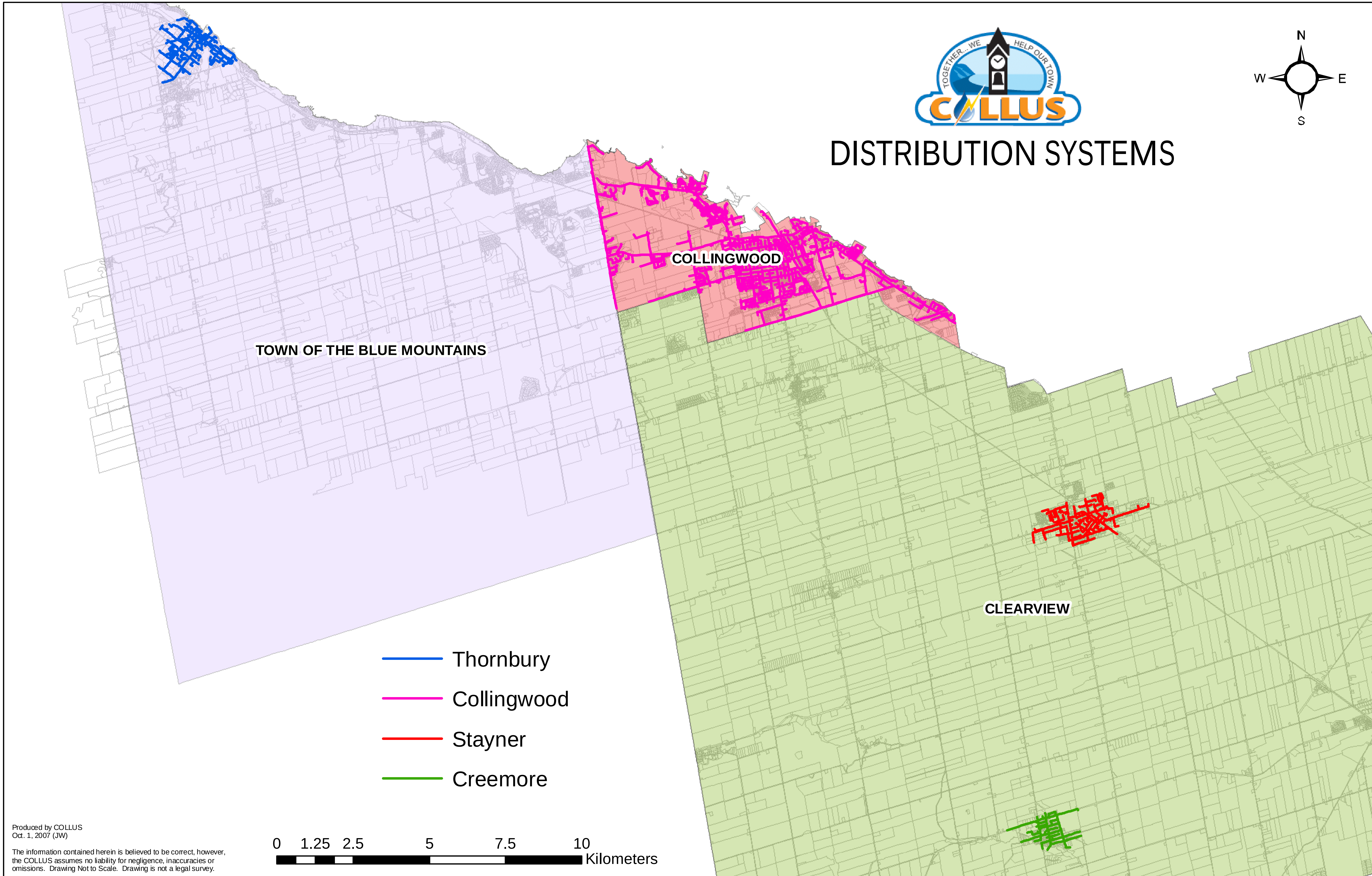
"ONTARIO POWER GENERATION INC. rebate" 139

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. 140

Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party. 141

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. 142

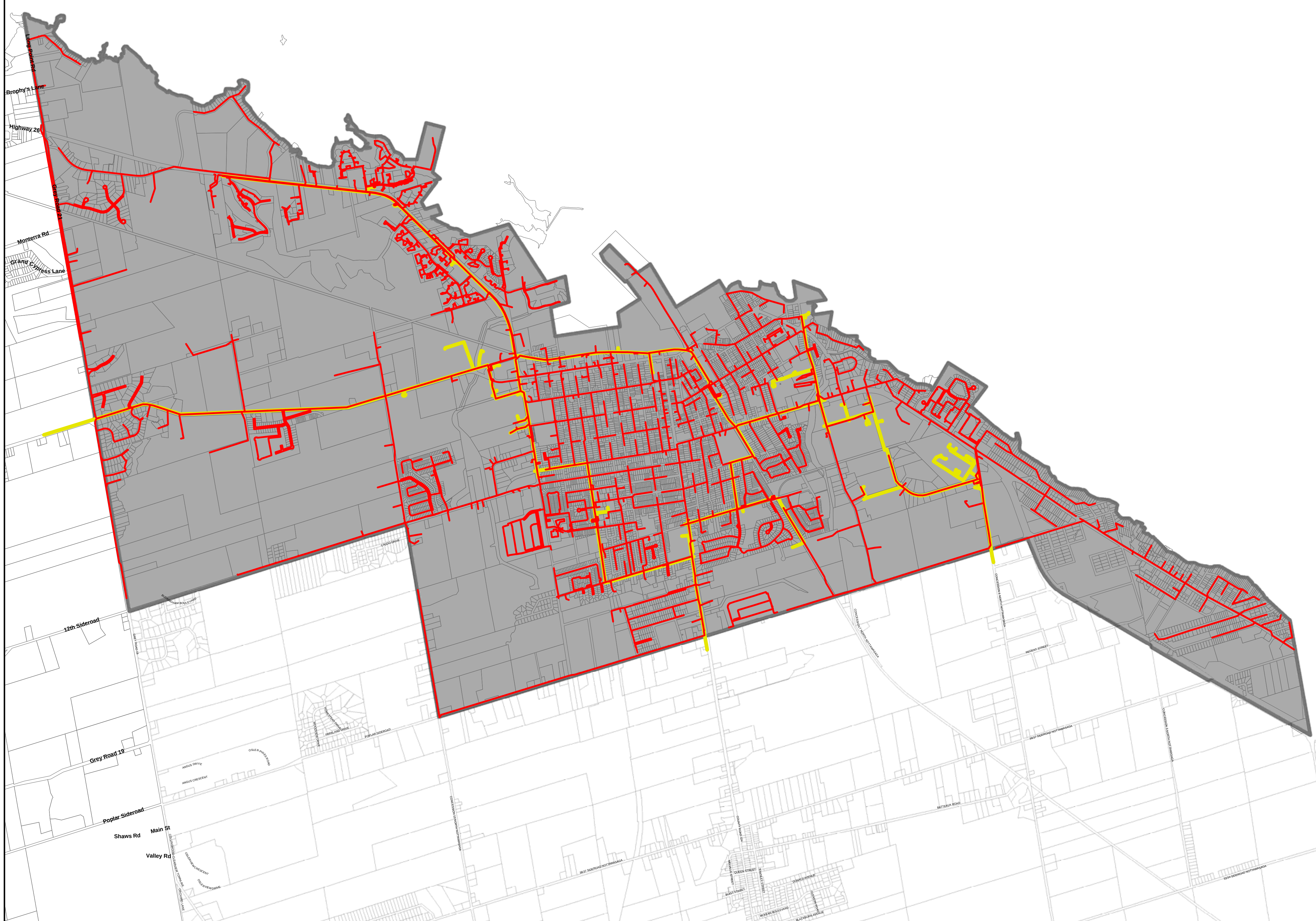
DISTRIBUTION SYSTEMS



Produced by COLLUS
Oct. 1, 2007 (JW)

The information contained herein is believed to be correct, however, the COLLUS assumes no liability for negligence, inaccuracies or omissions. Drawing Not to Scale. Drawing is not a legal survey.

Collingwood Distribution Systems



TOGETHER... WE HELP OUR TOWN
COLLUS

Collingwood (4 kV)

Transmission Lines (44kV)

Boundary

N
W E
S

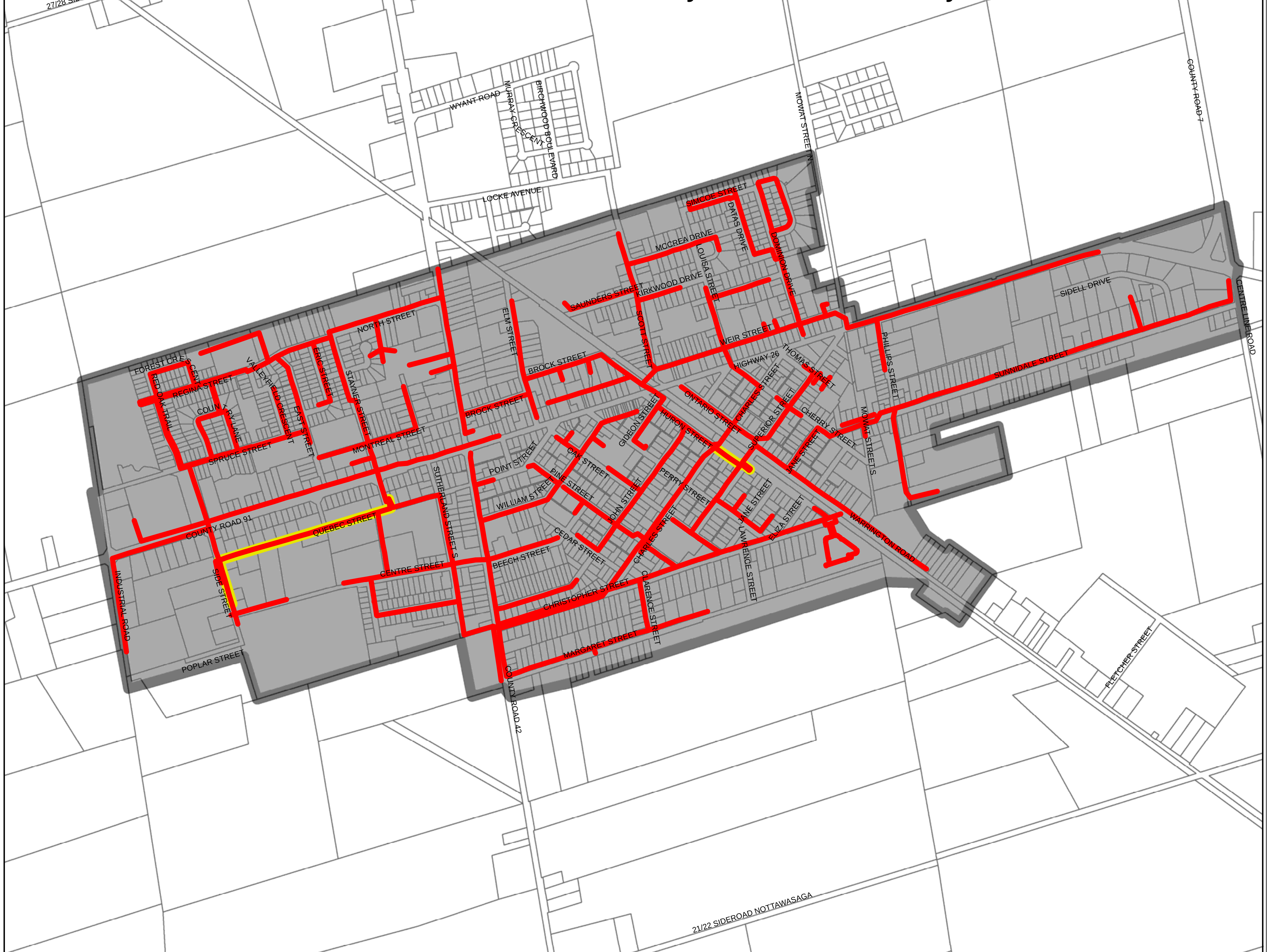
0 0.375 0.75 1.5 Kilometers

Source: Aerial Photography 2002 - County of Simcoe
Assessment Parcel Fabric - Teranet Inc.

Produced by COLLUS
July 16, 2008 (JW)

The information contained herein is believed to be correct, however, the COLLUS assumes no liability for negligence, inaccuracies or omissions. Drawing Not to Scale. Drawing is not a legal survey.

Stayner Distribution System



Stayner (4 kV)

44 kV

Boundary

N

W E

S

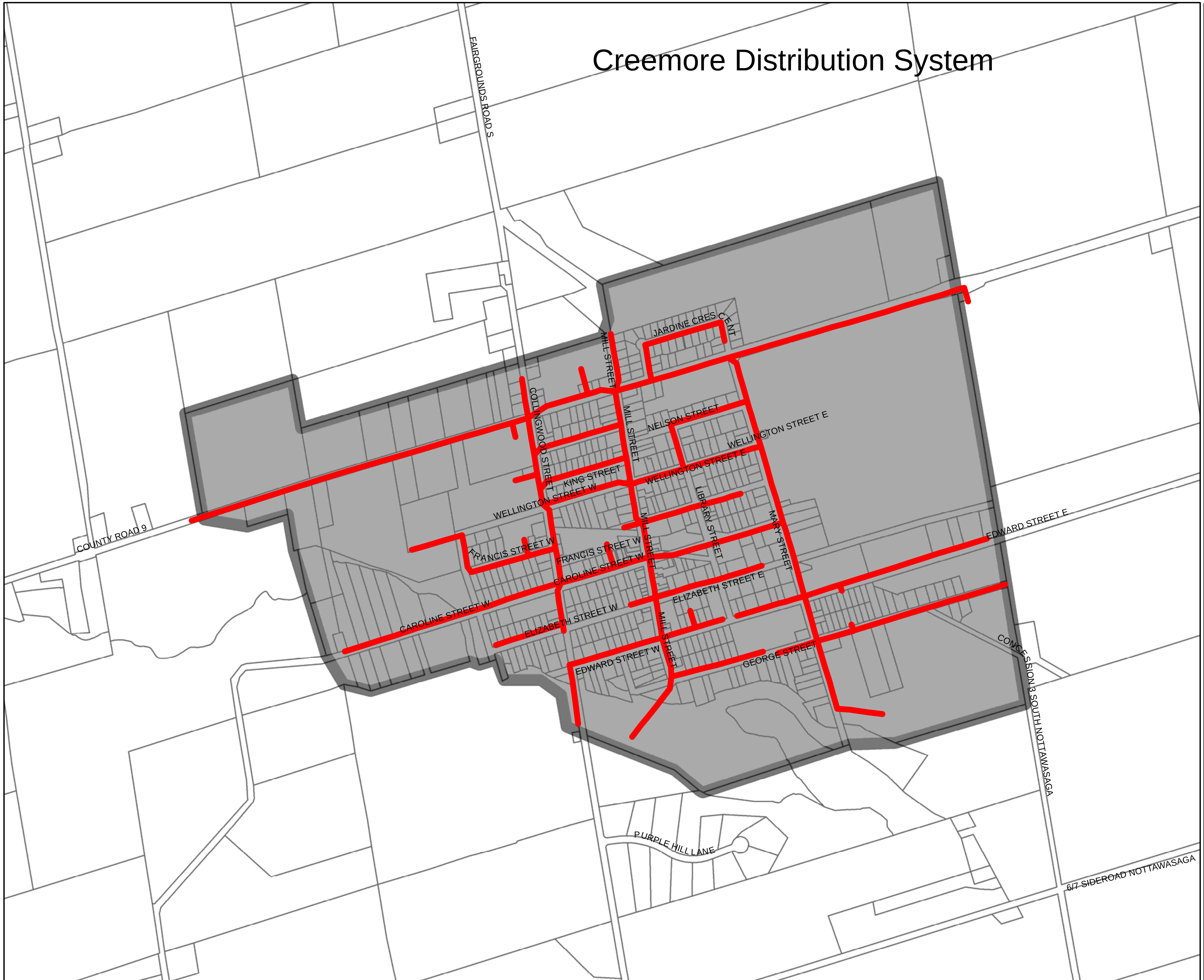
0 0.125 0.25 0.5 Kilometers

Source: Aerial Photography 2002 - County of Simcoe
Assessment Parcel Fabric - Teranet Inc.

Produced by COLLUS
July 16, 2008 (JW)

The information contained herein is believed to be correct, however, the COLLUS assumes no liability for negligence, inaccuracies or omissions. Drawing Not to Scale. Drawing is not a legal survey.

Creemore Distribution System



COLLUS

Creemore (8 kV)

Boundary

N
W E
S

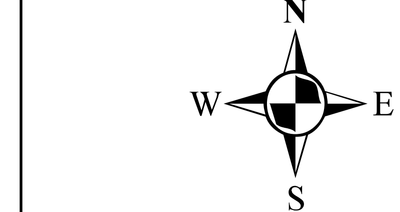
0 0.125 0.25 0.5 Kilometers

Source: Aerial Photography 2002 - County of Simcoe
Assessment Parcel Fabric - Teranet Inc.

Produced by COLLUS
July 16, 2008 (JW)

The information contained herein is believed to be correct, however, the COLLUS assumes no liability for negligence, inaccuracies or omissions. Drawing Not to Scale. Drawing is not a legal survey.

Thornbury Distribution System



- Thornbury (8 kV)
- 44 kV
- Boundary

N
W E
S

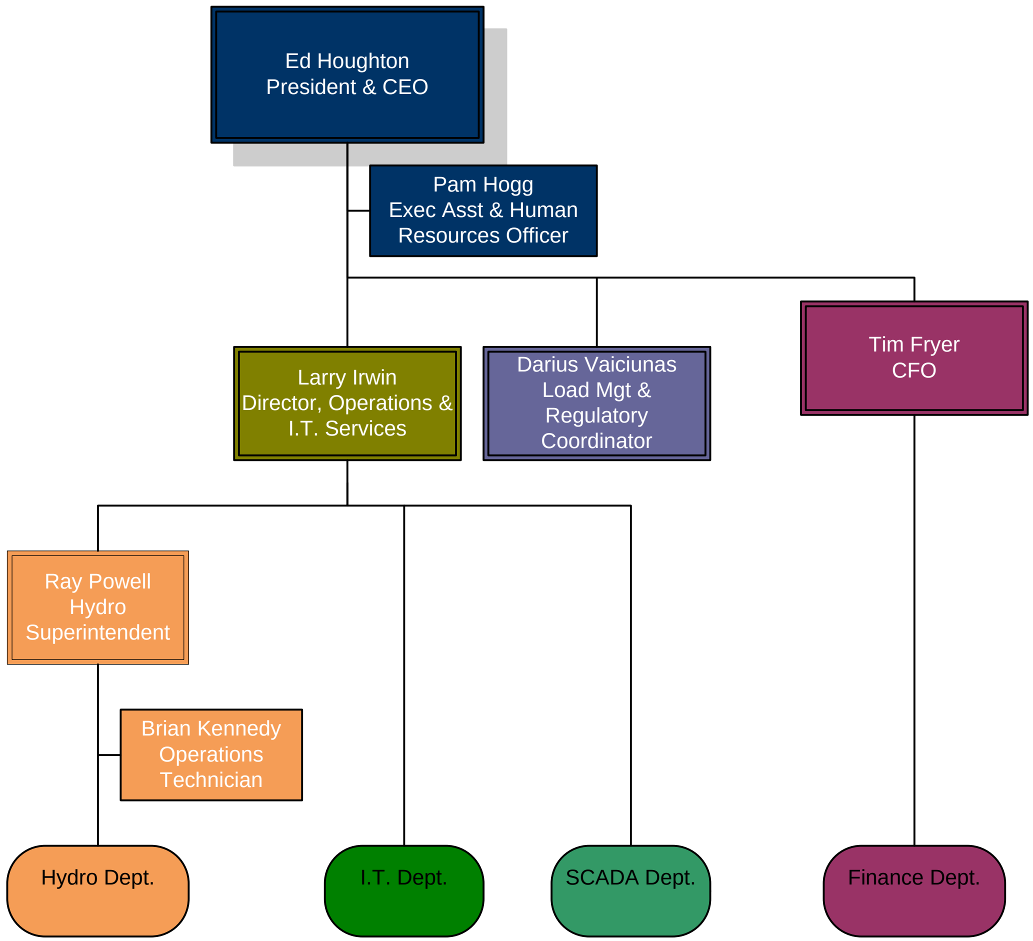
0 0.1 0.2 0.4 Kilometers

Source: Aerial Photography 2002 - County of Simcoe
Assessment Parcel Fabric - Teranet Inc.

Produced by COLLUS
July 16, 2008 (JW)

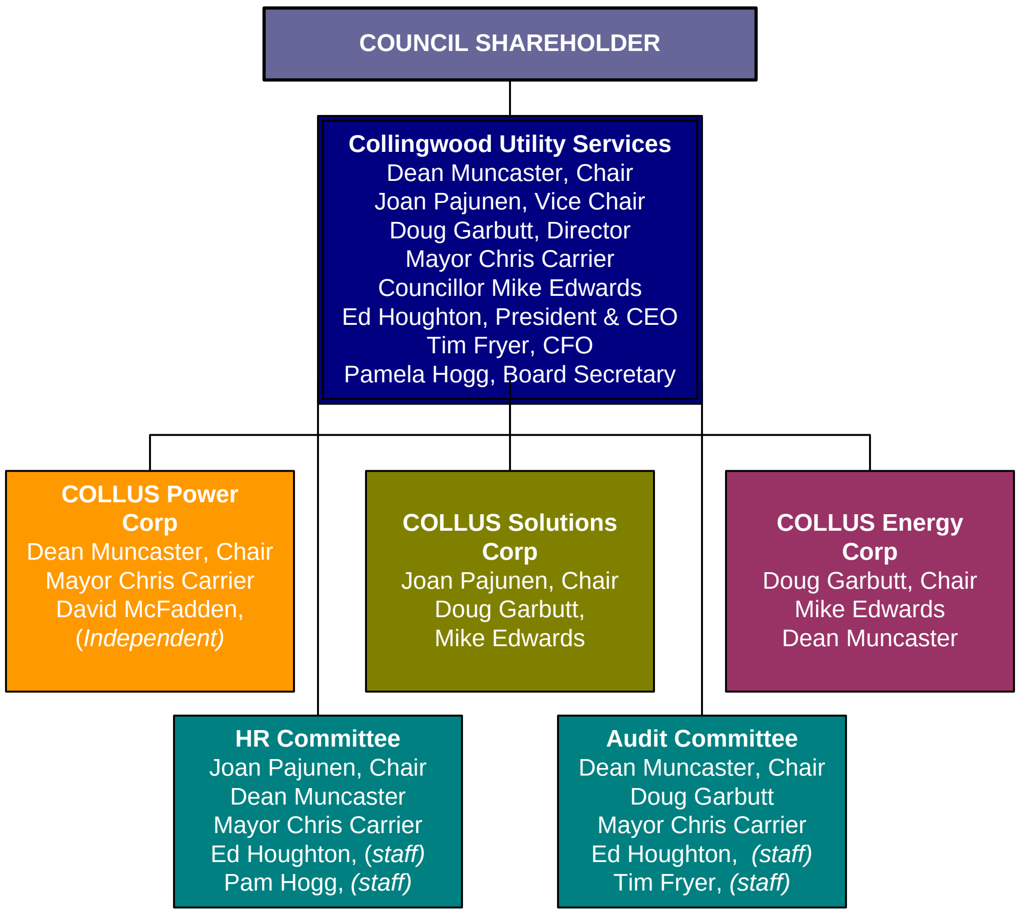
The information contained herein is believed to be correct, however, the COLLUS assumes no liability for negligence, inaccuracies or omissions. Drawing Not to Scale. Drawing is not a legal survey.

COLLUS Power
Organization Chart



Collingwood Utility Services

Board Structure



SA-1

AMENDING AGREEMENT

THIS AMENDING AGREEMENT is made this 17th day of Dec., 2003.

BETWEEN:

COLLUS POWER CORP., corporation incorporated pursuant to the laws of the Province of Ontario

(Hereinafter referred to as "**WIRESCO**")

-and-

COLLUS SOLUTIONS CORP. a corporation incorporated pursuant to the laws of the Province of Ontario

(Hereinafter referred to as "**SERVCO**")

WHEREAS WIRESCO and **SERVCO** (collectively the "**Parties**") have entered into an agreement (the "**Services Agreement**") dated as of January 1, 2002 whereby **SERVCO** has agreed to provide certain services to **WIRESCO** as provided in the Services Agreement; and

WHEREAS the Base Financial Consideration as specified in Section 5:01 of the Services Agreement was incorrectly specified as $765,838.00; and

WHEREAS the Effective Date of the Services Agreement was not clearly defined as January 1, 2002; and

WHEREAS the Parties wish to amend the Services Agreement to correct the Base Financial Consideration and clarify the Effective Date of the Services Agreement;

NOW THEREFORE THIS AMENDING AGREEMENT WITNESSETH that, in consideration of the mutual covenants and agreements herein contained and subject to the terms and conditions hereinafter set out, the Parties hereto agree as follows:

(a) The Base Financial Consideration of the Services Agreement is amended to $1,374,139.00.

(b) The Effective Date of the Services Agreement is January 1, 2004.

(c) Except as varied in this Amending Agreement the terms and conditions set forth in the Services Agreement shall remain in full force and effect.

(d) Capitalize terms not defined herein shall have the meanings ascribed thereto in the Services Agreement.

IN WITNESS WHEREOF this Amending Agreement has been executed by the parties hereto as of the date written above.

COLLUS POWER CORP.

By: D Muncaster

Name: Mr. Dean Muncaster
Title: Chair of the Board of Directors

COLLUS SOLUTIONS CORP.

By: Jack Gartley

Name: Mr. Jack Gartley
Title:Chair of the Board of Directors

COLLUS POWER CORP

- and -

COLLUS SOLUTIONS CORP

SERVICES AGREEMENT

December 18, 2002

SERVICES AGREEMENT

THIS SERVICES AGREEMENT is made as of the 18th day of December, 2002.

BETWEEN:

COLLUS POWER CORP, a corporation incorporated pursuant to the laws of the Province of Ontario

(Hereinafter referred to as "**WIRESCO**")

- and -

COLLUS SOLUTIONS CORP a corporation incorporated pursuant to the laws of the Province of Ontario

(hereinafter referred to as "**SERVCO**")

RECITALS

1. The Corporation of the Town of Collingwood pursuant to Section 142 of the *Electricity Act, 1998* caused WIRESCO to be incorporated on November 1, 2000.

2. SERVCO agrees to provide supervisory, operational, engineering, finance, administrative services and other services to WIRESCO on the terms as set forth in this Agreement, and SERVCO shall provide such other products and services as may be agreed to by the Parties from time to time.

3. This agreement shall not limit the activities of SERVCO, with the exception of those activities within the exclusive statutory and licensed jurisdictions of WIRESCO including the items specifically identified in this Agreement.

4. This agreement sets out certain arrangements between WIRESCO and SERVCO which were in place prior to the date of execution of this Agreement.

NOW THEREFORE in consideration of the mutual covenants contained herein and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto hereby agree as follows:

Article One INTERPRETATION

Section 1.01: Definitions

Unless the context otherwise specifies or requires, for the purposes of this Agreement all capitalized terms herein shall have the meanings set forth below:

(a) "**Advisors**" means employees, agents, professional advisors, contractors and subcontractors, and "**Advisor**" means any one of them;

(b) "**Affiliate,**" with respect to a corporation, shall have the same meaning as is ascribed to such term in the *Business Corporations Act* (Ontario);

(c) "**Agreement**" "**this Agreement**", "**the Agreement**", "**SERVCO Services, SERVCO Management Services Agreement**", "**hereto**", "**hereof**", "**herein**", "**hereby**", "**hereunder**" and similar expressions mean this SERVCO Services Agreement together with all Schedules attached hereto, as they may be amended from time to time;

(d) "**Base Direct Costs**" has the meaning ascribed to such term in Section 5.01;

(e) "**Base Financial Consideration**" has the meaning ascribed to such term in Section 5.01;

(f) "**Business Day**" means any day other than a Saturday or Sunday or a statutory or bank holiday in the Province of Ontario;

(g) "**Claims**" has the meaning ascribed to such term in Section 4.05;

(h) "**Confidential Consumer Information**" means information WIRESCO has obtained relating to a specific consumer, retailer or generator in the process of providing current or prospective distribution service;

(i) "**Default**" means in respect of WIRESCO, an event set out in Section 8.01 and, in respect of SERVCO, an event set out in Section 8.02;

(j) "**Effective Date**" means the date first written above;

(k) "**Event of Default**" means a Default, the notice and cure periods (if any) respecting, which have expired;

(l) "**Extraordinary Costs**" means cost as defined in Section 5.07;

(m) "**Force Majeure Event**" has the meaning ascribed to such term in Section 11.01;

(n) **"Law"** means any law, rule, regulation, Code, order, writ, judgement, decree or other legal or regulatory termination by a court, regulatory agency, including the IeMO, or governmental authority of competent jurisdiction;

(o) **"Person"** means an individual, corporation, partnership, joint venture, association, trust, pension fund, union, governmental agency, official, board, tribunal, ministry, commission or department;

(p) **"Prime Rate"** means, for any day, an annual rate of interest equal to the rate of interest which SERVCO's principal bank establishes at its principal office in Toronto as the reference rate of interest to determine interest rates that it will charge on such day for commercial loans in Canadian dollars made to its customers in Canada and which it refers to as its "prime rate of interest";

(q) **"Services"** are Services that are provided under Section 3.01 of this Agreement;

(r) **"Term"** has the meaning ascribed thereto in Section 2.01 of this Agreement; and

(s) **"Third Party Expenses"** means all fees, costs and charges paid to third parties by SERVCO on behalf of WIRESCO in connection with providing the Services and the Management Services or incurred by WIRESCO's employees while providing Services under this Agreement paid by SERVCO.

(t) **"Total Controllable Costs"** has the meaning ascribed to such term in Section 5.01;

(u) **"Utility"** means the predecessor municipal electric utility of WIRESCO.

Section 1.02: Construction of Agreement

In this Agreement:

(a) words denoting the singular include the plural and vice versa and words denoting any gender include all genders;

(b) all usage of the word "**including**" or the phrase "**e.g.,**" in this Agreement shall mean "including, without limitation," throughout this Agreement;

(c) any reference to a statute shall mean the statute in force as at the date hereof, together with all regulations promulgated there under, as the same may be amended, re-enacted, consolidated and/or replaced, from time to time, and any successor statute thereto, unless otherwise expressly provided;

(d) any reference to a specific executive position or an internal division or department of a Party shall include any successor positions, divisions or departments having substantially the same responsibilities or performing substantially the same functions;

(e) when calculating the period of time within which or following which any act is to be done or step taken, the date which is the reference day in calculating such period shall be excluded; and if the last day of such period is not a Business Day, the period shall end on the next Business Day;

(f) all dollar amounts are expressed in Canadian dollars;

(g) the division of this Agreement into separate Articles, Sections, subsections and Schedules, the provision of a table of contents and the insertion of headings is for convenience of reference only and shall not affect the construction or interpretation of this Agreement;

(h) words or abbreviations which have well known or trade meanings are used herein in accordance with their recognized meanings; and

(i) the terms and conditions hereof are the result of negotiations between the Parties and the Parties therefore agree that this Agreement shall not be construed in favour of or against any Party by reason of the extent to which any Party or its professional advisors participated in the preparation of this Agreement.

Article Two TERM

Section 2.01: Term

Unless terminated in accordance with Section 10.01 of this Agreement, the term of this Agreement shall be from the Effective Date to and including January 1, 2008 and the term shall be automatically extended for a further period of one (1) year unless either Party gives notice in writing that the Agreement is not to be extended on the date which is four (4) years prior to the end of the term, or the end of renewal as the case may be.

Article Three SERVCO SERVICES AND COVENANTS

Section 3.01: Services

Unless the parties otherwise agree in writing and subject to the terms, covenants and conditions contained in this Agreement and to the observance and performance by WIRESCO of all terms, covenants and conditions hereof, SERVCO will provide or cause to be provided to WIRESCO the following services (collectively, the **"Services"**):

Reconnect and Collection

Responses to reconnects and collection issues will be completed in an expeditious and timely fashion.

Meter Reading

The meters of WIRESCO'S Residential & General Service customers shall be read in a timely manner with a SENSUS hand held meter-reading device or other hand held meter-reading device that the parties may agree upon. A Schedule for meter reading will be supplied by SERVCO to WIRESCO for consideration.

Residential Service Connections

Each residential service connections will encompass the following:

- A single field representative will meet customers on site at the appointed time for not less than 98% of appointments made.
- Jobs will be discussed including prices on site with residential customers.
- Where appropriate, other utility lines such as telephone and TV cable may be laid for customers, at no additional cost to customers, during underground service work.
- Where conditions of supply are met, certified trained staff will perform cable connections within 48 hours upon receipt of ESA authorization.

Billing & Collecting

SERVCO shall utilize equipment that performs billing and collecting functions to North American industry standards. Said equipment shall meet the local needs of the community and shall be capable of providing customized local services such as equal payment plans. WIRESCO shall be entitled to review from time to time the capabilities of the system's workstations and network server to ensure that these local services are available to customers in the future.

All collections will be done from an established local community office.

Customer Service

Customer Service will be provided by qualified, readily accessible and knowledgeable local staff that meets the needs of existing and potential customers. Services will include the provision of local community and engineering planning information to serve new business. WIRESCO customer information will be readily available to WIRESCO in a local office in both electronic and hard copy. SERVCO staff shall be knowledgeable in respect of community demographics and shall provide personal and friendly customer service, including ongoing community services such as underground cable locates for customers.

Data Tracking

Competent SERVCO staff and equipment shall upon the request of WIRESCO maintain and collect numerous types of data by using technological means and integrated computer systems in order to track trends and circumstances as required by the Ontario Energy Board and others.

Accounting

Skilled local staff will provide and maintain accounting services that are readily accessible at the local level, including financial statements, financial planning, payroll, collection, withholding or remittance of taxes and other required functions. These records will be kept in a format that is acceptable to the Accounting Procedures Handbook for Electric Distribution Utilities and will be available for WIRESCO on request.

Distribution System Code ("DSC"), Retail Settlement System ("RSS") and Standard Supply Service ("SSS")

WIRESCO grants to SERVCO, WIRESCO'S authorization for SERVCO to administer WIRESCO'S DSC, RSS and SSS.

In acting as agent of WIRESCO, SERVCO will comply with all the regulatory requirements of the DSC, RSS and SSS, subject to the licensing provisions of the Ontario Energy Board.

DSC knowledge of the DSC and its application will be maintained locally and administered by SERVCO.

SSS will be billed by SERVCO on the behalf of WIRESCO and the incremental administration charges(initially set at $0.25/customer/month or $0.30/ customer/month for utility consolidated billing involving retailers) associated with SSS will accrue to the benefit of SERVCO.

Engineering Services

Certified knowledgeable staff with experience in the electrical utility field will utilize electrical engineering industry standards, recognising the local conditions. Load forecasting and load control will be provided to produce economic system stability through the use of engineering software packages.

Planning and Necessary Maintenance

Qualified staff will provide planning and necessary maintenance to the electrical system in a timely fashion appropriate for the maintenance need. To the extent practicable, this maintenance will be co-ordinated and integrated with municipal infrastructure projects, including other community utilities such as Bell Canada. Utilising its in depth local knowledge and information sources, SERVCO will respond to other local reconstruction programs to coordinate activity with the view to minimizing costs to all parties.

Contracting with Developers, Customers and others

Competent SERVCO staff with local knowledge will be utilized to provide services such as material procurement and handling, design, planning, cost estimating, installation, scheduling, inspection and liaison with other utilities, contractors, the municipality with respect to development, customers and others.

Subcontracting services

To the extent practicable, local services will generally be utilised for subcontracted services.

Maintenance of necessary inventory at SERVCO facilities within the community

Competent staff will procure the required material and the necessary inventory will be stored and maintained at a facility within the community, allowing ease of access to qualified staff. Inventory levels will be adequately maintained with accountable databases, to minimize response times in the event of an emergency.

After Hours Response

SERVCO will cause staff to respond to service calls within 30 minutes of a request for such service and shall have a crew in operation within the utility's service area within the time stated.

Emergency Response

SERVCO will cause staff to respond to Emergency call-outs within 15 minutes of a request for such service and shall have a crew in operation within WIRESCO'S service area within the time stated. Emergency call-outs are caused by third parties, Acts of God or normal wear and tear.

Normal Hours Response

SERVCO will cause staff to respond to service calls on a scheduled basis.

Emergency Preparedness

An Emergency Measures Plan will be maintained and updated as required.

Provision of Supervisory Services

All supervisory services provided by SERVCO under this agreement will be provided directly or indirectly by SERVCO. SERVCO will provide distribution plant maintenance supervision to WIRESCO.

Shared Facilities

The Parties acknowledge the existence of a bilateral lease between WIRESCO and the PUBLIC UTILITIES COMMISSION of the Town of Collingwood (PUC) regarding WIRESCO use of land and buildings or part thereof owned by the PUC.

Provision of Management Services

SERVCO shall provide to WIRESCO Management Services, which shall include but not be limited to human resources, regulatory assistance and advice and policy development. SERVCO shall provide to WIRESCO reports relating to Management Services rendered by SERVCO and such reports shall be provided to the President or CEO of WIRESCO and upon request to the WIRESCO Board of Directors.

In providing the Management Services, it is specifically understood that SERVCO is an independent contractor and not an agent or employee of WIRESCO. Management Services include the reports on such items as regulatory, policy, and human resources to WIRESCO on the terms as set forth in this Agreement.

As such, except as permitted by this Agreement, SERVCO shall not be authorized to bind or commit WIRESCO, either actually or apparently, in any manner whatsoever without the prior written authority from WIRESCO to do so. SERVCO does not have the authority to bind WIRESCO with respect to regular regulatory submissions without the prior approval of the President or CEO of WIRESCO who shall report such approval to the WIRESCO Board, but it is expected that SERVCO will respond to questions and interrogatories on regulatory submission once initiated. Regardless, SERVCO will report to WIRESCO on all regulatory activities.

SERVCO shall not be authorized to bind or commit WIRESCO, either actually or apparently, in any manner whatsoever without the prior written authority from WIRESCO to divestitures of any interest of WIRESCO in real property.

SERVCO shall not be authorized to bind or commit WIRESCO, either actually or apparently, in any manner whatsoever without the prior written authority from WIRESCO to divestitures of any interest of WIRESCO in personal property in excess of $5,000 annually.

Further, where WIRESCO has an approved policy with respect to the services, which SERVCO provides to third parties when providing services on behalf of WIRESCO, SERVCO shall be bound by that policy. If activities should have a policy, then SERVCO will expeditiously bring the matter to the attention of WIRESCO by way of a report to the WIRESCO Board for consideration.

Section 3.02: Capital Construction Activities by SERVCO

(a) With prior written annual approval of WIRESCO, SERVCO will undertake, by way of acquisition or construction, a capital construction program.

(b) For unplanned capital or construction activities, including any interest in real property the monthly capital amount will be limited to $20,000 but must not exceed $100,000 in any 12 month period. Such amounts will be billed by SERVCO within 90 days of the costs being incurred. On receipt of the approval of WIRESCO, any previously unplanned capital or construction activity shall be considered to have been planned. Any land acquisitions or construction on behalf of WIRESCO including easements, leases, or interest in real property shall be billed by SERVCO within 90 days of the costs being incurred and if not part of the approved capital construction program shall be limited to $5,000.

(c) In extreme and unusual situations, the President or the CEO or the Chair of WIRESCO may authorize unplanned acquisition or capital expenditures in excess of the previous limits, provided notification is provided to WIRESCO by SERVCO within 72 hours of the commencement of such activities.

(d) At the time capital is approved, the division of capital activities between WIRESCO resourced activities and SERVCO resourced activities will be established.

Section 3.03: Performance Standards

(a) SERVCO will endeavour to perform in the top quartile of industry standards, based on standards set by the Electricity Distributors Association, Electric Utility Safety Association, and Occupational Health & Safety Standards.

(b) SERVCO will make all reasonable efforts to meet or exceed performance measures established by the Ontario Energy Board.

(c) SERVCO commits to make all reasonable efforts to maintain the standards of service provided in 1999/2000 and to the extent practical improve those services.

(d) WIRESCO and SERVCO commit to attempting to provide distribution price stability for customers.

Section 3.04: Changes

WIRESCO and SERVCO may, from time to time, agree to modifications to the Services, by negotiating appropriate changes to the descriptions of the services and the consideration in connection with such changes and shall initial and attach amended schedules hereto.

Section 3.05: General SERVCO Covenants

(a) SERVCO shall be responsible for obtaining all necessary licences and permits and for complying with all applicable federal, provincial and municipal laws, codes and regulations in connection with the provision of the services hereunder and SERVCO shall when requested provide WIRESCO with adequate evidence of its compliance with this Section 3.05;

(b) SERVCO shall comply, while on the premises used by WIRESCO, with all the rules and regulations of WIRESCO from time to time in force, which are brought to its notice or of which it could reasonably be aware;

(c) SERVCO shall pay for and maintain for the benefit of SERVCO appropriate insurance concerning the operations and liabilities of SERVCO relevant to this Agreement including, without limiting the generality of the foregoing, workers' compensation and employment insurance in conformity with applicable statutory requirements in respect of any remuneration payable by SERVCO to any employees of SERVCO and public liability and property damage insurance;

(d) All SERVCO Personnel with responsibility for the provision of Services shall be familiar with the WIRESCO electric service area.

Section 3.06: Regulatory Change

If any change of Law after the date of this Master Agreement renders this Agreement illegal or unenforceable, then the Parties shall be required to renegotiate in good faith for thirty (30) days with a goal to developing a substitute agreement, which is consistent with the change of law.

Article Four MUTUAL COVENANTS

Section 4.01: Access and Co-operation

No Advisor of SERVCO shall have access to any Confidential Consumer Information in the possession of WIRESCO, except for purposes related to activities under this agreement.

Section 4.02: Confidentiality Arrangements

Both parties agree that accounting and financial separation of SERVCO from WIRESCO will be established and maintained. Further the parties agree to protect the confidentiality of customer information so as not to provide SERVCO with an unfair competitive advantage. This provision will include compliance with the provisions of the current version of section 5900 of the Canadian Institute of Chartered Accountants Handbook. Customer information will only be shared with SERVCO for the purposes of competitive activities with the express written permission of the customer, except where a customer currently has a relationship with SERVCO for rental equipment or other non-regulated services.

Section 4.03: Maintain Records

WIRESCO and SERVCO will maintain such records as may be necessary in connection with this Agreement and as are agreed upon by the Parties, acting reasonably.

Section 4.04: Notification of Changes of Circumstances

WIRESCO shall promptly give written notice to SERVCO of any changes or prospective changes in circumstances that would materially affect the resources required for the performance of the Services, including any anticipated material change in the nature or level of business of WIRESCO, the number of employees of WIRESCO, or any efforts relating to the organization of or collective bargaining by employees of WIRESCO, or any lease or service arrangements contemplated with any third parties.

Section 4.05: Notice of Claim, Etc.

WIRESCO shall promptly give written notice to SERVCO, and SERVCO shall promptly give notice to WIRESCO, of any material claim, proceeding, notice of regulatory non-compliance from any regulatory authority, dispute (including labour dispute) or litigation ("Claim") which it reasonably believes could have a material adverse effect on the fulfilment of any of the material terms hereof by WIRESCO or SERVCO (whether or not any such claim, proceeding, dispute or litigation is covered by insurance) in respect of its own operations of which any of them is aware. Each Party shall provide the other Party with all information reasonably requested from time to time concerning the status of such claim, proceeding, notice, dispute, or litigation, and any development relating thereto.

Article Five FEES AND PAYMENTS

Section 5.01: Base Financial Consideration

The Base Financial Consideration for this Agreement is a sum equal to the Total Controllable Costs of the Utility for the Regulatory Year 1999 in the amount of $1,215,131.52 less Base Direct Costs for 1999 and being $449,293.52 for a net sum of $765,838.00. The Base Financial Consideration shall be paid in equal monthly instalments not in advance and shall be due and payable on the first day of the month. The Base Financial Consideration shall be subject to adjustment in accordance with this Article Five.

(a) Excluding non-regulated activities, which include but are not limited to water heater and sentinel lighting maintenance, WIRESCO costs that will be paid directly by WIRESCO ("Base Direct Costs") include those following and any other direct costs it chooses to incur:-

- Income and corporate taxes or payments in lieu of taxes
- Property Taxes
- Land Taxes
- Directors Fees
- Insurance not jointly held or provided by the parties
- Costs of insurance jointly held will be shared on a pro rata basis
- Regulatory Costs
- The portion of the shared facilities lease cost that is incurred directly by WIRESCO in year one of that lease and thereafter
- Distribution plant maintenance directly provided by WIRESCO

Section 5.02: Adjustments to the Base Financial Consideration

(a) Adjustments to the Base Financial Consideration will include an adjustment based on 90% of the increase or decrease in customer count, calculated were able to, on an average distribution revenue/customer by class basis.

(b) Base Financial Consideration may be adjusted for any required Performance Based Regulation [PBR] reduction, which is required to ensure the regulatory compliance of WIRESCO with the PBR Program. This adjustment shall be shared between SERVCO and WIRESCO pro rata to SERVCO Base Financial Consideration as defined in Section 5.01 (a) and WIRESCO direct costs as defined in Section 5.01 (b) above.

Section 5.03: Adjustments for substantial Costs

In the event that SERVCO realizes substantially greater costs in providing any new services according to Section 3.04 of this Agreement, WIRESCO will meet with SERVCO to determine a mutually acceptable adjustment in the regular ongoing provision of services under this Agreement. Such discussions will normally occur on an annual basis and should be timed to permit any adjustments to be included in any year-end statements. It will be considered reasonable that 90% of the costs reasonably incurred in respect of the foregoing shall be incurred by WIRESCO and 10% by SERVCO.

Section 5.04: Savings realized by SERVCO

If SERVCO realizes substantially lower costs in providing the Services, WIRESCO will meet with SERVCO to determine an equitable sharing of the benefits. Such discussions will normally occur on an annual basis and should be timed to permit any adjustments to be included in any year-end statements. It will be considered reasonable that 90% of the benefit reasonably realized shall accrue to WIRESCO and 10% to SERVCO.

Section 5.05: Adjustments for Z factor and Transition Costs

WIRESCO hereby commits to make its best efforts to recover through rates and compensate SERVCO for all Z factor and transition costs and, failing recovery and compensation of these costs, to share such costs with SERVCO.

Section 5.06: Third Party Services Expenses

Prior to incurring any Third Party Services Expenses that materially exceed the historical levels of such expenses, SERVCO shall use reasonable efforts to notify WIRESCO of the amount of such differences and the circumstances giving rise thereto. In the event that WIRESCO considers any such increase to be unjustified, the Parties shall work together cooperatively and in good faith to minimize such expenses; provided, however that any material reduction in Third Party Services directly resulting from such increased Third Party Services Expenses not being paid shall not be considered an Event of Default.

Section 5.07: Adjustments for Extraordinary Costs for repair of damage from Acts of God

WIRESCO agrees to reimburse SERVCO for any costs ("Extraordinary Costs") over and above OM&A and Capital Works Costs which SERVCO may incur resulting from extraordinary unanticipated events such as wars, terrorism, fires, major storms, tornadoes, equipment failures, acts of God and the like, provided such equipment failures are not caused by negligence on the part of SERVCO to provide routine service and maintenance of the electrical distribution system; provided that the Extraordinary Costs result in more than $10,000 in maintenance or re-establishment costs.

Section 5.08: Capital Construction Activities

All costs applicable to all capital activities by SERVCO shall be recoverable from WIRESCO to the extent that such capital costs relate to assets that are under the control and management of WIRESCO and such capital costs shall be due and payable when a bill for such costs is rendered by SERVCO.

Section 5.09: Taxes

In addition to the Fees, WIRESCO shall pay to SERVCO an amount equal to any and all goods and services taxes, sales taxes, value-added taxes or any other taxes (excluding income taxes) properly eligible on the supply of the Third Party Services provided for under this Agreement.

Section 5.10: Late Payment

If WIRESCO fails to pay any amounts payable hereunder when due, such unpaid amounts shall bear interest from the due date thereof to the date of payment at Prime Rate plus two percentage points..

Section 5.11 Protection against financial losses

With respect to Standard Supply Service, WIRESCO agrees to indemnify SERVCO from all financial losses in the administration of Standard Supply Service. Any such losses will be due and payable when the bill is rendered and this shall not constitute a default under this Agreement.

Article Six REPRESENTATIONS AND WARRANTIES

Section 6.01: Representations and Warranties of SERVCO

SERVCO hereby represents and warrants to WIRESCO as follows and acknowledges that WIRESCO is relying on such representations and warranties in connection herewith:

(a) SERVCO is a company established pursuant to the laws of the Province of Ontario and it has the rights, powers and privileges to execute and deliver this Agreement and to perform its obligations hereunder;

(b) the execution, delivery and performance of this Agreement has been duly authorized by all necessary commission action;

(c) this Agreement has been duly executed and delivered by SERVCO and constitutes a legal, valid and binding obligation of SERVCO, enforceable against SERVCO by WIRESCO in accordance with its terms; and

(d) SERVCO has the necessary resources and expertise to acquire or perform the Services and Management Services.

Section 6.02: Representations and Warranties of WIRESCO

WIRESCO hereby represents and warrants to SERVCO as follows and acknowledges that SERVCO is relying on such representations and warranties in connection herewith:

(a) WIRESCO is a company, duly organized, validly existing and in good standing under the laws of the Province of Ontario and it has the rights, powers and privileges to execute and deliver this Agreement and to perform its obligations hereunder;

(b) the execution, delivery and performance of this Agreement has been duly authorized by all necessary corporate actions; and

(c) this Agreement has been duly executed and delivered by WIRESCO and constitutes a legal, valid and binding obligation of WIRESCO, enforceable against WIRESCO by SERVCO in accordance with its terms.

Article Seven INDEMNIFICATION

Section 7.01: Indemnification by WIRESCO

The parties shall indemnify each other, and their respective officers and directors, from any losses, liabilities and damages (including taxes and related penalties) and all related costs and expenses, including reasonable legal fees on a solicitor and client basis and expenses and costs of litigation, settlement, judgment, appeal, interest and penalties ("**Losses**") arising out of or relating to:

(a) any claim by Advisors, customers or suppliers of a party arising from or related to this Agreement or the Services, provided that such indemnity shall be without prejudice to any claim such party may have against the other party in connection therewith; and

(b) any claim based on the personal or bodily injury (including death) or damage to property received or sustained by any reason of any act or omission, whether negligent or otherwise, to the extent caused by a party or that party's Advisor at any location of the party in the course of or in connection with the performance of the Services and Management Services.

Section 7.02: Indemnification Procedures

If any third party makes a claim covered by this Agreement against any indemnitee hereunder (an "**Indemnitee**") with respect to which such Indemnitee intends to seek indemnification under this Agreement, such Indemnitee shall give notice of such claim to the indemnifying Party (the "**Indemnifying Party**") as soon as practicable, including a brief description of the amount and basis therefore, if known. Each Party shall co-operate fully with the other Party in its defence of any such claim. The indemnity obligations of an Indemnifying Party under this Agreement shall be conditional on notice of the claim having been provided and the Indemnifying Party having had the opportunity to consult with the Indemnitee regarding the claim. An Indemnitee seeking indemnification hereunder in respect of a claim shall not settle such claim without prior approval of the Indemnitor.

Article Eight DEFAULT

Section 8.01: Events of Default by WIRESCO

The occurrence of any one or more of the following events shall constitute a Default by WIRESCO under this Agreement and shall constitute an Event of Default if such Default is not remedied prior to the expiry of the relevant notice period (if any) and the relevant cure period (if any) applicable to such Default as hereinafter set out:

(a) if WIRESCO defaults in the payment of any amount due to SERVCO under this Agreement and such default shall continue unremedied for sixty (60) days following notice thereof to WIRESCO by SERVCO; and

(b) if WIRESCO fails in any material respect to perform or observe any of its other material obligations under this Agreement and such failure shall continue unremedied for a period of 60 days following notice thereof (giving particulars of the failure in reasonable detail) from SERVCO to WIRESCO or such longer period as may be reasonably necessary to cure such failure (if such failure is capable of being cured), provided that WIRESCO:

(i) proceeds with all due diligence to cure or cause to be cured such failure; and

(ii) its proceedings can be reasonably expected to cure or cause to be cured such failure within a reasonable time frame acceptable to SERVCO, acting reasonably.

Section 8.02: Default by SERVCO

It shall constitute a Default by SERVCO under this Agreement and shall constitute an Event of Default if such Default is not cured prior to the expiry of the relevant notice period (if any) and the relevant cure period (if any) applicable to such Default as hereinafter set out:

(a) if SERVCO defaults in the payment of any amount to WIRESCO under this Agreement and such default shall continue unremedied for sixty (60) days following notice thereof to SERVCO by WIRESCO; and

(b) if SERVCO fails in any material respect to perform or observe any of its respective material obligations under this Agreement, and such failure shall continue unremedied for a period of sixty (60) days following notice thereof (giving particulars of the failure in reasonable detail) from WIRESCO to SERVCO or such longer period as may be reasonably necessary to cure such failure (if such failure is capable of being cured), provided that SERVCO:

(i) proceeds with all due diligence to cure or cause to be cured such failure; and

(ii) SERVCO's proceedings can be reasonably expected to cure or cause to be cured such failure within a reasonable time frame acceptable to WIRESCO, acting reasonably.

Article Nine REMEDIES

Section 9.01: Default Remedies

(a) Unless otherwise agreed to in writing, in the event WIRESCO is in default under Section 8.01(a) and Section 8.01(b), SERVCO may terminate this Agreement and all amounts payable by WIRESCO hereunder shall become due and payable forthwith;

(b) Any dispute between the Parties in respect of Section 8.01(b) and 8.02(b) shall be submitted to and be definitively settled by arbitration on the request of any Party pursuant to Section 11.02 of this Agreement;

(c) While any dispute is being resolved by arbitration, the Parties shall continue to perform all obligations under this Agreement with due diligence and shall continue to comply with all terms of this Agreement;

(d) If a Party has failed to comply with the arbitrator's award or decision in accordance with said arbitrator's award or decision, the other Party may terminate this Agreement and all amounts owing by the Party to the other Party shall be due and payable and all properties of the other Party shall be returned forthwith;

(e) The remedies in this section are expressly in lieu of any or all of the remedies, which may be available to each of WIRESCO and SERVCO resulting from the furnishing, the failure to furnish or the quality of any Services. Each of WIRESCO and SERVCO hereby recognises and agrees that the Parties will come together to establish a reasonable remedy consistent with the intent of this Agreement, and the Parties further agree that WIRESCO will receive no additional compensation while establishing a reasonable remedy.

Section 9.02: Limitation of Liability

For breach or Default by SERVCO under or related to this Agreement, SERVCO's entire aggregate liability, regardless of the form of action, whether based on contract or tort, including negligence and including, without limitation, the furnishing, the failure to furnish or the quality of any Services, shall in no event exceed the amount paid by WIRESCO for the Services that is the subject of the claim.

Section 9.03: No Consequential Damages

In no event will SERVCO be liable to WIRESCO, or WIRESCO be liable to SERVCO for special, incidental, indirect or consequential loss or damage, lost business revenue, loss of profits, failure to realize expected profits or savings, or any damages or losses pursuant to claims brought by a third party (even if the Party causing such loss or damage has been advised of the possibility of same) in connection with this Agreement.

Article Ten TERMINATION

Section 10.01: Termination

This Agreement shall terminate:

(a) in accordance with the provisions of Section 9.01; or

(b) in accordance with Section 2.01 upon issuance of four year advance notice of termination.

Section 10.02: Notice of Termination

Any termination hereof pursuant to Section 10.01 shall be by written notice of the terminating Party.

Article Eleven GENERAL

Section 11.01: Force Majeure

No Party shall be liable for a failure or delay in the performance of its obligations pursuant to this Agreement:

(a) provided that such failure or delay could not have been prevented by reasonable precautions;

(b) provided that such failure or delay cannot reasonably be circumvented by the non-performing Party through the use of alternate sources, work around plans or other means; and

(c) if and to the extent such failure or delay is caused, directly or indirectly, by fire, flood, earthquake, elements of nature or acts of God, acts of war, terrorism, riots, civil disorders, rebellions, strikes, lock outs or labour disruptions or revolutions in Canada, or any other similar causes beyond the reasonable control of such Party,

(each, a "**Force Majeure Event**"). Upon the occurrence of a Force Majeure Event, the non-performing Party shall be excused from any further performance of those of its obligations pursuant to this Agreement affected by the Force Majeure Event only for so long as:

(a) such Force Majeure Event continues; and

(b) such Party continues to use commercially reasonable efforts to recommence performance whenever and to whatever extent possible without delay.

The Party delayed by a Force Majeure Event shall:

(a) immediately notify the other Parties by telephone (to be confirmed in writing within five (5) days of the inception of such delay) of the occurrence of a Force Majeure Event; and

(b) describe in reasonable detail the circumstances causing the Force Majeure Event.

Section 11.02: Dispute Resolution

If any dispute arising in relation to an event of default under Section 8.01(b) or Section 8.02(b) or its implementation of Section 8.01(b) or Section 8.02(b) cannot be resolved by negotiation between the Parties, then the dispute shall be referred to one arbitrator agreeable to and appointed by both Parties. If the Parties cannot agree on one arbitrator, the matter in dispute shall be referred to a panel of three arbitrators, one of which shall be appointed by WIRESCO, one appointed by SERVCO, and the third appointed by the two arbitrators selected by the two Parties. The arbitrator or arbitrators shall receive such oral and written evidence as may be required to investigate the matter in dispute and to render a decision. The arbitrator shall be guided by this agreement and the intent of this agreement. The decision of the arbitrator or arbitrators shall be provided in writing to all of the Parties no later than 30 days after the sole arbitrator or the third arbitrator has been appointed. The decision of the arbitrator or arbitrators shall be final and binding on all of the Parties.

Section 11.03: Assignment

Neither Party shall, without the Approval of the other Party hereto, which may be arbitrarily withheld in the sole discretion of either of them, assign or transfer its interest in this Agreement. This Agreement shall be binding on the Parties and their respective successors and permitted assigns. Any purported assignment in contravention of this Agreement shall be void.

Section 11.04: Notices

All notices, requests, approvals, consents and other communications required or permitted under this Agreement shall be in writing and addressed as follows:

(a) If to SERVCO,

COLLUS Solutions Corp

Attn: Chair of the Board of Directors
Fax: 705-445-8267

If to WIRESCO,

COLLUS Power Corp
Attn: Chair of the Board of Directors
Fax: 705-445-8267

and shall be sent by fax and the Party sending such notice shall telephone to confirm receipt. A copy of any such notice shall also be sent on the date such notice is transmitted by fax by registered express mail or courier with the capacity to verify receipt of delivery. Any Party may change its address or fax number for notification purposes by giving the other Party notice of the new address or fax number and the date upon which it will become effective in accordance with the terms of this Agreement. A notice shall be deemed to have been received as of the next Business Day following its transmission by fax.

Section 11.05: Severability

If any provision of this Agreement is held by a court of competent jurisdiction to be unenforceable or contrary to law, then the remaining provisions of this Agreement, or the application of such provisions to persons or circumstances other than those as to which it is invalid or unenforceable shall not be affected thereby, and each such provision of this Agreement shall be valid and enforceable to the extent granted by law. If any clause is deemed unenforceable or contrary to law, the parties shall alter the said clause and this agreement to produce enforceability or compliance with law such that the intent of the original clause is maintained and such change or alteration may be established through the dispute resolution clause in this agreement.

Section 11.06: Waiver

No delay or omission by a Party to exercise any right or power it has under this Agreement or to object to the failure of any covenant of any other Party to be performed in a timely and complete manner, shall impair any such right or power or be construed as a waiver of any succeeding breach or any other covenant. All waivers must be in writing and signed by the Party waiving its rights.

Section 11.07: Entire Agreement

This Agreement constitutes the entire Agreement among the Parties with respect to the Services or Management Services, and there are no other representations, understandings or agreements, either oral or written, between the Parties other than as herein set forth.

Section 11.08: Amendments

No amendment to, or change, waiver or discharge of, any provision of this Agreement shall be valid unless in writing and signed by authorized representatives of each Party.

Section 11.09: Governing Law

This Agreement shall be governed by the laws of the Province of Ontario and the laws of Canada applicable therein, excluding their rules governing conflicts of laws. The Parties hereby agree that the courts of the Province of Ontario shall have exclusive jurisdiction over disputes under this Agreement, and the Parties agree that jurisdiction and venue in such courts is appropriate and irrevocably attorn to the jurisdiction of such courts.

Section 11.10: Survival

The terms of Section 7, Section 9 and Section 11 shall survive the expiration of this Agreement or termination of this Agreement for any reason.

Section 11.11: Third Party Beneficiaries

Each Party intends that this Agreement shall not benefit or create any right or cause of action in or on behalf of any person or entity other than the Parties.

Section 11.12: Covenant of Further Assurances

The Parties agree that, subsequent to the execution and delivery of this Agreement and without any additional consideration, the Parties shall execute and deliver or cause to be executed and delivered any further legal instruments and perform any acts which are or may become necessary to effectuate the purposes of this Agreement and to complete the transactions contemplated hereunder.

COLLUS POWER CORP

Per: ______________________ c/s
Name: Mr Dean Muncaster

Title: Chair of the Board of Directors

Date December 18, 2002

COLLUS SOLUTIONS CORP

Per: Jack Gartley c/s
Name: Mr. Jack Gartley

Title: Chair of the Board of Directors

Date December 18, 2002

CONDITIONS OF SERVICE

Table of Contents

SECTION 1 INTRODUCTION

1.1 Identification of Distributor and Territory

The Distributor is a corporation, incorporated under the laws of the Province of Ontario to distribute electricity.

The Distributor is licensed by the Ontario Energy Board "OEB" to supply electricity to Customers as described in the Transitional Distribution License and thereafter by the Distribution License issued to the Distributor by the OEB. Additionally there are requirements imposed on the Distributor by the various codes referred to in the License and by the Electricity Act and the Ontario Energy Board Act.

The Distributor is limited to operate distribution facilities within their Licensed Territory as defined in the Distribution License.

1.1.1 General

Nothing contained in this document or in any contract for the supply of electricity by the Distributor shall prejudice or affect any rights, privileges, or powers vested in the Distributor by law under any Act of the Legislature of Ontario or the Parliament of Canada, or any regulations thereunder.

All operations performed by the distributor and its agents shall be performed within the rules and regulations set out by the appropriate authorities including but not limited to: ESA, Ministry of Labour, Ministry of Transportation, etc.

The Distributor will normally provide one electrical service to each customer location at a nominal service voltage.

Modifications to an existing service must comply with the requirements of the standards in effect at the time of the modifications.

The customer or their authorized representative must make application for new or upgraded electric services and temporary power services.

The customer or their representative shall consult with the Distributor concerning the availability of supply, the voltage of supply, service location, metering and any other details. These requirements are separate from and in addition to those of the Electrical Inspection Authority. The Distributor will confirm, in writing, the Characteristics of Electric Supply available at a specific site.

The customer is required to provide the Distributor sufficient lead-time in order to ensure:

(a) the timely provision of supply to new and upgraded premises or
(b) the availability of adequate capacity for additional loads to be connected in existing premises.

If special equipment is required or equipment delivery problems occur then longer lead times may be necessary. The customer will be notified of any extended lead times.

Customers will be required to pay the cost of repair or replacement of the Distributors' equipment that has been damaged through the customers' action or neglect.

The supply of electricity is conditional upon the Distributor being permitted and able to provide such a supply, obtaining the necessary apparatus and material, and constructing works to provide the service. Should the Distributor not be permitted to supply or not be able to do so, it is under no responsibility to the customer whatsoever.

The customer shall not build, plant or maintain or cause to be built, planted or maintained any structure, tree, shrub or landscaping that would or could obstruct the running of distribution lines, endanger the equipment of the Distributor, interfere with the proper and safe operation of the Distributor's facilities or adversely affect compliance with any applicable legislation in the sole opinion of the Distributor.

Prior to commencing any service work, the customer must consult with the Distributor to ensure compliance with current requirements.

The customer is responsible for selecting a qualified/competent contractor. Careful selection of a contractor can significantly affect the cost of a project. The Distributor shall be consulted prior to the selection of a mutually acceptable contractor.

The customer maintains the responsibility to ensure that all work is done in accordance with the distributor's design and technical standards and specifications.

The Distributor, at the expense of the customer, reserves the right to inspect the work throughout the duration of the project, and the Contractor shall supply him such accommodations as he may require. The Inspector shall request that the Contractor stop work at any time he feels the Contractor is not proceeding in accordance with these "conditions of service". The customer shall confer with the Distributor before work recommences to mitigate undue cost and construction delays for the project.

Customers may be required to pay Capital Contributions for the addition of new and upgraded electrical services in accordance with the Economic Evaluation process as defined in the Distribution System Code.

1.2 Related Codes and Governing Laws

The Distributor is limited in its scope of operation by the:

1. *Electricity Act, 1998*
   www.e-laws.gov.on.ca/html/statutes/english/elaws_statutes_98e15_e.htm
2. *Ontario Energy Board Act, 1998*
   www.e-laws.gov.on.ca/html/statutes/english/elaws_statutes_98o15_e.htm

3. *Distribution Licence*
   Licence Numbers
4. *Affiliate Relationships Code*
   http://www.collus.com/images/stories/Documents/ARC.pdf
5. *Distribution System Code*
   http://www.collus.com/images/stories/Documents/DSC.pdf
6. *Retail Settlements Code*
   http://www.collus.com/images/stories/Documents/RSC.pdf
7. *Standard Service Supply Code*
   http://www.collus.com/images/stories/Documents/SSSC.pdf
8. *Transmission System Code*
   http://www.collus.com/images/stories/Documents/TSC.pdf
9. *Ontario Regulation 22/04* - Electrical Distribution Safety
   http://www.e-laws.gov.on.ca/html/source/regs/english/2004/elaws_src_regs_r04022_e.htm
10. *Measurement Canada*
    http://strategis.ic.gc.ca/epic/site/mc-mc.nsf/en/h_lm03862e.html

In the event of a conflict between this document and the Distribution Licence or regulatory Codes issued by the OEB, or the Electricity Act, the provisions of the Act, the Distribution License and associated regulatory Codes shall prevail.

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. The work shall be conducted in accordance with the Ontario Occupational Health and Safety Act, the Regulations for Construction Projects and the E&USA (or the OHSC Safety) rulebook.

1.3 Interpretations

In these Conditions, unless the context otherwise requires:

- *Headings and underlining are for convenience only and do not affect the interpretation of these Rules.*
- *Words referring to the singular include the plural and vice versa.*
- *Words referring to a gender include any gender.*

1.4 Amendments and Changes

The provisions of these Conditions of Service and any amendments made from time to time form part of any Contract made between the Distributor and any connected Customer, Generator or their agents.

In the event of changes to this Conditions of Service, a Public notice shall be made in the form of either a notice in the local newspaper, or a notice on the Distributors' Website.

The Customer is responsible for contacting the Distributor to ensure that the Customer has, or to obtain the current version of the Conditions of Service. The Distributor may charge a reasonable fee to recover costs for providing the Customer with more than one copy of this document.

1.5 Contact Information

The Distributor and its agents can be contacted during normal working hours. Please refer to the Contact Listing in the Appendices for phone number of the Local Distribution Company servicing your area.

1.6 Customer Rights

In those instances where the Customer will own their secondary or primary service, the Customer has the right to hire a Contractor to supply and install the service.

The customer has the right to demand identification from any person purporting to be an authorized agent or employee of the distributor.

A customer, who believes that he has suffered damages to his property or equipment as a result of negligence on the part of the Distributor, may submit a written claim for damages to the Distributor. The Distributor will investigate the claim and respond in writing within 10 business days of the receipt of the claim.

1.7 Distributor Rights

In those instances where the Customer has the authority to hire a Contractor to construct plant which will become part of the Distributors' system, the Distributor shall have the right to require the Contractor to submit proof of previous experience and satisfactory performance, and, the Distributor shall have the right to investigate such proof and approve the Contractor prior to the Owner awarding a contract for the work to the Contractor.

The Distributor shall have access to Customer property in accordance with section 40 of the *Electricity Act, 1998*.

1.8 Disputes

If, following good faith negotiations between a customer or other market participant and the Distributor, a resolution cannot be reached, the dispute may be submitted to a dispute resolution process.

Any dispute which shall arise between the Distributor and a customer(s) and other market participants subject to the terms of these Conditions of Service concerning the rights, duties or obligations of the Distributor or others subject to these Conditions of Service, shall be subject to the following dispute resolution procedure:

Mediation

- Either party (the "Initiating Party") may invoke the dispute resolution procedure by sending a written notice to the other party (the "Respondent Party") describing the nature of the dispute and designating a representative of the Initiating Party with appropriate authority to be its representative in negotiations relating to the dispute. The responding Party shall, within five business days of the receipt of such notice, send a written notice to the Initiating Party, designating a representative of the Responding party with the appropriate authority to be its representative in negotiations relating to the dispute.

- Within ten business days of the receipt by the Initiating Party of the written notice of the Responding Party the designated representatives shall enter into good faith negotiations with a view to resolving the dispute. If the dispute is not resolved in thirty days of the commencement of such negotiations, or such longer period as may be agreed upon, either party may, by written notice to the other party, require that the parties be assisted in their negotiations by the Ontario Energy Board. In accordance with the OEB dispute resolution process, The Ontario Energy Board will complete its review of the dispute within 150 days.

SECTION 2 DISTRIBUTION ACTIVITIES (GENERAL)

2.1 Connections

This section includes information that is applicable to all customer classes of the distributor. Items that are applicable to only a specific customer class are covered in Section 3.

2.1.1 Building that Lies Along

As provided in Section 28 of the Electricity Act 1998 the Distributor has the Obligation to Connect any Building that 'lies along" its distribution system subject to conditions outlined in section 2.1.3.
A building 'lies along" a distribution line if it can be connected to the distributor distribution system without an expansion or enhancement.

A Building that appears to 'lie along' a distribution line may be refused connection to that line should the distribution line not have sufficient capacity for the requested connection. In such instances, the distributor shall make an offer to connect which will include the cost of the enhancement.

2.1.2 Offer to Connect

The Distributor will make an Offer to Connect to any customer requesting a connection within the Distributors licensed territory. As required by the Distribution Code, the Offer to Connect must be Fair and Reasonable and be based on the distributors' design standard. The Offer to Connect must also be made within a reasonable time from the request for connection and the receipt of all required information from the Customer.

The Distributor may require a customer to pay all or a part of the costs of electrical plant installed to supply only that customer. Such capital contributions will be calculated using the guidelines set out by the OEB in the Distribution System Code. If an expansion or enhancement of the distribution system is required to facilitate a connection, the LDC may need to perform an Economic Evaluation to establish the capital contribution required from the Customer. The Customer should review the attached Distribution Connection Process for further information.

2.1.3 Connection Denial

The Distribution System Code in section 3.1 sets outs the conditions for a Distributor to deny connections. A Distributor is not obligated to connect a building within its service territory if the connection would result in any of the following:

- Contravention of existing Canadian Laws, and those of the Province of Ontario.

- Violations of conditions in a Distributors' Licence.
- Use of a distribution system line for a purpose that it does not serve and that the Distributor does not intend to serve.
- Adverse effect on the reliability and safety of the distribution system.
- Imposition of an unsafe work situation beyond normal risks inherent in the operation of the distribution system.
- A material decrease in the efficiency of the distributors' distribution system.
- A material adverse effect on the quality of distribution services received by an existing connection.
- Discriminatory access to distribution services.
- Potential increases in monetary amounts that already are in arrears with the distributor

The distributor shall inform the person requesting the connection of the reason(s) for not connecting and, where the distributor is able to provide a remedy, make an offer to connect. If the distributor is unable to provide a remedy to resolve the issue, it is the responsibility of the customer to do so before a connection may be made.

2.1.4 Inspections Before Connections

The Distributor has the right to request an inspection prior to any connection.

All customer electrical installations shall be inspected and approved by the Electrical Safety Authority, referred to herein as the ESA.

The Distributor requires notification from the ESA of this approval prior to the connection of a customer's service.

Services that have been disconnected for a period of six months or longer shall also be inspected and approved by the ESA prior to reconnection.

Temporary services, for construction purposes, are approved by the ESA for a period of twelve months and must be re-inspected should the period of use exceed twelve months.

The Distributor reserves the right to inspect and approve Transformer rooms, Vaults and Pads prior to, during, and following the installation of equipment.

Provision for metering shall be inspected and approved by the Distributor prior to connection.

Customer owned substations must be inspected by both the Electrical Safety Authority and the Distributor, prior to connection to the Distribution system.

Duct banks and road crossings shall be inspected and approved by the Distributor prior to the pouring of concrete and again before backfilling.

The Distributor reserves the right to inspect any underground trenches prior to backfilling.

The Distributor reserves the right to approve the installation and location of all submarine cable. All documentation and permits required for laying of submarine cable must be provided to the Distributor. The installation of submarine cable must meet the requirements of all governing legislation.

All work done on existing Distributor plant must be authorized by the Distributor and carried out in accordance with all applicable safety acts and regulations.

In accordance with the Distribution System Code, if the Distributor refuses to connect a building in its service territory that lies along one of its distribution lines, the distributor shall inform the person requesting the connection of the reasons for not connecting, and where the distributor is able to provide a remedy, make an offer to connect. If the Distributor 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.

2.1.5 Relocation of Plant

The Distributor will, where feasible, accommodate requests to relocate electrical plant such as poles and metal enclosed equipment.

The customer will be required to pay all of the costs incurred by the relocation.

Requests by civic authorities to relocate distribution facilities will be done so in accordance with the appropriate regulations. See *Public Service Works on Highways Act*.

2.1.6 Easements

To maintain the reliability, integrity and efficiency of the distribution system, the Distributor has the right to have supply facilities on private property registered against title to the property. Easements are required whenever the Distributors' underground or overhead plant is to be located on private property or crosses over an adjacent private property to service a Customer.

The Customer shall acquire and grant in the distributors name, at no cost to the Distributor, where required, an easement to permit installation and maintenance of service. The width and extent of this easement shall be determined by the Distributor. The easement shall be granted prior to connection of the service.

The Owner shall furnish to the Distributor, free and clear of all encumbrances, sufficient easements to enable the servicing of all existing or proposed developments or subdivisions from plants located on the Owners' property.

Sufficient property at suitable locations shall be made available for the purpose of the installation of distributors' assets.

The Customer will prepare at its own costs a reference plan and associated easement documents to the satisfaction of the Distributors' solicitor prior to its registration and register the easement plan. Details will be provided upon application for service.

Where surface restoration by the Distributor is required following any repairs or maintenance to a service, the Distributor will in so far as is practicable, restore the property to its original condition; and provide compensation for any damages caused by the entry that cannot be repaired.

2.1.7 Contracts

Standard Form of Contract - All customers will be requested to complete and sign the standard form of contract to apply for a connection. A Standard Contract for service shall be considered as being in force from the date it is signed by the Customer and the Distributor and shall remain in force until terminated by either party.

Implied Contract - In all cases, notwithstanding the absence of a formal contract, the taking and using of electrical energy from the Distributor by any Person or Persons constitutes the acceptance of the terms and conditions of all regulations, conditions and rates as established by the Distributor. Such acceptance and use of energy shall be deemed to be the acceptance of a binding contract with the Distributor and the Person so accepting shall be liable for payment for such energy and the contract shall be binding upon the Person's heirs, administrators, executors, successors or assigns.

Special Contracts - Special 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*
- *non-permanent structures*
- *special occasions, etc.*
- *generation*

2.2 Disconnection

The Distributor has the right and/or obligation to disconnect the supply of electrical energy to a Customer for causes including but not limited to:

(a) contravention of the laws of Canada or the Province of Ontario including the Ontario Electrical Safety Code;

(b) violation of conditions in a distributor's licence;

(c) materially adverse effect on the reliability or safety of the distribution system;

(d) imposition of an unsafe worker situation beyond normal risks inherent in the operation of the distribution system;

(e) a material decrease in the efficiency of the distributor's distribution system;

(f) inability of the distributor to perform planned inspections and maintenance;
(g) a materially adverse effect on the quality of distribution services received by an existing connection; and
(h) if the person requesting the connection owes the distributor money for distribution services, or for non-payment of a security deposit.

2.3 Conveyance of Electricity

2.3.1 Guaranty of Supply

The Distributor agrees to use reasonable diligence in providing a regular and uninterrupted supply but does not guarantee a constant supply or the maintenance of unvaried frequency or voltage and will not be liable in damages to the Customer by reason of any failure in respect thereof.

Customers requiring a high degree of security of supply or power quality are responsible to provide their own back-up or standby facilities.

When power is interrupted, or the Customer is experiencing power quality problems the Customer or their electrical contractor shall first ensure that interruption is not due to problems within the customer owned installation. If after verifying that the cause of the problem does not reside on the customers' installation, the customer shall contact the Distributor. The Distributor will respond to and take reasonable steps to restore power. The Distributor reserves the right to recover costs from the customer for making false claims of interruptions.

Although it is the Distributors' policy to minimize inconvenience to Customers, it is necessary to occasionally interrupt a Customers' supply to maintain or improve the Distributors' system, or to provide new or upgraded services to other Customers. Whenever practical and cost effective, as determined by the Distributor, arrangements suitable to the Customer and the Distributor may be made to minimize any inconvenience. The Distributor will endeavor to provide the Customer with reasonable advance notice, except in cases of emergency, involving danger to life and limb, or impending severe equipment damage.

The Distributor will endeavor to notify Customers prior to interrupting the supply to any individual service. However, if an unsafe or hazardous condition is found to exist, or if the use of electricity by apparatus, appliances, or other equipment is found to be unsafe or damaging to the Distributor or the public, service may be discontinued without notice.

Depending on the outage duration and the number of Customers affected, the Distributor may issue a news release to advise the general public of the outage.

2.3.2 Power Quality

The distributor will respond to and take reasonable steps to investigate consumer power quality complaints and report to the consumer on the results of the investigation. The method and level of investigation will be at the discretion of the Distributor.

If the source of a power quality problem is caused by the consumer making the complaint, the distributor may seek reimbursement for the time and cost spent to investigate the complaint.

If the source of a power quality problem is caused by a consumer, the Distributor may direct the consumer to take corrective action. If the Consumer does not take such action within a reasonable time, the Distributor may disconnect the supply of power to the Customer. (*see section 2.2*)

2.3.3 Electrical Disturbances

There are levels of voltage fluctuation and other disturbances that can cause flickering lights and more serious difficulties for Customers connected to the Distributor distribution system.

Some types of electronic equipment, such as video display terminals, can be affected by the close proximity of high electrical currents that may be present in transformer rooms.

No electrical equipment, which may produce an undesirable system disturbance, shall be connected by a customer to a customer's service without prior approval of the Distributor.
Examples of equipment, which may cause disturbance, are large motors, welders and variable speed drives. In planning the installation of such equipment, the customer is required to consult with the Distributor.

The Distributor will endeavour to maintain voltage variation limits, under normal operating conditions, at the Customers' Delivery Points, as specified by the latest edition of the Canadian Standards Association, C235. However, more sensitive electronic equipment such as computers can be seriously affected by variations in quality of supply voltage. Customers who need electrical power of high quality and with rigid voltage tolerances are responsible for providing their own power conditioning equipment.

Customers requiring a three-phase supply 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 the Distributors' supply.

The customer shall provide such protective devices as may be necessary to protect his property or equipment from any disturbance beyond the control of the distributor.

2.3.4 Standard Voltage Offerings

2.3.4.1 For Secondary Voltage

The Supply Voltage governs the limit of supply capacity for any Customer. General guidelines for supply from overhead street circuits are as follows:

- *at 120/240 V. single phase, or*
- *347/600 V. three phase, four wire, or*
- *120/208 V three phase, four wire,*

OR

Where street circuits are buried, the Supply Voltage and limits will be determined upon application to the Distributor.

OR

Where the Customer or Developer provides a pad on private property;

- *at 120/240 V single phase, or*
- *at 120/208 V three phase, four wire, or*
- *at 347/600 V three-phase, four-wire*

2.3.4.2 For Primary Voltage

Primary supplies to transformers or customer-owned substations will be one of the following as determined by the Distributor:

- *2,400/4,160 volts 3 phase 4 wire*
- *4,800/8,320 volts 3 phase 4 wire*
- *7,200/12,400 volts 3 phase 4 wire*
- *8,000/13,800 volts 3 phase 4 wire*
- *16,000/27,600 volts 3 phase 4 wire*
- *27,600 volts 3 phase 3 wire delta*
- *44,000 volts 3 phase 3 wire*

The customer shall contact the Distributor when planning their service to verify standard transformer availability and supply capacity.

2.3.5 Voltage Guidelines

The Distributor maintains service voltage at the Customers' service entrance within the guidelines of C.S.A. Standard CAN3-C235 (latest edition) which allows variations from nominal voltage of: http://www.csa-intl.org/onlinestore/GetCatalogDrillDown.asp?Parent=542,

6% for Normal Operating Conditions
8% for Extreme Operating Conditions

Where voltages lie outside the indicated 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.

Where voltages lie outside the indicated limits for Extreme Operating Conditions, improvement or corrective action will be taken on an emergency basis. The urgency for such action will depend on many factors such as the location and nature of load or circuit involved, the extent to which limits are exceeded with respect to voltage levels and duration, etc.

2.3.6 Back-up Generators

Customers with portable or permanently connected emergency generation capability shall comply with all applicable criteria of the Ontario Electrical Safety Code and in particular, shall ensure that customer emergency generation does not back-feed on the Distributors' system.

To access the Code: http://www.esasafe.com/Corporate/gr_004.php?s=8
To review Generator Safety Info: http://www.esasafe.com/GeneralPublic/sgi_001.php?s=23

Customers with permanently connected emergency generation equipment shall notify the Distributor regarding the presence of such equipment.

The distributor reserves the right to have the connection of this equipment inspected.

Generation systems found to be feeding into the Distribution system without proper approval of the Distributor shall be subject to immediate disconnection.

2.3.7 Metering

2.3.7.1 General

2.3.7.1.1 Access

The Distributor or its agents shall have the right to access and read any of the Distributors' electricity meters on the Customer's premises.

All metering installations shall be accessible from a public area.

2.3.7.1.2 Costs

All the Distributor metering equipment located on the Customer's premises are in the care and at the risk of the Customer and if destroyed or damaged, other than by normal usage, the Customer will pay for the cost of repair or replacement.

Regardless of any charges for metering installations, all meters and meter instrumentation equipment shall remain the property of the Distributor and maintenance of this equipment shall be the Distributors' responsibility.

2.3.7.1.3 Voltage

Generally, metering will be at utilization voltage. Where the Distributor provides primary transformation, primary voltage metering will be allowed only in special circumstances following full discussion with the Distributor.

Customer-owned substations may require primary metering. The provisions required for these installations shall be specified and approved by the Distributor for each application.

2.3.7.1.4 Primary Metering

Primary metering units may be installed outdoors or within an electrical vault as outlined in the current Electrical Safety Code. Where the customer prefers not to provide an approved electrical vault, the Distributor at additional cost can provide a metering unit with non-flammable coolant.

2.3.7.1.5 Bulk Metering

Non-residential or mixed-use buildings will normally be bulk metered by a single meter. However, where specific areas are clearly and permanently defined and in other respects as a separate entity, individual metering of the loads may be required.

Individual residential condominium or apartment units should be metered individually to empower the residents with control over their individual costs. In such instances, one or more bulk meters may still be required at the facility for the purpose of calculating house loads and/or transformer allowances (on customer owned transformers) where applicable.

In all installations where the Customer requests revenue metering remote from the secondary entrance equipment or downstream from a Customer-owned dry-core transformer, provisions are required for a bulk meter directly after the main switch. This bulk metering is required in addition to any public metering provisions. The Customer will be required to contribute to the cost of the metering installation.

Where more than one meter is required, the meters shall be grouped where practical.

The customer shall permanently and legibly identify all metered services with respect to correct municipal 911 address and unit #. The identification shall be applied to all service switches and breakers and to all meter cabinets and meter mounting devices that are not immediately adjacent to the service switch. The customer shall insure that all service identifications are accurate and by not doing so will be held responsible. The Distributor shall issue a Meter Verification Sheet for this purpose to the owner or contractor.

In any case, a copy of the metering layout plan shall be forwarded to the Distributor for review and approval.

If the distribution of the metered load circuit is in dispute, (ie: circuits from one premise is found to supply a second premise) the Distributor reserves the right to transfer all accounts into the Property Owners' name until such time as the problem has been resolved, and the individual metering can be clearly identified with the individual units.

2.3.7.1.6 Locks

All devices on the line side of the Distributor metering shall have provisions for padlocking.

For commercial and industrial services the Customer's main switch shall have provisions for padlocking the switch handle in the open position, and the switch cover (or door) in the closed position.

When a disconnect device has been locked in the "OFF" position by the Distributor, under no circumstances shall anyone other than the Distributor or its authorized agent remove the lock.

At the discretion of the Distributor, a dual locking arrangement, a Distributor master key arrangement, a key box arrangement, or a copy of the access key will be required for access.

2.3.7.1.7 Meter Seals

All devices used by the Distributor for metering are sealed. Only the Distributor or its authorized agents have the authority to break this seal. Tampering with the seal will require the Distributor to investigate the cause of the tampering. Following the investigation, the proper authorities will be contacted as required (*ESA, Police, Fire*). The customer shall be responsible for all reasonable costs associated with the investigation.

2.3.7.2 Current Transformer Boxes

Where a current transformer box is required, it shall be CSA approved, of a size and type as stipulated by the Distributor, and include a provision for padlocks. A removable plate shall be provided in the box for mounting the equipment.

As an alternative to a separate CT box and meter, a single enclosure combining both functions may be feasible. Contact the Distributor for details.

In cases where the CTs only meter a portion of the metal clad switchgear (such as house loads), a separate disconnect switch must be installed ahead of the metering compartment so that the service can be de-energized without any interruption to the main service supply.

Generally, one house load meter only will be allowed. Additional house load meters will require authorization from the Distributor.

Conductors should enter the current transformer box at the top and leave at the bottom, or vice versa. If this cannot be arranged, the next largest CT box must be used to enable conductors to be trained in place. Where parallel conductors are used, the sum of the conductors will determine the size of the CT box to use. In all cases the Customer shall supply suitable cable termination lugs.

On all electrical services that require current transformers and the neutral for metering, an isolated neutral block shall be provided in the current transformer box.

2.3.7.3 Interval Metering

The Distribution System Code, as amended from time to time, requires the Distributor to meter Customers of specific load levels with pulse-recording meters, or interval meters, which are interrogated remotely. The Distributor, at its' sole discretion, may also require such metering on any customer whose load characteristics may have a significant impact on the Net System Load Shape, or where reasonable access to the meter for the purpose of acquiring metering data may be limited due to location.

A customer that requests interval metering shall compensate a distributor 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. The communication system utilized for interval meters shall be in accordance with the distributors' requirements.

Where such metering exists the Distributor will consider customer requests to provide a secondary pulse for load control or customer-owned metering at the customers' expense.

In keeping with the intent of the Legislation and accompanying amendments, once an interval meter installation is processed as part of the distributors' settlement process, and has affected the relevant changes to the distributors net system load, the installation must not be changed back to a non-interval meter installation.

Where a customer submits a request to read their own interval meter, the Distributor shall make this access available given the following conditions are met:

- The meter has the capability of read-only password protection
- The customer provides a signed copy of the “Interval Metering Access Agreement” to the Distributor.

2.3.7.3.1 Interval Metering Communications

- Solid-state recorders and/or Electronic Interval Meters installed by the Distributor have provision for remote interrogation. When a phone line is required for this purpose, the Owner will facilitate the provision of a telephone line in the metering cabinet for the Distributors’ metering purposes.
- At its’ sole discretion, for metering installations where loss of metering data would cause a substantial impact on the Distributors Settlement System and other customers, the Distributor may require the phone line to be dedicated for metering purposes only.
- When such dedicated phone lines are required, phone lines must be installed and functioning prior to the new service being energized
- A dedicated phone line is a voice quality telephone line, which is active 24 hours a day to the metering location extension jack, which is mounted on the metering board.

2.3.7.3.2 Smart Meters

The Ontario Government has mandated the installation of Smart Meters as a replacement to current metering technology. The LDC will install smart meters in accordance with regulations and policies set out by Government authorities.

Residential and small General Service customers, who are billed on an energy-only basis, will be provided with a smart meter free of charge during the smart meter conversion. Metering requirements for Large General Service customers will be reviewed in concert with any new Regulations.

2.3.7.4 Meter Reading

The Distributor will read all meters on a regularly scheduled basis whenever possible. If an actual 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.

2.3.7.5 Final Meter Reading

When a service is no longer required, or the Customer is switching Energy Providers, the Customer shall provide the Distributor sufficient notice of the date so that a final meter reading can be obtained. The Customer shall provide access to the Distributor 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. Estimates will be based on available historical consumption.

2.3.7.6 Faulty Registration of Meters

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. The Distributors' 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, the Distributor 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 energy supplied, a reasonable sum based on the reading of any meter formerly or subsequently installed on the premises by the Distributor, due regard being given to any change in the character of the installation and/or the demand.

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. The Distributor will correct the bills for that period in accordance with the regulations under the Act.
http://www.collus.com/images/stories/Documents/Measurement Errors.pdf

2.3.7.7 Meter Dispute Testing

The Distributor will attempt to resolve billing enquiries. However, to give Customers confidence in the accuracy of electricity meters, the Distributor will conduct an internal investigation to verify the accuracy of any meter the Customer believes to be recording incorrectly. If the internal investigation does not resolve the matter, the Customer or the Distributor may request Measurement Canada to test the meter.
http://www.collus.com/images/stories/Documents/Measurement Errors.pdf

If the test indicates that the meter is not accurate, the Customer's historic billing will be adjusted, and the Distributor shall pay the full costs of the meter dispute testing.

2.3.7.8 Location

The location of the indoor or outdoor meter shall be readily accessible at all times and acceptable to the Distributor. If a meter is recessed or enclosed after installation, without the prior approval of the Distributor, the service may be subject to disconnection.

The location of the service entrance, routing of duct banks, metering, and all other works will be established through consultation with the Distributor. Failure to comply may result in relocation of the service plant at the Owner's expense.

In all locations where Commercial/Industrial revenue metering is accessible to the general public, a lockable enclosure or a room for service equipment and meters, shall be provided by the Owner at the discretion of the Distributor, as follows:

- *An electrical room reserved solely for metering equipment or*
- *Metal enclosed switchgear approved by the Distributor or*
- *A suitable metal metering cabinet or*
- *A vandal proof cage.*

2.3.7.9 Meter Mounting Heights

Provision for metering shall facilitate a practical mounting height for revenue meters in compliance with the Distributor's standard specifications and all applicable codes and regulations.

2.3.7.10 Environment

The following requirements apply to the areas allocated for revenue metering.

The customer to the satisfaction of the Distributor shall provide where there is the possibility of danger to workmen, or damage to equipment from moving machinery, dust, fumes, or moisture, protective arrangements.

A clear safe working space of not less than 1.2 m (48") in front of the installation from the floor to ceiling with a minimum ceiling height of 2.1 m (84") provided to insure the safety of the Distributor or other authorized employee(s) who may be required to work on the installation.

Where excessive vibration may affect or damage metering equipment, adequate shock-absorbing mounting shall be provided and installed by the customer.

2.3.7.11 Meter Sockets

The owner will supply and install a meter socket as specified by the Distributor. Meter sockets will be directly accessible to the Distributors' staff.

A listing of approved revenue metering sockets is available from the Distributor.

2.3.7.12 Cabinets

Where required by these Conditions of Service the Owner shall supply and install a meter cabinet to The Distributors' requirements.

Meter cabinets shall be installed indoors, except where special permission is granted by the Distributor to install the meter cabinet outside. In such cases, an approved weather proof, lockable, C.S.A. approved meter cabinet shall be provided by the Customer.

2.3.7.13 Metering Loops

Three-phase, four-wire services will require a loop for metering, within the meter cabinet, for all three phases.

Mineral insulated, solid, or hard drawn wire conductors are not acceptable as metering loops.

2.3.7.14 Metal Enclosed Switchgear

The following regulations apply to the installation of instrument transformers and metering equipment within metal enclosed switchgear.

The Distributor will provide the following revenue metering equipment as required:

- Colour coded secondary wiring
- Revenue meters

The Owner shall:

- Consult with The Distributor regarding the installation of metering equipment, which may include:
  - Potential transformers
  - Potential transformer fuse holders and fuses
  - Current transformers
  - Phone line for remote interrogation of meters
  - Duplicate Pulse Initiators
  - Provide complete shipping instructions for instrument transformers for those projects where these are to be provided by the Distributor for installation by the switchboard manufacturer.
  - Install instrument transformers, metering cabinet and conduit.
  - Each main bus bar to be drilled and tapped (10-32) or (10-24) on the line side of the removable current transformer link.

- Submit two copies of the manufacturer's switchboard drawings, for approval, dimensioned to show provision for and arrangement of The Distributors' metering equipment.

Meters shall be installed by the Distributor in a customer-owned metal cabinet of a size and type pre-approved by the Distributor, mounted at an approved location separate from the switchgear.

Tamper proof or sealable rigid conduit or any equally approved conduit of a size and type specified by the Distributor shall be installed between the CT compartment of the switchgear and the meter cabinet.

For conduit installations greater than 30 m (100'), in length or where several bends are necessary, larger conduits or other special provision may be required, at the discretion of the Distributor.

2.3.7.15 Switchgear Connected to Wye Source

Where a Wye source neutral connection is to be used or grounded, the Owner shall provide a conductor sized to the requirements of the Ontario Electrical Safety Code from the instrument transformer compartment to the neutral connection.

2.3.7.16 Four Quadrant Metering (Generation)

All Ontario Energy Board-licensed generators connected to the distribution system that sell energy and settle through the distributor's retail settlement process shall be required to install metering that meets the requirements of the Distribution System Code as approved by the Ontario Energy Board, and/or the Market Rules as approved by the Independent Electricity System Operator. http://www.theIESO.com/

2.3.7.17 Net Metering for Embedded Generation

Customers with specific generation facilities may reduce their net energy costs by exporting surplus generated energy back onto the utility distribution system. Surplus energy exported onto the utility distributions system will be calculated as a credit against the energy the customer consumes from the distribution system.

All customers wishing to become a Net Metering participant must 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 utility's 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 - Embedded Generation Facilities

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

2.3.7.18 Ontario Power Authority (OPA) Standard Offer Program for Embedded Generation

The Ontario Power Authority has established a Standard Offer Program (SOP) 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 the distribution system in order to export electricity.

Generating facilities participating in the Standard Offer Program will connect directly to the distribution system at a voltage of 44kV or less. Output from the generating facility shall be metered in a manner to ensure proper collection of required information for settlements. Such metering may include:

a. for generators of 10 kW or less and connected to the line side of the load meter
   - (i) a bi-directional kWh meter to measure energy consumed and energy exported; or
   - (ii) a bi-directional interval meter to measure hourly energy consumed and energy exported

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

In some instances, the load meter may also have to be changed in order to accommodate proper settlement calculations for the SOP. The generator will be solely responsible for any costs associated with the connection to the distribution system and any required metering installation.

2.4 Tariffs and Charges

2.4.1 Service Connection

Charges for Service Connections are set out in the Distributors approved rates, (Miscellaneous Rates and Charges) and may be obtained by request from the Distributor. Notice of Rate revisions may be published in the local newspapers and or mailed out to all customers with the first billing issued at revised rates.

2.4.2 Energy Supply

The Distributor shall provide Customers connected to the Distribution System with access to electricity through Standard Supply Service as defined in the Retail Settlement Code published by the OEB or as mandated though Legislation or Regulations issued by the Ministry of Energy.

Disputes arising from charges relating to Standard Supply Service shall be directed to the Distributor.

Customers will be switched to their Retailer of choice only if the retailer has a Service Agreement with the Distributor. The Customer's authorized Retailer through the Electronic Business Transaction system (EBT) must make the Service Transfer Request (STR) in accordance with the rules established and amended from time to time by the Ontario Energy Board.

Disputes arising from charges relating to Retailer Service shall be directed to the Retailer.

The Distributor may, at its discretion, refuse to process a Service Transfer Request for a Customer to switch to a Retailer if that Customer owes money to the Distributor for Distribution Services and or Standard Supply Service.

2.4.2.1 Wheeling of Power

Customers considering delivery of electricity through the Distributors' Distribution System shall contact the Distributor for technical requirements and current applicable Rates.

2.4.3 Supply Deposits & Agreements

Whenever required by the Distributor, the Customer shall provide and maintain security as specified in the Distribution System Code. The Distributor shall require security amounts based on the existing security and deposit policies.

Where a customer proposes the development of premises that requires the Distributor to place equipment orders for special projects, the customer is required to sign the necessary Supply Agreements and furnish a suitable deposit before such equipment is ordered by the Distributor. If an expansion or enhancement of the distribution system is required to facilitate a connection, the LDC may need to perform an Economic Evaluation to establish the capital contribution required from the Customer. The Customer should review the attached Distribution Connection Process for further information.

2.4.4 Billing

The Distributor may, at its option, render bills to its Customers on either a monthly, bi-monthly, quarterly or annual basis. The option applicable to the customer shall be identified to the customer at the time of application for service.

Prorating of Service and Demand charges will be performed at the discretion of the Distributor.

2.4.4.1 Competitive Charges:

Are based on rates as determined by:

i. the Hourly Ontario Spot Market Price (HOEP); or
ii. the utilities Weighted Average Price (WAP) as determined by net system load; or
iii. the customers retailer contract rate; or
iv. the rates published by the OEB; or
v. Legislation or Regulations issued by the Ministry of Energy.

2.4.4.2 Non-competitive Charges:

Non-competitive Charges are based on rates approved by the Ontario Energy Board, and fall outside the scope of this document as they are adjusted on an annual basis. Approved rates as they relate to the transmission, distribution and other non-competitive elements may be attained through the utilities rate documents. These documents will be provided by the utility at the customer's request.

2.4.4.3 Billable Engineering Units:

Customers will be billed on:

i. actual or estimated meter reading data; or
ii. derived consumption data (Streetlights, sentinel lights and other scattered loads); or
iii. a flat rate, depending on the type of load being billed.

2.4.4.4 Use of Estimates:

In months where a bill is issued, but no reading is obtained, the Distributor estimates usage in order to determine billing quantities. The estimate is based on historical usage for the premise, or a pre-determined quantity if there is no historical usage information available.

2.4.5 Payments and Late Payment Charges

Bills are rendered for distribution services and electrical energy used by the Customer. Bills are payable in full by the due date.

Bills are due when rendered by the utility. A customer may pay the bill without the application of a late payment charge up to a due date, which shall be a minimum of sixteen calendar days from the date of mailing or hand delivery of the bill. This due date shall be identified clearly on the customer's bill.

Where payment is made by mail, payment will be deemed to be made on the date post-marked. Where payment is made at a financial institution acceptable to the utility, payment will be deemed to be made when stamped/acknowledged by the financial institution or an equivalent transaction record is made.
A partial payment will be applied to any outstanding arrears before being applied to the current billing, unless special considerations have been made by the utility.

Outstanding bills are subject to the collection process and may ultimately lead to the service being discontinued or limited. Service will be restored once satisfactory payment has been made. Discontinuance of service does not relieve the Customer of the liability for arrears.

The Distributor shall not be liable for any damage on the Customer's premises resulting from such discontinuance of service. A reconnection charge may apply where the service has been disconnected due to non-payment.

The Customer will be required to pay additional charges for the processing of non-sufficient fund (N.S.F.) cheques.

2.4.6 Unauthorized Energy Use

The Distributor shall use its discretion in taking action to mitigate unauthorized energy use. Upon identification of possible unauthorized energy use, the Distributor shall notify, if appropriate, Measurement Canada, The Electrical Safety Authority, Police Officials, Retailers that service customers affected by an authorized energy use, or other entities.

The Distributor may recover from the parties responsible for the unauthorized energy use all costs incurred by the Distributor arising from unauthorized energy use, including an estimate of the energy used, inspection and repair costs.

A service disconnected due to unauthorized use of energy shall not be reconnected until such time as all arrears resulting from the unauthorized use has been resolved to the satisfaction of the Distributor.

Prior to reconnection, the Distributor shall require proper authorization from applicable authorities.

2.5 Customer Information

The Distributor reserves the right to request specific information from the customer in order to facilitate the normal operation of its business. Failure of a customer to supply such information may prevent the normal continuation of service.

The Retail Settlement Code as amended from time to time specifies the rights of customers and their retailers to access current and historical usage information and related data and the obligations of distributors in providing access to such information.

Under these requirements, the Distributor shall upon authorization by a customer make the following information available to the Customer or the Retailer that provides electricity to a customer connected to the Distributors' distribution system:

- The Distributors' account number for the customer,
- The Distributors' meter number for the meter or meters located at the customer's service address
- The customer's service address,
- The date of the most recent meter reading,
- The date of the previous meter reading,
- Multiplied kilowatt-hours recorded at the time of the most recent meter reading,
- Multiplied kilowatt-hours recorded at the time of the previous meter reading,
- Multiplied kW for the billing period (if demand metered),
- Multiplied kVA for the billing period (if available),
- Usage (kWh's) for each hour during the billing period for interval-metered customers
- An indicator of the read type (e.g., distributor read, consumer read, distributor estimate, etc.)
- Average distribution loss factor for the billing period

This information will be provided to the Customer / Retailer upon request twice per year at no charge. The Distributor may request a fee to recover costs for additional requests. A request is considered to be data delivered to a single address. Thus, a single request to send information to three locations is considered three requests.

The Distributor acknowledges that no confidential information regarding its' customers shall be released to a third party without the expressed prior written consent of the customer unless the request is rightfully received from the third party requesting the information, or the Distributor is legally required to disclose such information under the terms and in accordance with the Freedom of Information and Protection of Privacy Act, R.S.O. 1990, c. F.31.
HOTLINK http://www.collus.com/images/stories/Documents/Measurement Errors.pdf

SECTION 3 CUSTOMER SPECIFIC

3.1 Residential

This section refers to the supply of electrical energy to Customers residing in residential dwelling units.

3.1.1 General

Energy is generally supplied as single phase, 3-wire, 60-Hertz, having a nominal voltage of 120/240 Volts.

There shall be only one Delivery Point to a dwelling.

In circumstances where two existing services are installed to a dwelling, and one service is to be upgraded, the upgraded service will replace both of the existing services.

All new single-family homes will be required to install their primary and secondary service wires to the specifications contained within the Distributors' technical specification document.

Whether the method of supply will be overhead or underground will be at the discretion of the distributor. The Distributor will adhere to any existing regulations subject to requirements of authorities.

Unless specifically documented otherwise to the Customer, where the distributor has taken ownership of such plant all services installed by the Distributor or by an approved contractor using approved materials, will be maintained by the Distributor.

3.1.2 Early Consultation

The Customer shall supply a completed Site Planning document and related information to the Distributor well in advance of installation commencement. (see appendix) The information shall be supplied in a manner requested by the Distributor at the time of the application.

3.1.3 Standard Connection Allowance

For the purposes of calculating customer connection fees, the Basic Connection for Residential consumers is defined as 100 amp 120/240 volt overhead service.

The basic connection for each customer shall include;

i. supply and installation of overhead distribution transformation capacity or an equivalent credit for transformation equipment; and
ii. up to 30 meters of overhead conductor or an equivalent credit for underground services.

In the case of an upgrade to an existing service, where the existing service is below the basic connection, the credit up to the basic connection will apply.

Secondary services exceeding the basic 30 meter length may require specific design approved by the Distributor to ensure power quality.

3.1.4 Variable Connection Fees

Any requirements above the defined basic connection shall be subject to a variable connection charge to be calculated as the costs associated with the installation of connection assets above and beyond the basic connection. The distributor may recover this amount from a customer through a connection charge or equivalent payment.

3.1.5 Point of Demarcation

In all cases the final Demarcation Point will be the decision of the Distributor.

The Customer must obtain a Demarcation Point Location from the Distributor before proceeding with the installation of any service. Failure to do so may result in the Demarcation Point having to be relocated at the Customer's expense.

Maintenance of the portion of the Secondary Service owned by the Distributor includes repair and like-for-like replacement of a wire or cable that has failed irreparably. The Customer is responsible for all civil work, supports, vegetation and landscaping associated with any such repair or replacement of the portion of Secondary Service owned by the Distributor.

3.1.5.1 Secondary Service Connections

The Point of Demarcation for residential services up to and including 400 amps is at the line side of the Meter Base for Underground services, and at the top of the stack for Overhead services, beyond which the customer bears full responsibility for installation and maintenance.

The Point of Demarcation for residential services over 400 amps is at the secondary side of the transformer.

For Secondary Services wholly owned and maintained by the Customer, the Demarcation Point is the secondary connection at the transformer or the service bus.

The Customer shall install, own, and maintain the secondary conductor under any of the following conditions:

(a) conductor terminations are inside the Customer's building;
(b) conductor is installed beyond the service entrance;
(c) conductor is connected to a Primary Service; or
(d) conductor is a non-standard installation.

3.1.5.2 Primary Service Connections

For Primary Service, the Demarcation Point is the primary connection at the Distributor's Distribution system.

3.1.6 Supply Voltage

(a) A Residential building is supplied at one service voltage per land parcel.

(b) Depending upon the location of the building the supply voltage will be one of the following:

- *120/240 Volts 1 Phase 3 Wire*
- *120/208 Volts 1 Phase 3 Wire*
- *120/208 Volts 3 Phase 4 Wire*
- *347/600 Volts 3 Phase 4 Wire*

(c) The Owner shall make provision to take delivery at one of the nominal utilization voltages as specified by the Distributor. The Owner shall obtain prior approval from the Distributor for the use of any specific voltage at any specific location.

3.1.7 Access:

At the Distributors discretion, service locations requiring access to adjacent properties (mutual drives, narrow side setbacks, etc.) will require the completion of an easement in the Distributors' name, or a "Letter of Permission "from the property owner(s) involved.

The Customer will provide unimpeded and safe access to the Distributor at all times for the purpose of installing, removing, maintaining, operating or changing metering and distribution equipment.

3.1.8 Metering:

The owner will supply and install a meter socket complete with collar acceptable to the Distributor. Meter sockets will be directly accessible to the Local Distribution Company and:

- Mounted 1.7 meters from the finished grade to the center of the meter and, either on the exterior of the front of the building or, within 3 meters of the front of the building on the driveway side.
- Installed ahead of (on the line side of) the main disconnect switch.
- Installed in a location, which is and will remain unobstructed by fences, hedges, expansions, sunrooms, porch enclosures, and any other impediments.
- If the meter is not to be installed on the actual building, it is important to contact the Distributor for specific location instructions prior to installation.

For more details refer to section 2.3.7 in these Conditions of Service.

3.1.9 Overhead Service

The Owner will provide service equipment to both the Distributors' and ESA requirements, and be of sufficient height to maintain proper minimum clearances. The Owner's main switch and the overhead service conductors will be of compatible capacity.

3.1.10 Underground Service

Underground secondary services will be installed at the Owners' expense, to the Distributor's specifications. The Owner's main switch and the underground service conductors will be of compatible capacity.

3.1.11 Street Townhouses and Condominiums:

NOTE: Street Townhouses and Condominiums requiring centralized or bulk metering will be covered under section 3.2 of these Conditions of Service. Also 3.1.11.2

3.1.11.1 Service Information:

The Owner will enter into a Servicing Agreement with the Distributor, governing the terms and conditions under which the electrical distribution system and services will be designed and installed.

The Owner will provide all of the civil works to accommodate the Distributor and will pay the complete cost of the electrical distribution system, design and services.

- The distribution system and services shall be underground unless otherwise approved.
- One service will be provided for each unit.
- The nominal service voltage will be 120/240 volts, 1 phase, 3 wire.
- The Distributor will approve the location of duct banks, service routings and meter bases.

- Distribution plant shall not be installed until grade is at +/- 150 mm of final grade unless otherwise approved by the Distributor.
- Street lighting will be to Municipal standards and installed at the Owner's expense.

3.1.11.2 Metering:

The Owner will supply and install meter sockets specified by the Distributor.

Multiple or grouped meter bases will be accepted only when prior approval has been given by the Distributor both as to type and proposed location. A completed meter verification form shall be provided to the distributor prior to energization.

Meter sockets will be located on the exterior front wall of the units and will be directly accessible to the Distributor.

- Mounted on the front wall 1.7 metres above finished grade to the centre of the meter
- Installed ahead of (on the line side of) the main disconnect switch
- Installed in a location, which is and will remain unobstructed by fences, hedges, expansions, sunrooms, porch enclosures, and any other impediments.
- If the meter is not to be installed on the actual building, it is important to contact the Distributor for specific location instructions prior to installation.

Normally the service will not be energized until the outside finish in the area of the revenue meter has been completed. If exceptions are made to this, then the general contractor will be responsible for ensuring that the meter is suitably protected while work is being done on the exterior wall adjacent to the meter. The general contractor will be entirely responsible for all costs for materials and labour for repairing or replacing a damaged meter. Meters must always remain fully accessible for reading, replacement, repair, and general maintenance. Customers and/or their contractors should contact the Distributor prior to enclosing meters and/or meter bases to ensure that safety and access are not compromised or the Distributor may disconnect the service until remedial action, as determined by the Distributor, are undertaken

3.1.12 Seasonal and Remote Dwellings:

Due to the varied nature of Seasonal and Remote Dwellings some special arrangements may be required to service these locations. Arrangements will be made in such a manner to provide services such as restoring power, maintenance of equipment or new construction requests to water access or remote customers, without endangering personnel or the public.

3.1.12.1 Service Information:

The Owner will enter into a Servicing Agreement with the Distributor, governing the terms and conditions under which the electrical distribution system services will be provided.

In the event of a power interruption, the Distributor will respond to and take reasonable steps to restore power. The Distributor reserves the right to recover costs from the customer for making false claims of interruptions.

3.1.12.2 Access:

All operations performed by the distributor and its agents shall be performed within the rules and regulations set out by the appropriate authorities including but not limited to: ESA, Ministry of Labour, Ministry of Transportation, etc.

- **Night crossings**

  The Distributors' transportation equipment will not be used to cross any water ½ hour before sunset and ½ hour after sunrise due to safety concerns. It will be at the discretion of the Distributor whether they will board customer owned transportation equipment in these circumstances.

- **Ice conditions**

  Recognizing seasonal ice hazards, the Distributor reserves the right to suspend water passage during freeze up and spring thaw, as well as any such time deemed unsafe by the Distributor.

- **Severe weather conditions**

  Recognizing that severe weather conditions may pose undue safety hazards, the Distributor reserves the right to postpone attempts to restore power until restoration can be performed in a safe manner.

3.1.13 Inspection:

Prior to connection of the service the Local Distribution Company requires notification from the Electrical Safety Authority that the electrical installation has been inspected and approved for connection.

Provision for metering shall be inspected and approved by the Distributor prior to connection.

The Distributor or Distributor-approved Contractor generally installs all services. All work done shall be as per the specifications of the Distributor and subject to inspection by the Distributor.

(Refer to section 2.1.4 for further inspection details)

3.2 General Service (Below 50 kW)

3.2.1 General

This section refers to the supply of electrical energy to General Service Buildings requiring a connection with a connected load less than 50 kW, and, Town Houses and Condominiums described in section 3.1.8 that require centralized bulk metering.

General Service buildings are defined as buildings that are used for purposes other than single-family dwellings.

3.2.2 Early Consultation

Detailed regulations cannot be stated which would be applicable to all cases, therefore the Owner will consult with the Distributor in the early planning stages to ascertain the Distributors' requirements.

The Owner shall supply a completed Electrical Planning Requirements Form to the Distributor well in advance of installation commencement to allow the Distributor time for proper planning, ordering of equipment etc.

3.2.3 Standard Connection Allowance

All costs attributed to the connection of a new General Service customer (Below 50 kW) shall be recovered through a variable connection Fee.

3.2.4 Variable Connection Fees

All costs associated with the installation of connection assets shall be subject to a variable connection charge. The distributor may recover this amount from a customer through a connection charge or equivalent payment. If an expansion or enhancement of the distribution system is required to facilitate a connection, the LDC may need to perform an Economic Evaluation to establish the capital contribution required from the Customer. The Customer should review the attached Distribution Connection Process for further information.

3.2.5 Point of Demarcation

In all cases the final Demarcation Point will be the decision of the Distributor.

The Customer must obtain a Demarcation Point Location from the Distributor before proceeding with the installation of any service. Failure to do so may result in the Demarcation Point having to be relocated at the Customer’s expense.

Maintenance of the portion of the Secondary Service owned by the Distributor includes repair and like for-like replacement of a wire or cable that has failed irreparably. The Customer is responsible for all civil work, supports, vegetation and landscaping associated with any such repair or replacement of the portion of Secondary Service owned by the Distributor.

The Distributor shall perform the maintenance or replacement of all underground looped cables that form part of the Distribution plant circuits. Following maintenance, surface restoration by the Distributor will include only soil, sod, gravel or asphalt.

Where damage can be shown to be the Owner’s liability, maintenance and repair are at the Owners’ expense

3.2.5.1 Secondary Service Demarcations

A General Service Customer Demarcation Point is at the secondary side of the transformer, or as otherwise set by the distributor, beyond which the customer bears full responsibility for installation and maintenance.

In some instances, where it is in the best interest of the operation of the distribution system, the Distributor may establish the Demarcation Point at the top of stack for overhead services or at the meter base for underground services.

The Demarcation Point might be located on an adjacent property. In such cases, a registered easement must exist.

3.2.5.2 Primary Service Demarcations

For Primary Service, the Demarcation Point is the primary connection at the Distributor’s Distribution system.

3.2.6 Supply Voltage

(a) A General Service building is supplied at one service voltage per land parcel.

(b) Depending upon the location of the building the supply voltage will be one of the following:

- *120/240 Volts 1 Phase 3 Wire*
- *120/208 Volts 1 Phase 3 Wire*
- *120/208 Volts 3 Phase 4 Wire*
- *347/600 Volts 3 Phase 4 Wire*

(c) The Owner shall make provision to take delivery at one of the nominal utilization voltages as specified by the Distributor. The Owner shall obtain prior approval from the Distributor for the use of any specific voltage at any specific location.

3.2.7 Access:

At the Distributors discretion, service locations requiring access to adjacent properties (mutual drives, narrow side setbacks, etc.) will require the completion of an easement in the Distributors' name, or a "Letter of Permission "from the property owner(s) involved.

The Customer will provide unimpeded and safe access to the Distributor at all times for the purpose of installing, removing, maintaining, operating or changing metering and distribution equipment.

3.2.8 Metering:

The owner will supply and install a meter socket complete with collar acceptable to the Distributor. Meter sockets will be directly accessible to the Distributor and unless otherwise specified during the early consultation process:

- Mounted 1.7 metres from the finished grade to the center of the meter and, either on the exterior of the front of the building or, within 3 metres of the front of the building on the driveway side.
- Installed ahead of (on the line side of) the main disconnect switch.
- Installed in a location, which is and will remain unobstructed by fences, hedges, expansions, sunrooms, porch enclosures, and any other impediments.
- If the meter is not to be installed on the actual building, it is important to contact the Distributor for specific location instructions prior to installation.

For more details refer to section 2.3.7 in these Conditions of Service.

3.2.9 Overhead Service:

In circumstances where Commercial buildings cannot reasonably be supplied electrical energy by an underground service, the Distributor shall use its' sole discretion based on acceptable industry practices in establishing the specific requirements for the service installation.

3.2.10 Underground Service:

Under normal circumstances, Commercial buildings are supplied electrical energy by an underground service through a single point of entry for each land parcel, at a location specified by the Distributor.

3.2.11 Supply of Equipment:

The Distributor supplies, installs and maintains subject to the variable connection fee:

- Primary switchgear.
- Primary transformation equipment.
- Meter and secondary metering transformers.

The Owner shall supply, install and maintain any additional equipment required for the connection beyond the point of Demarcation.

3.2.12 Inspection:

Prior to connection of the service the Local Distribution Company requires notification from the Electrical Safety Authority that the electrical installation has been inspected and approved for connection.

Provision for metering shall be inspected and approved by the Distributor prior to connection.

The Distributor or Distributor-approved Contractor generally installs all services. All work done shall be as per the specifications of the Distributor and subject to inspection by the Distributor.

(Refer to section 2.1.4 for further inspection details)

3.3 General Service (Above 50 kW)

3.3.1 General

This section refers to the supply of electrical energy to General Service Customers requiring a connection with a connected load greater than 50 kW.

3.3.2 Early Consultation

Detailed regulations cannot be stated which would be applicable to all cases, therefore the Owner will consult with the Distributor in the early planning stages to ascertain the Distributors' requirements.

The Owner shall supply a completed Electrical Planning Requirements Form to the Distributor well in advance of installation commencement to allow the Distributor time for proper planning, ordering of equipment etc.

3.3.3 Standard Connection Allowance

All costs attributed to the connection of a new General Service customer (Above 50 kW) shall be recovered through a variable connection Fee.

3.3.4 Variable Connection Fees

All costs associated with the installation of connection assets shall be subject to a "variable connection charge". The distributor may recover this amount from a customer through a connection charge or equivalent payment. If an expansion or enhancement of the distribution system is required to facilitate a connection, the LDC may need to perform an Economic Evaluation to establish the capital contribution required from the Customer. The Customer should review the attached Distribution Connection Process for further information.

3.3.5 Point of Demarcation

In all cases the final Demarcation Point will be the decision of the Distributor.

The Customer must obtain a Demarcation Point Location from the Distributor before proceeding with the installation of any service. Failure to do so may result in the Demarcation Point having to be relocated at the Customer's expense.

Maintenance of the portion of the Secondary Service owned by the Distributor includes repair and like for-like replacement of a wire or cable that has failed irreparably. The Customer is responsible for all civil work, supports, vegetation and landscaping associated with any such repair or replacement of the portion of Secondary Service owned by the Distributor.

The Distributor shall perform the maintenance or replacement of all underground looped cables that form part of the Distribution plant circuits. Following maintenance, surface restoration by the Distributor will include only soil, sod, gravel or asphalt.

Where damage can be shown to be the Owner's liability, maintenance and repair are at the Owners' expense

3.3.5.1 Secondary Service Connections

A General Service Customer Demarcation Point for customers above 50 kW is at the secondary side of the transformer, or as otherwise set by the distributor, beyond which the customer bears full responsibility for installation and maintenance.

In some instances, where it is in the best interest of the operation of the distribution system, the Distributor may establish the Delivery point at the top of stack for overhead services or at the meter base for underground services.

The location of the service entrance, routing of duct banks and all other works will be established through consultation with the Distributor. Failure to comply may result in relocation of the service plant at the Owner's expense.

The Demarcation Point might be located on an adjacent property. In such cases, a registered easement must exist.

3.3.5.2 Primary Service Connections

For Primary Service, the Demarcation Point is the primary connection at the Distributor's Distribution system.

In some circumstances the owner may be required to construct a private pole line. Primary conductors will be terminated complete with cut-out(s) at the Demarcation Point by the Distributor at the owners' expense.

Where a private pole line is to be constructed by the Owner with an approved contractor, this shall be constructed to the ESA and the Distributors' requirements.

An electrical requirement in excess of 300 kVA may require a customer owned substation.

In some instances primary metering may be required.

3.3.6 Supply Voltage

A General Service building is supplied at one service voltage per land parcel.
Depending upon the location of the building the supply voltage will be one of the following:

- *120/240 Volts 1 Phase 3 Wire*
- *120/208 Volts 3 Phase 4 Wire*
- *347/600 Volts 3 Phase 4 Wire*

Depending upon the location of the building Primary supplies to transformers and Customer owned Sub-Stations will be one of the following as determined by the Distributor:

- *2,400/4,160 volts 3 phase 4 wire*
- *4,800/8,320 volts 3 phase 4 wire*
- *7,200/12,400 volts 3 phase 4 wire*
- *8,000/13,800 volts 3 phase 4 wire*
- *16,000/27,600 volts 3 phase 4 wire*
- *44,000 Volts - 3 Phase 3 Wire*

The Owner shall make provision to take delivery at one of the nominal utilization voltages as specified by the Distributor. The Owner shall obtain prior approval from the Distributor for the use of any specific voltage at any specific location.

3.3.7 Access:

At the Distributors discretion, service locations requiring access to adjacent properties (mutual drives, narrow side setbacks, etc.) will require the completion of an easement in the Distributors' name, or a "Letter of Permission "from the property owner(s) involved.

The Customer will provide unimpeded and safe access to the Distributor at all times for the purpose of installing, removing, maintaining, operating or changing metering and distribution equipment.

3.3.8 Metering:

Meter installations will be directly accessible to the Distributor. The owner will consult with the Distributor well in advance of installation commencement to allow the Distributor time for proper planning and ordering of equipment.

For more details refer to section 2.3.7 in these Conditions of Service.

3.3.9 Overhead Service:

In circumstances where Commercial buildings cannot reasonably be supplied electrical energy by an underground service, the Distributor shall use its' sole discretion based on acceptable industry practices in establishing the specific requirements for the service installation.

3.3.10 Underground Service:

Under normal circumstances, Commercial buildings are supplied electrical energy by an underground service through a single point of entry for each land parcel, at a location specified by the Distributor.

3.3.11 Sub-transmission Service:

The Owner will pay for the full cost of sub-transmission services and may in some circumstances be required to construct a private pole line. The Distributor will terminate sub-transmission conductors complete with live line loops and hardware at the Demarcation Point.

3.3.12 Supply of Equipment:

The Distributor supplies, installs and maintains subject to the variable connection fee:

- Primary switchgear.
- Primary transformation equipment.
- Meter and secondary metering transformers.

The Owner shall supply, install and maintain any additional equipment required for the connection beyond the point of Demarcation.

3.3.13 Short Circuit Capacity:

The Owner shall ensure that the service entrance equipment has an adequate short-circuit interrupting capability.

3.3.14 Inspection:

Prior to connection of the service the Local Distribution Company requires notification from the Electrical Safety Authority that the electrical installation has been inspected and approved for connection.

Provision for metering shall be inspected and approved by the Distributor prior to connection.

The Distributor or Distributor-approved Contractor generally installs all services. All work done shall be as per the specifications of the Distributor and subject to inspection by the Distributor.

(Refer to section 2.1.4 for further inspection details)

3.4 General Service (Above 500 kW)

3.4.1 General

This section refers to the supply of electrical energy to General Service Services requiring a connection at a connected load greater than 500 kW.

3.4.2 Early Consultation

Detailed regulations cannot be stated which would be applicable to all cases, therefore the Owner will consult with the Distributor in the early planning stages to ascertain the Distributors' requirements.

The Customer shall supply a completed Electrical Planning Requirements Form to the Distributor well in advance of installation commencement to allow the Distributor time for proper planning, ordering of equipment, and coordination with ESA requirements etc.

Note: Larger services may require approval by the ESA to ensure compliance with their design requirements. The customer should contact the ESA early in the planning stages.

The Distributor will:

- *Advise the customer of the suitability of the in-service date*
- *Arrange with the customer for a Service Contract*
- *Review the submitted drawings; return one set to the customer with comments and/or approval. If requested by the Distributor, the customer shall resubmit the drawings where the comments are extensive and require major changes*
- *Specify the required main fuse link or relay setting for co-ordination with the system. In case of multiple transformer stations, a complete co-ordination study shall be submitted by the customer for approval.*
- *Make the final connection to the source of supply*
- *Determine metering requirements*
- *Advise the Transmitter of the particulars of the customer owned substation*

3.4.3 Standard Connection Allowance

All costs attributed to the connection of a new General Service customer (Above 500 kW) shall be recovered through a variable connection Fee.

3.4.4 Variable Connection Fees

All costs associated with the installation of connection assets shall be subject to a variable connection charge. The distributor may recover this amount from a customer through a connection charge or equivalent payment. If an expansion or enhancement of the distribution system is required to facilitate a connection, the LDC may need to perform an Economic Evaluation to establish the capital contribution required from the Customer. The Customer should review the attached Distribution Connection Process for further information.

3.4.5 Point of Demarcation

In all cases the final Demarcation Point will be the decision of the Distributor.

The Customer must obtain a Demarcation Point Location from the Distributor before proceeding with the installation of any service. Failure to do so may result in the Demarcation Point having to be relocated at the Customer's expense.

Maintenance of the portion of the Primary Service owned by the Distributor includes repair and like for-like replacement of a wire or cable that has failed irreparably. The Customer is responsible for all civil work, supports, vegetation and landscaping associated with any such repair or replacement of the portion of Secondary Service owned by the Distributor.

The Distributor shall perform the maintenance or replacement of all underground looped cables that form part of the Distribution plant circuits. Following maintenance, surface restoration by the Distributor will include only soil, sod, gravel or asphalt.

Where damage can be shown to be the Owner's liability, maintenance and repair are at the Owners' expense

The Distributor reserves the right to direct the operations of any customer owned switchgear connected to the distribution system including those located beyond the point of demarcation.

3.4.5.1 Service Installation

In General, the Demarcation Point for a General Service Customer with a demand of over 500 kW is on the primary side of the transformer at the first available distributor owned point of isolation, or as otherwise set by the distributor. This delivery point might be located on an adjacent property from which the Distributor has an authorized easement. In all cases the final Demarcation Point will be the decision of the Distributor.

The location of the service entrance, routing of duct banks, metering facilities, and all other works will be established through consultation with the Distributor. Failure to comply may result in relocation of the service plant at the Owner's expense.

The Distributor will install overhead supply lines and required cut-outs to the first point of support on private property. The location of this support must be approved by the Distributor and shall be within 30 metres of the Distributors' existing overhead plant. All costs for materials and labour shall be at the customers' expense.

The service pole or first point of support on private property shall be considered self-supported and shall be complete with suitable hardware for attaching the suspension insulators. The Customer shall be responsible for all costs associated with equipment, installation, and inspection.

Where the customer wishes an underground supply, the customer shall supply and install the underground cables and termination pole complete with primary switch, fuses and lightning arresters. The installation shall be subject to ESA inspection and specific approval of the Distributor. The customer owned termination pole must comply with items as prescribed by the Distributor.

At the Distributors' discretion, the customers' underground service may be connected to a termination pole owned by the distributor. In such cases, the Distributor shall supply and install at the customers expense, any required primary switch, fuses, and lightning arrestors.

When requested, the customer shall make provision in the substation switchgear or transformer, for loop feeding the Distributors' supply cables via load interrupter switches.

In some instances, primary metering may be required.

3.4.6 Supply Voltage

A General Service building is supplied at one service voltage per land parcel.

General Service connections above 500 kW may require a customer owned substation.

Depending upon the location of the building, Primary supplies to transformers and Customer owned Sub-Stations will be one of the following as determined by the Distributor:

- *2,400/4,160 volts 3 phase 4 wire*
- *4,800/8,320 volts 3 phase 4 wire*
- *7,200/12,400 volts 3 phase 4 wire*
- *8,000/13,800 volts 3 phase 4 wire*
- *16,000/27,600 volts 3 phase 4 wire*
- *44,000 Volts - 3 Phase 3 Wire*

The Owner shall make provision to take delivery at one of the nominal utilization voltages as specified by the Distributor. The Owner shall obtain prior approval from the Distributor for the use of any specific voltage at any specific location.

3.4.7 Access:

At the Distributors discretion, service locations requiring access to adjacent properties (mutual drives, narrow side setbacks, etc.) will require the completion of an easement in the Distributors' name, or a "Letter of Permission "from the property owner(s) involved.

The Customer will provide unimpeded and safe access to the Distributor at all times for the purpose of installing, removing, maintaining, operating or changing metering and distribution equipment.

Where the high voltage interrupting switches are located inside a building, a direct outside entrance to the switchgear room must be provided.

The outside door providing direct access to the transformer or switchgear room must be compliant with all applicable codes and requirements, and of a quality to be approved by the Distributor.

3.4.8 Metering:

The owner will supply and install provisions for metering following the details outlined both in these Conditions of Service, and technical documents provided to the customer during the consultation process.

For more details refer to section 2.3.7 in these Conditions of Service.

3.4.9 Sub-transmission Service:

The Owner will pay for the full cost of sub-transmission services and may in some circumstances be required to construct a private pole line.

The Distributor will terminate sub-transmission conductors complete with live line loops and hardware at the Demarcation Point.

3.4.10 Short Circuit Capacity:

The Owner shall ensure that the service entrance equipment has an adequate short-circuit interrupting capability.

3.4.11 Drawings

Apart from the regular drawings submission to the ESA, the customer shall provide two sets of the following drawings and details to the Distributor.

Survey Plan: prepared by an Ontario Land Surveyor, showing the property limits, registered plan and existing buildings or easements if any.

Site Plan: showing the location of the station relative to buildings, structures and set backs from adjacent property lines. The site plan shall also include the exact location of existing Distributor owned plant and the proposed route of the incoming supply.

Schematic or Single-Line Diagram: indicating the major components of the station and their electrical ratings. Where additions or alterations are being made, these shall be clearly distinguished from unchanged portions of the installation.

Electrical Details: sufficient details shall be provided in order to enable fast processing and approval of the station drawings. The following represents the minimum data required.

- Plan, elevation and profile views of the station structure, switchgear, transformer(s), termination poles, duct banks, etc.

- Dimensions to clearly indicate the electrical, physical and working clearances as well as relative location of all equipment.

- Pole or structure for dead-ending the Distributor lines shall be complete with suitable hardware for attaching the suspension insulators that will be supplied and installed by the Distributor.

- Fencing arrangement.

- Grounding details. (In the case of indoor metal enclosed switchgear, when the Distributor has operating control of any interrupter switches, the assembly shall further incorporate ground rod parking stands and stirrups per the Distributors Specifications.)

- Details of vault construction (if indoor substation).

- Manufacturer's drawings of metal-enclosed switchgear showing internal arrangement of equipment, clearances, means of access, interlocking and provision for personal safety. Where the Distributors' cables terminate in the switchgear, the customer shall provide suitable terminators for the size and type of cable as specified by the Distributor.

- When the customer's switchgear is used for loop feeding the Distributors' supply cables, provision for padlocking the in and out load interrupter switches and the associated bay doors shall be required.

- Indoor and outdoor switchgear assemblies shall contain a space heater and protective guard in each bay, along with thermostat(s), sized to promote air circulation and to prevent condensation from forming.

- At the discretion of the distributor, the customer shall make provisions for a future system neutral connection to the customer's dead-ending pole or structures installed by the Distributor. Where the Distributors' neutral terminates in the customer's switchgear, the customer shall provide a suitable connector on the ground bus for the size and type of cable specified by the Distributor.

3.4.12 Pre-Service Inspection

The customer shall present to the Distributor a final "Pre-service Inspection Report" a minimum of 3 working days before connection can be affected.

The "Pre-Service Inspection Report" shall outline and document the results of all tests and inspection carried out on the substation components. The information contained in the report must be to the satisfaction of the Distributor before connection can be authorized.

The "Pre-Service Inspection Report" shall be required in case of:

- ***<u>New Substation</u>****: in which case all components of the substation shall be reported upon.*

- ***<u>Modified substation</u>****: in which case all components of the substation shall be reported upon.*

Prior to connection of the service the Local Distribution Company requires notification from the Electrical Safety Authority that the electrical installation has been inspected and approved for connection.

Provision for metering shall be inspected and approved by the Distributor prior to connection.

The Distributor or Distributor-approved Contractor generally installs all services. All work done shall be as per the specifications of the Distributor and subject to inspection by the Distributor.

(Refer to section 2.1.4 for further inspection details)

3.5 Embedded Generation

3.5.1 General

An Embedded Generator shall provide the Distributor with proof of compliance of IESO or OEB registration Requirements, and appropriate Licences.

The Distributor shall collect costs reasonably incurred with making an offer to connect a generator from the entity requesting the connection. Costs reasonably incurred include costs associated with:

- Preliminary review for connection requirements.
- Detailed study to determine connection requirements.
- Final proposal to the generator.

A Generator that is or wishes to become connected to the distributors' distribution system shall enter into a Connection Agreement with the Distributor.

If damage or increased operating costs result from a connection with a Generator, the Generator shall reimburse the Distributor for these costs.

The Embedded Generator is responsible for providing suitable embedded generator equipment to protect his plant and equipment for any conditions on the distributor and interconnected transmission systems such as reclosing, faults and voltage unbalance.

To incorporate the connection of embedded generator to the distribution system, the line/feeder protection including settings and breaker reclosing circuits must be reviewed and modified if necessary by the distributor or transmission authority. This process may be complex and may require significant time.

The embedded generator must submit a proposed single line diagram and protection scheme for review to the distributor contact as identified by the distributor.

Based on the transformer connection proposed by the embedded generator additional significant protection cost may be incurred (e.g. delta HV transformer winding may require 3 phase HV breaker / reclosure device). The embedded generator shall not order the protection equipment and transformer until the station line diagram is reviewed and accepted by the distributor.

The purpose of the distributor review is to establish that the embedded generator electrical interface design meets the distributor requirements.

The protection schemes shall incorporate adequate facilities for testing/maintenance.

Negative phase sequence protection shall be installed where required, to detect abnormal system condition as well as to protect the generator.

The embedded generator may be required to install utility grade relays for those protections that could affect the distributor or transmission authority system.

The embedded generator may be required to submit a Ground Potential Rise study for review by the distributor, if telecommunications circuits are specified for remote transfer trip protection.

3.5.2 Protection

The embedded generator should provide protection systems to cover the following conditions:

3.5.2.1 Internal Faults:

The Generator should provide adequate protections to detect and isolate generator and station faults.

3.5.2.2 External Faults:

The protection system should be designed to provide full feeder coverage complete with a reliable DC supply. In some cases redundancy in protection schemes may be required.

Normally the following fault detection devices are required for synchronous generator(s) installation(s).

3.5.2.3 Ground Faults:

When the HV winding of the Generator station transformer is wye connected with the neutral solidly grounded, then ground over-current protection in the neutral is required to detect ground faults.

If the Embedded generator station transformer HV winding connected to the Distributor system is ungrounded wye or delta, then ground under-voltage and ground over-voltage protections shall be required to detect ground faults.

Depending on the size, type of generator and point of connection, a distributor may require the relaying system to be duplicated, complete with separate auxiliary trip relays and separately fused DC supplies to ensure reliable protection operation and successful isolation of the embedded generator.

3.5.2.4 Phase Faults:

To detect phase faults, at least one of the following protections should be installed with acceptable redundancy where required depending on fault values:

- Distance
- Phase directional over-current
- Voltage-restrained over-current
- Over-current
- Under-voltage

3.5.2.5 Islanding/Abnormal Conditions:

Voltage and frequency protections are required to separate the embedded generator from the distribution system for an islanded condition and thus maintain the quality of supply to distribution system customers. This also will enable speedy restoration of the distribution system.

Typically, the protections required to detect islanding/abnormal conditions are:

- Over-voltage
- Under-voltage
- Over-frequency
- Under-frequency
- Voltage-balance

The above protections should be timed to allow them to ride through minor disturbances.

3.5.3 Induction Generator

Due to the operating characteristics of the induction generator the protection package required is normally less complex than the synchronous generator. An embedded generator should design the protection scheme to trip for the same conditions as stated for synchronous generators. An induction generator is an asynchronous machine that requires an external source such as a healthy distribution system to produce normal 60 Hz power. Alternatively, if there is an outage in the distribution system then there is unlikely to be 60 Hz output from the induction generator. In certain instances, an induction generator may continue to generate electric power after the source is removed. This phenomenon, known as self-excitation, can occur whenever there is sufficient capacitance in parallel with the induction generator to provide the necessary excitation and when the connected load has certain resistive characteristics.

3.5.4 DC Remote Tripping / Transfer Tripping

Remote or transfer tripping may be required between the Generator and the feeder circuit breaker if the Generator is connected at a critical location in the distribution system. This feature will provide for isolation of the embedded generator when certain faults or system disturbances are detected at the feeder circuit breaker location.

Additional Protection Features, such as Remote Trip and Generator end open signal, may be required in some applications. Remote Trip Protection will often involve the participation of a neighboring or Host LDC. Early consultation is important to ensure a timely connection to the system.

3.5.5 Maintenance

An Embedded Generator shall have a regular scheduled maintenance plan to assure the Distributor that all connection devices and protection & control systems are maintained in good working order. These provisions shall be included in the Connection Agreement. A complete copy of the inspection report shall be delivered to the Distributor within 30 days.

In developing a maintenance plan, the Generator should consider the following requirements:

- Qualified personnel should carry out all inspections and repairs.

- Periodic tests should be performed on protection systems to verify that the system operates as designed. Testing intervals for protection systems should not exceed four (4) years for microprocessor-based systems and two (2) years for electro-mechanical based systems.

- Isolating devices at the point of connection should be operated at least once per year.

- The Generator facility should be inspected visually at least once per year to note obvious maintenance problems such as broken insulators or other damaged equipment.

- Any deficiencies identified during inspections shall be noted and repairs scheduled as soon as possible, with timing dependent on the severity of the problem, due diligence concerns (of both the Distributor and the Generator) and financial and material requirements. The Distributor shall be notified of any deficiencies involving critical protective equipment.

- The Distributor shall be provided with copies of all relevant inspection and repair reports that may affect the protection and performance of the Distributors' systems. The Distributor has the right to witness any relevant test being performed by the generator.

3.6 Embedded Market Participant

An Embedded Market Participant shall provide the Distributor with proof of compliance of IESO registration Requirements, and appropriate Licences.

Where the Conditions of Service of this Distributor exceed the technical requirements of any other licence or participant obligations, these Conditions of Service shall take precedence.

The Embedded Market Participant must meet at a minimum, the standards as set out in these Conditions of Service in order to connect to the Distributors' distribution facilities.

3.7 Embedded Distributor

An Embedded Distributor shall provide the Distributor with proof of compliance of IESO and OEB registration Requirements, and appropriate Licences.

Where the Conditions of Service of this Distributor exceed the technical requirements of any other licence or participant obligations, these Conditions of Service shall take precedence.

The Embedded Distributor must meet at a minimum, the standards as set out in these Conditions of Service in order to connect to the Distributors' distribution facilities.

Metering requirements of the Embedded Distributor shall be at the discretion of the Host Distributor.

3.8 Miscellaneous Small Services

This section pertains to the supply of electrical energy for Street Lighting, Traffic Signals, Bus Shelters, Telephone Booths, Cable T.V. Amplifiers, Decorative Street Lighting, Bill Boards, and other similar small loads.

3.8.1 General

At the discretion of the Distributor, the service voltage will be:

120/240 volts, single phase three wire or
120 volts, single phase two wire or
347/600V three phase, four wire

The method and location of the supply will vary based on the conditions present on the Distributors' plant, and will be established for each application through consultation with the Distributor.

Where specified by the Distributor during the Early Consultation process, the Customer will provide underground ducts to the Distributor's specifications.

The Owner shall be responsible for all costs associated with the supply and installation of service conductors

The Distributor at the Owners' expense will install required transformation.

Where at the discretion of the Distributor, a meter is not installed, energy consumption will based on the connected wattage and the calculated hours of use.

Prior to energization of a service the Distributor will require notification from the ESA that the installation has been inspected and approved for connection.

3.8.2 Early Consultation

The Owner shall supply a completed Electrical Planning Requirements Form to the Distributor well in advance of installation commencement to allow the Distributor time for proper planning, ordering of equipment etc. Information required includes:

- Required in-service date
- Requested Service Entrance Capacity and voltage rating of the service entrance equipment
- Locations of other services, gas, telephone, water and cable TV
- Survey plan and site plan indicating the proposed location of the service equipment with respect to public rights-of way and lot lines.

3.8.3 Street Lighting

Town street-lighting that is designed, installed, and maintained by the Distributor shall be fully funded by the Municipality to ensure adherence to the Affiliate Relationship Code and the Distributors' Licence.

3.8.4 Traffic Signals

Traffic Signals and Crosswalk Lights are owned and maintained by the applicable road authority.

3.8.5 Bus Shelters

Bus Shelter Lighting is owned and maintained by the Customer.

3.8.6 Decorative Street Lighting

Such installations could be lighting for festive occasions or "neighbourhood character" street-scaping and will be maintained by the Customer.

SECTION 4 GLOSSARY OF TERMS

"Conditions of Service" means the document developed by the distributor in accordance with subsection 2.3 of the Distribution System Code, that describes the operating practices and connection rules for the distributor;

"Condominiums" are located on common land, which is the property of a condominium corporation or is owned by the Owner of all of the units (rental property). These units usually front onto internal roads that are also privately owned;

"Condominium Development" is a structure or complex of structures each containing more than two residential units. A single residential customer would occupy each unit and have direct outside access at ground level;

"Connection" means the process of installing and activating connection assets in order to distribute electricity;

"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;

"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 distributors' main distribution system and the ownership Demarcation Point with that customer;

"Consumer" means a person who uses, for the person's own consumption, electricity that the person did not generate;

"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;

"Demand meter" means a meter that measures a consumers' peak usage during a specified period of time;

"Demarcation Point" means the point at which the obligation of the Distributor ends and those of the Customer begin for the purposes of maintenance and repair of the distribution service;

"Disconnection" means a deactivation of connection assets, which results in cessation of distribution services to a consumer;

"Distribute", with respect to electricity, means to convey electricity at voltages of 50 kilovolts or less;

"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;

"Distribution 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.;

"Distribution services" means services related to the distribution of electricity and the services the Board has required distributors to carry out.

"Distribution system / plant" 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;

"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;

"Distributor" means a person who owns or operates a distribution system;

***"Electricity Act*"** means the *Electricity Act, 199*8, S.O. 1998, c.15, Schedule A;

"Energy Competition Act" means the *Energy Competition Act, 199*8, S.O. 1998, c. 15;

"Electrical Safety Authority" or **"ESA"** means the person or body designated under the *Electricity Act* regulations as the Electrical Safety Authority;

"Embedded Distributor" means a distributor who is not a wholesale market participant and that is provided electricity by a host distributor;

"Embedded Generation Facility" means a generator whose generation facility is not directly connected to the IESO-controlled grid but instead is connected to a distribution system;

"Embedded Load Displacement Generation Facility" means an embedded generation facility connected to the customer side of the revenue meter where the generation facility does not inject electricity into the distribution system for the purpose of sale;

"Embedded Market Participant" means a consumer who is a wholesale market participant whose facility is not directly connected to the IESO-controlled grid but is connected to a distribution system;

"Emergency" means any abnormal system condition that requires remedial action to prevent or limit loss of a distribution system or supply of electricity, or that could adversely affect the reliability of the electricity system;

"Emergency backup generation facility" means a generation facility that has a transfer switch that isolates it from a distribution system;

"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;

"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;

"Four-quadrant Interval Meter" means an interval meter that records power injected into a distribution system and the amount of electricity consumed by the customer;

"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;

"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;

"Generator" means a person who owns or operates a generation facility;

"Geographic Distributor" with respect to a load transfer, means the distributor that is licensed to service a load transfer customer and is responsible for connecting and billing the load transfer customer;

"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;

"Holiday" means a Saturday, Sunday, statutory holiday, or any day as defined in the Province of Ontario as a legal holiday;

"IESO" means the Independent Electricity System Operator established under the Electricity Act;

"IESO-Controlled Grid" means the transmission systems with respect to which, pursuant to agreements, the IESO has authority to direct operation;

“Interval meter” means a meter that measures and records electricity use on an hourly or sub-hourly basis;

“Large Embedded Generation Facility” means an embedded generation facility with a name-plate rated capacity of 10MW or more;

“Lies Along” means a property can be connected to the distributor distribution system without an expansion or enhancement, and meets the conditions listed in the Conditions of Service of the distributor who owns or operates the distribution line.

“Load Transfer” means a network supply point of one distributor that is supplied through the distribution network of another distributor and where this supply point is not considered a wholesale supply or bulk sale point;

“Load Transfer Customer” means a customer that is provided distribution services through a load transfer;

“Market Rules” means the rules made under section 32 of the *Electricity Ac*t;

“Measurement Canada” means the Special Operating Agency established in August 1996 by the *Electricity and Gas Inspection Ac*t, 1980-81-82-83, c. 87., and Electricity and Gas Inspection Regulations (SOR/86-131);

“Medium Sized Embedded Generation Facility” means an embedded generation facility with a name-plate rated capacity of less than 10 MW and:

a) more than 500 kW in the case of a facility connected to a less than 15kV line;
b) more than 1 MW in the case of a facility connected to a 15 kV or greater line;

“Meter Service Provider” means any entity that performs metering services on behalf of a distributor, generator, or registered market participant;

“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;

“Metering Services” means installation, testing, reading and maintenance of meters;

“Micro Embedded Load Displacement Generation Facility” means an embedded load displacement generation facility with a name-plate rated capacity of 10 kW or less;

“Net Metering” means a settlement process for Embedded Generation behind a Load Customer meter as defined by Ontario Regulation 541/05

“Ontario Electrical Safety Code” means the code adopted by O. Reg. 164/99 as the Electrical Safety Code;

“Ontario Energy Board Act” means the *Ontario Energy Board Act, 199*8, S.O. 1998, c.15, Schedule B;

“Operational Demarcation Point” means the physical location at which a distributors’ responsibility for operational control of distribution equipment including connection assets ends at the customer;

“Ownership Demarcation Point” means the physical location at which a distributors’ ownership of distribution equipment including connection assets ends at the customer;

“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;

“Point of Supply” with respect to an embedded generation facility, means the connection point where electricity produced by the generation facility is injected into a distribution system;

“Rate” means any rate, charge or other consideration, and includes a penalty for late payment;

“Rate Handbook” means the document approved by the Board that outlines the regulatory mechanisms that will be applied in the setting of distributor rates;

“Regulations” means the regulations made under the *Act or the Electricity Act*;

“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.

“Retail Settlement Code” means the code approved by the Board and in effect at the relevant time, which, among other things, establishes a distributors’ obligations and responsibilities associated with financial settlement among retailers and customers and provides for tracking and facilitating customer transfers among competitive retailers;

“Retailer” means a person who retails electricity;

“Service Area” with respect to a distributor, means the area in which the distributor is authorized by its license to distribute electricity;

“Small Embedded Generation Facility” means an embedded generation facility which is not a micro-embedded generation facility with a name-plate rated capacity of 500 kW or less in the case of a facility connected to a less than 15 kV line and 1MW or less in the case of a facility connected to a 15 kV or greater line;

“Smart Meter” means a device that measures electrical energy use (kilowatt-hours, kWh) on an hourly or sub-hourly basis and is part of an integrated data management system. The meter records, stores and transmits date and time-stamped meter readings to a utility’s computer to facilitate Time-of-Use and Hourly billing. Smart meters may also include other capabilities and features to aid in load management and energy conservation.

“Standard Offer” means a settlement process for distribution connected Embedded Generation under contract for supply with the Ontario Power Authority.

“Total losses” means the sum of distribution losses and unaccounted for energy;

“Townhouses” are usually a free hold property, the land is owned by the individual Owners of each unit, fronting onto a municipal street;

“Townhouse Development” is a structure or complex of structures each containing more than two residential units. A single residential customer would occupy each unit, and have direct outside access at ground level;

“Transmission System” means a system for transmitting electricity, and includes any structures, equipment or other things used for that purpose;

“Transmission System Code” means the Board approved code that is in force at the relevant time, which regulates the financial and information obligations of the Transmitter with respect to its relationship with customers, as well as establishing the standards for connection of customers to, and expansion of a transmission system;

“Transmit” with respect to electricity, means to convey electricity at voltages of more than 50 kilovolts;

“Transmitter” means a person who owns or operates a transmission system;

“Unaccounted-for Energy” means all energy losses that cannot be attributed to distribution losses. These include measurement error, errors in estimates of distribution losses and un-metered loads, energy theft and non-attributable billing errors;

“Un-metered loads” means electricity consumption that is not metered and is billed based on estimated usage;

“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;

"Wholesale Market Participant" means a person that sells or purchases electricity or ancillary services through the IESO-administered markets;

SECTION 5 APPENDICIES

Contact Information

Local Distribution Company	Contact Phone Number	
Centre Wellington Hydro Ltd.		730 Gartshore Street, Box 217
Licence # ED-2002-0498	Phone: (519) 843-2900	Fergus, Ont. N1M 2W8
COLLUS Power Corp.		Box 189, 43 Stewart Road
Licence # ED-2002-0518	Phone: (705) 445-1800	Collingwood, Ont. L9Y 3Z5
Grand Valley Energy Inc.		P.O. Box 400 - 400 C Line
Licence # ED-2002-0512	Phone: (519) 928-3112	Orangeville, Ont. L9W 2Z7
Hydro 2000 Inc.		265 St. Philippe Street P.O.Box 370
Licence # ED-2002-0542	Phone: (613) 679-4093	Alfred, Ont. K0B 1A0
Innisfil Hydro Distribution Systems Limited.		2073 Commerce Park Drive
Licence # ED-2002-0520	Phone: (705) 431-4321	Innisfil, Ont. L9S 4A2
Lakefront Utilities Inc.		207 Division St. P.O. Box 577
Licence # ED-2002-0545	Phone: (905) 372-2193	Cobourg, Ont. K9A 4L3
Lakeland Power Distribution Ltd.		5-45 Cairns Cres.
Licence # ED-2002-0540	Phone: (705) 789-5442	Huntsville, Ont. P1H 2M2
Midland Power Utility Corporation		16984 Highway #12
Licence # ED-2002-0541	Phone: (705) 526-9361	Midland, Ont. L4R 4P4
Orangeville Hydro Ltd.		P.O. Box 400 - 400 C Line
Licence # ED-2002-0500	Phone: (519) 942-8000	Orangeville, Ont. L9W 2Z7
Orillia Power Distribution Corporation		360 West St. South, P.O. Box 398
Licence # ED-2002-0530	Phone: (705) 326-2495	Orillia, Ont. L3V 6J9
Parry Sound Power Corporation		125 William Street
Licence # ED-2003-0006	Phone: (705) 746-5866	Parry Sound, Ont. P2A 1V9
Rideau St. Lawrence Distribution Inc.		985 Industrial Rd. P.O. Box 699
Licence # ED-2003-0003	Phone: (613) 925-3851	Prescott, Ont. K0E 1T0
Wasaga Distribution Inc.		950 River Road West P.O. Box 20
Licence # ED-2002-0544	Phone: (705) 429-2517	Wasaga Beach, Ont. L0L 2P0
Wellington North Power Inc.		290 Queen Street West, P.O. Box 359
Licence # ED-2002-0511	Phone: (519) 323-1710	Mount Forest, Ont. N0G 2L0
Westario Power Inc.	Phone: (519) 507-6937	24 Eastridge Road R.R. #2
Licence # ED-2002-0515	Toll Free: 1-866-978-2746	Walkerton, Ont. N0G 2V0
West Coast Huron Energy Inc.		64 West Street
Licence # ED-2002-0510	Phone: (519) 524-7371	Goderich, Ont. N7A 2K4
Woodstock Hydro Services Inc.		16 Graham Street P.O. Box 1598
Licence # ED-2003-0011	Phone: (519) 537-3488	Woodstock, Ont. N4S 0A8

Note: Licence Numbers published by OEB as of May 8, 2008

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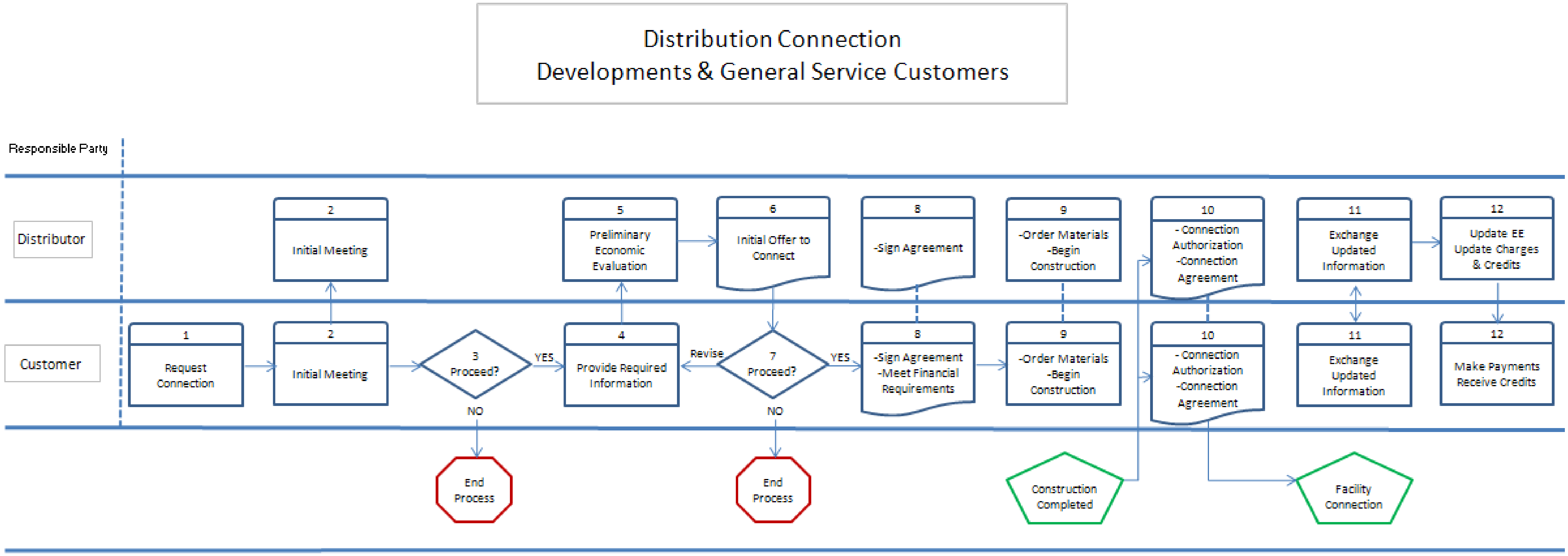
Distribution Connection



Distribution Connection
Developments & General Service Customers

If you are planning on building a Subdivision, Commercial Building, or an Industrial Development, the process of connecting to the Local Distribution Infrastructure will require coordination with the Distributor.

The following information in conjunction with the preceding chart is designed to assist the parties in meeting their respective obligations and facilitate the required connection. It is important to note although the steps identified in both the chart and the following descriptions need to be followed in proper order, some of the steps may be combined to help speed up the process if all the required information is provided in a timely manner.

Step 1 – Request for Connection

Customer submits a connection request to the Distributor. Initial request should at a minimum include the following information:

- Location of proposed development
- General description of development
- Proposed construction date
- Contact information for Development

Step 2 – Initial Meeting

Customer and Distributor meet to review proposed new development and connection requirements. Initial meeting will provide both parties with an opportunity to gain a better understanding of the proposed development and identify any issues related to timing and connection to the Distribution System.

Based on the information provided by the customer prior to the meeting, the Distributor will be able to provide at a high level:

- An initial concept of the type of work that may be required to facilitate a connection. ie:
    - Extension of an existing Feeder
    - Potential requirement for a new DS
    - Add a second or third phase to an existing feeder
- An understanding of the of the customer responsibilities
- An understanding of what must be managed by the Distributor
- An understanding of what may be contracted by the customer
- An estimated timeline required to provide connection facilities
- An initial estimate of required enhancement or expansion costs – note: more detailed estimates on costs will be provided with the Offer to Connect should the Customer choose to continue to Step 4.

Step 3 – Customer Decision
Based on the results of the initial meeting, the Customer decides on proceeding with the process or withdrawing their Request for Connection.

Step 4 – Customer Provides Required Information

If the Customer decides to proceed with the process for acquiring a connection, the Customer notifies the Distributor and provides the relevant detailed information as noted below:

- A statement noting if the Customer intends on managing the contestable work noted during the consultation
- Number of Residential Connections
- Residential – Type, Number, and size of units
- Number of Commercial / Industrial Connections
- Estimated Average Monthly consumption (at minimum winter & summer estimates)
- Estimated annual facility connections over five years from date of LDC system connection

The following information is also required however the Distributor reserves the right to perform the work internally or through an external consultant:

- Design and engineering specifications including but not limited to stamped site service drawings
- Determination of required Transformation based on estimated building loads
- Estimated Capital costs of facilities which would be assumed by the Distributor following energization

To assist the Customer in providing the required information, a submission summary sheet is provided as an attachment to this document.

Step 5 – Preliminary Economic Evaluation
Upon receipt of the required information from the Customer, if an expansion of the distribution system is required, the Distributor will perform a preliminary Economic Evaluation following the process as required in the Distribution System Code.
The Preliminary Economic Evaluation will assist the Distributor in calculating what (if any) portion of the Capital Costs the LDC will invest and will be used in the preparation of the Offer to Connect.

Step 6 – Offer to Connect
Using the information provided by the Customer, and following the completion of the Preliminary Economic Evaluation, the Distributor will prepare an "Offer to Connect". The Offer to Connect will contain the following information:

- A statement as to whether the offer is a firm offer or an estimate to be revised after the actual costs are known
- The amount of Capital Contribution that will be required from the Customer
- The amount of the Expansion Deposit that will be required from the Customer
- A description of the costs related to the Capital Contribution
- The costs for inspections
- A description of the deliverables required from the Customer before Connection
- An estimated Connection Date

Step 7 – Customer Decision
Customer Reviews Offer to Connect and decides if they would like to continue with the project as planned. Three options are available to the Customer:

- Customer elects to drop the project a notice of withdrawal of the Request for Connection shall be provided to the Distributor.
- Customer would like to revise their Connection request, a notice informing the Distributor of the requested changes shall be provided to the Distributor (go back to Step 4)
- Customer agrees with the Offer to Connect,

Step 8 – Construction Agreement

Once the Customer accepts the Distributor's Offer to Connect, the parties shall enter into an agreement covering the construction and connection requirements and responsibilities.
The Customer and the Distributor sign the agreement and the Customer provides the financial deposits and/or guarantees as required.

Step 9 – Construction

Following receipt of signed Construction Agreement and required financial deposits and/or guarantees from the Customer, both parties shall begin ordering materials and begin construction.

Step 10 – Connection Authorization

Once construction is completed, both parties will ensure that inspections are completed and all required connection authorizations are in place. After receipt of a signed connection agreement and any additional financial contributions, the Distributor will authorize and connect the facility. If the customer is coordinating the work on the expansion facilities within the development, the customer is also required to provide "As-Built" drawings and a detailed material listing to ensure the Distributor has sufficient information in hand to verify system security prior to energization.

Step 11 – Exchange Updated Information

The Customer and the Distributor shall exchange any required updated information on the project including, but not limited to:

- All applicable Connection Authorizations
- All applicable Warranties
- Any new information that was provided as an estimate in Step 4
- Actual costs of any "capital works" related to the expansion facilities within the development
- Detailed site plan with appropriate Municipal Address information for individual services

Step 12 –Updated Economic Evaluation

As required, the Distributor shall recalculate the Preliminary Economic Evaluation using actual information acquired during and following the construction process.

If the development includes estimated connections that are not energized at the time of the initial Connection, the Distributor shall re-run the Economic Evaluation on an annual basis using actual customer connection information during the five (5) year connection horizon used in the initial Economic Evaluation.

Request for Connection

Development Name:	
Site Plan Identification	

Contact Information:

Contact Name:	
Street:	
Town:	
Postal Code:	

Requested Connection Date:	

Multi-Phase Development?	Y / N
If YES - Identify Phase	

Type & Number of Connections:

		Average Monthly Consumption Per Unit - Winter	Per Unit - Summer
Residential:		Kwh's	Kwh's
Commercial:		Kwh's	Kwh's
Industrial:		Kwh's	Kwh's

Residential Dwelling Design:

Town Homes	
Semi-Detached	
< 1,500 SqFt Single Dwellings	
>1,500 <3,500 SqFt Single Dwellings	
> 3,500 SqFt Single Dwellings	

Connection Horizon

Year 1		
Year 2	Estimated connections in 1st year	
Year 3	Estimated connections in 2nd year	
Year 4	Estimated connections in 3rd year	
Year 5	Estimated connections in 4th year	
	Estimated connections in 5th year	

Capital Costs:

Distribution Infrastructure:	
Transformers:	
Ducts & Structures:	

Date: Submitted:	
Submitted By:	
Signature:	

Electrical Planning Requirements

It is essential that the following information be provided to:

a) enable an assessment to be made on the impact of the proposed project on the Electrical Distribution System.

b) enable the Distributor to prepare pertinent information for the developer.

Please supply answers to the following questions as soon as possible as electrical planning cannot proceed until the Distributor has reviewed this information.

Preliminary electrical site plan drawings are to be submitted together with this form. Electrical drawings are to be submitted to the Distributor for approval prior to any related job tenders or the commencement of any electrical construction. The drawings shall be drawn to a scale usable by the Distributor, shall show local pole locations, proposed transformer location, proposed electrical room/metering location and show how access to the metering would be gained (i.e.: the path to the metering).

Electrical site plan drawings are to be submitted to the Distributor on one (1) Paper copy and in an electronic format as approved by the Distributor.

Project Location: **(Municipal Address)** ____________________

Name of Project: ____________________

Name of Applicant: ____________________

Address: ____________________

Contact Name: ____________________

Address: ____________________

E-Mail: ____________________

Telephone: ( ) ____________________ **Fax:** ( ) ____________________

Service Classification (☒ as many as apply):

- ☐ Residential
- ☐ General Service < 50kW
- ☐ General Service > 50kW
- ☐ General Service >500kW
- ☐ Unmetered os Miscellaneous Load
- ☐ Temporary Service

Service Entrance Switchboard with Utility CT and PT Compartment ☐ Yes ☐ No

Capacity of Main Service (in Amperes):

Maximum rated capacity: ____________

Estimated Connected Load - Demand in kW:

Maximum initial Demand: ___________ kW

Maximum Future Demand: ___________ kW

What service voltage is required (☒ one only):

- ☐ 120/240 Volt Single Phase
- ☐ 120/208 Volt Three Phase
- ☐ 347/600 Volt Three Phase
- ☐ Primary

Metering Type (☒ one only):

- ☐ Single Meter
- ☐ Multiple Meters

Quantity of Meter installations

100A or less: _________

101A to 200A: _________

more than 200A: _________

Required In-Service Date:

Month / Day / Year ______/_______/_________

Comments: **Please use the back of this form for comments**

Signed: ____________________ **Date:** ____________________

(Representative of Applicant)

Name: ____________________ **Title:** ____________________

____

Electric Service Meter Base With Municipal Address Verification Form

LOCAL DISTRIBUTION COMPANY NAME: ______________________________ (UTILITY)

This form **must** be completed by a Licensed Electrical Contractor or their legal representative prior to service connection. Accurate information must be provided or service will not be activated. ***(Sections A & B must be fully completed.)***

Electric Service Municipal Address: (Print) ______________________________
Name of Owner: ______________________________
Telephone: (________) ______________________ Fax: (________)______________________
Name of Electrical Contractor: ______________________________
Telephone: (________) ______________________ Fax: (________)______________________

In area (A) provided below, a 'front-view' layout of the Electric Meter Base(s) is shown including an assigned number for each base. Provide Municipal Address (B) information for each corresponding meter base number for billing purposes.

(A) FRONT VIEW OF ELECTRIC METER BASE(S)	(B) MUNICIPAL ADDRESS (Print)
	1)
	2)
	3)
	4)
	5)
	6)
	7)
	8)

The following regulations are agreed upon by the undersigned with receipt of the completed form by an authorized representative of the Utility: *(A copy of the utility authorized form will be provided for your records.)*

1. That all information contained on this form is accurate.
2. That if any information is determined to be inaccurate, the Utility will not be able to energize the service connection(s).
3. That if any information has to be corrected by Utility personnel there will be applicable charges to prepare an amended form.
4. That an amended form must be signed and returned along with payment of any applicable invoice, as per Part 3, prior to further consideration as to the activation of the service connection.
5. **The Electrical Contractor completes Section (C) below to apply for service activation. A property owner MAY complete Section (D) rather than the contractor, to apply for service activation.**

(C) The undersigned acknowledges agreement to all terms and conditions contained on this form.
(Please print names in full)

Company Name:

Representative:

Title/Position: Date: (m / d / y)

Signature ______________________________

(D) OPTIONAL if section (C) has been completed. The undersigned acknowledges agreement to all terms and conditions contained on this form.

Owner Name: *(Please print)*

Signature: ______________________________ Date: (m / d / y)

For COLLUS Power office use only:

Received : ______________________ Date ___/___/___ Approved: ______________________
(Authorized Rep's Name) (m / d / y) (Rep's Signature)

______________________________ ______________________________
(Address) (Telephone #)

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COLLUS POWER CORP.

FINANCIAL STATEMENTS
DECEMBER 31, 2007

CONTENTS

GAVILLER & COMPANY LLP
CHARTERED ACCOUNTANTS

AUDITORS' REPORT

To the Shareholder of **COLLUS Power Corp.**:

We have audited the balance sheet of **COLLUS Power Corp.** as at December 31, 2007, and the statements of operations and retained income and cash flows for the year then ended. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

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

In our opinion, these financial statements present fairly, in all material respects, the financial position of COLLUS Power Corp. 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.

Gaviller & Company LLP
Licensed Public Accountants
Collingwood, Ontario
March 3, 2008

COLLUS POWER CORP.

BALANCE SHEET
AS AT DECEMBER 31

	2007	2006
	$	$
Assets		
Current		
Cash	**3,640,113**	5,272,508
Accounts receivable (Note 6)	**5,278,910**	3,934,210
Unbilled revenue	**3,329,616**	2,819,474
Inventory	**282,493**	245,218
	12,531,132	12,271,410
Capital		
Lands	**90,439**	90,439
Buildings	**80,668**	80,668
Distribution stations	**3,126,647**	2,051,269
Distribution lines	**16,259,805**	15,441,219
Distribution transformers	**4,067,170**	3,751,092
Distribution meters	**1,377,576**	1,343,478
Other capital assets	**1,539,550**	1,423,450
Load control (customer premises)	**878,887**	878,887
Load management control	**470,252**	406,595
Contributions in aid of construction (Note 2)	**(6,129,230)**	(5,648,240)
	21,761,764	19,818,857
Less accumulated depreciation	**(11,754,666)**	(10,943,323)
	10,007,098	8,875,534
Goodwill	**276,704**	276,704
Future taxes recoverable	**90,000**	26,000
	22,904,934	21,449,648

Approved by directors:

________________________________ Director

________________________________ Director

See accompanying notes to the financial statements

COLLUS POWER CORP.

BALANCE SHEET
AS AT DECEMBER 31

	2007	2006
	$	$ Restated (Note 4)
Liabilities		
Current		
Accounts payable and accruals (Notes 2, 3, 4 and 6)	**7,137,880**	6,909,238
Taxes payable	**20,222**	136,411
Customer deposits	**358,776**	332,398
Current portion of long-term	**1,441,597**	1,780,805
	8,958,475	9,158,852
Long-term (Note 5)	**1,710,170**	1,710,170
Employee future benefits (Note 11)	**211,109**	232,955
Other (Note 3 and 4)	**2,370,472**	1,249,036
Total liabilities	**13,250,226**	12,351,013
Shareholder's equity		
Capital stock		
Authorized		
Unlimited common shares		
Issued		
5,101,340 common shares	**5,101,340**	5,101,340
Miscellaneous paid in capital	**2,966,014**	2,966,014
Retained income	**1,587,354**	1,031,281
Total shareholder's equity	**9,654,708**	9,098,635
	22,904,934	21,449,648

See accompanying notes to the financial statements

COLLUS POWER CORP.

STATEMENT OF OPERATIONS AND RETAINED INCOME
FOR THE YEAR ENDING DECEMBER 31

	2007	2006
	$	$
Revenue		
Sale of power	**23,678,032**	23,554,168
Distribution services	**4,656,270**	4,447,191
	28,334,302	28,001,359
Cost of power		
Power purchased	**23,678,032**	23,554,168
Distribution income (16.4%, 2006 - 15.9%)	**4,656,270**	4,447,191
Other revenue	**573,530**	488,279
	5,229,800	4,935,470
Operating and maintenance expenses		
Distribution and transmission	**1,537,496**	1,521,568
Billing and collecting	**655,645**	592,333
General administration (Notes 5 and 6)	**1,438,190**	1,379,817
Depreciation and amortization	**782,359**	767,646
	4,413,690	4,261,364
Net income before taxes	**816,110**	674,106
Provision for (recovery of) taxes		
Current	**324,037**	274,436
Future	**(64,000)**	(51,000)
	260,037	223,436
Net income for the year	**556,073**	450,670
Retained income, beginning of year	**1,031,281**	580,611
Retained income, end of year	**1,587,354**	1,031,281

See accompanying notes to the financial statements

COLLUS POWER CORP.

STATEMENT OF CASH FLOW
FOR THE YEAR ENDING DECEMBER 31

	2007	2006
	$	$ Restated (Note 4)
Cash flows from (for):		
Operating activities		
Net income	**556,073**	450,670
Items not requiring funds		
Depreciation	**811,043**	811,895
Amortization of deferred charges	**8,155**	8,155
Future taxes	**(64,000)**	(51,000)
	1,311,271	1,219,720
Changes in		
Accounts receivable	**(1,344,700)**	(2,160,086)
Unbilled revenue	**(510,142)**	831,551
Inventory	**(37,275)**	(29,687)
Accounts payable and accruals	**228,642**	1,352,984
Taxes payable	**(116,189)**	111,643
Customer deposits	**26,378**	(23,572)
Employee future benefits	**(21,846)**	64,716
Other liabilities	**1,113,281**	554,635
	649,420	1,921,904
Investing activities		
Net additions to capital assets	**(2,423,597)**	(904,082)
Financing activities		
Repayment of long-term liabilities	**(339,208)**	(319,071)
Contributions in aid of construction	**480,990**	354,422
	141,782	35,351
Change in cash	**(1,632,395)**	1,053,173
Cash position, beginning of year	**5,272,508**	4,219,335
Cash position, end of year	**3,640,113**	5,272,508

See accompanying notes to the financial statements

NOTES TO THE FINANCIAL STATEMENTS
AS AT DECEMBER 31, 2007

1. Significant accounting policies

The financial statements of the corporation are the representations of management. Since precise determination of many assets and liabilities is dependent upon future events, the preparation of periodic financial statements necessarily involves the use of estimates and approximations. These have been made using careful judgment based on available information. The most significant estimates are included in unbilled revenue and economic evaluations. The financial statements have, in the opinion of management, been properly prepared within the framework of the accounting policies summarized below:

(a) The financial statements are prepared in accordance with the Ontario Energy Board (OEB) Accounting Procedures Handbook and directives.

(b) The company's distribution of electricity is subject to rate regulation by the OEB. This rate regulation results in the company accounting for specific transactions differently than it would if it was not rate-regulated. The differences in accounting treatment give rise to regulatory assets or liabilities. These balances will be recovered from or returned to customers by increases or decreases to rates in the future.

The electricity rates charged by the company are approved on an annual basis using performance-based regulation. For the rate year ending April 30, 2007, the company was authorized to earn 9% on equity and 6.25% on debt with a deemed debt to equity ratio of 1:0.89.

(c) The company recognizes revenue on an accrual basis, which includes unbilled revenue, which is an estimate of electricity consumed by customers to the end of year but not yet billed by the company.

(d) Purchases of wire and poles are normally carried as inventory, unless purchased for specific capital projects in process or as spare units. Items for specific capital projects, spare transformers and meters are recorded as capital assets. Inventory is stated at moving average cost.

(e) Capital assets are stated at cost. Contributions received in aid of construction of capital assets are capitalized and amortized at the same rate as the related asset. Capital assets are depreciated over their estimated useful lives, using the straight-line method. Assets constructed by others and donated to the company are recorded at cost to the developer. Depreciation rates are 4% except as follows:

Buildings	2%
Distribution stations	3.33%
Other capital assets	6.67% to 20%

(f) Deferred charges - service area expansion costs are being amortized on a straight-line basis over twenty-five years.

(g) Economic evaluation is an estimate of amounts due to subdivision developers in the future as repayment for the developers installation of hydro infrastructure.

.(h) The purchased power cost variance represent variances in the purchase and sale of electricity which will be recovered from or returned to customers by increases or decreases to rates in the future. Purchased power cost variance includes annual carrying charges accrued at the OEB quarterly interest rate in effect.

NOTES TO THE FINANCIAL STATEMENTS
AS AT DECEMBER 31, 2007

1. Significant accounting policies (continued)

(i) Taxes are calculated using the liability method of tax allocation accounting. Temporary differences arising from the difference between the tax basis of an asset or liability and its carrying amount on the balance sheet are used to calculate future tax liabilities or assets. Future tax liabilities or assets are calculated using tax rates anticipated to apply in the periods that the temporary differences are expected to reverse.

2. Contributions in aid of construction

Under the terms of the Distribution System Code, the corporation cannot charge a developer more than the difference between the present value of the projected capital costs and on-going maintenance costs for the equipment and the present value of the projected revenue for distribution services provided by those facilities. These amounts are determined by an economic evaluation study of the project. The corporation estimates that it will return $372,435 (2006 - $72,435) of the amounts collected. The liability is included in accounts payable. The balance of $6,129,230 (2006 - $5,648,240) is recorded as a reduction of the cost of capital assets.

NOTES TO THE FINANCIAL STATEMENTS
AS AT DECEMBER 31, 2007

3. Other assets (liabilities)

Other assets (liabilities) consist of the following:

	2007	2006
	$	$ Restated (Note 4)
Deferred charges-service area expansion (net of $74,434 accumulated amortization, 2006 - $66,279)	**130,480**	138,635
Regulatory assets		
Other regulatory assets	**89,521**	88,686
Regulatory liabilities		
Hydro One regulatory liability	**(80,711)**	(186,575)
Purchased power cost variance	**(2,245,724)**	(1,264,036)
Regulatory recoveries	**(114,357)**	(2,524)
Smart meter variance	**(16,348)**	(23,222)
Other regulatory liabilities	**(133,333)**	-
Total regulatory liabilities	**(2,590,473)**	(1,476,357)
Net liability	**(2,370,472)**	(1,249,036)

Other regulatory assets consist of the costs of processing $75 rebate cheques and pension costs from OMERS not recovered in rates. The pension cost deferral includes annual carrying charges accrued at the OEB quarterly interest rate in effect.

Hydro One regulatory liability represents 2002-2006 regulatory assets that Hydro One is collecting from embedded distributors over a 5 year period as authorized by the OEB. The current portion of the liability is $105,864 (2006 - $198,458) and is included in accounts payable and accruals. Payments to Hydro One are $9,666 per month for 3 years starting May 2005 and at $5,600 a month for 4 years starting in May 2006.

Purchased power cost variance includes the variances, including carrying costs accrued at the OEB quarterly rate in effect, that have occurred since the 2006 authorized recovery referred to in the following paragraph.

The OEB has authorized the recovery of regulatory asset or liability balances including the power purchase cost variance, qualifying transition factors and the pre-market opening energy variance which are accumulated in the regulatory recovery account.

The OEB, commencing in May 2006, authorized the collection of $.26 per residential customer per month towards the recovery of Smart Meter costs. Carrying charges are accrued on this account for 2007 and later years at the OEB quarterly interest rate in effect.

The OEB has allowed the company to recover the third tranche of its market adjusted revenue requirement (MARR) from customers with the requirement that it be spent on conservation and demand management activities. During the year the company recovered $NIL (2006 - $62,670) of MARR from customers and expended $71,280 (2006 - $100,646) in conservation and demand management activities. The balance of $81,654 (2006 - $152,934) will be spent on conservation and demand management activities in 2008.

Other regulatory liabilities consist of 2006 Tier II rate rider variances. The other regulatory liabilities include annual carrying charges accrued at the OEB quarterly interest rate in effect.

4. Prior period adjustment

The 2006 Purchased power cost variance (a component part of other liabilities) and accounts payable balances have been restated to adjust for an error in the calculation of the Independent Electricity System Operator's 2006 power invoices for Regulated Price Plan variance reimbursement as follows:

	Originally Stated	Restated	Change
	$	$	$
Other Liabilities	2,038,484	1,249,036	(789,448)
Accounts Payable	6,119,790	6,909,238	789,448

5. Long-term liabilities

Long-term liabilities consist of the following:

	2007	2006
	$	$
5.47% demand installment loan payable to the CIBC, repayable in monthly blended payments of $32,854, due January 2009, secured by a general security agreement and guaranteed by Collingwood Utility Services Corp.	**1,441,597**	1,748,805
9.75% debenture payable, due 2007	**-**	32,000
7.25% note payable to the Town of Collingwood, no set terms of repayment	**1,710,170**	1,710,170
	3,151,767	3,490,975
Current portion	**(1,441,597)**	(1,780,805)
	1,710,170	1,710,170

NOTES TO THE FINANCIAL STATEMENTS
AS AT DECEMBER 31, 2007

As the CIBC loan above is a demand loan the full amount is included in the portion due within one year. However there has been no demand for payment and the schedule below depicts the actual repayment terms negotiated by the company.

Principal payments in the next two years are as follows:

	$
2008	324,244
2009	1,117,352

Included in general administration expense is $211,925 (2006 - $221,858) of interest on long-term liabilities.

The corporation is contingently liable for a letter of credit in the amount of $1,631,702 (2006 - $2,272,370) to meet the prudential requirements of the Independent Electricity System Operator.

6. Related party transactions

Collingwood Public Utilities Service Board, COLLUS Solutions Corp., and the company are controlled by the council of the Town of Collingwood.

Related party transactions consist of the following:

	2007	2006
	$	$
Amounts payable to the Collingwood Public Utilities Service Board	**446,317**	842,040
Amounts receivable from COLLUS Solutions Corp.	**-**	219,512
Amounts payable to COLLUS Solutions Corp.	**13,942**	-
Amounts receivable from the Town of Collingwood	**1,250,369**	113,193
The company is leasing its operations centre from the Collingwood Public Utilities Service Board. The lease has a one year term and is renewable annually. These costs are included in general administration expense.	**150,000**	143,000
Operating and maintenance expenses include services purchased from COLLUS Solutions Corp.	**1,045,937**	967,635

7. Contingencies

A class 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 municipal electric utilities (LDCs) who received late payment penalties which constitute interest at 60% per year, contrary to section 347 of the Criminal Code. Pleadings have closed in this action. The action has not yet been certified as a class action and no discoveries have been held, as the parties were awaiting the outcome of a similar proceedings brought against Enbridge Gas Distribution Inc. (formerly Consumers Gas).

On April 22, 2004, the Supreme Court of Canada released a decision in the Consumers Gas case rejecting all of the defences which had been raised by Enbridge, although the court did not permit the plaintiff class to recover damages for any period prior to the issuance of the Statement of Claim in 1994 challenging the validity of late payment penalties. The Supreme Court remitted the matter back to the Ontario Supreme 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 and that settlement was approved by the Ontario Superior Court.

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.

COLLUS Power Corp. (formerly a department of Collingwood Public Utilities Commission) collected total late payment penalties of approximately $666,000 from and after 1994. No determination of the portion of these payments which may have constituted interest at an impermissible rate has been made.

8. Financial instruments

The company's financial instruments consist of cash, accounts receivable, unbilled revenue, accounts payable, customer deposits, and long-term liabilities. It is management's opinion that the company is not exposed to significant interest, currency or credit risks arising from these financial instruments. Fair value does not vary significantly from recorded value.

9. Supplemental cash flow information

Cash receipts and (payments) were made as follows:

	2007	2006
	$	$
Interest paid	**(211,925)**	(221,858)
Interest received	**247,182**	206,535
Taxes paid	**(448,482)**	(166,115)

10. Tax status

The company is exempt from income tax under section 149 of the Income Tax Act. The company is required to make payments in lieu of taxes calculated on the same basis as the Income Tax Act.

NOTES TO THE FINANCIAL STATEMENTS
AS AT DECEMBER 31, 2007

11. Employee future benefits

The employees of COLLUS Power Corp. participate in the Ontario Municipal Employees Retirement System ("OMERS"). Although the plan has a defined retirement benefit for employees, the related obligation of the corporation cannot be identified. The OMERS plan has several unrelated participating municipalities and costs are not specifically attributed to each participant. Amounts paid to OMERS during the year totaled $42,058 (2006 - $37,373).

In addition, COLLUS Power Corp. pays certain benefits on behalf of its retired employees. The corporation recognizes these post-retirement costs in the period in which the employees rendered the services. The accrued benefit obligation at December 31, 2007 of $211,109 and the net periodic benefit cost for 2007 was determined by actuarial valuation using discount rates of 5.0%. Actuarial valuations will be prepared every third year or when there are significant changes to the workforce.

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

	2007	2006
	$	$
Accrued benefit obligation		
Balance at the beginning of period	**232,955**	169,343
Current service cost for the period	**6,304**	53,809
Interest cost for the period	**13,540**	12,977
Actuarial loss	**17,571**	17,571
Prior period cost	**18,128**	22,660
Benefits paid for the period	**(8,325)**	(7,706)
Projected accrued benefit obligation at end of period as determined by actuarial valuation.	**280,173**	268,654
Unamortized actuarial loss	**(55,468)**	(17,571)
Unamortized prior service cost	**(13,596)**	(18,128)
Balance at end of period	**211,109**	232,955
Components of net periodic benefit cost		
Current service cost (recovery) for the period	**6,303**	53,809
Interest cost for the period	**13,540**	12,977
Amortization of actuarial losses	**4,955**	-
Amortization of prior service cost	**4,532**	4,532
Net periodic benefit cost	**29,330**	71,318

11. Employee future benefits (continued)

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 2007 and thereafter.

(b) Interest (discount) rate

The obligation as at December 31, 2007, of the present value of future liabilities was determined using a discount rate of 5.0%. This corresponds to the assumed CPI rate plus an assumed real rate of return of 2.9%.

(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 10.0% in 2007 graded down 1.0% a year until 2011 after which the rate is assumed to increase 5.0% annually.

(e) Dental costs

Dental costs were assumed to increase at 5.0% in 2006 and thereafter.

Ontario

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

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

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

Ministry Use

COPY

Corporation's Legal Name *(including punctuation)* COLLUS Power Corp.	Ontario Corporations Tax Account No. (MOF) 1800071
Mailing address 43 Stewart Road City: Collingwood · Province: ON · Country: CA · Postal code: L9Y 3Z5	This Return covers the Taxation Year Start: 2007/01/01 End: 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 2000/04/13
Registered/Head Office Address 43 Stewart Road City: Collingwood · Province: ON · Country: · Postal code: L9Y 3Z5	Ontario Corporation No. (MGS): 1402919
Location of Books and Records 43 Stewart Road City: Collingwood · Province: ON · Country: · Postal code: L9Y 3Z5	Canada Revenue Agency Business No. 866168834RC0001
Name of person to contact regarding this CT23 Return: Timothy Fryer · Telephone No.: (705) 445-1800 · Fax No.: ( ) -	Jurisdiction Incorporated: ONTARIO
Address of Principal Office in Ontario (*Extra-Provincial Corporations only*) (MGS) City · Province · Country · Postal code	If not incorporated in Ontario, indicate the date Ontario business activity commenced and ceased: Commenced: Ceased:
Former Corporation Name (*Extra-Provincial Corporations only*) ☐ *Not Applicable* (MGS)	☒ *Not Applicable*
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): 0 If there is no change to the Directors'/Officers'/Administrators' information previously submitted to MGS, please check ☑ this box. Schedule(s) A and K are not required (MGS). ▶ ☒ No Change	Preferred Language / *Langue de préférence* ☒ 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
Timothy Fryer

Title: D ☐ Director · O ☒ Officer · P ☐ Other individuals having knowledge of the Corporation's business activities

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

Taxation Year End

Exempt From Filing (EFF) Corporations Tax Return Declaration

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)

This EFF Declaration must be filed for each taxation year that the corporation is exempt from filing and must be filed within 6 months after the corporation's taxation year end.

Criteria for exempt from filing status:

a) has filed a federal Income Tax Return (T2) with Canada Revenue Agency for the taxation year;
b) had no Ontario taxable income for the taxation year (subject to the provisions in Note 2 below);
c) had no Ontario Corporations Tax payable for the taxation year;
d) was a Canadian-controlled private corporation throughout the taxation year (i.e. generally a private corporation with 50% or more shares owned by Canadian residents as defined by the *Income Tax Act* (Canada));
e) has provided its Canada Revenue Agency business number to the Ministry of Revenue; and
f) is **not** subject to the Corporate Minimum Tax (i.e. alone or as part of an associated group whose total assets exceed $5 million or whose total revenue exceeds $10 million for the taxation year).

Note 1: Filing of this declaration and the Annual Return does not constitute the filing of a Corporations Tax Return under section 75 of the *Corporations Tax Act*.

Note 2: The following loss situations will require otherwise EFF corporations to file a CT23 tax return complete with all related schedules and financial statements:

- If a corporation has a loss in the current taxation year that is to be carried back and applied to a previous taxation year(s), regardless of whether the loss is the same as for federal purposes or not, a CT23 tax return is required for the current taxation year. The corporation must also provide information indicating that the loss is to be carried back and specify the year and the amount of loss to be carried back to each taxation year.
- If a corporation has a prior year loss, that is not the same for both federal and Ontario purposes and the corporation is applying a loss carryforward from the prior year to the current year, a CT23 tax return is required for the current taxation year, and if not previously filed, a CT23 tax return for the prior taxation year in which the loss was incurred is also required. Although a tax return for the loss year is not required where the loss is not being applied, the ministry will accept the filing of a tax return for a loss year at the time the loss is incurred.
- If a corporation has a prior year loss, that is the same for both federal and Ontario purposes, but in the current taxation year the corporation is applying a different amount of loss for Ontario than the loss amount being applied for federal income tax purposes, the corporation is required to file a CT23 tax return for the current taxation year only.

The following 3 items MUST be completed for EFF declarations only. In cases where the Annual Return, which includes page 1, is also being filed, completion of these fields is not required.

1. Corporation's Mailing Address

City Province Country Postal code

2. Ontario Corporation No. (MGS)

3. Canada Revenue Agency Business No. RC

I, ______________________________ declare that:

The above corporation meets all of the exempt from filing criteria (a) through (f) above for the taxation year and therefore qualifies under the *Corporations Tax Act* as exempt from filing an Ontario Corporations Tax Return.

Signature	Title/Relationship to Corporation	Telephone number ( ) -	Date

Please note that making a false statement to avoid compliance with the *Corporations Tax Act* is an offence which can result in a penalty and/or fine.

If you check "Yes" to ALL of the following criteria, you are eligible to file the CT23 Short-Form Corporations Tax Return. To obtain a copy, contact the Ministry Information Centre at the numbers listed on page 2 of the Guide.

Yes	No	
X		(a) The corporation is a Canadian-controlled private corporation (CCPC) throughout the taxation year. Indicate Share Capital with full voting rights owned by Canadian Residents (nearest whole percentage) 0 %
	X	(b) The corporation's taxable income for the taxation year is $200,000 or less. For a taxation year with less than 51 weeks, taxable income must be grossed-up. (*Refer to Guide.*)
	X	(c) The corporation is not a member of a partnership/joint venture or a member of an associated group of corporations during the taxation year.
	X	(d) The corporation's taxation year ends on or after January 1, 2001, and its gross revenue and total assets are each $1,500,000 or less and the corporation is not a financial institution; or The corporation's taxation year commences after September 30, 2001, and its gross revenue and total assets are each $3,000,000 or less and the corporation is not a financial institution.
	X	(e) The corporation is **not** claiming a tax credit other than the Incentive Deduction for Small Business Corporations (IDSBC), Co-operative Education Tax Credit (CETC), Graduate Transitions Tax Credit (GTTC) or Apprenticeship Training Tax Credit (ATTC).
X		(f) The corporation's Ontario allocation factor is 100%.

Note: Family Farm or Fishing corporations that have a taxation year ending on or after January 1, 2000 and are **not** subject to the Corporate Minimum Tax, may also use the **CT23 Short-Form Corporations Tax Return** if the corporation checks "Yes" to a), b), c), e) and f) above.

CT23 Corporations Tax Return

Identification continued (for CT23 filers only)

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

Type of Corporation

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

Share Capital with full voting rights owned by Canadian Residents (nearest percent) 0 %

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

- [ ] This is the first year filing after incorporation or an amalgamation (If checked, attach Ontario Schedule 24.)
- [ ] Amended Return
- [ ] Taxation year end change - Canada Revenue Agency approval required
- [ ] Final taxation year up to dissolution (*Note: for discontinued businesses, see guide.*)
- [ ] Final taxation year before amalgamation
- [ ] The corporation has a floating fiscal year end
- [ ] There has been a transfer or receipt of asset(s) involving a corporation having a Canadian permanent establishment outside Ontario
- [ ] There was an acquisition of control to which subsection 249(4) of the federal *Income Tax Act* (ITA) applies since the previous taxation year
  If checked, date control was acquired ______
- [ ] 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).

Net income (loss) for Ontario purposes (per reconciliation schedule, page 15)	From 690 ±	951,898
Subtract: Charitable donations	1 -	
Subtract: Gifts to Her Majesty in right of Canada or a province and gifts of cultural property *(Attach schedule 2)*	2 -	
Subtract: Taxable dividends deductible, per federal Schedule 3	3 -	
Subtract: Ontario political contributions *(Attach schedule* 2A) (Int.B. 3002R)	4	
Subtract: Federal Part VI.1 tax ______ X 3	5 -	
Subtract: Prior years' losses applied - Non-capital losses	From 704	
Net capital losses (page 16) From 715 ______ X inclusion rate 50.000000 % =	714	
Farm losses	From 724 -	
Restricted farm losses	From 734 -	
Limited partnership losses	From 754 -	
Taxable income (Non-capital loss)	10 =	951,898
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 =	951,898

Taxable Income — **Number of days in Taxation Year**

From 10 (or 20)	951,898 X30 100.0000 % (Ontario Allocation)	X 12.5% X 33	Days after Dec. 31, 2002 and before Jan. 1, 2004:	÷ 73 Total Days: 365 =	29 +	
From 10 (or 20)	951,898 X30 100.0000 % (Ontario Allocation)	X 14.0% X 34	Days after Dec. 31, 2003: 365	÷ 73 Total Days: 365 =	32 +	133,266
Income Tax Payable (before deduction of tax credits) 29 + 32					40 =	133,266

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? (✓) ☒ Yes ☐ No

* Income from active business carried on in Canada for federal purposes (fed.s.125(1)(a))			50	951,898
Federal taxable income, less adjustment for foreign tax credit (fed.s.125(1)(b))	51 +	951,898		
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 -			
	=	951,898	54	951,898
Federal Business limit (line 410 of the T2 return) for the year before the application of fed.s.125(5.1)	55 +	337,440		

Ontario Business Limit Calculation

320,000 X 31 ______ (Days after Dec. 31, 2002 and before Jan. 1, 2004) ÷ ** 365 = + 46 ______

400,000 X 34 365 (Days after Dec. 31, 2003) ÷ ** 365 = + 47 400,000

Business limit for Ontario purposes 46 + 47 = 44 400,000 X 48 84.3600 % (Percentage of Federal Business limit (from T2 Schedule 23). Enter 100% if not associated.) = 45 337,440

Income eligible for the IDSBC From 30 100.0000 % (***Ontario Allocation) X 56 337,440 (Least of 50, 54 or 45) 60 = 337,440

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

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

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

continued on Page 5

Income Tax *continued from Page 4*

Number of Days in Taxation Year

		Days after Dec. 31, 2002 and before Jan. 1, 2004		Total Days		
Calculation of IDSBC Rate	7.0% X 31		÷ 73	365	= 89 +	
	8.5% X 34	Days after Dec. 31, 2003: 365	÷ 73	Total Days: 365	= 90 +	8.5000
IDSBC Rate for Taxation Year 89 + 90					78 =	8.5000
Claim	From 60	337,440	X From 78	8.5000 %	70 =	28,682

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

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

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

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

* **Taxable Income of the corporation** From 10 (or 20 if applicable) 80 + 951,898

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

Name of associated corporation (Canadian & foreign)	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End		* Taxable Income (if loss, enter nil)
Collus Solutions Corp.	1800072	2007/12/31	+ 82	62,563
Collingwood Utility Services Inc.	1800069	2007/12/31	+ 83	
Collus Energy Corp.	1800070	2007/12/31	+ 84	

Aggregate Taxable Income 80 + 82 + 83 + 84 , etc. 85 = 1,014,461

Number of days in Taxation Year

	Days after Dec. 31, 2002 and before Jan. 1, 2004		Total Days				
320,000 X 31		÷ 73	365	= 115 +			
400,000 X 34	Days after Dec. 31, 2003: 365	÷ 73	Total Days: 365	= 116 +	400,000		
			115 + 116	=	400,000	114 -	400,000
(If negative, enter nil)						86 =	614,461

Number of Days in Taxation Year

		Days after Dec. 31, 2002		Total Days		
Calculation of Specified Rate for Surtax	4.667% X 38	365	÷ 73	365	= 97 +	4.6670
From 86 614,461	X From 97	4.6670 % =			87 =	28,677
From 87 28,677	X From 60	337,440	÷ From 114	400,000	88 =	24,192

Surtax Lesser of 70 or 88 100 = 24,192

* ***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*

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 -	337,440
Add: Adjustment for Surtax on Canadian-controlled private corporations From 100 24,192 ÷ From 30 100.0000 % (*Ontario Allocation) ÷ From 78 8.5000 % = 121 284,612		
Lesser of 56 or 121	122 +	284,612
120 - 56 + 122	130 =	
Taxable income	From 10 +	951,898
Subtract: Income eligible for the Incentive Deduction for Small Business Corporations (IDSBC)	From 56 -	337,440
Add: Adjustments for Surtax on Canadian-controlled private corporations	From 122 +	284,612
Subtract: Taxable income 10 X Allocation % to jurisdictions outside Canada	140	
Subtract: Amount by which Canadian and foreign investment income exceeds net capital losses	141	
10 - 56 + 122 - 140 - 141	142 =	899,070

Claim

Number of Days in Taxation Year

143 ____ (Lesser of 130 or 142)	X From 30 100.0000 % (*Ontario Allocation)	X 1.5% X	33 ____ (Days after Dec. 31, 2002 and before Jan. 1, 2004)	÷ 73 365 (Total Days)	= 154 +
143 ____ (Lesser of 130 or 142)	X From 30 100.0000 % (*Ontario Allocation)	X 2.0% X	34 365 (Days after Dec. 31, 2003)	÷ 73 365 (Total Days)	= 156 +

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

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

Manufacturing and Processing Profits Credit for Electrical Generating Corporations 161 =

Manufacturing and Processing Profits Credit for Corporations that Produce and Sell Steam for uses other than the Generation of Electricity 162 =

Credit for Foreign Taxes Paid (s.40)

Applies if you paid tax to a jurisdiction outside Canada on foreign investment income (Int.B. 3001R). *(Attach schedule)* 170

Credit for Investment in Small Business Development Corporations (SBDC)

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

Eligible Credit 175 ____ Credit Claimed 180

Subtotal of Income Tax 40 - 70 + 100 - 110 - 160 - 161 - 162 - 170 - 180 190 = 128,776

continued on Page 7

Income Tax *continued from Page 6*

Specified Tax Credits *(Refer to Guide)*

Ontario Innovation Tax Credit (OITC) (s.43.3) ***Applies*** to scientific research and experimental development in Ontario.
Eligible Credit from **5620** OITC Claim Form *(Attach original Claim Form)* — 191 +

Co-operative Education Tax Credit (CETC) (s.43.4) ***Applies*** to employment of eligible students.
Eligible Credit from **5798** CT23 Schedule 113 *(Attach Schedule 113)* — 192 +

Ontario Film & Television Tax Credit (OFTTC) (s.43.5)
Applies to qualifying Ontario labour expenditures for eligible Canadian content film and television productions. — 204 Name of Production
Eligible Credit from **5850** of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC) *(Attach the original Certificate of Eligibility)* — 193 +

Graduate Transitions Tax Credit (GTTC) (s.43.6)
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
Eligible Credit from **5898** CT23 Schedule 114 *(Attach Schedule 114)* — 203 +

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

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

Income Tax 190 - 225 OR Enter **NIL** if reporting Non-Capital Loss *(amount cannot be negative)* — 230 = 128,776

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)

Total Assets of the corporation	240 + 20,615,173	
Total Revenue of the corporation		241 + 28,908,247

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 (✓) **242** ☒ (Yes)

Name of associated corporation (Canadian & foreign)	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End		Total Assets		Total Revenue
Collus Solutions Corp.	1800072	2007/12/31	+ 243	602,759	+ 244	1,782,316
Collingwood Utility Services Inc.	1800069	2007/12/31	+ 245		+ 246	
Collus Energy Corp.	1800070	2007/12/31	+ 247	100	+ 248	

Aggregate Total Assets **240 + 243 + 245 + 247** , etc.	249 = 21,218,032	
Aggregate Total Revenue **241 + 244 + 246 + 248**, etc.		250 = 30,690,563

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** 816,113 X From **30** 100.0000 % X 4% **276** = 32,645
If negative, enter zero — Ontario Allocation

Subtract: Foreign Tax Credit for CMT purposes *(Attach schedule)*	277 -	
Subtract: Income Tax	From 190 -	128,776
Net CMT Payable (if negative, enter Nil on page 17.)	280 =	

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

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

If **280** is greater than or equal to zero, transfer **230** to **Page 17** and transfer **280** to **Page 17**, and to **Part 4 of Schedule 101: Continuity of CMT Credit Carryovers.**

CMT Credit Carryover available From Schedule 101 — From **2333**

Application of CMT Credit Carryovers

A.	Income Tax (before deduction of specified credits)			From 190 +	128,776
	Gross CMT Payable	From 276 +	32,645		
	Subtract: Foreign Tax Credit for CMT purposes	From 277 -			
	If **276 - 277** is negative, enter NIL in **290**	=	32,645	290 -	32,645
	Income Tax eligible for CMT Credit			300 =	96,131
B.	Income Tax (after deduction of specified credits)			From 230 +	128,776
	Subtract: CMT credit used to reduce income taxes			310 -	
	Income Tax			320 =	128,776

Transfer to Page 17

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

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

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

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

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

Members of a partnership (limited or general) or a joint venture, must attach all financial statements of each partnership or joint venture of which they are a member. The Paid-up Capital of each corporate partner must include its share of liabilities that would otherwise be included if the partnership were a corporation. If Investment Allowance is claimed, Total Assets must be adjusted by adding the corporation's share of the partnership's Total Assets and by deducting investments in the partnership as it appears on the corporation's balance sheet, in addition to any other required adjustments (s.61(5)). Special rules apply to limited partnerships (Int.B. 3017R).

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

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

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

Paid-up Capital

Paid-up capital stock (Int.B. 3012R and 3015R)	350 +	5,101,340
Retained earnings (if deficit, deduct) (Int.B. 3012R)	351 ±	1,587,361
Capital and other surpluses, excluding appraisal surplus (Int.B. 3012R)	352 +	2,966,014
Loans and advances *(Attach schedule)* (Int.B. 3013R)	353 +	1,710,170
Bank loans (Int.B. 3013R)	354 +	1,441,597
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 +	211,109
Contingent, investment, inventory and similar reserves (Int.B. 3012R)	360 +	
Other reserves not allowed as deductions for income tax purposes *(Attach schedule)* (Int.B. 3012R)	361 +	
Share of partnership(s) or joint venture(s) paid-up capital *(Attach schedule(s))* (Int.B. 3017R)	362 +	
Subtotal	370 =	13,017,591
Subtract: Amounts deducted for income tax purposes in excess of amounts booked *(Retain calculations. Do not submit.)* (Int.B. 3012R)	371 -	(2,067,440)
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 =	15,085,031
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 =	15,085,031

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)

Total Assets per balance sheet	420 +	20,615,173
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 =	20,615,173
Amounts in **360** and **361** (if deducted from assets)	440 +	
Subtract: Amounts in **371**, **372** and **381**	441 -	(2,067,440)
Subtract: Appraisal surplus if booked	442 -	
Add or Subtract: Other adjustments (specify on an attached schedule)	443 ±	
Total Assets	450 =	22,682,613

Investment Allowance (410 ÷ 450) X 390	Not to exceed 410	460 =	
Taxable Capital 390 - 460		470 =	15,085,031

Gross Revenue (as adjusted to include the share of any partnership(s)/joint venture(s) Gross Revenue)

Gross Revenue of the corporation	28,908,247		
Corporation's Share of partnership(s)/joint venture(s) Gross Revenue *(Attach schedule)*			
Aggregate of Gross Revenue	28,908,247	480	28,908,247
Total Assets (as adjusted)		From 430	20,615,173

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**

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

		Days			Total Days		
0.3 % X	556	Days before Jan. 1, 2007	÷	73	365	= 511	%
0.285 % X	557	Days after Dec. 31, 2006 and before Jan. 1, 2009: 365	÷	73	365	= 512	0.2850 %
Capital Tax Rate		511 + 512				= 516	0.2850 %

continued on Page 11

Capital Tax Calculation *continued from Page 10*

SECTION C

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

C1. If **430** and **480** on page 10 are both $3,000,000 or less, enter NIL **in 550** on page 12 and complete the return from that point.

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

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

+ From **470** ________
- From **503** ________

= **471** ________ x From **30** 100.0000 % x From **516** 0.2850 % x **555** (Days in taxation year) / 365 = **523**+ ________

Ontario Allocation — Capital Tax Rate — 365 (366 if leap year) *If floating taxation year, refer to Guide.* — *Transfer to **543** on page 12 and complete the return from that point*

SECTION D

This section applies ONLY to a corporation that is a member of an associated group (excluding Financial Institutions and corporations exempt from Capital Tax) and/or partnership. You must check either **509** or **524** and complete this section before you can calculate your Capital Tax calculation under either Section E or Section F.

D1. ☐ **509** (✓ 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** (✓ 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*

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

Taxable Capital from **470** on page 10 — From 470 + 15,085,031

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	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End		Taxable Capital
Collus Solutions Corp.	1800072	2007/12/31	+ 531	383,636
Collingwood Utility Services Inc.	1800069	2007/12/31	+ 532	
Collus Energy Corp.	1800070	2007/12/31	+ 533	

Aggregate Taxable Capital **470 + 531 + 532 + 533**, etc. — 540 = 15,468,667

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 15,085,031 ÷ From **540** 15,468,667 X From **503** 12,500,000 541 = 12,189,989
*Transfer to **542** in Section E below*

Ss.69(2.1) Election Filed

☐ **591** (✓ 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 15,085,031
\- 542 12,189,989
= 471 2,895,042 x From 30 100.0000 % (Ontario Allocation) x From 516 0.2850 % (Capital Tax Rate) x 555 365 (Days in taxation year, *365 (366 if leap year)) = 523 + 8,251 (**Total Capital Tax for the taxation year**)
*Transfer to **543** and complete the return from that point*

SECTION F

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

+From
470 ______ X From 30 100.0000 % (Ontario Allocation) x From 516 0.2850 % (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 ______ X 555 365 (Days in taxation year, *365 (366 if leap year)) = 563 + (**Total Capital tax for the taxation year**)
*Transfer to **543** and complete the return from that point*

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

Capital Tax before application of specified credits — 543 = 8,251
Subtract: Specified Tax Credits applied to reduce capital tax payable *(Refer to Guide)* — 546 -
Capital Tax 543 - 546 *(amount cannot be negative)* — 550 = 8,251
Transfer to Page 17

continued on Page 13

Capital Tax *continued from Page 12*

Calculation of Capital Tax for Financial Institutions

1.1 Credit Unions Only

For taxation years commencing **after May 4, 1999** enter NIL **in 550** on page 12, and complete the return from that point.

1.2 Other than Credit Unions

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

565 ______ x567 0.5700 % x From 30 ______ % x 555 ______ (Days in taxation year) = 569+ ______

Lesser of adjusted Taxable Paid Up Capital and Basic Capital Amount in accordance with Division B.1 | Capital Tax Rate(1) *(Refer to Guide)* | Ontario Allocation | *365 (366 if leap year)

570 ______ x571 ______ % x From 30 ______ % x 555 ______ (Days in taxation year) = 574+ ______

Adjusted Taxable Paid Up Capital in accordance with Division B.1 in excess of Basic Capital Amount | Capital Tax Rate(2) *(Refer to Guide)* | Ontario Allocation | *365 (366 if leap year)

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)? (✓) ☐ 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

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 ±	951,898
				Transfer to Page 15

Add:

Federal capital cost allowance	601 +	671,644		
Federal cumulative eligible capital deduction	602 +	54,524		
Ontario taxable capital gain	603 +			
Federal non-allowable reserves. Balance beginning of year	604 +			
Federal allowable reserves. Balance end of year	605 +	81,654		
Ontario non-allowable reserves. Balance end of year	606 +			
Ontario allowable reserves. Balance beginning of year	607 +	152,934		
Federal exploration expenses (e.g. CEDE, CEE, CDE, COGPE)	608 +			
Federal resource allowance *(Refer to Guide)*	609 +			
Federal depletion allowance	610 +			
Federal foreign exploration and development expenses	611 +			
Crown charges, royalties, rentals, etc. deducted for Federal purposes *(Refer to Guide)*	617 +			
Management fees, rents, royalties and similar payments to non-arms' length non-residents				

Number of Days in Taxation Year

		Days after Dec. 31, 2002 and before Jan. 1, 2004		Total Days	
612	X 5/12.5 X33		÷73	365	= 633 +
		Days after Dec. 31, 2003		Total Days	
612	X 5/14.0 X34	365	÷73	365	= 634 +

Total add-back amount for Management fees, etc. 633 + 634 =	613 +			
Federal Scientific Research Expenses claimed in year from line 460 of fed. form T661 excluding any negative amount in 473 from Ont. CT23 Schedule 161	615 +			
Add any negative amount in 473 from Ont. CT23 Schedule 161	616 +			
Federal allowable business investment loss	620 +			
Total of other items not allowed by Ontario but allowed federally *(Attach schedule)*	614 +			
Total of Additions 601 to 611 + 617 + 613 + 615 + 616 + 620 + 614	=	960,756	640	960,756
				Transfer to Page 15

Deduct:

Ontario capital cost allowance (excludes amounts deducted under 675)	650 +	671,644
Ontario cumulative eligible capital deduction	651 +	54,524
Federal taxable capital gain	652 +	
Ontario non-allowable reserves. Balance beginning of year	653 +	
Ontario allowable reserves. Balance end of year	654 +	81,654
Federal non-allowable reserves. Balance end of year	655 +	
Federal allowable reserves. Balance beginning of year	656 +	152,934
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	960,756
		Transfer to Page 15

continued on Page 15

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 ±	951,898
Total of Additions on page 14	From 640 =	960,756

Sub Total of deductions on page 14 From 681 = 960,756

Deduct:

Ontario New Technology Tax Incentive (ONTTI) Gross-up
(*Applies* only to those corporations whose Ontario allocation is less than 100% in the current taxation year.)

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

ONTTI Gross-up deduction calculation:
From 662 ______ Gross-up of CCA x 100/ 30 From Ontario Allocation 100.0000 - From 662 ______ 663 =

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

Qualifying expenditures: 665 ______ x 30% x 100/ 30 From Ontario Allocation 100.0000 666 =

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

Qualifying expenditures: 667 ______ x 100% x 100/ 30 From Ontario Allocation 100.0000 668 =

Number of Employees accommodated 669

Ontario School Bus Safety Tax Incentive (OSBSTI)
(*Applies* to the eligible acquisition of school buses purchased after May 4, 1999 and before January 1, 2006.) *(Refer to Guide)*

Qualifying expenditures: 670 ______ x 30% x 100/ 30 From Ontario Allocation 100.0000 671 =

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

Qualifying expenditures: 672 ______ x 15% x 100/ 30 From Ontario Allocation 100.0000 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 = 960,756 680 960,756

Net income (loss) for Ontario Purposes 600 + 640 - 680 690 = 951,898

Transfer to Page 4

Continuity of Losses Carried Forward

	Non-Capital Losses (1)	Total Capital Losses	Farm Losses	Restricted Farm Losses	Listed Personal Property Losses	Limited Partnership Losses (6)
Balance at Beginning of Year	700 (2)	710 (2) 10,540	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 Pg 17	716 (2) To Pg 17	726 (2) To Pg 17	736 (2) To Pg 17	746	
Subtotal	707	717	727	737	747	757
Balance at End of Year	709 (8)	719 10,540	729	739	749	759

Analysis of Balance at End of Year by Year of Origin

Year of Origin (oldest year first)	Non-Capital Losses	Non-Capital Losses of Predecessor Corporations	Total Capital Losses from Listed Personal Property only	Farm Losses	Restricted Farm Losses
800 9th preceding taxation year	817 (9)	860 (9)		850	870
801 8th preceding taxation year	818 (9)	861 (9)		851	871
802 7th preceding taxation year 2000/12/31	819 (9)	862 (9)		852	872
803 6th preceding taxation year 2001/12/31	820	830	840	853	873
804 5th preceding taxation year 2002/12/31	821	831	841	854	874
805 4th preceding taxation year 2003/12/31	822	832	842	855	875
806 3rd preceding taxation year 2004/12/31	823	833	843	856	876
807 2nd preceding taxation year 2005/12/31	824	834	844	857	877
808 1st 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.

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

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

- If, after applying a loss carry-back to one or more previous years, there is a balance of loss available to carry forward to a future year, it is the corporation's responsibility to claim such a balance for those years following the year of loss within the limitations of fed.s.111, as made applicable by s.34.
- Where control of a corporation has been acquired by a person or group of persons, certain restrictions apply to the carry-forward and carry-back provisions of losses under fed.s.111(4) through 111(5.5), as made applicable by s.34.
- Refunds arising from the loss carry-back adjustment may be applied by the Minister of Finance to amounts owing under **any Act administered by the Ministry of Finance.**
- Any late filing penalty applicable to the return for which the loss is being applied will not be reduced by the loss carry-back.
- The application of a loss carry-back will be available for interest calculation purposes on the day that is the latest of the following:
  1) the first day of the taxation year after the loss year,
  2) the day on which the corporation's return for the loss year is delivered to the Minister, or
  3) the day on which the Minister receives a request in writing from the corporation to reassess the particular taxation year to take into account the deduction of the loss.
- If a loss is being carried back to a **predecessor corporation**, enter the predecessor corporation's account number and taxation year end in the spaces provided under Application of Losses below.

Application of Losses	Non-Capital Losses	Total Capital Losses	Farm Losses	Restricted Farm Losses
Total amount of loss	910	920	930	940
Deduct: Loss to be carried back to preceding taxation years and applied to reduce taxable income. **Predecessor Corporation's Tax Account No. (MOF)** / **Taxation Year Ending**				
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	+	128,776
Corporate Minimum Tax	From 280	+	
Capital Tax	From 550	+	8,251
Premium Tax	From 590	+	
Total Tax Payable	950	=	137,027
Subtract: Payments	960	-	297,000
Capital Gains Refund (s.48)	965	-	
Qualifying Environmental Trust Tax Credit *(Refer to Guide)*	985	-	
Specified Tax Credits *(Refer to Guide)*	955	-	
Balance	970	=	(159,973)
If payment due Enclosed *	990		
If overpayment: Refund *(Refer to Guide)*	975	=	159,973
Apply to	980		

(Includes credit interest)

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

Certification

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

Name
Timothy Fryer
Title
Treasurer
Full Residence Address
43 Stewart Road
City
Collingwood

Province	Country	Postal Code
ON		L9Y 3Z5

Signature	Date
	2008/04/27

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

OS4
Schedule 4

Ontario loss continuity

Part 1 - Non-capital loss

Determination of current-year non-capital loss

Net income (loss) for Ontario tax purposes		951,898
Deduct: (increase a loss)		
Net capital losses deducted in the year (enter a positive amount)		
Taxable dividends deductible under ITA sections 112, 113 or subsection 138(6)		
Amount of Part VI.1 tax deductible		
Subtotal - if positive, enter "0"		
Deduct: (increase a loss)		
ITA Section 110.5 and/or subparagraph 115(1)(a)(vii) - Addition for foreign tax deductions		
Subtotal		
Add: (decrease a loss) Current-year farm loss		
Current-year non-capital loss (if positive, enter "0")		

Continuity of non-capital losses and request for a carryback

Non-capital loss at end of preceding taxation year		
Deduct: Non-capital loss expired	-	
Non-capital losses at beginning of taxation year	=	
Add: Non-capital losses transferred on an amalgamation or the wind-up of a subsidiary corporation	+	
Current-year non-capital loss (from calculation above)		
Deduct:		
Amount applied against taxable income (enter on line 704 of the CT23)		
Section 80 - adjustments for forgiven amounts		
Other adjustments		
		-
Subtotal		
Deduct - Request to carry back non-capital loss to:		
First preceding taxation year to reduce taxable income		
Second preceding taxation year to reduce taxable income		
Third preceding taxation year to reduce taxable income		-
Non-capital losses - Closing balance		=

Part 2 - Capital losses

Continuity of capital losses and request for a carryback

		Gross amount
Capital losses at end of preceding taxation year	10,540	
Capital losses transferred on an amalgamation or the windup of a subsidiary corporation		10,540
Deduct:		
Other adjustments		
Section 80 adjustments for forgiven amounts		
Subtotal		= 10,540
Add:		
Current-year capital loss		+
Allowable business investment loss expired as a non-capital loss ____ / ____		+
Subtotal		= 10,540
Deduct:		
Amount applied against current year capital gain		-
Subtotal		= 10,540

Deduct - Request to carry back capital loss to:

	Loss applied		Inclusion rate		Total
First preceding taxation year		÷	50.0000 %	=	
Second preceding taxation year		÷	50.0000 %	=	
Third preceding taxation year		÷	50.0000 %	=	
			Subtotal		

	-
Capital losses - Closing balance	= 10,540

OS4
Schedule 4

Ontario loss continuity

Part 3 - Farm loss

Continuity of farm losses and request for a carryback

Farm losses at end of preceding taxation year		
Deduct: Farm loss expired after 10 taxation years	-	
Farm losses at beginning of taxation year	=	
Add: Farm losses transfered on an amalgamation or the windup of a subsidiary corporation	+	
Current-year farm loss	+	
Deduct:		
Amount applied against taxable income (enter on line 724 of the CT23)		
Section 80 - Adjustments for forgiven amounts		
Other adjustments		
		-
Deduct - Request to carry back farm loss to:		
First preceding taxation year to reduce taxable income		
Second preceding taxation year to reduce taxable income		
Third preceding taxation year to reduce taxable income		
		-
Farm losses - Closing balance		=

Part 4 - Restricted farm loss

Current-year restricted farm loss

Total losses for the year from farming business			A
Minus the deductible farm loss:			
$2,500 plus B or C, whichever is less			
(Amount A above – $2,500) divided by 2	B		
Maximum	C 6,250		
Deductible farm loss			-
Current-year restricted farm loss			

Continuity of restricted farm losses and request for a carryback

Restricted farm losses at end of preceding taxation year		
Deduct: Restricted farm loss expired after 10 taxation years	-	
Restricted farm losses at beginning of taxation year	=	
Add: Restricted farm losses transferred on an amalgamation or the windup of a subsidiary corporation	+	
Current-year restricted farm loss		
Deduct:		
Amount applied against taxable income (enter on line 734 of the CT23)		
Section 80 – Adjustments for forgiven amounts		
Other adjustments		
		-
Deduct – Request to carry back restricted farm loss to:		
First preceding taxation year to reduce farming income		
Second preceding taxation year to reduce farming income		
Third preceding taxation year to reduce farming income		
		-
Restricted farm losses - Closing balance		=

OS4
Schedule 4

Ontario loss continuity

Part 5 - Listed personal property loss

Continuity of listed personal property loss and request for a carryback

Listed personal property losses at end of preceding taxation year		
Deduct: Listed personal property losses expired after seven taxation years		
Listed personal property losses at beginning of taxation year		
Current-year listed personal property loss		
Subtotal		
Deduct:		
Amount applied against listed personal property gain		
Other adjustments		
Deduct – Request to carry back listed personal property loss to:		
First preceding taxation year to reduce listed personal property gains		
Second preceding taxation year to reduce listed personal property gains		
Third preceding taxation year to reduce listed personal property gains		
		-
Limited personal property losses - Closing balance		=

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

Year of origin	Non-capital losses *	Farm losses	Restricted farm losses	Listed personal property losses
2000/12/31				
2001/12/31				
2002/12/31				
2003/12/31				
2004/12/31				
2005/12/31				
2006/12/31				
2007/12/31				
Total				

* The carryforward period for non-capital losses arising in a taxation year ending after March 22, 2004, is changed from 7 to 10 taxation years.

Part 7 - Continuity of limited partnership losses

Partnership identifier	Losses at end of preceding taxation year	Losses transferred from amalgamation or windup of subsidiary	Current-year limited partnership loss	Limited partnership losses applied	Limited partnership losses closing balance
Total (enter this amount on line 754 of the CT23)					

Ontario

Ministry of Finance

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

Ontario Capital Cost Allowance
Schedule 8

ONTARIO CAPITAL COST ALLOWANCE

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
COLLUS Power Corp.	1800071	2007/12/31

Is the corporation electing under regulation 1101(5q)? 101 1 Yes ☐ 2 No ☒

1 Class number	2 Ontario undepreciated capital cost at the beginning of the year	3 Cost of acquisitions during the the year See note 1 below	4 Net adjustments	5 Proceeds of dispositions during the year	6 Ontario undepreciated capital cost (col 2 + 3 or col 2 - 4 - 5)	7 50% rule See note 2 below	8 Reduced undepreciated capital cost (col 6 - 7)	9 CCA rate %	10 Recapture of capital cost allowance	11 Terminal loss	12 Ontario capital cost allowance (col 8 x 9 or a lower amount)	13 Ontario undepreciated capital cost at the end of the year (col 6 - 12)
1	8,544,293				8,544,293		8,544,293	4			341,772	8,202,521
8	203,871	48,020			251,891	24,010	227,881	20			45,576	206,315
10	358,340	63,657		5,000	416,997	29,329	387,668	30			116,300	300,697
47	1,243,976	1,463,151		1,600	2,705,527	730,776	1,974,751	8			157,980	2,547,547
12	7,384	5,265			12,649	2,633	10,016	100			10,016	2,633
								Totals			671,644	

Enter in box **650** on the CT23

Note 1. Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule. See Regulation 1100(2) and (2.2) of the *Income Tax Act* (Canada).

Note 2. The net cost of acquisitions is the cost of acquisitions plus or minus certain adjustments from column 4.

Note 3. If the taxation year is shorter than 365 days, prorate the CCA claim.

Note 4. Ontario recapture should be included in net income after deducting the federal recapture and the Ontario terminal loss is deducted from net income after including the federal terminal loss.

Ontario

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Corporations Tax
33 King Street West
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Oshawa ON L1H 8E9

Ontario Cumulative Eligible Capital Deduction

Schedule 10

For taxation years 2002 and later

Corporation's Legal Name	Ontario Corporations Tax Account No.	Taxation Year End
COLLUS Power Corp.	(MOF) 1800071	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 beginning of taxation year *(if negative, enter zero)*					+ 778,910	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					= 778,910	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					= 778,910	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	778,910				
From N -					
Current year deduction M minus N	778,910	x 7%*	=+ 54,524	O	
N + O			= 54,524	▸	- 54,524 P

Note: The maximum current year deduction is 7%. Any amount up to the maximum deduction of 7% may be claimed. For taxation years starting after December 21, 2000, the deduction may not exceed the maximum amount prorated for the number of days in the taxation year divided by 365 or 366 days.

Enter amount in box 651 of the CT23

Ontario cumulative eligible capital - closing balance M minus P *(if negative, enter zero)* = 724,386 Q

See page 2 - part 2

Corporation's Legal Name	Ontario Corporations Tax Account No.	Taxation Year End
COLLUS Power Corp.	(MOF) 1800071	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 as a positive amount; not negative.*						R
Total of 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)			+	2		
Total of cumulative eligible capital deductions claimed for taxation years beginning before July 1, 1988	+	3				
Negative balances in the cumulative eligible capital account that were included in income for taxation years beginning before July 1, 1988	-	4				
Deduct line 4 from line 3 (*if negative, enter zero*)	=		+	5		
Total lines **1 + 2 + 5**			=	6		
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 1		7				
Amounts at **Line** Z from Ontario Schedule 10 of previous taxation years ending after February 27, 2000 (*This will be **Line T** in earlier versions of this schedule.*)	+	8				
Total lines 7 + 8	=		-	9		
Deduct line **9** from line **6** *(if negative, enter zero)*			=		-	S
R minus S *(if negative, enter zero)*					=	T
From Line 5 ______ x 1/2					= -	U
T minus U (*if negative, enter zero*)					=	V
From **V** ______ x 66.6667 %					=	W
Lesser of line **R** and **S**					= +	Z
Amount to be included in income W + Z						

Ontario

Ministry of Finance

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

Ontario Continuity of Reserves
Schedule 13

Corporation's Legal Name	Ontario Corporations Tax Account No.	Taxation Year End
COLLUS Power Corp.	(MOF) 1800071	2007/12/31

For use by corporations to provide a continuity of all reserves claimed which are allowed for tax purposes

Part 1 - Capital gains reserves

Description of property	Ontario balance at the beginning of the year	Transfer on amalgamation or wind-up of subsidiary	Ontario balance at the end of the year
Totals	A	B	C

The total capital gains reserve at the beginning of the taxation year **A** plus the total capital gains reserve transfer on amalgamation or wind-up of subsidiary **B**, should be entered on Schedule 6; and the total capital gains reserve at the end of the taxation year **C**, should also be entered on Schedule 6.

Part 2 - Other reserves

Description	Ontario balance at the beginning of the year	Transfer on amalgamation or wind-up of subsidiary	Ontario balance at the end of the year
Reserve for doubtful debts			
Reserve for undelivered goods and services not rendered	152,934		81,654
Reserve for prepaid rent			
Reserve for December 31, 1995 income			
Reserve for refundable containers			
Reserve for unpaid amounts			
Other tax reserves			
Totals	D 152,934	E	F 81,654

The amount from **D** plus the amount from **E** should be entered in **607** of the CT23.

The amount from **F** should be entered in **654** of the CT23.

Part 3 - Continuity of non-deductible reserves

Reserve	Ontario opening balance and transfers	Ontario additions	Ontario deductions	Other adjustments	Ontario closing balance
Totals					
	*Enter in box **653** of the CT23*				*Enter in box **606** of the CT23*

OTCW

Post-December 13, 2007 Ontario Tax Calculation Worksheet

The 2007 Economic Outlook and Fiscal Review proposed tax reductions that would see a reduction of the Capital Tax rate and the increase of the Ontario Small Business Deduction retroactive to January 01, 2007. While assessments are being done under the old rates and amounts, we provide this worksheet to highlight some of the major differences between the two sets of rates and to approximate the differences between the two.

	Pre-Announcement	Post-Announcement
IDSBC		
Ontario business limit (Line 44)	400,000	500,000
Income Eligible for the IDSBC	337,440	421,800
Calculation of Capital Tax except Financial Institutions		
Capital Tax rate (Line 516)	0.285	0.225
Capital Tax (Line 550)	8,251	6,514
Capital Tax for Financial Institutions		
1.2 Other than Credit Unions		
Capital Tax rate (Line 567)	0.57	0.45
Capital Tax rate (Line 571) enter post-announcment percentage manually	0.00	0.00
Capital Tax for Financial Institutions (Line 575)	0	0
Total Tax Payable (Line 950)	137,027	124,182
Approximate change in Ontario Tax Payable under rates announced in the December 13, 2007 Economic Outlook and Fiscal Review		12,845

Ontario Ministry of Finance
Corporations Tax
PO Box 620
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Paid-Up Capital: Loans and Advances

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
COLLUS Power Corp.	1800071	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)	
Town of Collingwood	1,710,170
Total	1,710,170

*Transfer to **353** on the CT23*

Ontario tax instalments

Instalment base

Year-end	Estimate for current year 2008/12/31	First instalment base 2007/12/31	Second instalment base 2006/12/31
Taxable income		951,898	861,542
Base amount of tax		133,266	120,616
Small business tax credit		28,682	27,676
Surtax on CCPCs		24,192	19,656
Manufacturing and processing profits credit			
Foreign tax credit			
Specified tax credits			
Other tax credits			
Income tax payable		128,776	112,596
Corporate minimum tax payable			
Capital tax payable		8,251	15,251
Premium tax payable			
Total tax payable		137,027	127,847
Days in taxation year	365	365	365
Tax payable adjusted for short taxation years		137,027	127,847
Estimated tax credits for the current year			
Instalment base		137,027	127,847
Monthly payment		11,419	10,654
Quarterly payment		34,257	31,962

Instalment payment options

- ☐ 1. based on estimated taxes for the current year
- ☐ 2. based on the first instalment base
- ☒ 3. based on the first and second instalment base
- ☐ 4. instalments are not required

Instalment payments

Date	Instalments required	Instalments paid	Instalments payable
2008/01/31	10,654		
2008/02/29	10,654		
2008/03/31	11,572		
2008/04/30	11,572		44,452
2008/05/31	11,572		11,572
2008/06/30	11,572		11,572
2008/07/31	11,572		11,572
2008/08/31	11,572		11,572
2008/09/30	11,572		11,572
2008/10/31	11,572		11,572
2008/11/30	11,572		11,572
2008/12/31	11,572		11,572
Total	137,028		137,028

Ontario

Ministry of Revenue

Corporations Tax
33 King Street West
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Oshawa ON L1H 8E9

Corporate Minimum Tax (CMT)
CT23 Schedule 101

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
COLLUS Power Corp.	1800071	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 ±	556,076
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 +	64,000		
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 on dividends declared and paid, under fed.s.191.1(1) ____ x 3 =	2109 +			
Subtotal	=	64,000	▶ 2110 -	64,000
Add (to extent reflected in net income/loss):				
Provision for current taxes / cost of current income taxes	2111 +	324,037		
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	=	324,037	▶ 2116 +	324,037

Add/Subtract:

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

** Fed.s.85	2117 +		or 2118 -	
** Fed.s.85.1	2119 +		or 2120 -	
** Fed.s.97	2121 +		or 2122 -	
** Amounts relating to amalgamations (fed.s.87) as prescribed in regulations for current/prior years	2123 +		or 2124 -	
** Amounts relating to wind-ups (fed.s.88) as prescribed in regulations for current/prior years	2125 +		or 2126 -	
** Amounts relating to s.57.10 election/ regulations for replacement re fed.s.13(4), 14(6) and 44 for current/prior years	2127 +		or 2128 -	
Interest allowable under ss. 20(1)(c) or (d) of ITA to the extent not otherwise deducted in determining CMT adjusted net income			2150 -	
Capital gains on eligible donations of publicly-listed securities and ecologically sensitive land made after May 1, 2006 (to the extent reflected in net income/loss)			2155 -	

Subtotal (Additions)	= ▶	2129 +	
Subtotal (Subtractions)	= ▶	2130 -	
** Other adjustments		2131 ±	
Subtotal ± 2100 - 2110 + 2116 + 2129 - 2130 ± 2131		2132 =	816,113
** 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 =	816,113
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 tax return.*

CMT Base	2136 =	816,113

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

Corporate Minimum Tax (CMT)

Part 2: Continuity of CMT Losses Carried Forward

CMT loss continuity by year

Year of origin	Beginning balance	Transfers on amalgamation	Transfers on wind-up	Adjustments	Current year loss	Applied	Ending balance
							Expired
2000/12/31							
2001/12/31							
2002/12/31							
2003/12/31							
2004/12/31							
2005/12/31							
2006/12/31							
2007/12/31							
Totals							

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 (✓) 2205 ☐ Yes Wind-up (✓) 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)	CMT Losses of Corporation	CMT Losses of Predecessor Corporations
2240	2260	2280
2241	2261	2281
2242 2000/12/31	2262	2282
2243 2001/12/31	2263	2283
2244 2002/12/31	2264	2284
2245 2003/12/31	2265	2285
2246 2004/12/31	2266	2286
2247 2005/12/31	2267	2287
2248 2006/12/31	2268	2288
2249 2007/12/31	2269	2289
Totals	2270	2290

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

Corporate Minimum Tax (CMT)

Part 4: Continuity of CMT Credit Carryovers

CMT credit continuity by year

Year of origin	Beginning balance	Transfers on amalgamation or wind-up	Adjustments	Current year credit	Applied	Expired	Ending balance
2001/12/31							
2002/12/31							
2003/12/31							
2004/12/31							
2005/12/31							
2006/12/31							
2007/12/31							
Totals							

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 (✓) 2315 ☐ Yes Wind-up (✓) 2320 ☐ Yes

Subtotal **2301 + 2310 + 2325** 2330 +

Adjustments *(Attach schedule)* 2332 ±

CMT Credit Carryover available 2330 ± 2332 2333 =

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

Subtract: CMT credit utilized during the year to reduce income tax
(**310** on page 8 of the CT23 or **351** on page 6 of the CT8.) + From **310** or **351**
CMT Credit expired during the year 2334 +

Subtotal = ▶ 2335 -

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

Notes:

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

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

Year of Origin (oldest year first)	CMT Credit Carryovers of Corporation	CMT Credit Carryovers of Predecessor Corporation(s)
2340	2360	2380
2341	2361	2381
2342	2362	2382
2343 2001/12/31	2363	2383
2344 2002/12/31	2364	2384
2345 2003/12/31	2365	2385
2346 2004/12/31	2366	2386
2347 2005/12/31	2367	2387
2348 2006/12/31	2368	2388
2349 2007/12/31	2369	2389
Totals	2370	2390

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

Ontario

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

Authorizing or Cancelling a Representative

Complete this form to:

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

Part 1 Client Information

Legal name: COLLUS Power Corp.

Phone number: (705) 445-1800

Mailing address
Apt./Suite/Unit no. Street number and name / PO Box, RR: 43 Stewart Road

City: Collingwood
Province/Territory: ON
Postal code: L9Y 3Z5

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

- [X] Corporations Tax Act 1800071
- [ ] Mining Tax Act
- [ ] Electricity Act

Part 2 Authorize the release of information to a representative

Name of representative (If a firm, name of firm.): Gaviller & Company LLP

Phone number: (705) 445-2020

Fax number: (705) 444-5833

Mailing address
Apt./Suite/Unit no. Street number and name / PO Box, RR: 115 Hurontario Street P.O. Box 130

City: Collingwood
Province/Territory: ON
Postal code: L9Y 3Z4

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

Title

Part 3 Authorization scope and applicable years

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

or

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

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

or

- [ ] Representative to act for **specific year or years** (describe). ▼

Part 4 Cancel the release of information to a representative

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

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

Name of person in firm
Last
First
Title

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

I authorize the Ministry of Finance to:

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

Name
Last: Fryer
First: Timothy

Title / Relationship to Corporation: Treasurer

Phone number: (705) 445-1800

Signature

Date: 2008/04/27 JF

Canada Revenue Agency / Agence du revenu du Canada

T2 CORPORATION INCOME TAX RETURN

Schedule 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 *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

Identification

Business number (BN) 001 86616 8834 RC 0001

COPY

Corporation's name
002 COLLUS Power Corp.

Has the corporation changed its name since the last time you filed your T2 return? 003 ☐ Yes ☒ No

If *Yes*, do you have a copy of the articles of amendment? 004 ☐ Yes ☐ No
(Do Not Submit)

Address of head office
Has this address changed since the last time you filed your T2 return? 010 ☐ Yes ☒ No
(If yes, complete lines 011 to 018)
011 43 Stewart Road
012
City: 015 Collingwood
Province, territory, or state: 016 ON
Country (other than Canada): 017
Postal code/Zip code: 018 L9Y 3Z5

Mailing address (if different from head office address)
Has this address changed since the last time you filed your T2 return? 020 Yes ☐ No ☒
(If yes, complete lines 021 to 028)
021 c/o
022 43 Stewart Road
023
City: 025 Collingwood
Province, territory, or state: 026 ON
Country (other than Canada): 027
Postal code/Zip code: 028 L9Y 3Z5

Location of books and records
Has the location of books and records changed since the last time you filed your T2 return? 030 ☐ Yes ☒ No
(If yes, complete lines 031 to 038)
031 43 Stewart Road
032
City: 035 Collingwood
Province, territory, or state: 036 ON
Country (other than Canada): 037
Postal code/Zip code: 038 L9Y 3Z5

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

To which tax year does this return apply?
From 060 2007/01/01 to 061 2007/12/31

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? 063 ☐ Yes ☒ No

If yes, provide the date control was acquired 065

Is the date on line 061 a deemed tax year-end in accordance with subsection 249(3.1) ? 066 ☐ Yes ☒ No

Is the corporation a professional corporation that is a member of a partnership? 067 ☐ Yes ☒ No

Is this the first year of filing after:
Incorporation? 070 ☐ Yes ☒ No
Amalgamation? 071 ☐ Yes ☒ 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 ☐ Yes ☒ No
If yes, complete and attach Schedule 24.

Is this the final tax year before amalgamation? 076 ☐ Yes ☒ No

Is this the final return up to dissolution? 078 ☐ Yes ☒ No

Is the corporation a resident of Canada? 080 ☒ Yes ☐ 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 ☐ Yes ☒ 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	X	4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205		5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) is the corporation claiming the refundable portion of Part I tax?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210	X	10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming reserves of any kind?	213	X	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		——
Is the corporation claiming a surtax credit?	237	X	37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177
Is the corporation subject to Part XIII.1 tax?	255		92 *

*** We do not print this schedule.**

Attachments - Continued from page 2

		Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	256	☐	T1134-A
Did the corporation have any controlled foreign affiliates?	258	☐	T1134-B
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	259	☐	T1135
Did the corporation transfer or loan property to a non-resident trust?	260	☐	T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261	☐	T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262	☐	T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263	☐	T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264	☐	T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265	☐	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266	☐	T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267	☐	T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268	☐	53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269	☐	54

Additional information

Is the corporation inactive?	280	1 Yes ☐	2 No ☒
Has the major business activity changed since the last return was filed? (enter yes for first-time filers)	281	1 Yes ☐	2 No ☒
What is the corporation's major business activity? (Only complete if yes was entered at line 281.)	282		
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	Utilities	285	100.000 %
286		287	%
288		289	%

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

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI			300	951,898	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")				951,898	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions			355		D
Taxable income (amount C plus amount D)			360	951,898	
Income exempt under paragraph 149(1)(t)			370		
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 minus line 370)					Z

* This amount is equal to 3 times the Part VI.1 tax payable at line 724 on page 8.

Small business deduction

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

Income from active business carried on in Canada from Schedule 7	400	951,898	A
Taxable income from line 360 on page 3, **minus** 10/3 of the amount on line 632 on page 7, **minus** 3 times the amount on line 636 on page 7, and **minus** any amount that, because of federal law, is exempt from Part I tax	405	951,898	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 / Number of days in the tax year	365 / 365	= 400,000	2
	Add amounts at lines 1 and 3		400,000	4

Business limit (see notes 1 and 2 below)	410	337,440	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 337,440 X 415 D / 11,250 = E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0")	425	337,440	F

Small business deduction

Amount A, B, C, or F whichever is the least	337,440	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	365 / 365	x 16% =	53,990	5
Amount A, B, C, or F whichever is the least	337,440	Number of days in the tax year after Dec.31, 2007 / Number of days in the tax year	/ 365	x 17% =		6

Total of amounts 5 and 6 - enter on line 9 of page 7	430	53,990	G

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 / 365	x 7% =		K
Resource deduction – total of amounts I and J (enter amount L on line 10 of page 7)			438		L

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360 on page 3				951,898 A
Amount Z from Part 9 of Schedule 27	x 100 / 7 =		B	
Amount QQ from Part 13 of Schedule 27			C	
Taxable resource income from line 435 on page 4			D	
Amount used to calculate the credit union deduction (from Schedule 17)			E	
Amount on line 400, 405, 410, or 425 on page 4, whichever is the least		337,440	F	
Aggregate investment income from line 440 of page 6			G	
Total of amounts B, C, D, E, F, and G		337,440	▶	337,440 H
Amount A **minus** amount H (if negative, enter "0")				614,458 I

Amount I 614,458	x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	365 / 365	x 7% =	43,012 J
Amount I 614,458	x	Number of days in the tax year after Dec. 31, 2007 and before Jan. 1, 2009 / Number of days in the tax year	/ 365	x 8.5% =	K

General tax reduction for Canadian-controlled private corporations - total of amounts J and K .... 43,012 L

Enter amount L on line 638 of page 7

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 on page 3 (for tax years starting after May 1, 2006, Amount Z on page 3)				M
Amount Z from Part 9 of Schedule 27	x 100 / 7 =		N	
Amount QQ from Part 13 of Schedule 27			O	
Taxable resource income from line 435 on page 4			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		x 7% =	T
Amount S	x	Number of days in the tax year after Dec. 31, 2007 and before Jan. 1, 2009 / Number of days in the tax year		x 8.5% =	U

General tax reduction - total of amounts T and U V

Enter amount V on line 639 of page 7.

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 on page 7					
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 on page 3			951,898		
Deduct:					
Amount on line 400, 405, 410, or 425 on page 4, whichever is the least		337,440			
Foreign non-business income tax credit from line 632 of page 7	x 25/9 =				
Foreign business income tax credit from line 636 of page 7	x 3 =				
		337,440	337,440		
			614,458 X 26 2/3% =	163,855	D
Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8)			180,190		
Deduct: Corporate surtax from line 600 of page 7			10,661		
Net amount			169,529	169,529	E
Refundable portion of Part I tax – Amount C, D, or E, whichever is the least			450	0	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	0	

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 on page 2 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 of page 8)		0	

Part I tax

Base amount of Part I tax

taxable income from page 3 (line 360 or amount Z, whichever applies) multiplied by 38%			550	361,721 A

Corporate surtax calculation

Base amount from line A above		361,721	1	
Deduct:				
10% of taxable income (line 360 or amount Z, whichever applies) from page 3		95,190	2	
Investment corporation deduction from line 620 below			3	
Federal logging tax credit from line 640 below			4	
Federal qualifying environmental trust tax credit from line 648 below			5	
For a mutual fund corporation or an investment corporation throughout the tax year, enter amount a, b, or c below on line 6, whichever is the least:				
28% of taxable income from line 360 on page 3	a			
28% of taxed capital gains	b		6	
Part I tax otherwise payable (line A **plus** lines C and D **minus** line F)	169,529 c			
Total of lines 2 to 6		95,190	7	
Net amount (line 1 **minus** line 7)		266,531	8	

Corporate surtax*

Line 8 266,531 x $\frac{\text{Number of days in the tax year before January 1, 2008}}{\text{Number of days in the tax year}}$ $\frac{365}{365}$ x 4% = 600 10,661 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 on page 6			i
Taxable income from line 360 on page 3	951,898		
Deduct:			
Amount on line 400, 405, 410, or 425 of page 4, whichever is the least	337,440		
Net amount	614,458 ▸	614,458	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)				372,382 E
Deduct:				
Small business deduction from line 430 on page 4		53,990	9	
Federal tax abatement	608	95,190		
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 on page 4			10	
General tax reduction for CCPCs from amount L on page 5	638	43,012		
General tax reduction from amount V on page 5	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		192,192 ▸		192,192 F
Part I tax payable – Line E **minus** line F				180,190 G

Enter amount G on line 700 of page 8.

Summary of tax and credits

Federal tax

Part I tax payable from page 7	700	180,190
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		180,190

Add provincial or territorial tax:

Provincial or territorial jurisdiction 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec, Ontario and Alberta)	760	
Provincial tax on large corporations (New Brunswick and Nova Scotia)	765	

Total tax payable 770 180,190 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780	
Dividend refund from page 6	784	
Federal capital gains refund from Schedule 18	788	
Federal qualifying environmental trust tax credit refund	792	
Canadian film or video production tax credit refund (Form T1131)	796	
Film or video production services tax credit refund (Form T1177)	797	
Tax withheld at source	800	
Total payments on which tax has been withheld 801		
Provincial and territorial capital gains refund from Schedule 18	808	
Provincial and territorial refundable tax credits from Schedule 5	812	
Tax instalments paid	840	
Total credits	890	B

Refund Code 894 ☐ Overpayment

Balance (line A minus line B) 180,190

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 180,190

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 ☒ NA ☐

Certification

I, 950 Fryer (Last name) 951 Timothy (First name) 954 Treasurer (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 2008/04/27 (Date) ______ Signature of the authorized signing officer of the corporation 956 (705) 445-1800 (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 959 ( ) - Telephone number

Language of correspondence - Langue de correspondance

990 Language of choice/Langue de choix 1 English / Anglais ☒ 2 Français / French ☐

Canada Revenue Agency / Agence du revenu du Canada

NET INCOME (LOSS) FOR INCOME TAX PURPOSES

Schedule 1

- 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.

Net income (loss) after taxes and extraordinary items per financial statements			A	556,076
Add:				
Provision for income taxes - current		101	324,037	
Provision for income taxes - deferred		102	(64,000)	
Amortization of tangible assets		104	782,059	
Non-deductible meals and entertainment expenses	2,000 X 50%	121	1,000	
Tax reserves deducted in prior year - Schedule 13		125	152,934	
Total of fields 201 to 294		199	46,086	
	Total of fields 101 to 199	500	1,242,116 ▶	1,242,116
Deduct:				
Gain on disposal of assets per financial statements		401	6,600	
Capital cost allowance - Schedule 8		403	671,644	
Cumulative eligible capital deduction - Schedule 10		405	54,524	
Tax reserves claimed in current year - Schedule 13		413	81,654	
Total of fields 300 to 394		499	31,872	
	Total of fields 401 to 499	510	846,294 ▶	846,294
Net income (loss) for income tax purposes (enter on line 300 of the T2 return)				951,898

Add:

Other additions:

604 Amortization contained in other expenses	28,984		
Interest in excess of legislated amount	17,102		
Other additions	46,086	294	46,086
Total of fields 201 to 294 (Enter this amount at line 199)			46,086

Deduct:

Other deductions:

700 Employee Future Benefits	390	21,846
701 Capital taxes included in tax expense added back 2006 adj.	391	10,026
Total of fields 300 to 394 (Enter this amount at line 499)		31,872

Canada Revenue Agency / Agence du revenu du Canada

Schedule 4

CORPORATION LOSS CONTINUITY AND APPLICATION

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

Part 1 – Non-capital losses

Determination of current-year non-capital loss

Net income (loss) for income tax purposes		951,898
Deduct: (increase a loss)		
Net capital losses deducted in the year (enter as a positive amount)		
Taxable dividends deductible under sections 112, 113, or subsection 138(6)		
Amount of Part VI.1 tax deductible		
Amount deductible as prospector's and grubstaker's shares - Paragraph 110(1)(d.2)		
	▸	
Subtotal (if positive, enter "0")		
Deduct: (increase a loss)		
Section 110.5 and/or subparagraph 115(1)(a)(vii) - Addition for foreign tax deductions		
Subtotal		
Add: (decrease a loss)		
Current-year farm loss		
Current-year non-capital loss (if positive, enter "0")		

Continuity of non-capital losses and request for a carryback

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

* A non-capital loss expires as follows:
- After 7 tax years if it arose in a tax year ending before March 23, 2004;
- After 10 tax years if it arose in a tax year ending after March 22, 2004, and before 2006; or
- After 20 tax years if it arose in a tax year ending after 2005.

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

Corporation loss continuity and application

Election under paragraph 88(1.1)(f)

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

Part 2 – Capital losses

Continuity of capital losses and request for a carryback

Capital losses at the end of the previous tax year	200	10,540		
Capital losses transferred on the amalgamation or the wind-up of a subsidiary corporation	205			10,540
Deduct:				
Other adjustments (includes adjustments for an acquisition of control)	250			
Section 80 - Adjustments for forgiven amounts	240			
		Subtotal		10,540
Add:				
Current-year capital loss (from the calculation on Schedule 6)			210	
Unused non-capital losses that expired in the tax year*			A	
Allowable business investment losses (ABIL) that expired as non-capital losses in the tax year**			B	
Enter amount from line A or B, whichever is less	215			
ABILs expired as non-capital loss: line 215 ______ divided by the inclusion rate*** ______			220	
		Subtotal		10,540

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

Deduct: Amount applied against the current-year capital gain (see Note 1)			225	
		Subtotal		10,540
Deduct - Request to carry back capital loss to (see Note 2):				
First previous tax year	951			
Second previous tax year	952			
Third previous tax year	953			
Capital losses - Closing balance			280	10,540

Note 1
Enter the amount from line 225 **multiplied** by 50% on line 332 of the T2 return.

Note 2
On lines 225, 951, 952, or 953, whichever applies, enter the actual amount of the loss. When the loss is applied, multiply this amount by the 50% inclusion rate.

* Enter the losses from the 8th previous tax year if the losses were incurred in a tax year ending before March 23, 2004. Enter the losses from the 11th previous tax year if the losses were incurred in a tax year ending after March 22, 2004, and before 2006. Enter the losses from the 21st previous tax year if the losses were incurred in a tax year ending after 2005. Enter the part that was not used in previous years and the current year on line A.

** Enter the losses from the 8th previous tax year if the losses were incurred in a tax year ending before March 23, 2004. Enter the losses from the 11th previous tax year if the losses were incurred in a tax year ending after March 22, 2004. Enter the full amount on line B.

*** This inclusion rate is the rate used to calculate your ABIL referred to at line B. Therefore, use one of the following inclusion rates, whichever applies:
- For ABILs incurred in the 1999 and previous tax years, use 0.75.
- For ABILs incurred in the 2000 and 2001 tax years, the inclusion rate is equal to amount M on Schedule 6 - version T2SCH6(01).
- For ABILs incurred in the 2002 and later tax years, use 0.50.

Corporation loss continuity and application

Part 3 – Farm losses

Continuity of farm losses and request for a carryback

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

* A farm loss expires as follows:
- After **10** tax years if it arose in a tax year ending before 2006; or
- After **20** tax years if it arose in a tax year ending after 2005.

Part 4 – Restricted farm losses

Current-year restricted farm loss

Total losses for the year from farming business			485	C
Minus the deductible farm loss:				
$2,500 plus D or E, whichever is less				
(Amount C above – $2,500) divided by 2		D		
	6,250	E		F
Current-year restricted farm loss (amount C minus amount F) (enter this amount on line 410)				

Continuity of restricted farm losses and request for a carryback

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

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

* A restricted farm loss expires as follows:
- After **10** tax years if it arose in a tax year ending before 2006; or
- After **20** tax years if it arose in a tax year ending after 2005.

Corporation loss continuity and application

Part 5 – Listed personal property losses

Continuity of listed personal property loss and request for a carryback

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

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

Year of origin	Non-capital losses *	Farm losses	Restricted farm losses	Listed personal property losses
2000/12/31				
2001/12/31				
2002/12/31				
2003/12/31				
2004/12/31				
2005/12/31				
2006/12/31				
2007/12/31				
Total				

* A non-capital loss expires as follows:
- After 7 tax years if it arose in a tax year ending before March 23, 2004;
- After 10 tax years if it arose in a tax year ending after March 22, 2004, and before 2006; or
- After 20 tax years if it arose in a tax year ending after 2005.

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

Corporation loss continuity and application

Part 7 – Limited partnership losses

Current-year limited partnership losses

1	2	3	4	5	6	7
Partnership identifier	Fiscal period ending	Corporation's share of limited partnership loss	Corporation's at-risk amount	Corp's share of partnership ITC, farming losses and resource expenses	Column 4 - 5 (If negative, enter "0")	Current-year limited partnership losses (Column 3 - 6)
600	602	604	606	608		620
Total (enter this amount on line 222 of Schedule 1)						

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

1	2	3	4	5	6	7
Partnership identifier	Fiscal period ending	Limited partnership losses at the end of the previous tax year	Corporation's at-risk amount	Corp's share of partnership ITC, business or property losses, and resource expenses	Column 4 - 5 (if negative, enter "0")	Limited partnership losses that may be applied in the year (the lesser of columns 3 and 6)
630	632	634	636	638		650

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

Partnership identifier	Limited partnership losses at the end of the previous tax year	Limited partnership losses transferred on an amalgamation or the wind-up of a subsidiary	Current-year limited partnership losses (from column 620)	Limited partnership losses applied (cannot exceed column 650)	Limited partnership losses closing balance (662+664+670-675)
660	662	664	670	675	680
Total (enter this amount on line 335 of the T2 return)					

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CAPITAL COST ALLOWANCE

Schedule 8

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 200	2 UCC at start of year 201	3 Cost of additions in the year 203	4 Net adjustments 205	5 Proceeds of dispositions in the year 207	7 Adjustment for additions (1/2 x (col 3 - 5)) 211	8 Base amount for CCA	9 Rate % 212	10 Recapture of CCA 213	11 Terminal loss 215	12 CCA for the year (col 8 x 9 or a lower amount) 217	13 UCC at the end of the year 220
1	8,544,293					8,544,293	4			341,772	8,202,521
8	203,871	48,020			24,010	227,881	20			45,576	206,315
10	358,340	63,657		5,000	29,329	387,668	30			116,300	300,697
47	1,243,976	1,463,151		1,600	730,776	1,974,751	8			157,980	2,547,547
12	7,384	5,265			2,633	10,016	100			10,016	2,633
Totals	10,357,864	1,580,093		6,600	786,748	11,144,609				671,644	11,259,713

Lines to Actual UCC on Reg. CCA [illegible]

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RELATED AND ASSOCIATED CORPORATIONS

Schedule 9

This form is to be completed by a corporation having one or more of the following:
- related corporation(s)
- associated corporation(s)

Name	Country (if not Canada)	Business # (Canadian corporation only)	Code note 1	Common shares		Preferred shares		Book value of capital stock
				# owned	% owned	# owned	% owned	
100	**200**	**300**	**400**	**500**	**550**	**600**	**650**	**700**
Collus Solutions Corp.		86616 8636 RC 0001	3					
Collingwood Utility Services Inc.		87011 2323 RC 0001	1	5,101,340	100.000			5,101,340
Collus Energy Corp.		87011 2125 RC 0001	3					

Note 1 : Enter the code number of the relationship that applies: 1- Parent 2 - Subsidiary 3 - Associated 4 - Related, but not associated

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CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Schedule 10

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	778,910	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	778,910	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)					778,910	K
Cumulative eligible capital for a property no longer owned after ceasing to carry on that business			249			
amount K	778,910					
less amount from line 249						
Current year deduction	778,910 x 7% =		250	54,524 *		
(line 249 plus line 250) (enter this amount at line 405 of Schedule 1)				54,524	54,524	L
Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0")				300	724,386	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.

Line D29 CCA
[illegible]

Part 2 – Amount to be included in income arising from disposition

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	66.6667		S
Amount N or amount O, whichever is less						T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)				410		

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CONTINUITY OF RESERVES

Schedule 13

- For use by corporations to provide a continuity of all reserves claimed which are allowed for tax purposes.

Part 1 - Capital gains reserves

Description of property 001	Balance at the beginning of the year 002	Transfer on wind-up or amalgamation 003	Balance at the end of the year 004
Totals	008	009	010

The total capital gains reserve at the beginning of the taxation year plus the total transfer on wind-up or amalgamation should be entered on line 880, and the total capital gains reserve at the end of the taxation year should be entered on line 885 of Schedule 6.

Part 2 - Other reserves not deducted for accounting purposes

Description of property	Balance at the beginning of the year	Transfer on wind-up or amalgamation	Balance at the end of the year
Reserve for doubtful debt	110	115	120
Reserve for undelivered goods and services not rendered	130 152,934	135	140 81,654
Reserve for prepaid rent	150	155	160
Reserve for December 31, 1995 income	170	175	180
Reserve for returnable containers	190	195	200
Reserve for unpaid amounts	210	215	220
Other tax reserves	230	235	240
Totals	270 152,934	275	280 81,654

The amount from line 270 plus the amount from line 275 should be included on line 125 of Schedule 1 as an addition.
The amount from line 280 should be included on line 413 of Schedule 1 as a deduction.

Part 3 - Accounting reserves not deductible for tax purposes

Description of property	Balance at the beginning of the year	Balance at the end of the year
Totals	A	B

Enter amount A on line 414 of Schedule 1 as a deduction.
Enter amount B on line 126 of Schedule 1 as an addition.

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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, including non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* 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

Enter the calendar year to which the agreement applies 050 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 Association code 300
1	COLLUS Power Corp.	86616 8834 RC 0001	1
2	Collus Solutions Corp.	86616 8636 RC 0001	1
3	Collingwood Utility Services Inc.	87011 2323 RC 0001	1
4	Collus Energy Corp.	87011 2125 RC 0001	1

Allocate business limit using: ☒ % ☐ $

	Taxation year Start	Taxation year End	4 Business limit for the year (before allocation) $	5 Percentage of the business limit (%) 350	6 Business limit allocated $ 400	7 Gross Part I.3 tax for business limit reduction
1	2007/01/01	2007/12/31	400,000	84.360	337,440	
2	2007/01/01	2007/12/31	400,000	15.640	62,560	
3	2007/01/01	2007/12/31	400,000			
4	2007/01/01	2007/12/31	400,000			
TOTALS				100.000	A 400,000	

If the taxation year of the corporation filing this form is less than 51 weeks, enter the prorated business limit in this box. $ 337,440

AGREEMENT AMONG ASSOCIATED CCPCs TO ALLOCATE THE BUSINESS LIMIT

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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PART I.3 TAX ON LARGE CORPORATIONS

Schedule 33

- File this schedule if the total taxable capital employed in Canada of the corporation (other than a financial institution or an insurance corporation) and its related corporations is greater than $10,000,000.
- Even if there is no Part I.3 tax payable for the days in the tax year that are after 2005, you must still complete this schedule (except parts 5 and 9).
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 181(1) defines the terms "financial institution", "long-term debt" and "reserves".
- Subsection 181(3) provides the basis to determine the carrying value of a corporation's assets or any other amount under Part I.3 for its capital, investment allowance, taxable capital, or taxable capital employed in Canada, or for a partnership in which it has an interest.
- No Part I.3 tax is payable for a taxation year by a corporation that was:
  1) bankrupt [as defined by subsection 128(3)] at the end of the year;
  2) a deposit insurance corporation throughout the year, as defined by subsection 137.1(5), or deemed to be a deposit insurance corporation by subsection 137.1(5.1);
  3) exempt from tax under section 149 throughout the year on all of its taxable income;
  4) neither resident in Canada nor carrying on a business through a permanent establishment in Canada at any time in the year; or
  5) a corporation described in subsection 136(2) throughout the year, the principal business of which was marketing (including any related processing) natural products belonging to or acquired from its members or customers.
- File the completed Schedule 33 with the *T2 Corporation Income Tax Return* no later than six months from the end of the tax year.
- This schedule may contain changes that had not yet become law at the time of printing.

If the corporation was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada, go to Part 4, "Taxable capital employed in Canada."

Part 1 - Capital

Add the following amounts at the end of the year:

Reserves that have not been deducted in computing income for the year under Part I	101	211,109		
Capital stock (or members' contributions if incorporated without share capital)	103	5,101,340		
Retained earnings	104	1,587,361		
Contributed surplus	105			
Any other surpluses	106	2,966,014		
Deferred unrealized foreign exchange gains	107			
All loans and advances to the corporation	108			
All indebtedness of the corporation represented by bonds, debentures, notes, mortgages, hypothecary claims, bankers' acceptances, or similar obligations	109	3,151,766		
Any dividends declared but not paid by the corporation before the end of the year	110			
All other indebtedness of the corporation (other than any indebtedness for a lease) that has been outstanding for more than 365 days before the end of the year	111			
Proportion of the amount, if any, by which the total of all amounts (see note below) for the partnership of which the corporation is a member at the end of the year exceeds the amount of the partnership's deferred unrealized foreign exchange losses	112			
Subtotal		13,017,590	13,017,590	A

Deduct the following amounts:

Deferred tax debit balance at the end of the year	121	90,000		
Any deficit deducted in computing its shareholders' equity (including, for this purpose, the amount of any provision for the redemption of preferred shares) at the end of the year	122			
Any amount deducted under subsection 135(1) in computing income under Part I for the year, as long as the amount may reasonably be regarded as being included in any of lines 101 to 112 above	123			
The amount of deferred unrealized foreign exchange losses at the end of the year	124			
Subtotal		90,000	90,000	B
Capital for the year (amount A minus amount B) (if negative, enter "0")			190	12,927,590

PART I.3 TAX ON LARGE CORPORATIONS

Part 2 - Investment allowance

Add the carrying value at the end of the year of the following assets of the corporation:

A share of another corporation	401	
A loan or advance to another corporation (other than a financial institution)	402	
A bond, debenture, note, mortgage, hypothecary claim, or similar obligation of another corporation (other than a financial institution)	403	
Long-term debt of a financial institution	404	
A dividend receivable on a share of the capital stock of another corporation	405	
A loan or advance to, or a bond, debenture, note, mortgage, hypothecary claim, or similar obligation of, a partnership all of the members of which, throughout the year, were other corporations (other than financial institutions) that were not exempt from tax under Part I.3 [other than by reason of paragraph 181.1(3)(d)]	406	
An interest in a partnership	407	
Investment allowance for the year (add lines 401 to 407)	490	

Part 3 - Taxable capital

Capital for the year (line 190)		12,927,590	C
Deduct: Investment allowance for the year (line 490)			D
Taxable capital for the year (amount C minus amount D) (if negative, enter "0")	500	12,927,590	

Part 4 - Taxable capital employed in Canada

To be completed by a corporation that was resident in Canada at any time in the year

Taxable capital for the year (line 500) 12,927,590 x (Taxable income earned in Canada 610 951,898 / Taxable income 951,898) = 690 Taxable capital employed in Canada 12,927,590

Notes: 1. Regulation 8601 gives details on calculating the amount of taxable income earned in Canada.
2. Where a corporation's taxable income for a tax year is "0," it shall, for the purposes of the above calculation, be deemed to have a taxable income for that year of $1,000.
3. In the case of an airline corporation, Regulation 8601 should be considered when completing the above calculation.

To be completed by a corporation that was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada

Total of all amounts each of which is the carrying value at the end of the year of an asset of the corporation used in the year or held in the year, in the course of carrying on any business it carried on during the year through a permanent establishment in Canada			701	
Deduct the following amounts:				
Corporation's indebtedness at the end of the year [other than indebtedness described in any of paragraphs 181.2(3)(c) to (f)] that may reasonably be regarded as relating to a business it carried on during the year through a permanent establishment in Canada	711			
Total of all amounts each of which is the carrying value at the end of year of an asset described in subsection 181.2(4) of the corporation that it used in the year, or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada	712			
Total of all amounts each of which is the carrying value at the end of year of an asset of the corporation that is a ship or aircraft the corporation operated in international traffic, or personal or movable property used or held by the corporation in carrying on any business during the year through a permanent establishment in Canada	713			
Total deductions (add lines 711, 712, and 713)				E
Taxable capital employed in Canada (line 701 minus amount E) (if negative, enter "0")			790	

PART I.3 TAX ON LARGE CORPORATIONS

Part 5 - Calculation of gross Part I.3 tax

If the tax year starts after 2005, do not complete this part.

Taxable capital employed in Canada (line 690 or 790, whichever applies)		12,927,590
Deduct: Capital deduction claimed for the year (enter $50,000,000 or, for related corporations, the amount allocated on Schedule 36)		50,000,000
Excess of taxable capital employed in Canada over capital deduction	811	
Line 811 ______ x (Number of days in the tax year in 2004 ______ / Number of days in the tax year 365) x 0.002 =		F
Line 811 ______ x (Number of days in the tax year in 2005 ______ / Number of days in the tax year 365) x 0.00175 =		G

Note: The Part I.3 tax rate is reduced to 0% for the days in the tax year that are after 2005.

Subtotal (add amounts F and G)		H

Where the tax year of a corporation is less than 51 weeks, calculate the amount of gross Part I.3 tax as follows:

Amount H ______ X (Number of days in the year (______) / 365) =		I
Gross Part I.3 tax (amount H or I, whichever applies)	820	

Part 6 – Calculation of gross Part I.3 tax for purposes of the unused surtax credit

Taxable capital employed in Canada (line 690 or 790, whichever applies)		12,927,590	J
Deduct: Capital deduction claimed for the year (enter $50,000,000 or, for related corporations, the amount allocated on Schedule 36) 801 50,000,000 x 1/5 =		10,000,000	K
Excess (amount J minus amount K) (if negative, enter "0")		2,927,590	L
Amount L 2,927,590 x 0.00225 =		6,587	M

Where the tax year of a corporation is less than 51 weeks, calculate the amount of gross Part I.3 tax for purposes of the unused surtax credit as follows:

Amount M ______ x (Number of days in the year (______) / 365) =			N
Gross Part I.3 tax for purposes of the unused surtax credit (amount M or N, whichever applies)	821	6,587	

PART I.3 TAX ON LARGE CORPORATIONS

Part 7 - Calculation of current-year surtax credit available

- Corporations can claim a credit against their Part I.3 tax for the amount of Canadian surtax payable for the year. This is called the surtax credit.
- Any unused surtax credit can be carried back three years or carried forward seven years. Unused surtax credits must be applied in order of the oldest first.
- Refer to subsection 181.1(7) when calculating the amount deductible for a corporation's unused surtax credits where control of the corporation has been acquired between the year in which the credits arose and the year in which you want to claim them.

For a corporation that was a non-resident of Canada throughout the year, enter amount **a** or **b** at line O, whichever is less:

a) line 600 from the T2 return		a		
b) line 700 from the T2 return		b		O

In any other case, enter amount **c** or **d** at line P, whichever is less:

c) line 600 from the T2 return 10,661 x (line 690 ÷ line 500) =	10,661	c		
d) line 700 from the T2 return	180,190	d	10,661	P
Current-year surtax credit available (amount O or P, whichever applies)		**830**	10,661	

Part 8 - Calculation of current-year unused surtax credit

Current-year surtax credit available (line 830)		10,661
Less: Gross Part I.3 tax for purposes of the unused surtax credit (line 821)		6,587
Current-year unused surtax credit (if negative, enter "0")	**850**	4,074

Enter this amount at line 600 on Schedule 37.

Part 9 - Calculation of net Part I.3 tax payable

If the tax year starts after 2005, do not complete this part.

Gross Part I.3 tax (line 820)				Q
Deduct:				
Current-year surtax credit applied (line 820 or 830, whichever is less)	861			
Unused surtax credit from previous years applied (amount from line 320 on Schedule 37)	862			
Subtotal (cannot be more than amount on line 820)				R
Net Part I.3 tax payable (amount Q minus amount R)			870	

Enter this amount at line 704 of the T2 return.

Part 10 - Calculation for purposes of the small business deduction

This part is applicable only to corporations that are not associated in the current year, but were associated in the prior year.

Taxable capital employed in Canada (line 690 or 790, whichever applies)	12,927,590	S
Deduct:		
Capital deduction claimed for the year (enter $10,000,000)	10,000,000	T
Excess (amount S minus amount T) (if negative, enter "0")	2,927,590	U
Gross Part I.3 tax for purposes of the small business deduction (Amount U x 0.00225)	6,587	V

Enter this amount at line 415 of the T2 return.

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AGREEMENT AMONG RELATED CORPORATIONS - PART I.3 TAX

Schedule 36

- Corporations related at any time in their tax year that ends in the calendar year of the agreement should use this schedule to allocate the capital deduction of $50,000,000 among the members of the related group if:
  - any member has to pay Part I.3 tax;
  - any member applies the surtax credit against Part I.3 tax in a tax year starting before January 1, 2006; or
  - any member wants to carry back an unused surtax credit against Part I.3 tax to a tax year starting before January 1, 2006.
- According to subsection 181.5(7) of the Income Tax Act, a Canadian-controlled private corporation is not considered to be related to another corporation for the capital deduction unless it is also associated with that corporation.
- In cases where a related corporation has more than one tax year ending in a calendar year, it has to file this agreement for each of those tax years.
- Any corporation in the related group may file this agreement on behalf of the group. However, if an agreement is not already on file with us when we assess any of the returns for a tax year ending in the calendar year of the agreement, we will ask for one.
- Attach additional schedules if more space is required.

Agreement

Date filed (for departmental use only) .... 010 ________

Is this an amended agreement? .... 020 ☐ 1 Yes ☒ 2 No

Calendar year to which the agreement applies 030 2007

Note: This agreement must include all the information indicated below for all members of the related group, including members to which no amount of capital deduction is allocated for the year. However, any member that is exempt from Part 1.3 tax under subsection 181.1(3) of the *Income Tax Act* does not have to be included.

Names of all corporations which are members of the related group 200	Business number (if a corporation is not registered, enter "NR") 300	Allocation of capital deduction for the year $ 400	Taxation year end to which this agreement applies * 500
COLLUS Power Corp.	86616 8834 RC 0001	50,000,000	yyyy/mm/dd
Collus Solutions Corp.	86616 8636 RC 0001	0	yyyy/mm/dd
Collingwood Utility Services Inc.	87011 2323 RC 0001	0	yyyy/mm/dd
Collus Energy Corp.	87011 2125 RC 0001	0	yyyy/mm/dd
Total (cannot be more than $50,000,000)		50,000,000	

* Entries are only required in this column for a corporation that has more than one tax year ending in the same calendar year and is related in two or more of those tax years to another corporation that has a tax year ending in that calendar year. The capital deduction of the first corporation for each such tax year at the end of which it is related to the other corporation is an amount equal to its capital deduction for the first such tax year. Enter the tax year-end to which this agreement applies.

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CALCULATION OF UNUSED SURTAX CREDIT

SCHEDULE 37

- Use this schedule to calculate a corporation's unused surtax credit.
- You should also use this schedule to request a carryback of unused surtax credit. This request should be filed by the required filing date of the T2 return for the year in which the surtax credit arose.
- Any unused surtax credit can be carried back three years and carried forward seven years. Unused surtax credits must be applied in order of the oldest first.
- Refer to subection 181.1(7) of the *Income Tax Act* when calculating the amount deductible for a corporation's unused surtax credits where control of the corporation has been acquired between the year in which the credits arose and the year in which you want to claim them.
- Attach this schedule to the T2 return or mail it separately to the tax centre where the return is filed.

Part 1 - Unused surtax credits

Year of origin	Unused surtax credit at end of preceding tax year	Transfers on amalgamation or wind-up	Current year credit	Applied	Ending balance
		Expired			
2000/12/31					
2001/12/31					
2002/12/31					
2003/12/31	268				268
2004/12/31	3,855				3,855
2005/12/31	4,912				4,912
2006/12/31	9,649				9,649
2007/12/31			4,074		4,074
Totals	18,684				22,758

Calculation of closing balance of unused surtax credit

Unused surtax credit at the end of the preceding tax year		18,684	
Deduct: Unused surtax credit expired after seven tax years	115		
Unused surtax credit at beginning of the tax year	120	18,684	
Add: Unused surtax credit transferred on amalgamation or the wind-up of subsidiary	220		
Subtotal		18,684	A
Deduct: Amount of unused surtax credit carried forward from previous years and applied to reduce Part I.3 tax payable in the current year (see line 862 of Schedule 33, line 862 of Schedule 34, or line 862 of Schedule 35, whichever applies)	320		
Unused surtax credit balance		18,684	
Deduct: Amount of unused surtax credit carried forward from previous years and applied to reduce Part VI tax payable in the current year (If the current tax year ends before July 1, 2006, enter amount from line 887 of Schedule 38. If the current tax year starts after June 30, 2006, enter amount from line 885 of Schedule 38. If the current tax year straddles July 1, 2006, enter amount from line 887 of Schedule 38 multiplied by the number of days in the tax year before July 1, 2006, divided by the number of days in the tax year, plus line 885 of Schedule 38 multiplied by the number of days in the tax year after June 30, 2006, divided by the number of days in the tax year)	420		
Excess		18,684	
Add: Current year unused surtax credit (enter amount from line 850 of Schedule 33, line 850 of Schedule 34, or line 850 of Schedule 35)	600	4,074	
Subtotal		22,758	
Deduct: Unused surtax credit carried back to preceding taxation year(s) (complete Part 2 below)			B
Closing balance of unused surtax credit	820	22,758	

Part 2 - Request for carryback of unused surtax credit

			To Part I.3 tax		To Part VI tax	
1st preceding tax year	2006/12/31	Credit to be applied **901**		**911**		
2nd preceding tax year	2005/12/31	Credit to be applied **902**		**912**		
3rd preceding tax year	2004/12/31	Credit to be applied **903**		**913**		
		Subtotal		C		D

Total of C and D (enter this amount at line B in Part 1 above) ______

- If you carry back an amount against Part VI tax to a tax year that straddles July 1, 2006, see Part 3.

Part 3 – Calculation of current-year unused surtax credit that can be carried back against Part VI tax payable to a tax year that straddles July 1, 2006

Line 600* 4,074 X Days in the tax year** before July 1, 2006(181) = 2,020 E
Days in the tax year** (365)

Net Part VI tax payable for the period before July 1, 2006
(line HH of Schedule 38 for the straddle tax year) F

Enter amount E or F, whichever is less G

Line 600* 4,074 X Days in the tax year** after June 30, 2006(184) = 2,054 H
Days in the tax year** (365)

Net Part VI tax payable for the period after June 30, 2006
(line RR of Schedule 38 for the straddle tax year) I

Enter amount H or I, whichever is less J

Current-year unused surtax credit that can be carried back against Part VI tax payable to a tax year that straddles July 1, 2006 (amount G plus amount J) K

Amount K is the maximum amount that you can carry back against Part VI tax payable to a tax year that straddles July 1, 2006. Enter the amount you want to carry back on line 911, 912 or 913 (whichever applies).

* Deduct from line 600 any amount that is being carried back to another tax year against Part 1.3 or Part VI tax payable.

** Tax year to which the credit will be carried back

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SHAREHOLDER INFORMATION

Schedule 50

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	Business Number (If a corporation is not registered, enter "NR") * 200	Social Insurance Number * 300	Trust Number (If a trust number is not available, enter "NA") * 350	Percentage common shares 400	Percentage preferred shares 500
Collingwood Utility Services Corp.	87011 2323 RC 0001			100.000	
	RC				

* For a taxation year commencing before January 1, 2004, if the shareholder is a trust, enter NR at field 200 or NA at field 300. Do not enter a trust number in field 350.

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BALANCE SHEET INFORMATION

Schedule 100

Assets	Code	Current year	Prior year
Cash and deposits	1000	3,640,113	5,272,508
Accounts Receivable	1060	8,608,526	6,753,684
Inventories	1120	282,493	245,218
Land	1600	90,439	90,439
Buildings	1680	80,668	80,668
Accumulated amortization of buildings	1681	(52,010)	(49,868)
Machinery, equipment, furniture and fixtures	1740	21,062,245	19,229,015
Accumulated amortization of machinery, equipment, furniture and fixtures	1741	(11,702,656)	(10,893,455)
Other tangible capital assets	1900	805,116	695,439
Other long term assets	2420	(2,289,761)	(1,851,908)
Future income taxes	2421	90,000	26,000
Total assets	2599	20,615,173	19,597,740

Liabilities	Code	Current year	Prior year
Bank overdraft	2600		
Amounts payable and accrued liabilities	2620	6,001,552	3,920,946
Interest payable	2629	5,030	7,255
Taxes payable	2680	20,222	136,411
Due to related parties	2860	641,383	1,568,244
Other current liabilities	2960	1,059,793	1,188,695
Long term debt	3140	1,710,170	1,710,170
Chartered bank loan	3143	1,441,597	1,748,805
Bonds and debentures	3210		32,000
Other long term liabilities	3320	80,711	186,575
Total liabilities	3499	10,960,458	10,499,101

Equity	Code	Current year	Prior year
Common shares	3500	5,101,340	5,101,340
Contributed and other surplus	3540	2,966,014	2,966,014
Retained earnings / deficit	3600	1,587,361	1,031,287
Total equity	3620	9,654,715	9,098,641
Total liabilities and equity	3640	20,615,173	19,597,742

Retained earnings	Code	Current year	Prior year
Retained earnings/deficit-start	3660	1,031,285	580,614
Net income / loss	3680	556,076	450,673
Total retained earnings	3849	1,587,361	1,031,287

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INCOME STATEMENT INFORMATION

Schedule 125

Details

Operating name, if different from the corporations' legal name
0001 ______

Description of operation, if filing multiple Schedules 125
0002 ______

Revenue	Code	Current year	Prior year
Trade sales of goods and services	8000	28,338,132	28,004,024
Total sales of goods and services	8089	28,338,132	28,004,024
Investment revenue	8090	261,417	180,656
Rental revenue	8140	83,030	110,667
Realized gains / losses on disposal of assets	8210	6,600	10,000
Other revenue	8230	219,068	184,293
Total revenue	8299	28,908,247	28,489,640

Cost of sales	Code	Current year	Prior year
Opening inventory	8300		
Purchases / cost of materials	8320	23,788,955	23,724,570
Direct wages	8340	142,685	133,241
Other direct costs	8450	615,493	590,120
Cost of sales	8518	24,547,133	24,447,931
Gross profit / loss (item 8089 - item 8518)	8519	3,790,999	3,556,093

Operating expenses	Code	Current year	Prior year
Advertising and promotion	8520	71,280	100,646
Bad debt expense	8590	60,636	19,072
Amortization of tangible assets	8670	774,204	759,491
Interest and bank charges	8710	337,278	240,619
Business taxes, licences and memberships	8760	1,960	15,822
Office expenses	8810	461	270
Restructuring costs	8874	8,155	8,155
Rental	8910	30,000	27,500
Repairs and maintenance	8960	1,262,942	1,200,795
Salaries and wages	9060	282,115	265,079
Other expenses	9270	715,557	730,151
Total operating expenses	9367	3,544,588	3,367,600
Total expenses	9368	28,091,721	27,815,531
Net non-farming income	9369	816,526	674,109

Farming revenue	Code	Current year	Prior year
Grains and oilseeds	9370		
Total farm revenue	9659		

Farming expenses	Code	Current year	Prior year
Crop expenses	9660		
Total farm expenses	9898		
Net farm income	9899		
Net income / loss before taxes and extraordinary items	9970	816,526	674,109

Summary

Complete this section if only one Schedule 125 is filed, Schedule 140 is used to summarize the information from multiple Schedules 125.

Extraordinary items	9975-	413	-	
Legal settlements	9976-		-	
Unrealized gains / losses	9980+		+	
Unusual items	9985-		-	
Current income taxes	9990-	324,037	-	274,436
Future income tax provision	9995-	(64,000)	-	(51,000)
Net income / loss after taxes and extraordinary items	9999=	556,076	=	450,673

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NOTES CHECKLIST

Schedule 141

- 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 ☒ Yes ☐ No

Is the accounting practitioner connected* with the corporation? 097 ☐ Yes ☒ No

* 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 ☒

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 ☐ Yes ☒ No

Part 4 – Other information

Were notes to the financial statements prepared? 101 ☒ Yes ☐ No

If *Yes* , complete lines 102 to 107 below:

Are any values presented at other than cost? 102 ☐ Yes ☒ No

Has there been a change in accounting policies since the last return? 103 ☐ Yes ☒ No

Are subsequent events mentioned in the notes? 104 ☐ Yes ☒ No

Is re-evaluation of asset information mentioned in the notes? 105 ☐ Yes ☒ No

Is contingent liability mentioned in the notes? 106 ☒ Yes ☐ No

Is information regarding commitments mentioned in the notes? 107 ☒ Yes ☐ No

Does the corporation have investments in joint venture(s) or partnership(s)? 108 ☐ Yes ☒ No

If *Yes* , complete line 109 below:

Are you filing financial statements of the joint venture(s) or partnership(s)? 109 ☐ Yes ☐ No

Tax instalments paid

Jurisdiction	Description	Date	Amount
Ontario			297,000
Federal			
		Total	297,000

* Enter Québec instalments paid on form CO-1027.VE

Summary by jurisdiction

Federal	
British Columbia	
Alberta	
Saskatchewan	
Manitoba	
Ontario	297,000

Capital dividend account continuity

Summary

		Prior years	Current year	Total
	Non-taxable (non-deductible) portion of capital gain (loss)	(5,270)		(5,270)
	Non-taxable portion of allowable business investment (loss)	+		
A.	Net non-taxable gain eligible for CDA (Enter "0" if negative)	=		
B.	Capital dividends received	+		
	ECP amount included in income under 14(1)(b)			
	Amount(s) deducted under 20(4.2) or portion of allowable capital loss under 20(4.3)			
C.	Net non taxable portion of ECP proceeds eligible for CDA	+		
D.	Net proceeds (in excess of adjusted cost base) of life insurance policy where corporation is beneficiary	+		
E.	Non taxable portion of capital gains distributed from a trust	+		
F.	Non taxable portion of capital dividends distributed from a trust	+		
G.	**Subtotal** (A to F)	=		
H.	Capital dividends paid	-		
I.	**Capital dividend account at end of the year** (G - H) (Enter "0" if negative)	=		

Adjustments

Adjusted CDA balance

Federal tax instalments

Instalment base

Year-end	Estimate for current year 2008/12/31	First instalment base 2007/12/31	Second instalment base 2006/12/31
Taxable income		951,898	861,542
Base amount of Part I tax		361,721	327,386
Corporate surtax		10,661	9,649
Refundable tax on CCPC's investment income			
Small business deduction		53,990	39,072
Federal tax abatement		95,190	86,154
Manufacturing and processing profits deduction			
Foreign tax credits			
Tax reductions		43,012	43,214
Political contribution tax credit			
Investment tax credit			
Other credits			
Part I tax payable		180,190	168,595
Part I.3 tax payable			
Part VI tax payable			
Part VI.1 tax payable			
Part XIII.1 tax payable			
Net provincial or territorial tax payable			
Total tax payable		180,190	168,595
Days in taxation year	365	365	365
Tax payable adjusted for short taxation years		180,190	168,595
Estimated credits for the current year:			
Investment tax credit refund			
Dividend refund			
Other			
Total estimated credits			
Instalment base		180,190	168,595
Monthly payment		15,016	14,050

Instalment payment options

- ☐ 1. based on estimated taxes for the current year
- ☐ 2. based on the first instalment base
- ☒ 3. based on the first and second instalment base
- ☐ 4. instalments are not required

Instalment payments

Date	Instalments required	Instalments paid	Instalments payable
2008/01/31	14,050		
2008/02/29	14,050		
2008/03/31	15,209		
2008/04/30	15,209		58,518
2008/05/31	15,209		15,209
2008/06/30	15,209		15,209
2008/07/31	15,209		15,209
2008/08/31	15,209		15,209
2008/09/30	15,209		15,209
2008/10/31	15,209		15,209
2008/11/30	15,209		15,209
2008/12/31	15,209		15,209
Total	180,190		180,190

Related and Associated Corporations Summary

		Corporation #1	Corporation #2	Corporation #3	Total
Corporation name		COLLUS Power Corp.	Collus Solutions Corp.	Collingwood Utility Services Inc.	
Business number		86616 8834 RC 0001	86616 8636 RC 0001	87011 2323 RC 0001	
Taxation year end		2007/12/31	2007/12/31	2007/12/31	
Federal					
Schedule 9	# of common shares owned			5,101,340	5,101,340
	% of common shares owned			100.000	100.000
	# of preferred shares owned				
	% of preferred shares owned				
	Book value of capital stock			5,101,340	5,101,340
Schedule 23	Business limit (before allocation)	400,000	400,000	400,000	1,600,000
	% of the business limit	84.360	15.640		100.000
	Allocation of the business limit	337,440	62,560		400,000
Schedule 49	Allocation of SR&ED expenditure limit				
Capital tax					
Schedule 36	Allocation of capital deduction	50,000,000			50,000,000
Schedule 39	Allocation of capital deduction	200,000,000			200,000,000
Schedule 343	Allocation of capital deduction	5,000,000			5,000,000
Schedule 362	Allocation of capital deduction	5,000,000			5,000,000
Alberta					
AT1 Schedule 1	% of business limit	84.360	15.640		100.000
	Allocation of the base amount	168,720	31,280		200,000
AT1 Schedule 6	Allocation of Crown royalty shelter	2,000,000			2,000,000
Ontario					
OMinimum	Total assets	20,615,173	602,759		21,218,032
	Total revenue	28,908,247	1,782,316		30,690,563
OSurtax	Taxable income	951,898	62,563		1,014,461
CT21	Taxable capital	15,085,031	383,636		15,468,667
Schedule 591	Allocation of net deduction				
OITC	Allocation of OITC expenditure limit				
Québec					
CO-1137.E	% of the $1,000,000 deduction	100.0000			100.0000
	Paid-up capital	9,098,639			9,098,639
CO-737.18.18	Paid-up capital	9,098,639			9,098,639
CO-1138.1	Allocation of farming and fishing deduction				
RD-1029.7	Assets	20,615,173			20,615,173
RD-1029.7.8	Allocation of SR&ED expenditure limit	2,000,000			2,000,000
CO-771.1.3.V	% of the business limit	84.360	15.640		100
	Allocation of the business limit	337,440	62,560		400,000
Manitoba					
MCT1	Allocation of capital deduction	5,000,000			5,000,000
British Columbia					
Schedule F	Net paid-up capital				
	BC paid-up capital				

Related and Associated Corporations Summary

		Corporation #4	Corporation #5	Corporation #6	Total
Corporation name		Collus Energy Corp.			
Business number		87011 2125 RC 0001	RC	RC	
Taxation year end		2007/12/31			
Federal					
Schedule 9	# of common shares owned				5,101,340
	% of common shares owned				100.000
	# of preferred shares owned				
	% of preferred shares owned				
	Book value of capital stock				5,101,340
Schedule 23	Business limit (before allocation)	400,000			1,600,000
	% of the business limit				100.000
	Allocation of the business limit				400,000
Schedule 49	Allocation of SR&ED expenditure limit				
Capital tax					
Schedule 36	Allocation of capital deduction				50,000,000
Schedule 39	Allocation of capital deduction				200,000,000
Schedule 343	Allocation of capital deduction				5,000,000
Schedule 362	Allocation of capital deduction				5,000,000
Alberta					
AT1 Schedule 1	% of business limit				100.000
	Allocation of the base amount				200,000
AT1 Schedule 6	Allocation of Crown royalty shelter				2,000,000
Ontario					
OMinimum	Total assets	100			21,218,032
	Total revenue				30,690,563
OSurtax	Taxable income				1,014,461
CT21	Taxable capital				15,468,667
Schedule 591	Allocation of net deduction				
OITC	Allocation of OITC expenditure limit				
Québec					
CO-1137.E	% of the $1,000,000 deduction				100.0000
	Paid-up capital				9,098,639
CO-737.18.18	Paid-up capital				9,098,639
CO-1138.1	Allocation of farming and fishing deduction				
RD-1029.7	Assets				20,615,173
RD-1029.7.8	Allocation of SR&ED expenditure limit				2,000,000
CO-771.1.3.V	% of the business limit				100
	Allocation of the business limit				400,000
Manitoba					
MCT1	Allocation of capital deduction				5,000,000
British Columbia					
Schedule F	Net paid-up capital				
	BC paid-up capital				

Canada Revenue Agency | Agence du revenu du Canada

BUSINESS CONSENT FORM

Complete this form to consent to the release of confidential information about your Business Number (BN) account(s) to the representative named below, or to cancel consent for an existing representative. **Send this completed form to your tax centre.** You can also give or cancel consent by providing the requested information online through My Business Account at **www.cra.gc.ca/mybusinessaccount.**

Note: Read all instructions on the last page before completing this form.

Part 1 - Business Information - Complete this part to identify your business (all fields have to be completed)

Business Name: COLLUS Power Corp. **Business Number:** 866168834

Telephone Number: (705) 445-1800

Part 2 - Authorize a representative

If you are giving consent for an individual, enter that person's full name or if you are giving consent to a firm, enter the name of the firm and the BN. If you want us to deal with a specific individual in that firm, enter **both** the individual's name and the name of the firm. If you do not identify an individual of the firm then you are giving us consent to deal with anyone from that firm.

Name of Individual: ______ Name of Firm: Gaviller & Company LLP

Telephone Number: (705) 445-2020 **BN:** 116806530

Authorize online access

You can authorize your representative to deal with us through our online services for representatives. You have to provide the RepID of the individual or the Business Number of the firm indicated above. The name of the firm provided above must be the same name that is registered with the Represent a Client service at **www.cra.gc.ca/representatives.** If the firm names differ then online access will not be granted. Our online services do not have a year specific option, so your representative will have access to all years.

RepID: ______ (for above individual) OR **BN:** 116806530 The BN must be registered with the Represent a Client service to be an online representative.

Part 3 - Which Accounts and Which Years?

i) Accounts - Select which accounts the above individual or firm is authorized to access (check only box A or B).

A. [X] This authorization applies to all BN accounts and all years. **Note: oline access is available for box A only.**

Expiry date: yyyy/mm/dd

OR

B. [ ] This authorization applies only to BN accounts and periods listed in Part 3ii.

Authorization level: check one box

[ ] Disclose information only

OR

[X] Disclose information and make changes to your BN account(s)

RC59 E (07)

Canada

BUSINESS CONSENT FORM (RC59 continued)

ii) Details of accounts and fiscal periods - Complete this area if you checked box "B" in Part 3 i).

If you checked box B in part 3i, you have to provide at least one program identifier (see Instructions on the last page). You can then check the "all accounts" box for that program identifier or enter a specific account number. Provide the authorization level ("1" to disclose information or "2" to disclose information and make changes). You can also check the "All years" box to allow unlimited tax year access or enter a specific fiscal period **(specific period authorization is not available for online access)**. You can also enter an expiry date to automatically cancel authorization. If additional authorizations or more than four program identifiers are needed complete another RC59.

Program identifier	All accounts	or	Specific account	Authorization level	All years	or	Specific fiscal period (not available for online access) Year End	Expiry date
RC	☐	or		1	☐	or	yyyy/mm/dd	yyyy/mm/dd
RC	☐	or		1	☐	or	yyyy/mm/dd	yyyy/mm/dd
RC	☐	or		1	☐	or	yyyy/mm/dd	yyyy/mm/dd
RC	☐	or		1	☐	or	yyyy/mm/dd	yyyy/mm/dd

Part 4 - Cancel one or more existing authorizations - Complete this section only to cancel existing authorization(s)

☐ A. Cancel all authorizations

☐ B. Cancel authorization for the individual or firm identified below.

Name of Individual: ____________ Name of Firm: ____________

Part 5 - Certification

This form must be signed by an authorized person of the business such as a proprietor of a proprietorship, a partner of a partnership, a director of a corporation, an officer of a non profit organization or a trustee of an estate. By signing and dating this form, you authorize the CRA to deal with the individual or firm listed in Part 2 of this form and/or cancel the authorizations listed in Part 4.

First name: Timothy Last name: Fryer

Title: Treasurer

Sign here ▸ [signature]

Date 2008/04/27 [initials]

WE WILL NOT PROCESS THIS FORM UNLESS IT IS SIGNED AND DATED BY AN AUTHORIZED PERSON OF THE BUSINESS.

COLLUS Power Corp
2008 BALANCE SHEET

Account Description	Total
1050-Current Assets	
1005-Cash	2,259,489.01
1010-Cash Advances and Working Funds	-
1020-Interest Special Deposits	-
1030-Dividend Special Deposits	-
1040-Other Special Deposits	-
1060-Term Deposits	-
1070-Current Investments	-
1100-Customer Accounts Receivable	2,500,000.00
1102-Accounts Receivable - Services (1110-0001)	100,000.00
1104-Accounts Receivable - Recoverable Work	500,000.00
1105-Accounts Receivable - Merchandise, Jobbing, etc.	250,000.00
1110-Other Accounts Receivable(1110, 1110-02)	900,000.00
1120-Accrued Utility Revenues	3,100,000.00
1130-Accumulated Provision for Uncollectable Accounts – Credit	(81,157.00)
1140-Interest and Dividends Receivable	32,153.50
1150-Rents Receivable	-
1170-Notes Receivable	-
1180-Prepayments	79,157.22
1190-Miscellaneous Current and Accrued Assets	-
1200-Accounts Receivable from Associated Companies	-
1210-Notes Receivable from Associated Companies	-
1050-Current Assets Total	**9,639,642.73**

Account Description	Total
1100-Inventory	
1305-Fuel Stock	-
1330-Plant Materials and Operating Supplies	282,492.57
1340-Merchandise	-
1350-Other Material and Supplies	-
1100-Inventory Total	**282,492.57**

Account Description	Total
1150-Non-Current Assets	
1405-Long Term Investments in Non-Associated Companies	-
1408-Long Term Receivable - Street Lighting Transfer	-
1410-Other Special or Collateral Funds	-
1415-Sinking Funds	-
1425-Unamortized Debt Expense	-
1445-Unamortized Discount on Long-Term Debt–Debit	-
1455-Unamortized Deferred Foreign Currency Translation Gains and Losses	-
1460-Other Non-Current Assets	-
1465-O.M.E.R.S. Past Service Costs	-
1470-Past Service Costs - Employee Future Benefits	-
1475-Past Service Costs -Other Pension Plans	-
1480-Portfolio Investments - Associated Companies	-
1485-Investment In Subsidiary Companies - Significant Influence	-
1490-Investment in Subsidiary Companies	-
1150-Non-Current Assets Total	**-**

Account Description	Total
1200-Other Assets and Deferred Charges	
1505-Unrecovered Plant and Regulatory Study Costs	-
1508-Other Regulatory Assets	89,521.17
1510-Preliminary Survey and Investigation Charges	-
1515-Emission Allowance Inventory	-
1516-Emission Allowance Withheld	-
1518-0	-
1525-Miscellaneous Deferred Debits	122,325.00
1530-Deferred Losses from Disposition of Utility Plant	-
1540-Deferred Losses from Disposition of Utility Plant	-
1545-Development Charge Deposits/ Receivables	-
1548-RCVA - Service Transaction Request (STR)	-
1550-LV Charges - Variance	334,851.00
1555-Smart Meters Recovery	(107,000.00)
1556-Smart Meters OM & A (+ Capital 07)	88,250.00
1562-Deferred PILs	95,510.34
1563-Deferred PILs - Contra	(95,510.34)
1565-C & DM Costs	(376,000.00)
1566-C & DM Costs Contra	376,000.00
1570-Qualifying Transition Costs	-
1571-Pre Market CofP Variance	-
1572-Extraordinary Event Losses	-
1574-Deferred Rate Impact Amounts	-
1580-RSVA - Wholesale Market Services	(634,379.85)
1582-RSVA - One-Time	21,444.35
1584-RSVA - Network Charges	(595,887.94)
1586-RSVA - Connection Charges	(1,171,976.87)
1588-RSVA - Commodity (Power)(& 1589 GA)	(199,775.63)
1590-Recovery of Regulatory Assets (25% of 2002 bal.)	(226,000.00)
1200-Other Assets and Deferred Charges Total	**(2,278,628.77)**

1450-Distribution Plant	
1805-Land	90,438.88
1806-Land Rights	-
1808-Buildings and Fixtures	80,668.44
1810-Leasehold Improvements	-
1815-Transformer Station Equipment - Normally Primary above 50 kV	-
1820-Distribution Station Equipment - Normally Primary below 50 kV	3,126,646.68
1825-Storage Battery Equipment	-
1830-Poles, Towers and Fixtures	-
1835-Overhead Conductors and Devices	9,792,501.46
1840-Underground Conduit	-
1845-Underground Conductors and Devices	6,768,890.93
1850-Line Transformers	4,245,170.32
1855-Services	528,412.57
1860-Meters	1,437,576.23
1865-Other Installations on Customer's Premises	-
1450-Distribution Plant Total	**26,070,305.51**

Account Description	Total
1500-General Plant	
1905-Land	-
1906-Land Rights	-
1908-Buildings and Fixtures	-
1910-Leasehold Improvements	-
1915-Office Furniture and Equipment	175,327.34
1920-Computer Equipment - Hardware	-
1925-Computer Software	458,853.12
1930-Transportation Equipment	1,315,996.65
1935-Stores Equipment	6,634.98
1940-Tools, Shop and Garage Equipment	-
1945-Measurement and Testing Equipment	51,800.00
1950-Power Operated Equipment	37,260.00
1955-Communication Equipment	71,751.41
1960-Miscellaneous Equipment	203,814.49
1970-Load Management Controls - Customer Premises	878,887.18
1975-Load Management Controls - Utility Premises	-
1980-System Supervisory Equipment	586,251.55
1985-Sentinel Lighting Rentals	7,063.04
1990-Other Tangible Property	-
1995-Contributions and Grants	(6,379,229.55)
1500-General Plant Total	**(2,585,589.79)**

1550-Other Capital Assets	
2005-Property Under Capital Leases	-
2010-Electric Plant Purchased or Sold	-
2020-Experimental Electric Plant Unclassified	-
2030-Electric Plant and Equipment Leased to Others	-
2040-Electric Plant Held for Future Use	-
2050-Completed Construction Not Classified–Electric	-
2055-Construction Work in Progress–Electric	146,049.29
2060-Electric Plant Acquisition Adjustment	276,703.91
2065-Other Electric Plant Adjustment	-
2070-Other Utility Plant	-
2075-Non-Utility Property Owned or Under Capital Lease	-
1550-Other Capital Assets Total	**422,753.20**

1600-Accumulated Amortization	
2105-Accumulated Amortization of Electric Utility Plant - Property, Plant and Equipment	(12,729,382.16)
2120-Accumulated Amortization of Electric Utility Plant - Intangibles	-
2140-Accumulated Amortization of Electric Plant Acquisition Adjustment	-
2160-Accumulated Amortization of Other Utility Plant	-
2180-Accumulated Amortization of Non-Utility Property	-
1600-Accumulated Amortization Total	**(12,729,382.16)**

Total Assets	**18,821,593.29**

Account Description	Total
1650-Current Liabilities	
2205-Accounts Payable (2205-00,01,02,03&04) (2206&07 LTD&GST)	3,573,997.52
2208-Customer Credit Balances	477,835.37
2210-Current Portion of Customer Deposits (&Int 2210-00&01)	358,775.82
2215-Dividends Declared (Const Work Deposits 2211)	744,720.80
2220-Miscellaneous Current and Accrued Liabilities	500,000.00
2225-Notes and Loans Payable	-
2240-Accounts Payable to Associated Companies (OPG Rebate)	12,072.51
2242-Notes Payable to Associated Companies	-
2250-Competition Transition Charges Payable (DRC)	178,124.58
2252-Transmission Charges Payable	-
2254-Electric Safety Authority Fees Payable	-
2256-Independent Market Operator Fees and Penalties Payable	-
2260-Current Portion of Long Term Debt	-
2262-Ontario Hydro Debt - Current Portion	-
2264-Pensions and Employee Benefits - Current Portion	-
2268-Accrued Interest on Long Term Debt	-
2270-Matured Long Term Debt	-
2272-Matured Interest on Long Term Debt	-
2285-Obligations Under Capital Leases--Current	-
2290-Commodity Taxes	20,221.68
2292-Payroll Deductions / Expenses Payable	25,448.48
2294-Accrual for Taxes, "Payments in Lieu" of Taxes, Etc.	-
2296-Future Income Taxes - Current	-
1650-Current Liabilities Total	**5,891,196.76**

1700-Non-Current Liabilities	
2305-Accumulated Provision for Injuries and Damages	-
2306-Employee Future Benefits	211,109.00
2308-Other Pensions - Past Service Liability	-
2310-Vested Sick Leave Liability	-
2315-Accumulated Provision for Rate Refunds	-
2320-Other Miscellaneous Non-Current Liabilities	80,710.92
2325-Obligations Under Capital Lease--Non-Current	-
2330-Devolpment Charge Fund	-
2335-Long Term Customer Deposits	-
2340-Collateral Funds Liability	-
2345-Unamortized Premium on Long Term Debt	-
2348-O.M.E.R.S. - Past Service Liability - Long Term Portion	-
2350-Future Income Tax - Non-Current	(90,000.00)
2405-Other Regulatory Liabilities	333,333.36
2410-Deferred Gains From Disposition of Utility Plant	-
2415-Unamortized Gain on Reacquired Debt	-
2425-Other Deferred Credits	-
2435-Accrued Rate-Payer Benefit	-
1700-Non-Current Liabilities Total	**535,153.28**

Account Description	Total
1800-Long-Term Debt	
2505-Debentures Outstanding - Long Term Portion	-
2510-Debenture Advances	-
2515-Required Bonds (LTD CIBC 2551)	793,112.53
2520-Other Long Term Debt	-
2525-Term Bank Loans - Long Term Portion	-
2530-Ontario Hydro Debt Outstanding - Long Term Portion	-
2550-Advances from Associated Companies	1,710,170.00
1800-Long-Term Debt Total	**2,503,282.53**

1850-Shareholders' Equity	
3005-Common Shares Issued	5,101,340.00
3008-Preference Shares Issued	-
3010-Contributed Surplus	-
3020-Donations Received	-
3022-Devolpment Charges Transferred to Equity	-
3026-Capital Stock Held in Treasury	-
3030-Miscellaneous Paid-In Capital (Dev Chg Trust to Equity)	2,966,013.72
3035-Installments Received on Capital Stock	-
3040-Appropriated Retained Earnings	-
3045-Unappropriated Retained Earnings	1,587,358.76
3046-Balance Transferred From Income	237,248.24
3047-Appropriations of Retained Earnings - Current Period	-
3048-Dividends Payable-Preference Shares	-
3049-Dividends Payable-Common Shares	-
3055-Adjustment to Retained Earnings	-
3065-Unappropriated Undistributed Subsidiary Earnings	-
1850-Shareholders' Equity Total	**9,891,960.72**

Total Liabilities & Shareholder's Equity	**18,821,593.29**

Balance Sheet Total	0.00

COLLUS Power Corp
2008 STATEMENT OF INCOME AND RETAINED EARNINGS

Account Description	Total
3000-Sales of Electricity	
4006-Residential Energy Sales (plus RPP Variance Settlement)	(5,589,816.15)
4010-Commercial Energy Sales	(7,875,182.83)
4015-Industrial Energy Sales	-
4020-Energy Sales to Large Users	(1,970,890.04)
4025-Street Lighting Energy Sales	(122,013.68)
4030-Sentinel Energy Sales	-
4035-General Energy Sales	-
4040-Other Energy Sales to Public Authorities	-
4045-Energy Sales to Railroads and Railways	-
4050-Revenue Adjustment	-
4055-Energy Sales for Resale	(2,552,682.67)
4060-Interdepartmental Energy Sales	-
4062-WMS	(2,060,286.78)
4064-Billed WMS-One Time	-
4066-NS	(1,344,654.03)
4068-CS (plus Low voltage)	(818,656.00)
4075-LV Charges	(550,000.00)
3000-Sales of Electricity Total	**(22,884,182.17)**
3050-Revenues From Services - Distirbution	
4080-Distribution Services Revenue	(4,559,000.00)
4082-RS Rev	(23,000.00)
4084-Serv Tx Requests	(8,000.00)
4090-Electric Services Incidental to Energy Sales	-
3050-Revenues From Services - Distirbution Total	**(4,590,000.00)**
3100-Other Operating Revenues	
4205-Interdepartmental Rents	-
4210-Rent from Electric Property	(85,000.00)
4215-Other Utility Operating Income	-
4220-Other Electric Revenues	-
4225-Late Payment Charges	(55,000.00)
4230-Sales of Water and Water Power	-
4235-Miscellaneous Service Revenues (4220,4235-00,01,02,03)	(155,000.00)
4240-Provision for Rate Refunds	-
4245-Government Assistance Directly Credited to Income	-
3100-Other Operating Revenues Total	**(295,000.00)**

Account Description	Total
3150-Other Income & Deductions	
4305-Regulatory Debits	18,527.77
4310-Regulatory Credits	-
4315-Revenues from Electric Plant Leased to Others	-
4320-Expenses of Electric Plant Leased to Others	-
4325-Revenues from Merchandise, Jobbing, Etc.	-
4330-Costs and Expenses of Merchandising, Jobbing, Etc	-
4335-Profits and Losses from Financial Instrument Hedges	-
4340-Profits and Losses from Financial Instrument Investments	-
4345-Gains from Disposition of Future Use Utility Plant	-
4350-Losses from Disposition of Future Use Utility Plant	-
4355-Gain on Disposition of Utility and Other Property	-
4360-Loss on Disposition of Utility and Other Property	-
4365-Gains from Disposition of Allowances for Emission	-
4370-Losses from Disposition of Allowances for Emission	-
4375-Revenues from Non-Utility Operations	-
4380-Expenses of Non-Utility Operations	-
4385-Expenses of Non-Utility Operations	-
4390-Miscellaneous Non-Operating Income	-
4395-Rate-Payer Benefit Including Interest	-
4398-Foreign Exchange Gains and Losses, Including Amortization	-
3150-Other Income & Deductions Total	**18,527.77**
3200-Investment Income	
4405-Interest and Dividend Income	(132,741.05)
4415-Equity in Earnings of Subsidiary Companies	-
3200-Investment Income Total	**(132,741.05)**
3350-Power Supply Expenses	
4705-Power Purchased (plus Global Adj. 4706)	18,110,585.37
4708-WMS	2,060,286.78
4710-Cost of Power Adjustments	-
4712-0	-
4714-NW	1,344,654.03
4715-System Control and Load Dispatching	-
4716-NCN	818,656.00
4720-Other Expenses	-
4725-Competition Transition Expense	-
4730-Rural Rate Assistance Expense	-
4750-LV Charges	550,000.00
3350-Power Supply Expenses Total	**22,884,182.17**

Account Description	Total
3500-Distribution Expenses - Operation	
5005-Operation Supervision and Engineering	73,300.00
5010-Load Dispatching (SCADA)	43,500.00
5012-Station Buildings and Fixtures Expense	18,000.00
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	6,000.00
5020-Overhead Distribution Lines and Feeders - Operation Labour	22,000.00
5025-Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	-
5030-Overhead Subtransmission Feeders - Operation	-
5035-Overhead Distribution Transformers - Operation	3,000.00
5040-Underground Distribution Lines and Feeders - Operation Labour	-
5045-Underground Distribution Lines and Feeders - Operation Supplies and Expenses	-
5050-Underground Subtransmission Feeders - Operation	-
5055-Underground Distribution Transformers - Operation	-
5060-Street Lighting and Signal System Expense	-
5065-Meter Expense	1,500.00
5070-Customer Premises - Operation Labour	-
5075-Customer Premises - Materials and Expenses	-
5085-Miscellaneous Distribution Expense	77,000.00
5090-Underground Distribution Lines and Feeders - Rental Paid	-
5095-Overhead Distribution Lines and Feeders - Rental Paid	-
5096-Other Rent	30,000.00
3500-Distribution Expenses - Operation Total	**274,300.00**

Account Description	Total
3550-Distribution Expenses - Maintenance	
5105-Maintenance Supervision and Engineering	60,000.00
5110-Maintenance of Structures	25,000.00
5112-Maintenance of Transformer Station Equipment	-
5114-Mtaint Dist Stn Equip	38,100.00
5120-Maintenance of Poles, Towers and Fixtures	72,725.00
5125-Maintenance of Overhead Conductors and Devices	247,500.00
5130-Maintenance of Overhead Services	170,500.00
5135-Overhead Distribution Lines and Feeders - Right of Way	218,000.00
5145-Maintenance of Underground Conduit	-
5150-Maintenance of Underground Conductors and Devices	110,000.00
5155-Maintenance of Underground Services	201,500.00
5160-Maintenance of Line Transformers	111,000.00
5165-Maintenance of Street Lighting and Signal Systems	-
5170-Sentinel Lights - Labour	-
5172-Sentinel Lights - Materials and Expenses	-
5175-Maintenance of Meters	246,500.00
5178-Customer Installations Expenses - Leased Property	-
5195-Maintenance of Other Installations on Customer Premises	-
3550-Distribution Expenses - Maintenance Total	**1,500,825.00**

Account Description	Total
3650-Billing and Collecting	
5305-Supervision	36,000.00
5310-Meter Reading Expense	82,000.00
5315-Customer Billing (5315, 0000-2)	429,109.00
5320-Collecting (5315-0003,5320)	55,000.00
5325-Collecting - Cash Over and Short	-
5330-Collection Charges	-
5335-Bad Debt Expense	70,000.00
5340-Miscellaneous Customer Accounts Expenses	-
3650-Billing and Collecting Total	**672,109.00**

Account Description	Total
3700-Community Relations	
5405-Supervision	-
5410-Community Relations - Sundry	-
5415-Energy Conservation	-
5420-Community Safety Program	-
5425-Miscellaneous Customer Service and Informational Expenses	90,085.00
3700-Community Relations Total	**90,085.00**

Account Description	Total
3800-Administrative and General Expenses	
5605-Executive Salaries and Expenses (plus Board Exp)	221,296.00
5610-Management Salaries and Expenses	173,700.00
5615-General Administrative Salaries and Expenses	308,695.00
5620-Office Supplies and Expenses	-
5625-Administrative Expense Transferred-Credit	-
5630-Outside Services Employed	251,300.00
5635-Property Insurance	2,000.00
5640-Injuries and Damages	1,000.00
5645-Employee Pensions and Benefits	-
5650-Franchise Requirements (Extra Expense rate app	-
5655-Regulatory Expenses	2,750.00
5660-General Advertising Expenses (ESA Expense)	7,250.00
5665-Miscellaneous Expenses	4,750.00
5670-Rent	-
5675-Maintenance of General Plant	20,250.00
5680-Electrical Safety Authority Fees	-
5685-Independent Market Operator Fees and Penalties	-
5695-OM&A Contra Account	-
3800-Administrative and General Expenses Total	**992,991.00**
3850-Amortization Expense	
5705-Amortization Expense - Property, Plant and Equipment(759490.55+8155.00)	886,996.98
5710-Amortization of Limited Term Electric Plant	-
5715-Amortization of Intangibles and Other Electric Plant	-
5720-Amortization of Electric Plant Acquisition Adjustments	-
5725-Miscellaneous Amortization	-
5730-Amortization of Unrecovered Plant and Regulatory Study Costs	-
5735-Amortization of Deferred Development Costs	-
5740-Amortization of Deferred Charges	-
3850-Amortization Expense Total	**886,996.98**

Account Description	Total
3900-Interest Expense	
6005-Interest on Long Term Debt	194,073.00
6010-Amortization of Debt Discount and Expense	-
6015-Amortization of Premium on Debt-Credit	-
6020-Amortization of Loss on Reacquired Debt	-
6025-Amortization of Gain on Reacquired Debt-Credit	-
6030-Interest on Debt to Associated Companies	-
6035-Other Interest Expense	50,000.00
6040-Allowance for Borrowed Funds Used During Construction-Credit	-
6042-Allowance for Other Funds Used During Construction	-
6045-Interest Expense on Capital Lease Obligations	-
3900-Interest Expense Total	**244,073.00**
3950-Taxes Other Than Income Taxes	
6105-Taxes Other Than Income Taxes	8,916.00
3950-Taxes Other Than Income Taxes Total	**8,916.00**
4000-Income Taxes	
6110-Income Taxes	91,669.07
6115-Provision for Future Income Taxes	-
4000-Income Taxes Total	**91,669.07**
4100-Extraordinary & Other Items	
6205-Donations	-
6210-Life Insurance	-
6215-Penalties	-
6225-Other Deductions (Extraordinary Inc)	-
4100-Extraordinary & Other Items Total	**-**
Net Income - (Gain)/Loss	**(237,248.24)**

COLLUS Power Corp
2009 BALANCE SHEET

Account Description	Total
1050-Current Assets	
1005-Cash	800,767.48
1010-Cash Advances and Working Funds	-
1020-Interest Special Deposits	-
1030-Dividend Special Deposits	-
1040-Other Special Deposits	-
1060-Term Deposits	-
1070-Current Investments	-
1100-Customer Accounts Receivable	2,500,000.00
1102-Accounts Receivable - Services (1110-0001)	100,000.00
1104-Accounts Receivable - Recoverable Work	500,000.00
1105-Accounts Receivable - Merchandise, Jobbing, etc.	250,000.00
1110-Other Accounts Receivable(1110, 1110-02)	900,000.00
1120-Accrued Utility Revenues	3,100,000.00
1130-Accumulated Provision for Uncollectable Accounts -- Credit	(81,157.00)
1140-Interest and Dividends Receivable	32,153.50
1150-Rents Receivable	-
1170-Notes Receivable	-
1180-Prepayments	79,157.22
1190-Miscellaneous Current and Accrued Assets	-
1200-Accounts Receivable from Associated Companies	-
1210-Notes Receivable from Associated Companies	-
1050-Current Assets Total	**8,180,921.20**

1100-Inventory	
1305-Fuel Stock	-
1330-Plant Materials and Operating Supplies	282,492.57
1340-Merchandise	-
1350-Other Material and Supplies	-
1100-Inventory Total	**282,492.57**

1150-Non-Current Assets	
1405-Long Term Investments in Non-Associated Companies	-
1408-Long Term Receivable - Street Lighting Transfer	-
1410-Other Special or Collateral Funds	-
1415-Sinking Funds	-
1425-Unamortized Debt Expense	-
1445-Unamortized Discount on Long-Term Debt--Debit	-
1455-Unamortized Deferred Foreign Currency Translation Gains and Losses	-
1460-Other Non-Current Assets	-
1465-O.M.E.R.S. Past Service Costs	-
1470-Past Service Costs - Employee Future Benefits	-
1475-Past Service Costs -Other Pension Plans	-
1480-Portfolio Investments - Associated Companies	-
1485-Investment in Subsidiary Companies - Significant Influence	-
1490-Investment in Subsidiary Companies	-
1150-Non-Current Assets Total	**-**

Account Description	Total
1200-Other Assets and Deferred Charges	
1505-Unrecovered Plant and Regulatory Study Costs	-
1508-Other Regulatory Assets	89,521.17
1510-Preliminary Survey and Investigation Charges	-
1515-Emission Allowance Inventory	-
1516-Emission Allowance Withheld	-
1518-0	-
1525-Miscellaneous Deferred Debits	114,170.00
1530-Deferred Losses from Disposition of Utility Plant	-
1540-Deferred Losses from Disposition of Utility Plant	-
1545-Development Charge Deposits/ Receivables	-
1548-RCVA - Service Transaction Request (STR)	-
1550-LV Charges - Variance	334,851.00
1555-Smart Meters Recovery	(150,000.00)
1556-Smart Meters OM & A (+ Capital 07)	128,750.00
1562-Deferred PILs	95,510.34
1563-Deferred PILs - Contra	(95,510.34)
1565-C & DM Costs	(376,000.00)
1566-C & DM Costs Contra	376,000.00
1570-Qualifying Transition Costs	-
1571-Pre Market CofP Variance	-
1572-Extraordinary Event Losses	-
1574-Deferred Rate Impact Amounts	-
1580-RSVA - Wholesale Market Services	(634,379.85)
1582-RSVA - One-Time	21,444.35
1584-RSVA - Network Charges	(595,887.94)
1586-RSVA - Connection Charges	(1,171,976.87)
1588-RSVA - Commodity (Power)(& 1589 GA)	(199,775.63)
1590-Recovery of Regulatory Assets (25% of 2002 bal.)	(300,000.00)
1200-Other Assets and Deferred Charges Total	**(2,363,283.77)**

1450-Distribution Plant	
1805-Land	90,438.88
1806-Land Rights	-
1808-Buildings and Fixtures	80,668.44
1810-Leasehold Improvements	-
1815-Transformer Station Equipment - Normally Primary above 50 kV	-
1820-Distribution Station Equipment - Normally Primary below 50 kV	5,026,646.68
1825-Storage Battery Equipment	-
1830-Poles, Towers and Fixtures	-
1835-Overhead Conductors and Devices	10,298,501.46
1840-Underground Conduit	-
1845-Underground Conductors and Devices	7,005,390.93
1850-Line Transformers	4,420,170.32
1855-Services	528,412.57
1860-Meters	1,497,576.23
1865-Other Installations on Customer's Premises	-
1450-Distribution Plant Total	**28,947,805.51**

Account Description	Total
1500-General Plant	
1905-Land	-
1906-Land Rights	-
1908-Buildings and Fixtures	-
1910-Leasehold Improvements	-
1915-Office Furniture and Equipment	265,327.34
1920-Computer Equipment - Hardware	-
1925-Computer Software	518,853.12
1930-Transportation Equipment	1,465,996.65
1935-Stores Equipment	6,634.98
1940-Tools, Shop and Garage Equipment	-
1945-Measurement and Testing Equipment	51,800.00
1950-Power Operated Equipment	37,260.00
1955-Communication Equipment	71,751.41
1960-Miscellaneous Equipment	203,814.49
1970-Load Management Controls - Customer Premises	878,887.18
1975-Load Management Controls - Utility Premises	-
1980-System Supervisory Equipment	626,251.55
1985-Sentinel Lighting Rentals	7,063.04
1990-Other Tangible Property	-
1995-Contributions and Grants	(6,579,229.55)
1500-General Plant Total	**(2,445,589.79)**

1550-Other Capital Assets	
2005-Property Under Capital Leases	-
2010-Electric Plant Purchased or Sold	-
2020-Experimental Electric Plant Unclassified	-
2030-Electric Plant and Equipment Leased to Others	-
2040-Electric Plant Held for Future Use	-
2050-Completed Construction Not Classified--Electric	-
2055-Construction Work in Progress--Electric	146,049.29
2060-Electric Plant Acquisition Adjustment	276,703.91
2065-Other Electric Plant Adjustment	-
2070-Other Utility Plant	-
2075-Non-Utility Property Owned or Under Capital Lease	-
1550-Other Capital Assets Total	**422,753.20**

1600-Accumulated Amortization	
2105-Accumulated Amortization of Electric Utility Plant - Property, Plant and Equipment	(13,831,050.16)
2120-Accumulated Amortization of Electric Utility Plant - Intangibles	-
2140-Accumulated Amortization of Electric Plant Acquisition Adjustment	-
2160-Accumulated Amortization of Other Utility Plant	-
2180-Accumulated Amortization of Non-Utility Property	-
1600-Accumulated Amortization Total	**(13,831,050.16)**

Total Assets	**19,194,048.76**

Account Description	Total
1650-Current Liabilities	
2205-Accounts Payable (2205-00,01,02,03&04) (2206&07 LTD&GST)	3,573,997.52
2208-Customer Credit Balances	477,835.37
2210-Current Portion of Customer Deposits (&Int 2210-00&01)	358,775.82
2215-Dividends Declared (Const Work Deposits 2211)	744,720.80
2220-Miscellaneous Current and Accrued Liabilities	500,000.00
2225-Notes and Loans Payable	-
2240-Accounts Payable to Associated Companies (OPG Rebate)	12,072.51
2242-Notes Payable to Associated Companies	-
2250-Competition Transition Charges Payable (DRC)	178,124.58
2252-Transmission Charges Payable	-
2254-Electric Safety Authority Fees Payable	-
2256-Independent Market Operator Fees and Penalties Payable	-
2260-Current Portion of Long Term Debt	-
2262-Ontario Hydro Debt - Current Portion	-
2264-Pensions and Employee Benefits - Current Portion	-
2268-Accrued Interest on Long Term Debt	-
2270-Matured Long Term Debt	-
2272-Matured Interest on Long Term Debt	-
2285-Obligations Under Capital Leases--Current	-
2290-Commodity Taxes	20,221.68
2292-Payroll Deductions / Expenses Payable	25,448.48
2294-Accrual for Taxes, "Payments in Lieu" of Taxes, Etc.	-
2296-Future Income Taxes - Current	-
1650-Current Liabilities Total	**5,891,196.76**

1700-Non-Current Liabilities	
2305-Accumulated Provision for Injuries and Damages	-
2306-Employee Future Benefits	211,109.00
2308-Other Pensions - Past Service Liability	-
2310-Vested Sick Leave Liability	-
2315-Accumulated Provision for Rate Refunds	-
2320-Other Miscellaneous Non-Current Liabilities	80,710.92
2325-Obligations Under Capital Lease--Non-Current	-
2330-Devolpment Charge Fund	-
2335-Long Term Customer Deposits	-
2340-Collateral Funds Liability	-
2345-Unamortized Premium on Long Term Debt	-
2348-O.M.E.R.S. - Past Service Liability - Long Term Portion	-
2350-Future Income Tax - Non-Current	(90,000.00)
2405-Other Regulatory Liabilities	425,000.00
2410-Deferred Gains From Disposition of Utility Plant	-
2415-Unamortized Gain on Reacquired Debt	-
2425-Other Deferred Credits	-
2435-Accrued Rate-Payer Benefit	-
1700-Non-Current Liabilities Total	**626,819.92**

Account Description	Total
1800-Long-Term Debt	
2505-Debentures Outstanding - Long Term Portion	-
2510-Debenture Advances	-
2515-Required Bonds (LTD CIBC 2551)	880,000.00
2520-Other Long Term Debt	-
2525-Term Bank Loans - Long Term Portion	-
2530-Ontario Hydro Debt Outstanding - Long Term Portion	-
2550-Advances from Associated Companies	1,710,170.00
1800-Long-Term Debt Total	**2,590,170.00**

1850-Shareholders' Equity	
3005-Common Shares Issued	5,101,340.00
3008-Preference Shares Issued	-
3010-Contributed Surplus	-
3020-Donations Received	-
3022-Devolpment Charges Transferred to Equity	-
3026-Capital Stock Held in Treasury	-
3030-Miscellaneous Paid-In Capital (Dev Chg Trust to Equity)	2,966,013.72
3035-Installments Received on Capital Stock	-
3040-Appropriated Retained Earnings	-
3045-Unappropriated Retained Earnings	1,766,933.47
3046-Balance Transferred From Income	251,574.89
3047-Appropriations of Retained Earnings - Current Period	-
3048-Dividends Payable-Preference Shares	-
3049-Dividends Payable-Common Shares	-
3055-Adjustment to Retained Earnings	-
3065-Unappropriated Undistributed Subsidiary Earnings	-
1850-Shareholders' Equity Total	**10,085,862.08**

Total Liabilities & Shareholder's Equity	**19,194,048.76**

Balance Sheet Total	(0.00)

COLLUS Power Corp
2009 STATEMENT OF INCOME AND RETAINED EARNINGS

Account Description	Total
3000-Sales of Electricity	
4006-Residential Energy Sales (plus RPP Variance Settlement)	(5,807,793.92)
4010-Commercial Energy Sales	(8,777,906.52)
4015-Industrial Energy Sales	-
4020-Energy Sales to Large Users	(2,108,919.02)
4025-Street Lighting Energy Sales	(122,013.68)
4030-Sentinel Energy Sales	-
4035-General Energy Sales	-
4040-Other Energy Sales to Public Authorities	-
4045-Energy Sales to Railroads and Railways	-
4050-Revenue Adjustment	-
4055-Energy Sales for Resale	(2,631,691.95)
4060-Interdepartmental Energy Sales	-
4062-WMS	(2,212,475.67)
4064-Billed WMS-One Time	-
4066-NS	(1,451,363.72)
4068-CS (plus Low voltage)	(882,936.74)
4075-LV Charges	(550,000.00)
3000-Sales of Electricity Total	**(24,545,101.23)**
3050-Revenues From Services - Distirbution	
4080-Distribution Services Revenue	(4,946,700.00)
4082-RS Rev	(23,000.00)
4084-Serv Tx Requests	(8,000.00)
4090-Electric Services Incidental to Energy Sales	-
3050-Revenues From Services - Distirbution Total	**(4,977,700.00)**
3100-Other Operating Revenues	
4205-Interdepartmental Rents	-
4210-Rent from Electric Property	(85,000.00)
4215-Other Utility Operating Income	-
4220-Other Electric Revenues	-
4225-Late Payment Charges	(55,000.00)
4230-Sales of Water and Water Power	-
4235-Miscellaneous Service Revenues (4220,4235-00,01,02,03)	(155,000.00)
4240-Provision for Rate Refunds	-
4245-Government Assistance Directly Credited to Income	-
3100-Other Operating Revenues Total	**(295,000.00)**

Account Description	Total
3150-Other Income & Deductions	
4305-Regulatory Debits	-
4310-Regulatory Credits	-
4315-Revenues from Electric Plant Leased to Others	-
4320-Expenses of Electric Plant Leased to Others	-
4325-Revenues from Merchandise, Jobbing, Etc.	-
4330-Costs and Expenses of Merchandising, Jobbing, Etc	-
4335-Profits and Losses from Financial Instrument Hedges	-
4340-Profits and Losses from Financial Instrument Investments	-
4345-Gains from Disposition of Future Use Utility Plant	-
4350-Losses from Disposition of Future Use Utility Plant	-
4355-Gain on Disposition of Utility and Other Property	-
4360-Loss on Disposition of Utility and Other Property	-
4365-Gains from Disposition of Allowances for Emission	-
4370-Losses from Disposition of Allowances for Emission	-
4375-Revenues from Non-Utility Operations	-
4380-Expenses of Non-Utility Operations	-
4385-Expenses of Non-Utility Operations	-
4390-Miscellaneous Non-Operating Income	-
4395-Rate-Payer Benefit Including Interest	-
4398-Foreign Exchange Gains and Losses, Including Amortization	-
3150-Other Income & Deductions Total	**-**
3200-Investment Income	
4405-Interest and Dividend Income	(68,855.77)
4415-Equity in Earnings of Subsidiary Companies	-
3200-Investment Income Total	**(68,855.77)**
3350-Power Supply Expenses	
4705-Power Purchased (plus Global Adj. 4706)	19,448,374.82
4708-WMS	2,212,475.67
4710-Cost of Power Adjustments	-
4712-0	-
4714-NW	1,451,363.72
4715-System Control and Load Dispatching	-
4716-NCN	882,936.74
4720-Other Expenses	-
4725-Competition Transition Expense	-
4730-Rural Rate Assistance Expense	-
4750-LV Charges	550,000.00
3350-Power Supply Expenses Total	**24,545,150.95**

Account Description	Total
3500-Distribution Expenses - Operation	
5005-Operation Supervision and Engineering	76,800.00
5010-Load Dispatching (SCADA)	46,500.00
5012-Station Buildings and Fixtures Expense	19,000.00
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	10,000.00
5020-Overhead Distribution Lines and Feeders - Operation Labour	26,000.00
5025-Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	-
5030-Overhead Subtransmission Feeders - Operation	-
5035-Overhead Distribution Transformers - Operation	3,500.00
5040-Underground Distribution Lines and Feeders - Operation Labour	-
5045-Underground Distribution Lines and Feeders - Operation Supplies and Expenses	-
5050-Underground Subtransmission Feeders - Operation	-
5055-Underground Distribution Transformers - Operation	-
5060-Street Lighting and Signal System Expense	-
5065-Meter Expense	1,500.00
5070-Customer Premises - Operation Labour	-
5075-Customer Premises - Materials and Expenses	-
5085-Miscellaneous Distribution Expense	78,000.00
5090-Underground Distribution Lines and Feeders - Rental Paid	-
5095-Overhead Distribution Lines and Feeders - Rental Paid	-
5096-Other Rent	30,000.00
3500-Distribution Expenses - Operation Total	**291,300.00**

Account Description	Total
3550-Distribution Expenses - Maintenance	
5105-Maintenance Supervision and Engineering	62,000.00
5110-Maintenance of Structures	26,000.00
5112-Maintenance of Transformer Station Equipment	-
5114-Mtaint Dist Stn Equip	59,600.00
5120-Maintenance of Poles, Towers and Fixtures	68,225.00
5125-Maintenance of Overhead Conductors and Devices	263,500.00
5130-Maintenance of Overhead Services	189,000.00
5135-Overhead Distribution Lines and Feeders - Right of Way	244,000.00
5145-Maintenance of Underground Conduit	-
5150-Maintenance of Underground Conductors and Devices	120,000.00
5155-Maintenance of Underground Services	236,500.00
5160-Maintenance of Line Transformers	100,000.00
5165-Maintenance of Street Lighting and Signal Systems	-
5170-Sentinel Lights - Labour	-
5172-Sentinel Lights - Materials and Expenses	-
5175-Maintenance of Meters	259,500.00
5178-Customer Installations Expenses - Leased Property	-
5195-Maintenance of Other Installations on Customer Premises	-
3550-Distribution Expenses - Maintenance Total	**1,628,325.00**
3650-Billing and Collecting	
5305-Supervision	49,000.00
5310-Meter Reading Expense	85,000.00
5315-Customer Billing (5315, 0000-2)	489,093.00
5320-Collecting (5315-0003,5320)	69,000.00
5325-Collecting - Cash Over and Short	-
5330-Collection Charges	-
5335-Bad Debt Expense	70,000.00
5340-Miscellaneous Customer Accounts Expenses	-
3650-Billing and Collecting Total	**762,093.00**
3700-Community Relations	
5405-Supervision	-
5410-Community Relations - Sundry	-
5415-Energy Conservation	-
5420-Community Safety Program	-
5425-Miscellaneous Customer Service and Informational Expenses	107,389.00
3700-Community Relations Total	**107,389.00**

Account Description	Total
3800-Administrative and General Expenses	
5605-Executive Salaries and Expenses (plus Board Exp)	230,611.00
5610-Management Salaries and Expenses	192,500.00
5615-General Administrative Salaries and Expenses	324,130.00
5620-Office Supplies and Expenses	-
5625-Administrative Expense Transferred-Credit	-
5630-Outside Services Employed	181,500.00
5635-Property Insurance	2,000.00
5640-Injuries and Damages	1,000.00
5645-Employee Pensions and Benefits	-
5650-Franchise Requirements (Extra Expense rate app	-
5655-Regulatory Expenses	43,000.00
5660-General Advertising Expenses (ESA Expense)	7,500.00
5665-Miscellaneous Expenses	5,000.00
5670-Rent	-
5675-Maintenance of General Plant	21,500.00
5680-Electrical Safety Authority Fees	-
5685-Independent Market Operator Fees and Penalties	-
5695-OM&A Contra Account	-
3800-Administrative and General Expenses Total	**1,008,741.00**
3850-Amortization Expense	
5705-Amortization Expense - Property, Plant and Equipment(759490.55+8155.00)	983,056.00
5710-Amortization of Limited Term Electric Plant	-
5715-Amortization of Intangibles and Other Electric Plant	-
5720-Amortization of Electric Plant Acquisition Adjustments	-
5725-Miscellaneous Amortization	-
5730-Amortization of Unrecovered Plant and Regulatory Study Costs	-
5735-Amortization of Deferred Development Costs	-
5740-Amortization of Deferred Charges	-
3850-Amortization Expense Total	**983,056.00**

Account Description	Total
3900-Interest Expense	
6005-Interest on Long Term Debt	181,806.00
6010-Amortization of Debt Discount and Expense	-
6015-Amortization of Premium on Debt-Credit	-
6020-Amortization of Loss on Reacquired Debt	-
6025-Amortization of Gain on Reacquired Debt-Credit	-
6030-Interest on Debt to Associated Companies	-
6035-Other Interest Expense	50,000.00
6040-Allowance for Borrowed Funds Used During Construction-Credit	-
6042-Allowance for Other Funds Used During Construction	-
6045-Interest Expense on Capital Lease Obligations	-
3900-Interest Expense Total	**231,806.00**
3950-Taxes Other Than Income Taxes	
6105-Taxes Other Than Income Taxes	8,916.00
3950-Taxes Other Than Income Taxes Total	**8,916.00**
4000-Income Taxes	
6110-Income Taxes	68,305.16
6115-Provision for Future Income Taxes	-
4000-Income Taxes Total	**68,305.16**
4100-Extraordinary & Other Items	
6205-Donations	-
6210-Life Insurance	-
6215-Penalties	-
6225-Other Deductions (Extraordinary Inc)	-
4100-Extraordinary & Other Items Total	**-**
Net Income - (Gain)/Loss	**(251,574.89)**

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. COLLUS Power Corp rate base calculation excludes any non-distribution assets. Controllable expenses include operations and maintenance, billing and collecting and administration expenses.

COLLUS Power Corp has provided its rate base calculations for the years 2006 Board Approved, 2006 Actual, 2007 Actual, 2008 Bridge Year and 2009 Test Year in Table 1 below. COLLUS Power Corp has calculated its 2009 rate base as $ 15,966,037 .

Table 1
Summary of Rate Base

Description	2006 OEB Approved	2006 Actual	2007 Actual Year	2008 Bridge Year	2009 Test Year
Gross Fixed Assets	18,377,154	19,735,623	21,615,716	23,484,716	26,502,216
Accumulated Depreciation	(9,025,507)	10,943,323	11,754,666	12,729,382	13,831,050
Net Book Value	9,351,647	8,792,300	9,861,050	10,755,334	12,671,166
Average Net Book Value	9,351,647	8,965,035	9,326,675	10,308,192	11,713,250
Working Capital	29,779,174	26,807,266	26,972,085	26,423,408	28,351,915
Working Capital Allowance	4,466,876	4,021,090	4,045,813	3,963,511	4,252,787
Rate Base	**13,818,523**	**12,986,124**	**13,372,488**	**14,271,703**	**15,966,037**

COLLUS Power Corp 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. Details of COLLUS Power Corp calculation of its working capital allowance are provided at Exhibit 2, Tab 4, Schedule 1, below.

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	26,526,514	23,554,168	23,678,032	22,884,182	24,545,151
Operations	260,626	285,179	245,331	274,300	291,300
Maintenance	1,163,605	1,263,888	1,322,165	1,500,825	1,628,325
Billing & Collecting	538,249	592,333	655,645	722,109	762,093
Community Relations	88,563	154,243	157,924	100,085	107,389
Administration & General Expense	1,200,627	952,430	904,732	932,991	1,008,741
Property Taxes	990	5,025	8,256	8,916	8,916
Working Capital	**29,779,174**	**26,807,266**	**26,972,085**	**26,423,408**	**28,351,915**

COLLUS Power Corp Distribution System:

COLLUS Power Corp owns and operates the electricity distribution system in its licensed service area in the Town of Collingwood and Towns of Thornbury, Stayner and Creemore, serving approximately 14,500 Residential, General Service, Large Use, Street Light and Unmetered Scattered Load customers.

COLLUS Power Corp is supplied through the Hydro One transmission system at voltages of 44 kV as well as 8 kV . Electricity is then distributed through COLLUS Power Corp service area of 57 square kilometres, over 109 kilometres of underground cable and 213 kilometres of overhead cable. COLLUS Power Corp delivers electricity at its primary supply voltage to Industrial Customers (44 kV delta), General Service (8 or 4 kV wye) and Residential (4.8 or 2.4 kV). Through its owned 12 distribution stations primary voltage is stepped down to service Industrial & General Service (347/600 wye 600 delta, 240 delta, 120/208 wye, three phase) and Residential (120/240 single phase). Voltage is stepped down through approximately 1,550 LDC owned transformers.

COLLUS Power Corp monitors its distribution system through a control system at its' Operation Center (43 Stewart Road Collingwood). The control center operates the Supervisory Control and Data Acquisition ("SCADA") system twenty-four hours a day, seven days a week.

COLLUS Power Corp owns and maintains approximately 14,500 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. COLLUS Power Corp is currently not active in installing smart meters as part of the Province of Ontario's smart meter initiative, but is following the provincial process to become part of the regulated activity.

In managing its distribution system assets, COLLUS Power Corp main objective is to optimize performance of the assets at a reasonable cost with due regard for system reliability, safety and customer service requirements. In this application there are Distribution System Capital & Maintenance Budget Plans that have been incorporated in determining the required revenue requirement to bring these plans to fruition. Further information will be provided later in this application. COLLUS Power Corp considers performance-related asset information including, such as but not limited to, data on reliability, asset age and condition, loading, customer connection requirements, and system configuration, to determine investment needs of the system.

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

In addition to the capital needs of the network, COLLUS Power Corp provides for maintenance planning for the assets. The same preparation and consideration steps are undertaken before the Finance department establishes the recommended budget amounts. Further information on the application's Capital and Operation, Maintenance & Administration amounts will follow later in this application.

COLLUS Power Corp assets fall into two broad categories – distribution plant which includes assets such as wires, overhead and underground electricity distribution infrastructure, transformers, meters and substations; and general plant which includes assets such as buildings, computer hardware and software, office furniture and equipment, transportation equipment, communications equipment and tools. More detailed lists of distribution and general plant categories can be found in the Gross Assets Table at Exhibit 2, Tab 2, Schedule 2.

Distribution Plant Capital Projects:

The distribution plant capital projects normally are characterized under certain aspects of the general areas of concern that have to be considered carefully in fulfilling the goals of the LDC.

- **Customer Demand:**

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

- **Renewal:**

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

- **Security:**

There are some areas of the distribution system where failure of equipment may cause large outages, which cannot be restored through switching to alternate supplies. The probability and impact of asset failure at peak load are considered to determine the risk the failure creates. In these cases, projects are developed to add switching devices or create a backup feeder supply to reduce the risk to typical restoration times for COLLUS Power Corp.

- **Capacity:**

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

- **Reliability:**

The main driver for these investments is an analysis of what measures could be undertaken to improve COLLUS Power Corp reliability performance as measured by SAIDI, SAIFI and CAIDI indices, as well as direct feedback from our customers. These indices are indicators of the reliability of COLLUS Power Corp distribution system. These activities will support maintenance of or improvement to the Service Quality Indices measured and submitted to the OEB each year by COLLUS Power Corp.

- **Regulatory Requirements:**

These projects are system capital investments which are being driven by regulatory requirements. These may include, among others, directions from the OEB, the IESO, the Ministry of Energy or the Ministry of Environment. From 2006 to 2008 COLLUS Power Corp has placed into this category those projects relating to the elimination of long-term load transfers pursuant to the DSC.

- **Substations:**

Substation investments are undertaken to improve or maintain reliability to large numbers of customers and to maintain security and safety at the substations.

- **Customer Connections and Metering:**

Capital expenditures in this pool include meter installations and upgrades, capital components of wholesale and retail meter verification activities. COLLUS Power Corp is undertaking to initiate a smart meter program, as approved by Ontario Regulation 427/06 (Authorized Discretionary Metering Activity).

<u>General Plant Capital Projects</u>:

General plant capital projects have also been categorized into project pools. Each pool has a specific focus:

- **Customer Information System (CIS) Software:**

An extensive review of COLLUS Power Corp information technology ("IT") needs was required after its' current CIS software provider (Advanced Utility Systems owned by Harris Computer Systems) notified COLLUS Power Corp that, in the near future, the current Infinity System would not be maintained for the Ontario De-Regulated Market processes. The business applications chosen will be established to properly support the meter-to-bill business for the deregulated marketplace and to provide multi-functional support to asset management, work order management, finance, human resources management and supply chain management. COLLUS Power Corp critically relies on business applications architecture to reduce business risk for the utility and our customers. In short, the review determined that COLLUS Power Corp will implement the Harris Computer System's NorthStar 6 system to provide the required infrastructure. In keeping with COLLUS Power Corp's co-operative spirit in order to help minimize future costs, the CIS system will be combined in a single template format with Utility Collaborative System's five (5) other Ontario LDC's. By working together and utilizing the same system setup there will be major cost avoidance as the members split all on-going costs.

- **Other Computer Hardware and Software:**

This project pool includes required capital expenditures pertaining to the acquisition of new and replacement computer hardware, and new and upgraded computer software, based on a five year life cycle.

- **Transportation and Related Equipment:**

This project pool includes capital expenditures pertaining to the completion of the acquisition and modification of required new vehicles to support the construction and maintenance of the electricity distribution system. The vehicles outlined for acquisition will replace aging units.

- **Communications Equipment:**

This project pool includes capital expenditures pertaining to the purchase of telephone test equipment, meter reading communication equipment, desk phones, radios and backup equipment.

- **Tools and Equipment:**

This project pool includes capital expenditures pertaining to the replacement of tools and equipment that are worn, or have come to the end of their useful life, with newer and more ergonomically friendly tools and equipment.

COLLUS Power Corp capital projects for the 2009 Test Year are discussed in further detail below. Where capital projects have a projected cost greater than $126,712 (1% of COLLUS Power Corp total net fixed assets, being the materiality threshold in the Filing Requirements), COLLUS Power Corp has provided a project-specific justification. Similarly, written explanations have been provided for rate base-related variances that exceed materiality.

In support of its rate base calculation, COLLUS Power Corp has enclosed the information contemplated by the Filing Requirements, with respect to Gross Assets (Exhibit 2, Tab 2, Schedules 2 and 3); Accumulated Depreciation (Exhibit 2, Tab 2, Schedules 4 and 5); and Working Capital (Exhibit 2, Tab 4, Schedule 1).

Continuity schedules for 2006 Actual, the 2008 Bridge Year and the 2009 Test Year are provided at Exhibit 2, Tab 2, Schedule 1.

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 COLLUS Power Corp 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.

COLLUS Power Corp Budget Process:

The following comments provide an overview of COLLUS Power Corp budgeting process. Currently COLLUS Power Corp does not have a formal Asset Management Program in place, but it is in the process of implementing a formal process in the near future.

- **Overall Budget Process**

The 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, it does not change, but provides a plan against which actual results may be evaluated.

- **Responsibilities**

> It is the responsibility of the Finance department to coordinate the development of the operating budget, capital budget and forecast processes.

> Each department is responsible for preparing its operating budget, capital budget, and rolling forecasts.

> The CEO with assistance by the CFO 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 COLLUS Power Corp. It puts capital and operational plans into a common financial plan. The final document provides a comprehensive package of department budgets that collectively ensure that appropriate resources are designated for the various capital and operational needs of the utility for the coming year.

The departmental Budget Plans represent the output of detailed work plans based on required activities for the year. A copy of the 2008 and 2009 Capital Budget Plan for COLLUS Power Corp accompany this Schedule as Appendix A.

- **Budget Review Process:**

COLLUS Power Corp budget review process is as follows:

> Each department budget is reviewed and approved by the corresponding Manager/Director and submitted to the Finance department.

> The Finance department consolidates all departmental work plan budgets to produce budget reports by functional areas to be reviewed by the corresponding Management Team member(s).

> The Management Team member(s) will then have an opportunity to make recommendations to the consolidated budgets.

> A final budget package is produced to present to the Management Team for its review and approval for final recommendation to the Board.

- **The Actual-to-Budget Review Process:**

Once the budget is final, each department reviews and tracks progress against the budget on a monthly basis. Further, quarterly reviews and forecasts of actual and/or expected results against the budget are performed during the budget year. This review process involves the following activities:

> All Directors/Managers review budget progress on a monthly basis.

> All Directors/Managers review year-to-date ("YTD") operating results for their area(s) of responsibility on a quarter end basis.

> Significant variances in capital and operating expenditures based on YTD results are reviewed along with work plans in order to identify any changes that may have an impact on the forecast of actual expenditures.

> Any significant and/or material expenditures/savings that will affect the current year's operating results are incorporated into the actual-to-budget forecast. All expenditures and/or savings of greater than $10,000 are reported. An initial draft of the forecast is prepared based on the information provided and a review of significant variances/changes is conducted with each Manager/Director to create the forecast.

> The Management Team reviews the forecast and provides feedback, comments and adjustments before the forecast is finalized.

> The President/CEO approves the final forecast for presentation to the Board of Directors.

RATE BASE VARIANCE ANALYSIS:

The following Table 1 sets out COLLUS Power Corp 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	18,377,154	19,735,623	1,358,469	21,615,716	1,880,092	23,484,716	1,869,000	26,502,216	3,017,500
Accumulated Depreciation	9,025,507	10,943,323	1,917,816	11,754,666	811,343	12,729,382	974,716	13,831,050	1,101,668
Net Book Value (Actual not approved)	9,351,647	8,792,300	(559,347)	9,861,050	1,068,749	10,755,334	894,284	12,671,166	1,915,832
Average Net Book Value(Act not App)	9,351,647	8,965,035	(386,612)	9,326,675	361,640	10,308,192	981,517	11,713,250	1,405,058
Working Capital	29,779,174	26,807,266	(2,971,908)	26,972,085	164,819	26,423,408	(548,677)	28,351,915	1,928,507
Working Capital Allowance	4,466,876	4,021,090	(445,786)	4,045,813	24,723	3,963,511	(82,302)	4,252,787	289,276
Rate Base	13,818,523	12,986,124	(832,399)	13,372,488	386,363	14,271,703	899,215	15,966,037	1,694,334

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 & Tier 2 Adjustments. The variance between 2006 Actual and 2006 OEB Approved spans a two year period.

COLLUS Power Corp has calculated the variance threshold on its rate base to be $126,712 for 2009 in accordance with the Filing Requirements. This calculation and those for 2006, 2007 and 2008 are 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	$18,377,154	19,735,623.33	$21,615,716	$23,484,716	$26,502,216
Accumulated Depreciation	$9,025,507	10,943,323.25	$11,754,666	$12,729,382	$13,831,050
Net Book Value	$9,351,647	8,792,300.08	$9,861,050	$10,755,334	$12,671,166
Variance calc 1% NBV		$87,923	$98,610	$107,553	$126,712

COLLUS Power Corp 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 $15,966,037. Average net fixed assets accounts for $11,713,250 of this total. The allowance for working capital totals $4,252,787.

- **Comparison to 2008 Bridge Year:**

The total rate base is expected to be $1,694,334 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 $1,405,058. The increase in fixed assets along with the required detailed information for projects in excess of the applicable variance is discussed in detail by capital project in Exhibit 2, Tab 3, Schedule 1.

The working capital allowance increased by $289,276 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 4, Schedule 1.

2008 Bridge Year:

The total rate base for the 2008 Bridge Year is expected to be $14,271,703, which represents an increase of $899,215 over the 2007 Actual year. This change results in part from an increase in average net assets of $981,517. COLLUS Power Corp had two capital projects which exceeded the variance analysis threshold as calculated above in Table 1 for 2008, as determined in the Filing Requirements. The detailed analysis by project that is required is provided later in the report.

The working capital allowance decreased by $(82,302) from 2007. A detailed calculation of the working capital allowance for the 2008 Bridge Year can be found at Exhibit 2, Tab 4, Schedule 1.

2007 Actual:

The rate base of $13,372,488 for 2007 Actual increased over 2006 Actual by $386,363. This increase is made up of a change in average net assets of $361,640 and an increase in working capital allowance of $24,723. There were no specific projects that exceeded the materiality threshold level noted above for 2007.

2006 Actual:

The rate base of $12,986,124 for 2006 Actual was lower than the 2006 Board Approved by $(1,019,433). This difference is due to the expected 2006 EDR Tier 2 approved $1,000,000 investment in Substation infrastructure which was not completed until 2007, due to delivery timelines for transformers, and the main reason that the average net assets were lower by $(386,612). Also working capital allowance was lower by $(632,821).

CONTINUITY STATEMENTS:

Table 1
COLLUS Power Corp - Distribution & Operations
Fixed Asset Continuity Schedule
As at December 31, 2006

Fixed Asset Continuity Schedule (Distribution & Operations)
As at December 31, 2006

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
N/A	1805	Land	90,438.88	0.00		90,438.88	0.00	0.00		0.00	90,438.88
CEC	1806	Land Rights		0.00		0.00				0.00	0.00
1	1808	Buildings and Fixtures	80,668.44	0.00		80,668.44	47,726.44	2,142.00		49,868.44	30,800.00
	1810	Leasehold Improvements		0.00		0.00				0.00	0.00
	1815	Transformer Station Equipment - Normally Primary above 50 kV		0.00		0.00				0.00	0.00
1	1820	Distribution Station Equipment - Normally Primar	1,998,838.72	52,430.09		2,051,268.81	1,059,250.72	69,096.09		1,128,346.81	922,922.00
	1825	Storage Battery Equipment		0.00		0.00				0.00	0.00
1	1830	Poles, Towers and Fixtures		0.00		0.00				0.00	0.00
1	1835	Overhead Conductors and Devices	8,371,480.56	325,122.60		8,696,603.16	4,050,840.56	343,155.60		4,393,996.16	4,302,607.00
1	1840	Underground Conduit		0.00		0.00				0.00	0.00
1	1845	Underground Conductors and Devices	6,186,513.29	139,367.45		6,325,880.74	2,747,712.29	263,738.45		3,011,450.74	3,314,430.00
1	1850	Line Transformers	3,572,610.69	178,480.81		3,751,091.50	1,731,957.73	137,735.81		1,869,693.54	1,881,397.96
1	1855	Services	299,833.58	118,901.38		418,734.96	17,274.58	16,751.38		34,025.96	384,709.00
1	1860	Meters	1,267,871.58	75,606.89		1,343,478.47	650,775.58	49,216.89		699,992.47	643,486.00
	1865	Other Installations on Customer's Premises		0.00		0.00				0.00	0.00
N/A	1905	Land		0.00		0.00				0.00	0.00
CEC	1906	Land Rights		0.00		0.00				0.00	0.00
1	1908	Buildings and Fixtures		0.00		0.00				0.00	0.00
	1910	Leasehold Improvements		0.00		0.00				0.00	0.00
8	1915	Office Furniture and Equipment	90,327.34	0.00		90,327.34	81,201.34	2,675.00		83,876.34	6,451.00
45	1920	Computer Equipment - Hardware		0.00		0.00				0.00	0.00
12	1925	Computer Software	38,821.01	14,767.09		53,588.10	0.00	10,716.10		10,716.10	42,872.00
10	1930	Transportation Equipment	783,080.02	36,146.99		819,227.01	580,151.02	50,583.99		630,735.01	188,492.00
10	1935	Stores Equipment	6,634.96	0.00		6,634.96	6,634.96	0.04		6,635.00	(0.04)
8	1940	Tools, Shop and Garage Equipment		0.00		0.00				0.00	0.00
	1945	Measurement and Testing Equipment	51,800.00	0.00		51,800.00	51,800.00	0.00		51,800.00	0.00
	1950	Power Operated Equipment	37,260.00	0.00		37,260.00	7,452.00	3,726.00		11,178.00	26,082.00
10	1955	Communication Equipment	70,500.77	0.00		70,500.77	36,125.77	7,290.04		43,415.81	27,084.96
	1960	Miscellaneous Equipment	203,814.49	0.00		203,814.49	186,637.49	7,035.96		193,673.45	10,141.04
	1970	Load Management Controls - Customer Premise	878,887.18	0.00		878,887.18	780,239.18	46,852.00		827,091.18	51,796.00
	1975	Load Management Controls - Utility Premises		0.00		0.00				0.00	0.00
	1980	System Supervisory Equipment	378,276.15	28,319.17		406,595.32	128,689.15	27,106.17		155,795.32	250,800.00
	1985	Sentinel Lighting Rentals	7,063.04	0.00		7,063.04	7,063.04			7,063.04	0.00
	1990	Other Tangible Property		0.00		0.00				0.00	0.00
1	1995	Contributions and Grants	(5,293,817.78)	(354,422.06)		(5,648,239.84)	(2,040,103.06)	(225,927.06)		(2,266,030.12)	(3,382,209.72)
										0.00	0.00
										0.00	0.00
		Total before Work in Process	**19,120,902.92**	**614,720.41**	**0.00**	**19,735,623.33**	**10,131,428.79**	**811,894.46**	**0.00**	**10,943,323.25**	**8,792,300.08**
WIP		Work in Process				0.00	0.00	0.00	0.00	0.00	0.00
		Total after Work in Process	**19,120,902.92**	**614,720.41**	**0.00**	**19,735,623.33**	**10,131,428.79**	**811,894.46**	**0.00**	**10,943,323.25**	**8,792,300.08**

10	1935	Transportation
10	1955	Communication Equipment

Less: Fully Allocated Depreciation			
Transportation	50,583.99		
Communication	1,819.92	only a portion allocated	
Net Depreciation	759,490.55		10,943,323.25
Deferred Charge	8,155		
From Trial Balance	767,646		10,943,323
Difference	(0)	(Communication not fully allocated)	

TABLE 2
COLLUS Power Corp - Distribution & Operations
Fixed Asset Continuity Schedule
As at December 31, 2007

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
N/A	1805	Land	90,438.88	0.00		90,438.88	0.00	0.00		0.00	90,438.88
CEC	1806	Land Rights	0.00	0.00		0.00	0.00			0.00	0.00
1	1808	Buildings and Fixtures	80,668.44	0.00		80,668.44	49,868.44	2,142.00		52,010.44	28,658.00
0	1810	Leasehold Improvements	0.00	0.00		0.00	0.00			0.00	0.00
0	1815	Transformer Station Equipment - Normally Prim	0.00	0.00		0.00	0.00			0.00	0.00
1	1820	Distribution Station Equipment - Normally Prima	2,051,268.81	1,075,377.87		3,126,646.68	1,128,346.81	84,309.87		1,212,656.68	1,913,990.00
0	1825	Storage Battery Equipment	0.00	0.00		0.00	0.00			0.00	0.00
1	1830	Poles, Towers and Fixtures	0.00	0.00		0.00	0.00			0.00	0.00
1	1835	Overhead Conductors and Devices	8,696,603.16	615,898.30		9,312,501.46	4,393,996.16	360,350.30		4,754,346.46	4,558,155.00
1	1840	Underground Conduit	0.00	0.00		0.00	0.00			0.00	0.00
1	1845	Underground Conductors and Devices	6,325,880.74	93,010.19		6,418,890.93	3,011,450.74	267,476.19		3,278,926.93	3,139,964.00
1	1850	Line Transformers	3,751,091.50	316,078.82		4,067,170.32	1,869,693.54	150,738.38		2,020,431.92	2,046,738.40
1	1855	Services	418,734.96	109,677.61		528,412.57	34,025.96	21,139.61		55,165.57	473,247.00
1	1860	Meters	1,343,478.47	34,097.76		1,377,576.23	699,992.47	50,571.76		750,564.23	627,012.00
0	1865	Other Installations on Customer's Premises	0.00	0.00		0.00	0.00			0.00	0.00
N/A	1905	Land	0.00	0.00		0.00	0.00			0.00	0.00
CEC	1906	Land Rights	0.00	0.00		0.00	0.00			0.00	0.00
1	1908	Buildings and Fixtures	0.00	0.00		0.00	0.00			0.00	0.00
0	1910	Leasehold Improvements	0.00	0.00		0.00	0.00			0.00	0.00
8	1915	Office Furniture and Equipment	90,327.34	0.00		90,327.34	83,876.34	2,675.00		86,551.34	3,776.00
45	1920	Computer Equipment - Hardware	0.00	0.00		0.00	0.00			0.00	0.00
12	1925	Computer Software	53,588.10	5,265.02		58,853.12	10,716.10	11,771.02		22,487.12	36,366.00
10	1930	Transportation Equipment	819,227.01	46,769.64		865,996.65	630,735.01	35,567.64		666,302.65	199,694.00
10	1935	Stores Equipment	6,634.96	0.02		6,634.98	6,635.00	0.00		6,635.00	(0.02)
8	1940	Tools, Shop and Garage Equipment	0.00	0.00		0.00	0.00			0.00	0.00
0	1945	Measurement and Testing Equipment	51,800.00	0.00		51,800.00	51,800.00	0.00		51,800.00	0.00
0	1950	Power Operated Equipment	37,260.00	0.00		37,260.00	11,178.00	3,726.00		14,904.00	22,356.00
10	1955	Communication Equipment	70,500.77	1,250.64		71,751.41	43,415.81	1,945.60		45,361.41	26,390.00
0	1960	Miscellaneous Equipment	203,814.49	0.00		203,814.49	193,673.45	4,632.04		198,305.49	5,509.00
0	1970	Load Management Controls - Customer Premise	878,887.18	0.00		878,887.18	827,091.18	28,110.00		855,201.18	23,686.00
0	1975	Load Management Controls - Utility Premises	0.00	0.00		0.00	0.00			0.00	0.00
0	1980	System Supervisory Equipment	406,595.32	63,656.23		470,251.55	155,795.32	31,347.23		187,142.55	283,109.00
0	1985	Sentinel Lighting Rentals	7,063.04	0.00		7,063.04	7,063.04	0.00		7,063.04	0.00
0	1990	Other Tangible Property	0.00	0.00		0.00	0.00			0.00	0.00
1	1995	Contributions and Grants	(5,648,239.84)	(480,989.71)		(6,129,229.55)	(2,266,030.12)	(245,159.71)		(2,511,189.83)	(3,618,039.72)
0	0	-	0.00			0.00	0.00			0.00	0.00
0	0	-	0.00			0.00	0.00			0.00	0.00
		Total before Work in Process	**19,735,623.33**	**1,880,092.39**	**0.00**	**21,615,715.72**	**10,943,323.25**	**811,342.93**	**0.00**	**11,754,666.18**	**9,861,049.54**
WIP	0	Work in Process	0.00			0.00	0.00	0.00	0.00	0.00	0.00
		Total after Work in Process	**19,735,623.33**	**1,880,092.39**	**0.00**	**21,615,715.72**	**10,943,323.25**	**811,342.93**	**0.00**	**11,754,666.18**	**9,861,049.54**

	1935	Transportation
	1940	Stores Equipment

Less: Fully Allocated Depreciatic			
Transportation	35,567.64		
Communication	1,571.20	only a portion allocated	
Net Depreciation	774,204.09		11,754,666.18
Deferred Chrg	8,155		
From Trial Bala	782,359		11,754,666
Difference	0.00		-

Table 3
COLLUS Power Corp - Distribution & Operations
Fixed Asset Continuity Schedule
2008 Bridge Year @ Dec. 31, 2008

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
N/A	1805	Land	90,438.88	0.00		*90,438.88*	0.00	0.00		*0.00*	90,438.88
CEC	1806	Land Rights	0.00			*0.00*	0.00			*0.00*	0.00
1	1808	Buildings and Fixtures	80,668.44	0.00		*80,668.44*	52,010.44	2,142.00		*54,152.44*	26,516.00
0	1810	Leasehold Improvements	0.00			*0.00*	0.00			*0.00*	0.00
0	1815	Transformer Station Equipment - Normally Prim	0.00			*0.00*	0.00			*0.00*	0.00
1	1820	Distribution Station Equipment - Normally Prima	3,126,646.68	0.00		*3,126,646.68*	1,212,656.68	95,427.00		*1,308,083.68*	1,818,563.00
0	1825	Storage Battery Equipment	0.00			*0.00*	0.00			*0.00*	0.00
1	1830	Poles, Towers and Fixtures	0.00			*0.00*	0.00			*0.00*	0.00
1	1835	Overhead Conductors and Devices	9,312,501.46	480,000.00		*9,792,501.46*	4,754,346.46	**374,657.00**		*5,129,003.46*	4,663,498.00
1	1840	Underground Conduit	0.00			*0.00*	0.00			*0.00*	0.00
1	1845	Underground Conductors and Devices	6,418,890.93	**350,000.00**		*6,768,890.93*	3,278,926.93	**270,120.00**		*3,549,046.93*	3,219,844.00
1	1850	Line Transformers	4,067,170.32	178,000.00		*4,245,170.32*	2,020,431.92	157,493.00		*2,177,924.92*	2,067,245.40
1	1855	Services	528,412.57			*528,412.57*	55,165.57	21,137.00		*76,302.57*	452,110.00
1	1860	Meters	1,377,576.23	60,000.00		*1,437,576.23*	750,564.23	53,814.00		*804,378.23*	633,198.00
0	1865	Other Installations on Customer's Premises	0.00			*0.00*	0.00			*0.00*	0.00
N/A	1905	Land	0.00			*0.00*	0.00			*0.00*	0.00
CEC	1906	Land Rights	0.00			*0.00*	0.00			*0.00*	0.00
1	1908	Buildings and Fixtures	0.00			*0.00*	0.00			*0.00*	0.00
0	1910	Leasehold Improvements	0.00			*0.00*	0.00			*0.00*	0.00
8	1915	Office Furniture and Equipment	90,327.34	85,000.00		*175,327.34*	86,551.34	10,740.00		*97,291.34*	78,036.00
45	1920	Computer Equipment - Hardware	0.00			*0.00*	0.00			*0.00*	0.00
12	1925	Computer Software	58,853.12	400,000.00		*458,853.12*	22,487.12	91,771.00		*114,258.12*	344,595.00
10	1930	Transportation Equipment	865,996.65	450,000.00		*1,315,996.65*	666,302.65	83,039.00		*749,341.65*	566,655.00
10	1935	Stores Equipment	6,634.98	0.00		*6,634.98*	6,635.00	(0.02)		*6,634.98*	0.00
8	1940	Tools, Shop and Garage Equipment	0.00			*0.00*	0.00			*0.00*	0.00
0	1945	Measurement and Testing Equipment	51,800.00	0.00		*51,800.00*	51,800.00	0.00		*51,800.00*	0.00
0	1950	Power Operated Equipment	37,260.00	0.00		*37,260.00*	14,904.00	3,726.00		*18,630.00*	18,630.00
10	1955	Communication Equipment	71,751.41			*71,751.41*	45,361.41	4,680.00		*50,041.41*	21,710.00
0	1960	Miscellaneous Equipment	203,814.49			*203,814.49*	198,305.49	3,249.00		*201,554.49*	2,260.00
0	1970	Load Management Controls - Customer Premise	878,887.18			*878,887.18*	855,201.18	20,202.00		*875,403.18*	3,484.00
0	1975	Load Management Controls - Utility Premises	0.00			*0.00*	0.00			*0.00*	0.00
0	1980	System Supervisory Equipment	470,251.55	116,000.00		*586,251.55*	187,142.55	37,689.00		*224,831.55*	361,420.00
0	1985	Sentinel Lighting Rentals	7,063.04			*7,063.04*	7,063.04	0.00		*7,063.04*	0.00
0	1990	Other Tangible Property	0.00			*0.00*	0.00			*0.00*	0.00
1	1995	Contributions and Grants	(6,129,229.55)	(250,000.00)		*(6,379,229.55)*	(2,511,189.83)	(255,170.00)		*(2,766,359.83)*	(3,612,869.72)
0	0	-	0.00			*0.00*	0.00			*0.00*	0.00
0	0	-	0.00			*0.00*	0.00			*0.00*	0.00
		Total before Work in Process	**21,615,715.72**	**1,869,000.00**	**0.00**	***23,484,715.72***	**11,754,666.18**	**974,715.98**	**0.00**	***12,729,382.16***	**10,755,333.56**
WIP		Work in Process	0.00			0.00	0.00			0.00	0.00
		Total after Work in Process	**21,615,715.72**	**1,869,000.00**	**0.00**	**23,484,715.72**	**11,754,666.18**	**974,715.98**	**0.00**	**12,729,382.16**	**10,755,333.56**

	1935	Transportation
	1940	Stores Equipment

Less: Fully Allocated Depreciation			
Transportation	83,039.00		
Communication	4,680.00	fully allocated	
Net Depreciation	886,996.98		12,729,382.16
From Inc St 08	886,997		12,729,382
Difference	-		-

Table 4
COLLUS Power Corp - Distribution & Operations
Fixed Asset Continuity Schedule
2009 Test Year@ Dec. 31, 2009

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
N/A	1805	Land	90,438.88	0.00		*90,438.88*	0.00	0.00		*0.00*	90,438.88
CEC	1806	Land Rights	0.00	0.00		*0.00*	0.00			*0.00*	0.00
47	1808	Buildings and Fixtures	80,668.44	0.00		*80,668.44*	54,152.44	2,142.00		*56,294.44*	24,374.00
13	1810	Leasehold Improvements	0.00			*0.00*	0.00	0.00		*0.00*	0.00
47	1815	Transformer Station Equipment - Normally Primar	0.00			*0.00*	0.00	0.00		*0.00*	0.00
47	1820	Distribution Station Equipment - Normally Primary	3,126,646.68	1,900,000.00		*5,026,646.68*	1,308,083.68	158,770.00		*1,466,853.68*	3,559,793.00
47	1825	Storage Battery Equipment	0.00			*0.00*	0.00			*0.00*	0.00
47	1830	Poles, Towers and Fixtures	0.00			*0.00*	0.00			*0.00*	0.00
47	1835	Overhead Conductors and Devices	9,792,501.46	506,000.00		*10,298,501.46*	5,129,003.46	391,456.00		*5,520,459.46*	4,778,042.00
47	1840	Underground Conduit	0.00			*0.00*	0.00			*0.00*	0.00
47	1845	Underground Conductors and Devices	6,768,890.93	236,500.00		*7,005,390.93*	3,549,046.93	279,580.00		*3,828,626.93*	3,176,764.00
47	1850	Line Transformers	4,245,170.32	175,000.00		*4,420,170.32*	2,177,924.92	164,493.00		*2,342,417.92*	2,077,752.40
47	1855	Services	528,412.57	0.00		*528,412.57*	76,302.57	21,137.00		*97,439.57*	430,973.00
47	1860	Meters	1,437,576.23	60,000.00		*1,497,576.23*	804,378.23	56,214.00		*860,592.23*	636,984.00
N/A	1865	Other Installations on Customer's Premises	0.00			*0.00*	0.00			*0.00*	0.00
N/A	1870	Leased Property on Customer Premises				*0.00*				*0.00*	0.00
N/A	1875	Street Lighting and Signal Systems				*0.00*				*0.00*	0.00
N/A	1905	Land	0.00			*0.00*	0.00			*0.00*	0.00
CEC	1906	Land Rights	0.00			*0.00*	0.00			*0.00*	0.00
47	1908	Buildings and Fixtures	0.00	0.00		*0.00*	0.00			*0.00*	0.00
13	1910	Leasehold Improvements	0.00			*0.00*	0.00			*0.00*	0.00
8	1915	Office Furniture and Equipment	175,327.34	90,000.00		*265,327.34*	97,291.34	18,847.00		*116,138.34*	149,189.00
10	1920	Computer Equipment - Hardware	0.00	0.00		*0.00*	0.00			*0.00*	0.00
12	1925	Computer Software	458,853.12	60,000.00		*518,853.12*	114,258.12	103,771.00		*218,029.12*	300,824.00
10	1930	Transportation Equipment	1,315,996.65	150,000.00		*1,465,996.65*	749,341.65	114,682.00		*864,023.65*	601,973.00
8	1935	Stores Equipment	6,634.98			*6,634.98*	6,634.98	0.00		*6,634.98*	0.00
8	1940	Tools, Shop and Garage Equipment	0.00			*0.00*	0.00	0.00		*0.00*	0.00
8	1945	Measurement and Testing Equipment	51,800.00			*51,800.00*	51,800.00	0.00		*51,800.00*	0.00
8	1950	Power Operated Equipment	37,260.00			*37,260.00*	18,630.00	3,726.00		*22,356.00*	14,904.00
8	1955	Communication Equipment	71,751.41			*71,751.41*	50,041.41	3,930.00		*53,971.41*	17,780.00
8	1960	Miscellaneous Equipment	203,814.49			*203,814.49*	201,554.49	2,260.00		*203,814.49*	0.00
47	1970	Load Management Controls - Customer Premises	878,887.18			*878,887.18*	875,403.18	3,484.00		*878,887.18*	0.00
47	1975	Load Management Controls - Utility Premises	0.00			*0.00*	0.00	0.00		*0.00*	0.00
47	1980	System Supervisory Equipment	586,251.55	40,000.00		*626,251.55*	224,831.55	40,346.00		*265,177.55*	361,074.00
47	1985	Sentinel Lighting Rentals	7,063.04			*7,063.04*	7,063.04	0.00		*7,063.04*	0.00
47	1990	Other Tangible Property	0.00			*0.00*	0.00	0.00		*0.00*	0.00
47	1995	Contributions and Grants	(6,379,229.55)	(200,000.00)		*(6,579,229.55)*	(2,766,359.83)	(263,170.00)		*(3,029,529.83)*	(3,549,699.72)
		Total before Work in Process	**23,484,715.72**	**3,017,500.00**	**0.00**	**26,502,215.72**	**12,729,382.16**	**1,101,668.00**	**0.00**	**13,831,050.16**	**12,671,165.56**
WIP		Work in Process	0.00			0.00	0.00			0.00	0.00
		Total after Work in Process	**23,484,715.72**	**3,017,500.00**	**0.00**	**26,502,215.72**	**12,729,382.16**	**1,101,668.00**	**0.00**	**13,831,050.16**	**12,671,165.56**

	1925	Transportation
	1930	Stores Equipment

Less: Fully Allocated Depreciation			
Transportation	114,682.00		
Communication	3,930.00	fully allocated	
Net Depreciation	983,056.00		13,831,050.16
From Trial Balance	983,056		13,831,050
Difference	-		-

COLLUS Power Corp
EB-2008-0226
Exhibit 2
Tab 2
Schedule 2
Page 1 of 1
Filed: August 15, 2008

GROSS ASSETS TABLE:
Table 1

Description	2006 Board Approved ($)	2006 Actual ($)	Variance from 2006 Board Approved	2007 Actual ($)	Variance from 2006 Actual	2008 Bridge ($)	Variance from 2007 Bridge	2009 Test ($)	Variance from 2008 Bridge
Land and Buildings									
1805-Land	90,439	90,439	(0)	90,439		90,439		90,439	
1806-Land Rights									
1808-Buildings and Fixtures	80,668	80,668	0	80,668		80,668		80,668	
1905-Land									
1906-Land Rights									
1810-Leasehold Improvements									
Sub-Total-Land and Buildings	**171,107**	**171,107**	**0**	**171,107**		**171,107**		**171,107**	
TS Primary Above 50									
1815-Transformer Station Equipment - Normally Primary above 50 kV									
Sub-Total-TS Primary Above 50									
DS									
1820-Distribution Station Equipment - Normally Primary below 50 kV	2,241,870	2,051,269	(190,601)	3,126,647	1,075,378	3,126,647		5,026,647	1,900,000
Sub-Total-DS	**2,241,870**	**2,051,269**	**(190,601)**	**3,126,647**	**1,075,378**	**3,126,647**		**5,026,647**	**1,900,000**
Poles and Wires									
1830-Poles, Towers and Fixtures									
1835-Overhead Conductors and Devices	7,730,845	8,696,603	965,758	9,312,501	615,898	9,792,501	480,000	10,298,501	506,000
1840-Underground Conduit									
1845-Underground Conductors and Devices	4,936,351	6,325,881	1,389,530	6,418,891	93,010	6,768,891	350,000	7,005,391	236,500
Sub-Total-Poles and Wires	**12,667,196**	**15,022,484**	**2,355,288**	**15,731,392**	**708,908**	**16,561,392**	**830,000**	**17,303,892**	**742,500**
Line Transformers									
1850-Line Transformers	2,844,907	3,751,092	906,185	4,067,170	316,079	4,245,170	178,000	4,420,170	175,000
Sub-Total-Line Transformers	**2,844,907**	**3,751,092**	**906,185**	**4,067,170**	**316,079**	**4,245,170**	**178,000**	**4,420,170**	**175,000**
Services and Meters									
1855-Services	66,210	418,735	352,525	528,413	109,678	528,413		528,413	
1860-Meters	1,121,815	1,343,478	221,663	1,377,576	34,098	1,437,576	60,000	1,497,576	60,000
1861-Smart Meters									
Sub-Total-Services and Meters	**1,188,025**	**1,762,213**	**574,188**	**1,905,989**	**143,775**	**1,965,989**	**60,000**	**2,025,989**	**60,000**
General Plant									
1908-Buildings and Fixtures									
1910-Leasehold Improvements									
Sub-Total-General Plant									
IT Assets									
1920-Computer Equipment - Hardware									
1921-Computer Equipment - Hardware post March 22, 2004									
1925-Computer Software		53,588	53,588	58,853	5,265	458,853	400,000	518,853	60,000
Sub-Total-IT Assets		**53,588**	**53,588**	**58,853**	**5,265**	**458,853**	**400,000**	**518,853**	**60,000**
Equipment									
1915-Office Furniture and Equipment	90,327	90,327	0	90,327		175,327	85,000	265,327	90,000
1930-Transportation Equipment	692,706	819,227	126,521	865,997	46,770	1,315,997	450,000	1,465,997	150,000
1935-Stores Equipment	6,635	6,635	(0)	6,635	0	6,635		6,635	
1940-Tools, Shop and Garage Equipment									
1945-Measurement and Testing Equipment	51,800	51,800		51,800		51,800		51,800	
1950-Power Operated Equipment	18,630	37,260	18,630	37,260		37,260		37,260	
1955-Communication Equipment	41,954	70,501	28,547	71,751	1,251	71,751		71,751	
1960-Miscellaneous Equipment	211,914	203,814	(8,100)	203,814		203,814		203,814	
Sub-Total-Equipment	**1,113,966**	**1,279,565**	**165,599**	**1,327,585**	**48,020**	**1,862,585**	**535,000**	**2,102,585**	**240,000**
Other Distribution Assets									
1825-Storage Battery Equipment									
1970-Load Management Controls - Customer Premises	878,887	878,887	0	878,887		878,887		878,887	
1975-Load Management Controls - Utility Premises									
1980-System Supervisory Equipment	289,635	406,595	116,960	470,252	63,656	586,252	116,000	626,252	40,000
1985-Sentinel Lighting Rental Units		7,063	7,063	7,063		7,063		7,063	
1990-Other Tangible Property									
1995-Contributions and Grants - Credit	(3,018,439)	(5,648,240)	(2,629,801)	(6,129,230)	(480,990)	(6,379,230)	(250,000)	(6,579,230)	(200,000)
1996-Hydro One S/S Contribution									
Sub-Total-Other Distribution Assets	**(1,849,917)**	**(4,355,694)**	**(2,505,777)**	**(4,773,028)**	**(417,333)**	**(4,907,028)**	**(134,000)**	**(5,067,028)**	**(160,000)**
GROSS ASSET TOTAL	**18,377,154**	**19,735,623**	**1,358,469**	**21,615,716**	**1,880,092**	**23,484,716**	**1,869,000**	**26,502,216**	**3,017,500**

VARIANCE ANALYSIS ON GROSS ASSETS:

The variance analysis for the 2009 Test Year is provided in Exhibit 2, Tab 3, Schedule 1. As noted earlier from Table 1 at Exhibit 2 Tab 1 Schedule 2 COLLUS Power Corp has a variance analysis threshold for 2009 capital projects of $$\boxed{\$126,712}$. Information by project category is provided for 2009 and then also for projects based on the applicable variance threshold for the 2006 Actual, 2007 Actual and 2008 Bridge Year for comparative purposes.

ACCUMULATED DEPRECIATION:
Table 1
Accumulated Depreciation

Description	2006 Board Approved ($)	2006 Actual ($)	2006 Board Approved	2007 Actual ($)	Variance from 2006 Actual	2008 Bridge ($)	Variance from 2007 Bridge	2009 Test ($)	from 2008 Bridge
Land and Buildings									
1805-Land									
1806-Land Rights									
1808-Buildings and Fixtures	43,513	49,868	6,355	52,010	2,142	54,152	2,142	56,294	2,142
1905-Land									
1906-Land Rights									
1810-Leasehold Improvements									
Sub-Total-Land and Buildings	**43,513**	**49,868**	**6,355**	**52,010**	**2,142**	**54,152**	**2,142**	**56,294**	**2,142**
TS Primary Above 50									
1815-Transformer Station Equipment - Normally Primary above 50 kV									
Sub-Total-TS Primary Above 50									
DS									
1820-Distribution Station Equipment - Normally Primary below 50 kV	838,109	1,128,347	290,238	1,212,657	84,310	1,308,084	95,427	1,466,854	158,770
Sub-Total-DS	**838,109**	**1,128,347**	**290,238**	**1,212,657**	**84,310**	**1,308,084**	**95,427**	**1,466,854**	**158,770**
Poles and Wires									
1830-Poles, Towers and Fixtures									
1835-Overhead Conductors and Devices	3,558,209	4,393,996	835,787	4,754,346	360,350	5,129,003	374,657	5,520,459	391,456
1840-Underground Conduit									
1845-Underground Conductors and Devices	1,373,698	3,011,451	1,637,753	3,278,927	267,476	3,549,047	270,120	3,828,627	279,580
Sub-Total-Poles and Wires	**4,931,907**	**7,405,447**	**2,473,540**	**8,033,273**	**627,826**	**8,678,050**	**644,777**	**9,349,086**	**671,036**
Line Transformers									
1850-Line Transformers	1,032,087	1,869,694	837,607	2,020,432	150,738	2,177,925	157,493	2,342,418	164,493
Sub-Total-Line Transformers	**1,032,087**	**1,869,694**	**837,607**	**2,020,432**	**150,738**	**2,177,925**	**157,493**	**2,342,418**	**164,493**
Services and Meters									
1855-Services	2,646	34,026	31,380	55,166	21,140	76,303	21,137	97,440	21,137
1860-Meters	584,799	699,992	115,193	750,564	50,572	804,378	53,814	860,592	56,214
1861-Smart Meters									
Sub-Total-Services and Meters	**587,445**	**734,018**	**146,573**	**805,730**	**71,711**	**880,681**	**74,951**	**958,032**	**77,351**
General Plant									
1908-Buildings and Fixtures									
1910-Leasehold Improvements									
Sub-Total-General Plant									
IT Assets									
1920-Computer Equipment - Hardware									
1921-Computer Equipment - Hardware post March 22, 2004									
1925-Computer Software		10,716	10,716	22,487	11,771	114,258	91,771	218,029	103,771
Sub-Total-IT Assets		**10,716**	**10,716**	**22,487**	**11,771**	**114,258**	**91,771**	**218,029**	**103,771**
Equipment									
1915-Office Furniture and Equipment	76,021	83,876	7,855	86,551	2,675	97,291	10,740	116,138	18,847
1930-Transportation Equipment	623,008	630,735	7,727	666,303	35,568	749,342	83,039	864,024	114,682
1935-Stores Equipment	6,635	6,635		6,635		6,635	(0)	6,635	
1940-Tools, Shop and Garage Equipment									
1945-Measurement and Testing Equipment	51,800	51,800		51,800		51,800		51,800	
1950-Power Operated Equipment	1,863	11,178	9,315	14,904	3,726	18,630	3,726	22,356	3,726
1955-Communication Equipment	29,644	43,416	13,772	45,361	1,946	50,041	4,680	53,971	3,930
1960-Miscellaneous Equipment	177,453	193,673	16,220	198,305	4,632	201,554	3,249	203,814	2,260
Sub-Total-Equipment	**966,424**	**1,021,314**	**54,890**	**1,069,860**	**48,546**	**1,175,294**	**105,434**	**1,318,739**	**143,445**
Other Distribution Assets									
1825-Storage Battery Equipment									
1970-Load Management Controls - Customer Premises	644,530	827,091	182,562	855,201	28,110	875,403	20,202	878,887	3,484
1975-Load Management Controls - Utility Premises									
1980-System Supervisory Equipment	92,566	155,795	63,230	187,143	31,347	224,832	37,689	265,178	40,346
1985-Sentinel Lighting Rental Units	7,063	7,063	0	7,063		7,063		7,063	
1990-Other Tangible Property									
1995-Contributions and Grants - Credit	(118,136)	(2,266,030)	(2,147,895)	(2,511,190)	(245,160)	(2,766,360)	(255,170)	(3,029,530)	(263,170)
1996-Hydro One S/S Contribution									
Sub-Total-Other Distribution Assets	**626,023**	**(1,276,081)**	**(1,902,103)**	**(1,461,783)**	**(185,702)**	**(1,659,062)**	**(197,279)**	**(1,878,402)**	**(219,340)**
ACCUMULATED DEPRICIATION TOTAL	**9,025,507**	**10,943,323**	**1,917,817**	**11,754,666**	**811,343**	**12,729,382**	**974,716**	**13,831,050**	**1,101,668**

VARIANCE ANALYSIS ON ACCUMULATED DEPRECIATION:

Changes in accumulated depreciation are directly affected by changes in fixed assets due to additions, the removal of fully depreciated assets from the grouped asset classes, and the disposition of identifiable assets. The 2006 Board Approved closing balance for accumulated depreciation is based on COLLUS Power Corp's 2004 year end account balances, plus Tier 1 & 2 capital adjustments approved in COLLUS Power Corp 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, COLLUS Power Corp has a variance analysis threshold of $ $126,712 for 2009. The accumulated depreciation variance threshold as indicated in Table 1 at Exhibit 2 Tab 1 Schedule 2 for the 2006 Actual to 2006 Board Approved is rounded to $89,000; 2007 Actual to 2006 Actual is $98,000; 2008 Bridge Year to the 2007 Actual Year is $107,000; and the 2009 Test Year to the 2008 Bridge Year is $126,000.

For the years 2006 thru 2009 COLLUS Power Corp exceeded the variance threshold in four OEB accounts: Distribution Stations (Account 1820); Overhead Conductors and Devices (Account 1835); Underground Conductors and Devices (Account 1845); and Line Transformers (Account 1850). 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 $2,200,000 for Distribution Stations, $7,700,000 for Overhead Conductors and Devices, $4,900,000 for Underground Conductors and Devices and $2,800,000 for Line Transformers, and these asset balances increase annually with additions. By 2009 these accounts are expected to increase to in excess of $5,000,000, $10,200,000, $7,000,000 and $4,400,000 respectfully.

Depreciation is written on a straight line basis over twenty five years, and as such, the annual additions to accumulated depreciation would be over $69,000, $343,000, $263,000 and $137,000 respectively, in 2006, as shown in Exhibit 2, Tab2, Table 1 earlier. These amounts will increase with additions to fixed assets in each of 2007 Actual, 2008 Bridge Year and 2009 Test Year. The amount of depreciation can be located in Exhibit2, Tab2 Table 2, 3 and 4 for their respective years. These increases are the reason for the variances experienced in the accumulated depreciation accounts over the reporting years.

CAPITAL BUDGET:

Overview and Capital Budget by Project:

COLLUS Power Corp 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. COLLUS Power Corp overall capital budget for 2009 Test year is $ 3,017,500 reflecting an increase of $ 1,148,500 over 2008 Bridge amount of $ 1,869,000. Although 2009 does not have a major vehicle or software purchase requirement. The plan includes the construction of a new distribution station and the associated feeders, thus the major level of increase.

The capital budget is prepared annually by management and is reviewed and approved by COLLUS Power Corp Board of Directors. The budget is prepared before the start of each fiscal year. Once approved, it does not change, but provides a plan against which actual results may be evaluated.

The capital budget process is a component of the overall budget process described in Exhibit 2, Tab 1, Schedule 1 and a summary of 2008 and 2009 by project is provided in Appendix B with this schedule for ease of reference.

- **Capital Work plans:**

Each department Manager/Director is responsible for the preparation of the departmental capital budget. The following directives are provided to each Manager or Director:

> All department budgets are to be built using a “bottom up” approach, which requires each functional area within COLLUS Power Corp to build work plans that identify resources, including labor, vehicles, materials and other third party costs that are required to execute the work plans. This approach ensures that budgets are developed based on the actual work to be completed during the fiscal year, as opposed to a historical costing approach.

> Where applicable, Activity Based Costing ("ABC") work order methodology is to be used in the creation of work plans.

> Significant variances from prior year must be explained and documented.

- **Project Capital Budget Plan:**

Once all projects have been identified, they are evaluated in order to affect a relative ranking of projects. Decisions on priorities are made to include those projects determined to be the most important within a level of affordability. This plan is evaluated by the Managers responsible for Design & Construction and Network Planning and then reviewed and supported by the Chief Financial Officer. A final budget package is produced to present to the Management Team for their review and approval.

The subsequent actual-to-budget review process is outlined in the overall budget process, discussed at Exhibit 2, Tab 1, Schedule 1, above.

This Schedule contains descriptions of certain key elements of COLLUS Power Corp 2009 capital budget, in the following categories:

- Distribution Plant:
    - 2009 Distribution Plant Projects
    - Customer Connections and Metering

- General Plant:
    - Facilities;
    - Customer Information System Software;
    - Other Computer Hardware and Software;
    - Transportation and Related Equipment;
    - Communications Equipment; and
    - Tools and Equipment.

KEY ELEMENTS OF THE CAPITAL BUDGET:

The following narratives describe COLLUS Power Corp significant projects planned for 2009 and either completed or planned for 2008. Appendix B provides the Summary Schedule:

- **DISTRIBUTION PLANT:**

The following discussion addresses various key projects within the distribution plant component of COLLUS Power Corp 2009 Capital Budget. Overall, COLLUS Power Corp intends to spend a total of $2,677,500 on the distribution plant component in 2009, in the following categories of projects outlined below in Table 1. As indicated for 2008 a level of $818,000 in distribution plant capital spending is intended. Additionally information is provided for the years 2006 – 2007 in the table for comparative purposes.

Table 1

Distribution Plant Capital 2006-2009 Total By Type

ASSET TYPE (Category) (Category # indicated on App. B)	**2006** ($000)	**2007** ($000)	**2008** ($000)	**2009** ($000)
Customer Demand & Renewal (Categories 1 & 2)	323	743	808	797.5
Security & Reliability (Cat. 3)	119	109	100	120
Capacity		0	0	0
Customer Metering (Cat. 4)	75	35	81	60
Required Regulatory (Cat. 5)	320	282	100	0
Distribution Stations (Cat. 6)	52	1,075	0	1,900
DP – Capital Contribution(Cat. 7)	-354	-481	-250	-200
Sub-Total (Distribution Plant)	**535**	**1,763**	**839**	**2,677.5**
Facilities	0	0	85	90
CIS Software System	15	5	400	60
Transportation	36	47	450	150
Communication	29	65	95	40
Sub-Total (General Plant)	**80**	**117**	**1,030**	**340**
TOTAL CAPITAL SPENDING	**615**	**1,880**	**1,869**	**3,017.5**

Gross Fixed Asset Variance Explanation:

As noted above in Table 1 the components of the 2009 Capital Budget have major impact in the Customer Demand & Renewal category and the Distribution Station category. Included in the CD&R category is the forecasted cost of completing the distribution plant work required to properly link the new distribution infrastructure into the existing grid. The project is identified as Project #17016 Sixth Street from High Street to Stewart Road and is more detailed in the attachments contained in Appendix C.

Appendix C provides reports by consultants and staff that were recently updated and provide the explanation and recommendations that were made. Barkley Technologies Inc (Appendix C-1) provided expert review of the system load situation for Collingwood, in order to make a set of recommendations. The supervision staff reviewed the "Barkley Report" and then made their recommendations (Appendix C-2). Following the appropriate levels of scrutiny the recommendations have been approved through to the President/CEO levels and moved forward to be included in the COLLUS Power Corp Board's approved Capital Budget.

Included as well in Appendix C is information regarding the other capital project component, identified as Project 17070 MS # 8 South West Substation, that is in excess of the materiality threshold level. A project of this magnitude requires additional information and this is provided in the form of the chart (Appendix C-3) provided by Black & McDonald, a company that recently constructed a new distribution substation for COLLUS Power Corp in 2007. A tender process has not yet been undertaken, and in fact may not be, until a decision has been received from the Ontario Energy Board regarding this portion of the 2009 Cost of Service rate application. Therefore the cost being submitted for consideration is based on this detailed estimate.

For comparison of price quote to completion price Appendix C-4 is provided which is the contractor statement on the recently completed upgrade to MS #5 in 2007. As noted the quoted price was maintained in the final charges. Therefore COLLUS Power Corp is confident with the quoted numbers for the 2009 proposed project.

An additional piece of information that is provided as Appendix C-5 is the timetable outline when COLLUS Power Corp plans to complete the project. Once approval is received from the OEB for May 1, 2009 implementation of new rates, if this project is included in the rate base engineering, planning & construction will begin immediately with targeted completion before year end. The chart also shows the expected timeline for Project #17016 since the two are linked.

As noted above in Table 1 the expected capital expenditure on Distribution Plant is $818,000. The major portion of this is in the Customer Demand & Renewal category. As indicated in the Summary Schedule (Appendix B) there are four projects that exceed the materiality threshold of $107,000. These are listed and explained as follows:

1. Project # 17011 – Parkside Avenue Line Renewal/Rebuild – Detailed in Appendix D
2. Project # 17012 – First St. between Hurontario & Balsam Streets - “
3. Project # 17016 – Georgian Trail & Rear Lot Renewal - “
4. Project # 17600 – Economic Evaluation Investment – Explained below.

In regards to item #4 above this is the planned capital investment amount that COLLUS Power Corp will have to make in order to reimburse development driven project owners that initially had to make capital contributions in order to have electricity supplied to their project. The calculations of the amounts to be invested by returning a portion of the initial contributed capital are made in conjunction with the Economic Evaluation rules found in the Distribution System Code. As indicated in Appendix B there is an expectation for amounts to be paid in 2009 and will continue in future years.

Table 1 above also provided a breakdown of the capital spending in 2007. The materiality level is $98,000 and there were two projects that exceeded this amount. The largest one was Project

#17040 which was the upgrade capital work on MS #5. As noted earlier provided as Appendix C-4 is the Cost Breakdown sheet that the third party constructor Black & McDonald provided. As it indicates of the $1,075,378 that was recorded into the asset account, 99% was their cost. The other small portion was work undertaken by COLLUS Power Corp line staff to complete the required links to the local distribution system.

The other one was Project #17018 Boundary Line Expansion in the amount of $282,342 which was for the work by COLLUS Power Corp line staff on the municipal distribution system in order to undertake the elimination of load transfer customers with neighboring utilities. This project was undertaken to meet the requirements of the Ontario Energy Board for the elimination of load transfer situations, as well as to provide a loop feed to sections of our system to increase reliability of supply for our customers.

In regards to 2006 the materiality threshold level is $88,000 and since 2006 was more of a typical or average capital investment spending year (only $535,000 in Distribution Plant) there was only one project that exceeded the level. This also was the Project #17018 Boundary Line Expansion with a total spending amount of $319,518.

This completes the variance analysis of the Distribution Plant capital additions.

The next section will detail the variance analysis for spending on General Plant capital additions.

GENERAL PLANT:

Introduction:

General plant includes assets such as buildings, computer hardware and software, office furniture and equipment, transportation equipment, communications equipment and tools. Appendix B is the Summary Schedule of the Capital Budget for 2008 and 2009 and indicated this includes spending on Catogories #10, #11 & #12. These are outlined below.

- **Facilities (Building & Fixtures) - Category #10:**

Even though the materiality threshold for 2009 and 2008 is in excess of any project in this category, the following discussion addresses various key projects within the Building & Fixtures component of COLLUS Power Corp 2009 Capital Budget. Overall, COLLUS Power Corp intends to spend a total of $90,000 in capital investment on its buildings and fixtures in 2009. There is $85,000 expected in spending in 2008 for a portion of the required storage area to be put in place for wire and transformer storage. The transformer and wire racking will be completed in 2009. Secure storage of wire and transformers will decrease potential for damage or theft which is becoming more of an issue across the Province for all LDC's.

- **Intellectual Technology (Hardware & Software) – Category #11:**

CUSTOMER INFORMATION SYSTEM SOLUTION:

There is a major capital investment spending plan in place for 2008 in regards to Project #17163 and this will be reviewed below.

OVERVIEW:

An extensive review of COLLUS Power Corp information technology ("IT") needs was required after its' current CIS software provider (Advanced Utility Systems owned by Harris Computer Systems) notified the LDC that the functioning Infinity System would not be maintained for the Ontario De-Regulated Market processes. COLLUS Power Corp was notified of this decision in January of 2007 with a deadline date of December 31, 2008.

As part of the review process COLLUS Power Corp participated in a coalition identified as CODAC, which consisted of the remaining Infinity System Ontario LDC clients of AUS, along with some other LDC's that were interested in examining the cost of a new CIS system. The process included an in-depth tendering process which garnered tenders from 6 vendor solutions. The concept that was being brought forward by CODAC during this process was a shared template format and a commitment by all members to use the same processes and procedures with their new system. From a scale basis the size of the CODAC group (9 members at the beginning representing over 200,000 customer accounts) indicated that the preferred option would be a solution that utilized SAP software, in conjunction with the template that was being prepared for London Hydro. Decisions were made along the way by some LDC's to utilize a different solution and ultimately the decision was made by COLLUS Power Corp to do the same.

The further review process determined that COLLUS Power Corp should implement the Harris Computer System's Northstar 6 system to provide the required CIS infrastructure. In keeping with COLLUS Power Corp's co-operative spirit and to help minimize future costs, the CIS system will be combined in a single template format with the existing company Utility Collaborative Systems and five (5) other Ontario LDC clients. By working together and utilizing the same system setup there will be major cost avoidance as the members split all on-going costs.

The expected expenditure for 2008 of $400,000 is based on the quote price from Harris Computer Systems as outlined below. It includes the addition of File Nexus software, an electronic record keeping system which will be used to coordinate a more efficient and cost effective storage system for the Administration Department. A budget item of $60,000 has been put into the 2009 Capital Budget for additional software in the area of on-line bill presentment, a service that many customers are inquiring and making requests for.

Detailed CIS Cost Outline

Conversion cost from legacy Infinity to Harris Northstar 6 System	$ 186,900
Miscellaneous Expenses during Conversion & Training Process	$ 18,250
Cost of Cognos Reporting Software System Licence for Regulatory Reports	$ 7,500
Installation of Cognos by UCS Personnel to COLLUS Power Corp's Spec.	$ 6,000
Set up of Cognos Internal Processes	$ 3,750
Final Cut-over Process to move from Legacy Infinity to Northstar 6 System	$ 3,750
Licenses for COLLUS Power Corp System User Accounts	$ 7,500
Printer Configuration for COLLUS Power Corp Utility Bill format	$ 1,800
Set-up Spoke & Hub System Tools to work with Northstar 6 System	$ 20,000
File Nexus System Software Licence & Implementation of System	$ 95,000
Training and Other related Expenses	$ 20,000
Provincial Taxes	$ 29,550
TOTAL FORECASTED COST OF IMPLEMENTATION	**$ 400,000**

Appendix A included with this Schedule provides detailed information in Sections A-1, A-2, A-3 and A-4, regarding the extensive study and eventual attempt to utilize the chosen option. As noted earlier COLLUS Power Corp made the decision that the SAP solution would not be the preferred option and that the Harris NorthStar would be. Although this change in vendor was made the preferred option of using a single template and matching internal processes with other UCS members is still being maintained.

The new CIS system will allow COLLUS Power Corp to implement additional customer service focused tools, such as the on-line bill payment processing mentioned earlier. These tools will ensure that our customers will be able to utilize multiple services in a most efficient and effective manner. The ease of access is an important part of finding ways to help our customers conserve on their use of electricity. Conservation is very important part of the puzzle for the Provincial government in its attempts to meet growing energy requirements. Customer conservation is critical and a multi-functional CIS will contribute to the success of achieving reductions.

- **TRANSPORTATION AND RELATED EQUIPMENT (Category #12:**

Vehicle and Related Equipment Replacement and Modification:

2008 Capital Forecast: $450,000

2009 Capital Budget: $150,000

Description:

In 2008 $400,000 was planned for replacement of a 1992 Double Bucket Truck with a new vehicle. The other $50,000 forecasted expenditure is to replace the 1973 Forklift Vehicle. In 2009 $100,000 is budgeted to purchase a new chassis for Truck #29. The 1996 ½ Ton Pickup Truck used by the Line Department will also be replaced at a cost of $50,000.

Justification:

These projects are justified based on the need to maintain vehicles and major equipment functionality and provide safe, reliable tools and equipment.

COLLUS Power Corp practice is to replace as required large vehicles every eight years and small vehicles every ten years, subject to kilometers, usage and experience with respect to vehicle reliability.

COLLUS Power Corp vehicle replacement process considers the following criteria:

- Vehicle operational condition (# of repairs and cost during the previous years);
- Vehicle safety;
- Mileage & age;
- Department needs; and
- Replacement of vehicles before they become costly to repair, uneconomic and unsafe to operate.

Problems, deficient conditions and maintenance needs are monitored as part of the vehicle preventative maintenance program.

New vehicles and equipment support productivity through innovation, improved crew response time, reduced fuel costs and lower maintenance costs; and increase environmental responsibility through fuel reduction and alternate fuel usage.

Vehicle replacement supports a safe working environment, which reduces costs from lost time accidents caused by equipment failure; and maintains productivity.

In regards to 2008's projects, Project 17126-2 Replace Existing 1992 Double Bucket Truck has been taken through the tender process and has recently been awarded. Appendix E-1 provides the outline report that staff have put together to complete the decision making process. As indicated in the report the expected cost of the new vehicle is less than the $400,000 amount in the budget. Adjustment has not been made to the Cost of Service application from the budgeted amount because there still is the requirement to get the vehicle and ensure that it meets all requirements, and also there is an additional vehicle purchase to be made which could exceed the budgeted amount. Appendix E-2 is also provided which is the report from the Line Department supervisor that initiated the tendering process to begin.

There are not any other projects in this category for 2008 or 2009 that exceed the variance threshold.

- **COMMUNICATION EQUIPMENT (Category #13):**

COLLUS Power Corp communications equipment includes its telephone system and its vehicle and portable two way radio systems. In 2008 the expected expenditure of $95,000 is less than the materiality threshold. In 2009 $40,000 is planned for spending on the Communication units at 2 of the distribution substations, to provide connection to the existing SCADA monitoring system.

For 2006 and 2007 there were no General Plant capital spending additions that exceeded the materiality threshold levels determined earlier in Table 1. These levels were $98,000 for 2007 and $88,000 for 2006.

In closing off this section it should be noted that the years 2007, 2008 and 2009 all required an unusually high level of capital spending. Generally capital budgets are set at levels that do not exceed the annual amount of depreciation expense. But over the years leading up to 2007 COLLUS Power Corp had to make decisions based on earning a lower rate of return than anticipated in rates. One of the major reasons for this was the decision of the OEB to utilize a "floor" mechanism in regards to LDC's that had a negative return in 1999. The resulting adverse impact on COLLUS Power Corp was recognized in the OEB's decision to allow Tier 2 adjustments by approving the plan that was being submitted. In the years leading up to 2007 COLLUS Power Corp had to tighten its spending and investment into the infrastructure. Capital spending on the distribution system became a high priority from a spending perspective in 2007 and for 2008 and 2009 because delays could no longer be maintained.

Specifically for 2009 the capital program includes $2.2 Million for the new substation and the associated feeder system which is critical to enhance and even maintain the distribution system. COLLUS Power Corp expects spending to level out to a yearly amount that is less than total depreciation expense.

CAPITALIZATION POLICY:

COLLUS Power Corp 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 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. COLLUS Power Corp 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 $1,000 will be capitalized.

- Expenditures that create a physical betterment or improvement of the asset (i.e. there is a significant increase in the physical output or service capacity; or the useful life of the capital asset is extended) will be capitalized.

- With respect to transportation equipment (e.g. vehicles), all costs associated with putting a vehicle into service are capitalized.

WORKING CAPITAL CALCULATION:

- **OVERVIEW:**

COLLUS Power Corp working capital allowance is forecast to be $ 4,252,787 for 2009 and is based on the "15% of specific O,M&A accounts formula approach" referred to at page 15 of the Board's Filing Requirements. COLLUS Power Corp $ **28,351,915** 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

(provided on next page to maximize size of table)

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	69,738	10,461	70,082	10,512	73,300	10,995	76,800	11,520
5010-Load Dispatching	41,714	6,257	40,932	6,140	43,500	6,525	46,500	6,975
5012-Station Buildings and Fixtures Expense	14,403	2,161	19,782	2,967	18,000	2,700	19,000	2,850
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	0	0	0	0	0	0	0	0
5017-Distribution Station Equipment - Operation Supplies and Expenses	63,013	9,452	(15,622)	(2,343)	6,000	900	10,000	1,500
5020-Overhead Distribution Lines and Feeders - Operation Labour	410	61	13,088	1,963	22,000	3,300	26,000	3,900
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	104	16	12,150	1,823	0	0	0	0
5030-Overhead Sub transmission Feeders - Operation	0	0	0	0	0	0	0	0
5035-Overhead Distribution Transformers- Operation	2,726	409	1,456	218	3,000	450	3,500	525
5040-Underground Distribution Lines and Feeders - Operation Labour	0	0	0	0	0	0	0	0
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	0	0	0	0	0	0	0	0
5050-Underground Sub transmission Feeders - Operation	0		0		0		0	0
5055-Underground Distribution Transformers - Operation	0	0	0	0	0	0	0	0
5060-Street Lighting and Signal System Expense	0		0		0		0	0
5065-Meter Expense	753	113	1,550	232	1,500	225	1,500	225
5070-Customer Premises - Operation Labour	0	0	0	0	0	0	0	0
5075-Customer Premises - Materials and Expenses	0	0	0	0	0	0	0	0
5085-Miscellaneous Distribution Expense	64,818	9,723	71,913	10,787	77,000	11,550	78,000	11,700
5090-Underground Distribution Lines and Feeders - Rental Paid	0		0		0		0	0
5095-Overhead Distribution Lines and Feeders - Rental Paid	0		0		0		0	0
5096-Other Rent	27,500	4,125	30,000	4,500	30,000	4,500	30,000	4,500
Sub-Total	**285,179**	**42,777**	**245,331**	**36,800**	**274,300**	**41,145**	**291,300**	**43,695**
Maintenance								
5105-Maintenance Supervision and Engineering	63,093	9,464	59,223	8,883	60,000	9,000	62,000	9,300
5110-Maintenance of Buildings and Fixtures - Distribution Stations	5,514	827	23,103	3,465	25,000	3,750	26,000	3,900
5112-Maintenance of Transformer Station Equipment	0		0		0		0	0
5114-Maintenance of Distribution Station Equipment	58,133	8,720	59,921	8,988	38,100	5,715	59,600	8,940
5120-Maintenance of Poles, Towers and Fixtures	82,222	12,333	44,397	6,660	72,725	10,909	68,225	10,234
5125-Maintenance of Overhead Conductors and Devices	236,540	35,481	217,058	32,559	247,500	37,125	263,500	39,525
5130-Maintenance of Overhead Services	232,107	34,816	138,066	20,710	170,500	25,575	189,000	28,350
5135-Overhead Distribution Lines and Feeders - Right of Way	193,455	29,018	178,169	26,725	218,000	32,700	244,000	36,600
5145-Maintenance of Underground Conduit	0	0	0	0	0	0	0	0
5150-Maintenance of Underground Conductors and Devices	57,625	8,644	99,113	14,867	110,000	16,500	120,000	18,000
5155-Maintenance of Underground Services	45,799	6,870	187,822	28,173	201,500	30,225	236,500	35,475
5160-Maintenance of Line Transformers	130,216	19,532	81,061	12,159	111,000	16,650	100,000	15,000
5165-Maintenance of Street Lighting and Signal Systems	0		0		0		0	0
5170-Sentinel Lights - Labour	0		0		0		0	0
5172-Sentinel Lights - Materials and Expenses	0		0		0		0	0
5175-Maintenance of Meters	159,183	23,877	234,232	35,135	246,500	36,975	259,500	38,925
5178-Customer Installations Expenses- Leased Property	0		0		0		0	0
5185-Water Heater Rentals - Labour	0		0		0		0	0
5186-Water Heater Rentals - Materials and Expenses	0		0		0		0	0
5190-Water Heater Controls - Labour	0		0		0		0	0
5192-Water Heater Controls - Materials and Expenses	0		0		0		0	0
5195-Maintenance of Other Installations on Customer Premises	0		0		0		0	0
Sub-Total	**1,263,888**	**189,583**	**1,322,165**	**198,325**	**1,500,825**	**225,124**	**1,628,325**	**244,249**
Billing and Collections								
5305-Supervision	31,990	4,799	34,315	5,147	46,000	6,900	49,000	7,350
5310-Meter Reading Expense	77,385	11,608	80,380	12,057	82,000	12,300	85,000	12,750
5315-Customer Billing	409,197	61,380	426,328	63,949	459,109	68,866	489,093	73,364
5320-Collecting	54,419	8,163	53,525	8,029	65,000	9,750	69,000	10,350
5325-Collecting- Cash Over and Short	270	40	461	69	0		0	0
5330-Collection Charges	0		0		0		0	0
5335-Bad Debt Expense	19,072	2,861	60,636	9,095	70,000	10,500	70,000	10,500
5340-Miscellaneous Customer Accounts Expenses	0	0	0	0	0	0	0	0
Sub-Total	**592,333**	**88,850**	**655,645**	**98,347**	**722,109**	**108,316**	**762,093**	**114,314**
Community Relations								
5405-Supervision	0	0	0	0	0	0	0	0
5410-Community Relations - Sundry	0	0	0	0	0	0	0	0
5415-Energy Conservation	100,646	15,097	71,280	10,692	0	0	0	0
5420-Community Safety Program	0	0	0	0	0	0	0	0
5425-Miscellaneous Customer Service and Informational Expenses	53,597	8,040	86,644	12,997	100,085	15,013	107,389	16,108
5505-Supervision	0		0		0		0	0
5510-Demonstrating and Selling Expense	0	0	0	0	0	0	0	0
5515-Advertising Expense	0	0	0	0	0	0	0	0
5520-Miscellaneous Sales Expense	0	0	0	0	0	0	0	0
Sub-Total	**154,243**	**23,136**	**157,924**	**23,689**	**100,085**	**15,013**	**107,389**	**16,108**
Administrative and General Expenses								
5605-Executive Salaries and Expenses	163,872	24,581	198,380	29,757	221,296	33,194	230,611	34,592
5610-Management Salaries and Expenses	169,862	25,479	154,925	23,239	173,700	26,055	192,500	28,875
5615-General Administrative Salaries and Expenses	272,171	40,826	280,631	42,095	308,695	46,304	324,130	48,620
5620-Office Supplies and Expenses	0	0	0	0	0	0	0	0
5625-Administrative Expense Transferred Credit	0		0		0		0	0
5630-Outside Services Employed	237,750	35,663	244,500	36,675	191,300	28,695	181,500	27,225
5635-Property Insurance	1,929	289	1,490	224	2,000	300	2,000	300
5640-Injuries and Damages	533	80	234	35	1,000	150	1,000	150
5645-Employee Pensions and Benefits	0	0	0	0	0	0	0	0
5650-Franchise Requirements	0		0		0	0	0	0
5655-Regulatory Expenses	15,822	2,373	1,960	294	2,750	413	43,000	6,450
5660-General Advertising Expenses	5,533	830	5,780	867	7,250	1,088	7,500	1,125
5665-Miscellaneous General Expenses	51,892	7,784	0	0	4,750	713	5,000	750
5670-Rent	0		0		0		0	0
5675-Maintenance of General Plant	33,067	4,960	16,832	2,525	20,250	3,038	21,500	3,225
5680-Electrical Safety Authority Fees	0		0		0		0	0
5685-Independent Market Operator Fees and Penalties	0		0		0		0	0
Sub-Total	**952,430**	**142,864**	**904,732**	**135,710**	**932,991**	**139,949**	**1,008,741**	**151,311**
Property Taxes								
6105 - Property Taxes	5,025	754	8,256	1,238	8,916	1,337	8,916	1,337
Sub-Total	**5,025**	**754**	**8,256**	**1,238**	**8,916**	**1,337**	**8,916**	**1,337**
Cost of Power								
4705-Power Purchased	17,651,824	2,647,774	19,159,103	2,873,866	18,110,585	2,716,588	19,448,375	2,917,256
4708-Charges-WMS	1,790,294	268,544	1,756,381	263,457	2,060,287	309,043	2,212,476	331,871
4710-Cost of Power Adjustments	1,246,890		0		0	0	0	0
4712-Charges-One-Time	0		0				0	0
4714-Charges-NW	1,696,140	254,421	1,529,569	229,435	1,344,654	201,698	1,451,364	217,705
4716-Charges-CN	952,315	142,847	851,209	127,681	818,656	122,798	882,937	132,441
4730-LV Charges	216,705	32,506	381,770	57,265	550,000	82,500	550,000	82,500
5685-Independent Market Operator Fees and Penalties	0		0				0	
Sub-Total	**23,554,168**	**3,346,092**	**23,678,032**	**3,551,705**	**22,884,182**	**3,432,627**	**24,545,151**	**3,681,773**
WORKING CAPITAL ALLOWANCE TOTAL	**26,807,266**	**3,834,056**	**26,972,085**	**4,045,813**	**26,423,408**	**3,963,511**	**28,351,915**	**4,252,787**

An major component of the working capital calculation is the Cost of Power amount. In Table 2 below the calculation of the Cost of Power accounts are provided.

Table 2 COST of Power Accounts 2008 & 2009

Customer Class	Cost of Power	WMS & RRA	Tr. Connection	Tr. Connection	Tr. Network	Tr. Network
kWh Consumed & with losses applied 2008	2008	2008	Rate	$'s	Rate	$'s
	$ 0.0545	**$ 0.0062**				
Residential	**^ Rate/kWh ^**	**^ Rate/kWh ^**				
115,725,785			$ 0.0029	$ 335,605	$ 0.0047	$ 543,911
125,423,606	**$ 6,835,587**	**$ 777,626**				
Gen Ser < 50 kW						
45,826,838			$ 0.0026	$ 119,150	$ 0.0043	$ 197,055
49,667,127	**$ 2,706,858**	**$ 307,936**				
Gen Ser > 50 kW						
109,107,536						
118,250,748	**$ 6,444,666**	**$ 733,155**				
258,647			**$ 1.0322**	$ 266,976	**$ 1.7399**	$ 450,020
Large Use						
34,974,004						
36,163,120	**$ 1,970,890**	**$ 224,211**				
70,103			**$ 1.2940**	$ 90,713	**$ 2.0461**	$ 143,437
Street Light						
2,065,679						
2,238,783	**$ 122,014**	**$ 13,880**				
6,100			**$ 0.7979**	$ 4,867	**$ 1.3122**	$ 8,005
USL						
517,563			$ 0.0026	$ 1,346	$ 0.0043	$ 2,226
560,935	**$ 30,571**	**$ 3,478**				
		$ 2,060,287		$ 818,656		$ 1,344,654
TOTAL	**$ 18,110,585**	**$ 4,223,597**				
308,217,406		**$ 22,334,182**				
1.0838	2008 Loss Factor for most rate classes consumption in kWhs Column A					
1.034	2008 Large Use Loss Factor for consumption in kWhs in Column A					

Customer Class	Cost of Power	WMS	Tr. Connection	Tr. Connection	Tr. Network	Tr. Network
Customer Class kWh & with losses 2009	2009	2009	Rate	$'s	Rate	$'s
	$ 0.0545	**$ 0.0062**				
121,128,423			$ 0.0029	$ 351,272	$ 0.0047	$ 569,304
130,219,087	**$ 7,096,940**	**$ 807,358**				
45,443,633			$ 0.0026	$ 118,153	$ 0.0043	$ 195,408
48,854,169	**$ 2,662,552**	**$ 302,896**				
126,855,660						
136,376,152	**$ 7,432,500**	**$ 845,532**				
300,721			**$ 1.0322**	$ 310,404	**$ 1.7399**	$ 523,224
37,423,367						
38,695,762	**$ 2,108,919**	**$ 239,914**				
75,012			**$ 1.2940**	$ 97,066	**$ 2.0461**	$ 153,482
2,061,153						
2,215,842	**$ 120,763**	**$ 13,738**				
6,087			**$ 0.7979**	$ 4,857	**$ 1.3122**	$ 7,987
455,702			$ 0.0026	$ 1,185	$ 0.0043	$ 1,960
489,902	**$ 26,700**	**$ 3,037**				
		$ 2,212,476		$ 882,937		$ 1,451,364
TOTAL	**$ 19,448,375**	**$ 4,546,776**				
333,367,939		**$ 23,995,151**				
1.0750	2009 Loss Factor for most rate classes consumption in kWhs Column A					
1.034	2009 Large Use Loss Factor for consumption in kWhs in Column A					

The total of $ $ 22,334,182 for 2008 and $ $ 23,995,151 for 2009 don't match exactly to the Total Cost of Power amounts shown on the Working Capital information in Table 1. The difference between each of the amounts results from the Low Voltage Charges as they are not included as part of Table 2. The details of the calculation of the Low Voltage Charges are provided in Exhibit 9, Tab 1, Schedule 1, (Page 8) of this application.

End of Exhibit 2 (Rate Base).

APPENDIX B 2008 and 2009 - COLLUS Power Corp Capital Budget Summary Schedule

Project or Class No	Asset Category	Project Description	2008 Budgeted	O/H	U/G	P&T	2009 Projected	O/H	U/G	P&T
		DISTRIBUTION PLANT - CUSTOMER DEMAND & RENEWAL CATEGORY : Major Construction Projects								
17011	1&2	Parkside Avenue - 4 kV line rebuild project	$120,000.00	$90,000.00	$18,000.00	$12,000.00				
17012	1&2	First Street Rebuild Project- Hurontario to Balsam Street	$110,000.00	$44,000.00	$44,000.00	$22,000.00				
17015	1&2	Creemore Main Street Replacement Project	$50,000.00		$50,000.00	$0.00				
17016	1&2	Sixth Street High to 6th for new Sub. + 2nd Pine to Birch					$330,000.00	$264,000.00	$49,500.00	$16,500.00
17013	1&2	Georgian Trail & Back Lot Project - New Line Installation	$110,000.00	$47,000.00	$35,000.00	$28,000.00	$0.00			
		DISTRIBUTION PLANT - SECURITY & RELIABILITY CATEGORY : Miscellaneous Projects - Resulting from Annual System Inspections (ESA 22/04)								
17016	3	Rebuild Projects (Poles, Conductor & Hardware) Specifically attributed to the Annual Inspections. Note This amount also includes the system inspection costs. (Increase $20,000 in 09)	$100,000.00	$40,000.00	$40,000.00	$20,000.00	$120,000.00	$48,000.00	$48,000.00	$24,000.00
		DISTRIBUTION PLANT - REGULATORY CATEGORY : Distribution System Boundary Line Expansion (Load Transfers Elimination Project)								
17018	5	New 4kV Polelines - Osler Bluff Road, Long Point Road, Madeline Avenue in Collingwood and 10th Line in Thornbury	$100,000.00	$60,000.00	$20,000.00	$20,000.00	$0.00			
17055/7		DISTRIBUTION PLANT - CUSTOMER METERING CATEGORY : Wholesale Metering Capital Projects (2008 and 10)								
	4	The expected upgrade/replacement work that will be required.	$21,000.00				$0.00			
		DISTRIBUTION PLANT - CAPACITY CATEGORY : Distribution Substation Capital Projects								
17040	6	Construction of new MS#8 Sub-Station in the South West Portion of Collingwood as per 2005 System optimization study results updated in 2008 for current situation.	$0.00				$1,900,000.00			
17050		DISTRIBUTION PLANT - CUSTOMER METERING CATEGORY : Electric Metering Capital Projects (Not part of the Provincial Smart Meter Program)								
	4	Annual replacement program for resid. & comm. hydro meters	$60,000.00				$60,000.00			
		DISTRIBUTION PLANT - CUSTOMER DEMAND & RENEWAL CATEGORY : Distribution Transformer Capital Projects								
17070	1&2	To accommodate any new distribution transformers required for general load growth (Add $20,000 in 09 due to supplier inc.)	$100,000.00			$100,000.00	$120,000.00			$120,000.00
		GENERAL PLANT - COMMUNICATIONS EQUIPMENT CATEGORY : SCADA Capital Projects								
17091	13	New RTU's for Sub-Stations, New Data Radios and Fault Indicators for 44kV feeders	$95,000.00				$40,000.00			
		GENERAL PLANT - TRANSPORTATION EQUIPMENT CATEGORY : Large Vehicles & Equipment Purchases								
17126	12	Replace Existing 1973 Forklift	$50,000.00				$0.00			
		Replace Existing Tr 29	$0.00				$100,000.00			
			$0.00				$0.00			
			$0.00				$0.00			
	12	Replace Existing 1992 Double Bucket Truck	$400,000.00				$0.00			
	12	Replace Existing 1996 1/2 Ton Pickup Truck (Locator)	$0.00				$50,000.00			
17170,180, 190,200		DISTRIBUTION PLANT - CUSTOMER DEMAND & RENEWAL CATEGORY : Collingwood - Overhead & Underground Service Capital Projects								
	1&2	Utility spending on any new o/h & u/g residential & general service as per conditions of service or customer request.	$100,000.00	$40,000.00	$40,000.00	$20,000.00	$112,000.00	$44,800.00	$44,800.00	$22,400.00
		DISTRIBUTION PLANT - CUSTOMER DEMAND & RENEWAL CATEGORY : Thornbury - Overhead & Underground Service Capital Projects								
17401-4	1&2	Utility spending on any new o/h & u/g residential & general service as per conditions of service or customer request.	$60,000.00	$24,000.00	$24,000.00	$12,000.00	$64,500.00	$25,800.00	$25,800.00	$12,900.00
		DISTRIBUTION PLANT - CUSTOMER DEMAND & RENEWAL CATEGORY : Clearview - Overhead & Underground Service Capital Projects								
17301-4	1&2	Utility spending on any new o/h & u/g residential & general service as per conditions of service or customer request.	$38,000.00	$15,200.00	$15,200.00	$7,600.00	$71,000.00	$28,400.00	$28,400.00	$14,200.00
		GENERAL PLANT - COMPUTER SYSTEM CATEGORY : CIS & Accounting Enhancements - Specific for COLLUS Power								
17163	11	Enhancements to the customer information system and general accounting system specifically for COLLUS Power. In particular requirements of changes to the electric market.	$400,000.00				$60,000.00			

APPENDIX B 2008 and 2009 - COLLUS Power Corp Capital Budget Summary Schedule

Project or Class No.	Asset Category	Project Description	2008 Budgeted	O/H	U/G	P&T	2009 Projected	O/H	U/G	P&T
17600		DISTRIBUTION PLANT - CUSTOMER DEMAND & RENEWAL CATEGORY : Economic Evaluations - Portion paid to developers								
	1&2	The portion paid to developers attributed to their original contributed capital calculations.	$120,000.00	$48,000.00	$48,000.00	$24,000.00	$100,000.00	$40,000.00	$40,000.00	$20,000.00
17130		GENERAL PLANT - FACILITIES CATEGORY : Operations Centre - Capital Additions								
	10	Transformer racking added 09. Office Equipment 2008-10	$85,000.00				$90,000.00			
		GROSS TOTAL Before Contributed Capital =	$2,119,000.00				$3,217,500.00			
N/A		NON-CATEGORY ITEM : Rechargeable Mtce Projects & Light Work Re-billed (Not included into totals-used to track utility spending on this non-capital item)								
		Small Mtce Projects and other work recorded to track spending	$60,000.00				$60,000.00			
18000		Rechargeable Capital Work (Used to track utility spending on this item that contributed capital nets against)								
	7	Large Capital Work Projects net impact of $0 to capital	$100,000.00				$100,000.00			
18000		DISTRIBUTION PLANT - CUSTOMER DEMAND & RENEWAL CATEGORY : Contributed Capital (customer portion of utility spending on capital projects listed above)								
	7	Contributions from developers and others for capital work done.	-$350,000.00				-$300,000.00			
(See Schedule B-2 Line 19)		NET CAPITAL SPENDING REQUIREMENT (Net of Contributed Capital) =	$1,869,000.00				$3,017,500.00			

O/H	U/G	P&T		Supervisory	Meters	Transformers	Supervisory	Vehicles	CIS - Software	Op Ct - Equip	Substation	Total
2008												
1	2	Sub 1&2		3	4	5	6	7	8	9	10	
$ 408,200	$ 334,200	$	165,600	$21,000	$60,000	$100,000	$95,000	$450,000	$400,000	$85,000		$ 2,119,000
$ 71,800	$ 15,800	$	(165,600)			$78,000						
$ 480,000	$ 350,000	$	-	$ 21,000	$ 60,000	$ 178,000	$ 95,000	$ 450,000	$ 400,000	$ 85,000	$ -	$ 2,119,000
											Less CC Amt	-$250,000
2009												$ 1,869,000
$451,000	$236,500		$110,000	$0	$60,000	$120,000	$40,000	$150,000	$60,000	$90,000	$1,900,000	$ 3,217,500
55000	0		-110000			$55,000.00						
$ 506,000	$ 236,500	$	-	$ -	$ 60,000	$ 175,000	$ 40,000	$ 150,000	$ 60,000	$ 90,000	$ 1,900,000	$ 3,217,500
												-$200,000
												$ 3,017,500

CODAC Mission and Objective

January 26, 2007

CODAC is a group of Ontario LDC's that have been put in the position of replacing their Customer Information System as a result of the withdrawal of support by their vendor. The purpose of this group is to act as a bulk buying agent in the selection and implementation of a new Customer Information System, and to take advantage of economies of scale, wherever possible.

CODAC will be requesting RFP's on behalf of its members, and will recommend the selection of a vendor; however, there is no guarantee to the vendor that each member will enter into a contractual agreement. CODAC will inform the RFP participants that the bid documents will be distributed through one member, representing the entire coalition.

A SFTP (Secure FTP) site will be created for all members of CODAC to access and share documents pertaining to the group's activities.

Mission Statements:

• Ensure that all participating LDC's have a Customer Information System that is capable of meeting current and future regulatory requirements

• Minimize expenses in the selection, conversion, training and implementation of a new Customer Information System

• Share expertise and experiences

• Reduce implementation time-frames

Objectives:

1. Proceed expeditiously with the selection, conversion, training and implementation from current Customer Information System(s) to the new system. With smart metering implementation right around the corner, we need to get the new Customer Information System implemented and stabilized as quickly as possible. Smart metering with Time-of-use rates cannot proceed until the new system is in place and operational. Also, it is preferable to have the new system in place before the installation of smart meters commences, as many LDC's will be required to automate work order processes.

2. Deficiencies with current Customer Information Systems will be inventoried and documented and used to form part of the RFP information requirements. Each LDC will be responsible for preparing their own list and a working group will organize these into one inclusive list. The working group will also document the high level functionality required for the Customer Information System.

3. The Elimination of in-house custom applications or unnecessary interfaces, wherever possible, will be a key element of the vendor selection process. It is understood that there may be no reasonable justification for the elimination of custom applications or unnecessary interfaces. This will be a last-resort option only.

4. The notion of an Application Service Provider (ASP) solution will be explored during this process to determine if there is a potential benefit.

Request For Proposal

Customer Information and Billing System

Table of Contents

1 General Information

1.1 Background

This Request for Proposal (RFP) is intended to assist Local Distribution Companies (LDC's), named in Section 1.2, in the selection of a Customer Information and Billing System (CIS). Vendors (this includes Application Service Providers) are invited to submit proposals to provide a CIS that will be capable of meeting all current and future Regulatory requirements in the Province of Ontario. The distribution of this RFP is limited to CIS Vendors currently providing services to at least one LDC in the Province of Ontario. The outline of this RFP is such that it will:

- Provide general LDC information
- Specify the relevant business requirements that prospective Vendors should satisfy if selected
- Specify the relevant functional requirements that prospective Vendors should satisfy if selected
- Provide Vendors with the necessary templates to complete proposals in a timely and consistent fashion
- Communicate the criteria and timelines established by the "CODAC Working Group"
- Ask Vendors to provide flexible pricing options

1.2 The "CODAC Working Group"

The "CODAC Working Group" (Group) currently represents **<u>24</u>** Ontario LDC's utilizing **<u>17</u>** independent Customer Information and Billing Systems. The needs of the Group ranges from those required to change to those currently exploring alternatives to their current CIS.

CODAC Members Details

Company Name	Total Number of Accounts	Electric Meters	Water Meters	Basic Account Types: All Interval Metered Inc.Streetlights	Basic Account Types: General Service > 50	Basic Account Types: General Service < 50	Basic Account Types: Residential	Basic Account Types: Unmetered Scattered Load	Basic Account Types: Other Non-Electric Account Types	Basic Account Types: Total Basic Account Types	Current CIS System	Current Financial System	Current GIS System
Cambridge and North Dumfries Hydro Inc.	49,800	48,700	38,900	210	510	4,470	44,000	70	540	49,800	Advanced	CMIC	GENTRY
Collus Power Corp.	14,483	14,252	8,484	48	121	1,607	12,497	27	183	14,483	Advanced	Great Plains	Arcview
ELK Energy	13,702	10,596	7,279	7	110	977	9,502	36	3,070	13,702	Advanced	AccPac	none
Greater Sudbury Utilities***	67,556	45,918	45,654	38	273	3,871	41,511	157	21,706	67,556	Advanced	HTE	In-house
Grimsby Power Inc.	9,611	9,522	0	35	75	654	8,763	84	0	9,611	Advanced	APPX (COS)	CableCad
Haldimand County Hydro	20,919	20,833	8,372	27	125	2,423	18,245	86	13	20,919	Advanced	Great Plains	ESRI
Hawkesbury Hydro	5,275	5,250	0	9	74	564	4,611	17	0	5,275	Advanced	AccPac	none
Orangeville Hydro Limited **	10,724	10,724	9,071	19	130	1,056	9,483	36	0	10,724	Advanced	Great Plains	Microstation
Ottawa River Power *	13,500	13,178	0	27	159	1,781	11,165	42	326	13,500	Advanced	AccPac	ESRI
Tillsonburg Hydro Inc.	6,579	6,466	5,930	22	61	644	5,739	19	94	6,579	Advanced	Great Plains	ESRI
Wasaga Distribution Inc.	10,963	10,963	0	8	31	795	10,120	0	9	10,963	Advanced	Business Vision	Autodesk
Niagara-On-The-Lake Hydro	8,263	7,628	5,859	15	109	1,211	6,299	24	605	8,263	APPX (COS)	APPX (COS)	ArcGIS 9
Welland Hydro-Electric System Corp.	21,547	21,589	0	27	187	1,675	19,435	223	0	21,547	APPX (COS)	APPX (COS)	Autodesk
Barrie Hydro	67,851	67,551	46,417	54	2,542	4,049	60,906	300	0	67,851	HTE	JDEdwards	ESRI
Great Lakes Power	11,590	11,800	0	15	39	955	10,490	91	0	11,590	HTE	HTE	CableCad
North Bay Hydro	24,042	24,020	0	34	224	2,728	21,036	20	0	24,042	HTE	HTE	ESRI
Thunder Bay Hydro ****	61,986	61,986	5,785	6	4,641	2,040	55,099	200	0	61,986	HTE	HTE	all over the map
									0	0			
Totals	**418,391**	**390,976**	**181,751**	**601**	**9,411**	**31,500**	**348,901**	**1,432**	**26,546**	**418,391**			

* Includes Embrun Hydro (1,800 Accounts) & Hydro 2000 (1,200 Accounts)
** Includes Grand Valley Energy Inc. (687 Acounts)
*** Includes West Nipissing Energy Inc. (3,143 Acounts)
****Includes Kenora, Sioux Lookout & Fort Frances (12,903)

Total # of CIS Systems:	**17**
Total # of LDC's:	**24**

The approach of the Group is to work collaboratively in researching current and future requirements, preparing this RFP Document and meeting with a short list of prospective Vendors that are considered best-fit to our needs. Based on the Mission Statement of the Group, LDC's have no obligation to pursue any alternative presented by prospective Vendors or other LDC's within the Group. In other words, LDC's may wish to pursue their own alternatives. Other LDC's may wish to continue with additional members and pursue a group purchasing strategy. Regardless of the ultimate outcome, Group Members have agreed to explore all alternatives collectively up to the point of meeting with a short list of prospective Vendors.

In light of this, the Group has decided that it would like to explore a number of options as it relates to pricing. The options are:

1. Individual Installations with LDC Defined Set-up
2. Individual Installations with Group Defined Set-up
3. One Installation Containing Multiple Companies with Group Defined Set-up (ASP)

Vendors should consider these alternatives when completing Costing Templates in Appendix B.

1.3 Current System Functionality

The current "CODAC Working Group" members are presently utilizing Advanced CIS Infinity, SunGard H.T.E. and APPX Customer Information and Billing Systems. The Advanced CIS Infinity Billing System is windows based with either SQL or Oracle as the database. SunGard H.T.E. runs on an IBM AS/400 with DB2 as the database. APPX runs on an ISAM database. All systems are modular. Current Core CIS functionality includes:

- Billing
- Meter Reading
- General Customer Care
- Contact Management
- Cash Management
- Adjustment Management
- Collections Management
- Automatic Payment Plan Management
- Deposit Management
- Interface to External Financial System
- Wholesale and Retail Management
- Retailer Management
- Electronic Business Transactions (EBT)
- Regulatory Reporting and Filing
- General Financial and Statistical Reporting
- Service / Work Order Management
- Meter and Other Inventories
- Land Management
- Lien Processing
- Security
- Support

1.4 Proposed System Functionality

The proposed CIS should, at a minimum, correspond to the core CIS functionality outlined in Section 1.3. Further to this, Vendors should be able to demonstrate current or pending functionality as it relates to:

- The Province of Ontario Smart Meter Initiative
- The Province of Ontario Net Metering, Sub-Metering and Standard Offer Programs
- Complex Reporting Capabilities Relative to Customer, Metering, Billing, Financial and Regulatory
- User-Friendly Screens and Easy Access to Data
- Display, Access, and Adjustment of Meter Information: details of meter, as well as, details of consumption at customer level
- Interface to Electronic Business Transactions via EBT Hub Service Providers
- Interface to Legacy Financial Systems
- Interface to Legacy Operational or Engineering Applications (GIS)
- Ability to Process Multiple Service Types including but not limited to: Metered, Un-metered and Rental Equipment

- Multiple Company Environment

A comprehensive list of Functional Requirements is outlined in Appendix B (Tab 3. Functional Requirements).

2 Vendor Pre-Qualifications

2.1 Expectations of Vendor

The distribution of this RFP Document and all its associated attachments has been limited to Vendors currently providing a CIS solution to at least one LDC in the Province of Ontario. It is expected that Vendors invited to participate in the RFP process have a comprehensive understanding of the Ontario Market and possess the necessary expertise required to fulfil their obligations as outlined in this RFP document.

The successful Vendor(s) should be actively involved with Regulatory initiatives and be able to provide a system that has the required flexibility to effectively operate in the Ontario Market. The success of this RFP initiative has a direct correlation to prospective Vendors ability to correctly identify, customize and leverage existing and emerging business processes.

As with all new development or customization work, a suitably rigorous testing regime will be required to ensure the system is delivered as per outlined expectations and the successful Vendor(s) will be expected to provide assurance that current operations will not be impacted at any stage throughout this initiative.

As outlined in Section 1.2, the Group is wishing to explore multiple options. Regardless of the end solution chosen by individual Group Members, all have expressed the need for a Go-Live date of no later than **September 30, 2008**. In the event that options 2 or 3 are chosen by some or all of the Group Members, the **September 30, 2008** date would be in reference to the Go-Live date for the last Group Member. It is recognized that a phased implementation approach would be necessary for both options 2 and 3. Vendors that would have difficulty in meeting this timeline are asked to provide comments to this affect in **Appendix B (Tab 20. Comments)**.

2.2 Vendor Background and Qualifications

Vendors are required to complete the Vendor Background and Qualifications spreadsheet located in **Appendix B (Tab 1. Vendor Background)**. This completed spreadsheet and any associated supporting documentation is to be submitted as part of the Proposal. This spreadsheet is not to be changed or altered in any way by prospective Vendors. Only those fields that are left unprotected may be updated by Vendors. Any supporting documentation should be attached to **Appendix C** in PDF format.

2.3 Confidentiality

All vendors will need to sign a Confidentiality Agreement in accordance to the Privacy Act. The details of the confidentiality agreement are outlined below.

VENDOR will treat as such all confidential proprietary information obtained from the CODAC Working Group in the course of the engagement and, except as described in this Section, will not use such information except in connection with the performance of its services hereunder. VENDOR will be entitled to include a description of the services in marketing and research materials and disclose such information to third parties, provided that all such information will be rendered anonymous and not subject to association with the CODAC Working Group. This restriction shall not apply to any confidential information that VENDOR is required by law or professional standards to disclose, that is in or hereafter enters the public domain, that is or hereafter becomes known to VENDOR without breach of any confidentiality obligation or that is independently developed by VENDOR. VENDOR shall be entitled to share any and all confidential information with all other member firms of VENDOR International performing services hereunder, and within VENDOR (and its subsidiaries) to allow VENDOR to offer the CODAC Working Group services or products that may be of interest to the CODAC Working Group. VENDOR may retain and may disclose to other member firms of VENDOR International, subject to terms of this Section, copies of the CODAC Working Groups confidential information required for compliance with applicable professional standards or internal policies or quality reviews.

By signing the Intent to Respond Template found in **Appendix A**, the Vendor is agreeing to the Confidentiality terms outlined above.

2.4 RFP General Filing Requirements

Vendors interested in responding to this RFP, will be required to complete the Intent to Respond Template **(Appendix A)** and email to the Groups main contact no later than **April 16, 2007 at 4:00pm**.

All requests for further information, clarification of requirements or general questions should be directed to the Groups main contact. All Vendor questions and Group responses will be shared with each prospective Vendor. The question and response period will be between the dates of **April 4, 2007 – April 30, 2007**.

Vendor Proposals must be received by **May 4, 2007 at 12:00pm**. All Proposals are to be directed to the Groups main contact.

The main contact for the Group can be found in Section 5 of this RFP document.

3 General Instructions

3.1 RFP Scope and Process

This RFP is concerned with the analysis, design, testing, training, implementation and support of, at a minimum, one new Customer Information and Billing System (CIS).

The initiative is to be provisioned in entirety as per the current business processes within this RFP and its associated appendices.

All documents submitted, as part of the vendor's proposal will be deemed confidential during the evaluation process. Vendor proposals will not be available for review by anyone other than the evaluation team or its designated agents. There shall be no disclosure of any Vendor's information to a competing Vendor prior to award of the contract(s). All applicable information will be subject to public disclosure in accordance with the Freedom of Information Act, at award of contract(s), cancellation of this RFP, or within 12 months, whichever shall occur first.

The following table outlines the general timelines for the RFP process that the Group will be working towards. These dates may change at the discretion of the Group.

STEP	DATE & TIME	STEP DESCRIPTION
1	**March 29, 2007**	Issue RFP
2	**April 4, 2007 at 2:00 pm**	Conference Call with Prospective Vendors
3	**April 16, 2007 at 4:00 pm**	Intent to Submit Deadline
4	**April 4 to April 30, 2007**	Group to Respond to Questions, Clarifications and/or Issues
5	**May 4, 2007 at 12:00 pm**	Proposal Submission Deadline
6	**May 11, 2007 by 4:00 pm**	Notify Short Listed Vendors

7	**May 22 to May 25, 2007** **(Location – TBD)**	Presentations by Short Listed Vendors – Includes Presentation / Demonstration of CIS Solution and Q & A – Full Day / Vendor is anticipated
8	**June 4 to June 8, 2007**	Customer Site Visits and Completion of Customer Satisfaction Survey
9	**June 13, 2007 by 4:00 pm**	Issue Detailed Project Plan Requirements to Short Listed Vendors – List of Vendors could be short listed again based on the results of Presentations
10	**June 20, 2007 by 4:00 pm**	Detailed Project Plan Deadline
11	**TBD**	End of the Evaluation of the RFP Responses
12	**TBD**	Advise Vendors

Vendors should mark these timelines in their calendars and more specifically, the dates after **May 11, 2007**. As Section 4 will outline, A Detailed Project Plan is not required with Vendors responses to this RFP but the Group is asking that Vendors build the necessary templates for those requirements outlined in this Section. Prior to the issuance of the Detailed Project Plan Requirements, Group Members should be in a position to make a decision on whether or not they are interested in proceeding. If Group Members have indicated they are interested in proceeding, selected Vendor(s) will be provided this information to assist in the completion of their Detailed Project Plan.

3.2 Selection Process

It is anticipated that the following phases will encompass the selection process:

- Request for Proposal to be Sent to Vendors
- Review of Response to Request for Proposal from Vendors
- Presentations and Demonstrations by a Short List of Vendors
- Customer Site Visits
- Detailed Project Plan Requirements Sent to Short Listed Vendors
- Review of Detailed Project Plans Received from Vendors
- LDC Vendor Selection(s)

3.3 RFP Filing Requirements

- The purpose of this RFP is to identify vendors that are capable of satisfying the needs of the Group as set out in Appendix B.
- All costs for developing Proposals and all other costs associated with the RFP process are the exclusive responsibility of the Vendor.
- Before acting in reliance on any information contained in the RFP, the Vendor should conduct its own investigations and analysis in relation to their Proposal and should check the accuracy, reliability and completeness of their Proposal and obtain independent and specific advice from appropriate professional advisers.
- In the event that a group of organizations wish to respond to the RFP, one organization is to act as prime contractor with responsibility for authorizing the RFP response and signing the contract. Partner organizations and their roles are to be identified in **Appendix B (Tab 20. Comments)**.
- During the RFP process, there should be no direct contact between Vendors and Group Members. All questions or issues should be directed via email to the Groups main contact identified in Section 5.
- Each proposal will be prepared on the Excel forms provided and be submitted in a sealed envelope bearing the title of work and the name of the Vendor. All supporting documentation should be attached to **Appendix C** in PDF format. Submissions should include **1** signed paper copy and **1** electronic copy on a CD. The paper copy will be held by the Groups main contact and

the electronic copy will be electronically distributed to all Group Members. Vendor Proposals must be delivered to the office of the Groups main contact (Section 5) by the date and time specified in Section 2.4. It is the sole responsibility of the Vendor to ensure that their Proposal is received. All Proposals will be Date and Time Stamped when received. Any Proposal received after this time shall be eliminated from consideration and returned to the Vendor unopened.

3.4 Functional Requirements

The Functional Requirements spreadsheet outlines the required functional and business requirements established by the Group with regards to the Customer Information and Billing System (CIS). Due to the fact that this RFP is limited to Vendors currently operating in the Ontario Market; some assumptions have been made by the Group. Each Vendor will be evaluated on their ability to meet these functional requirements.

Vendors are required to complete the Functional Requirements spreadsheet located in **Appendix B (Tab 3. Functional Requirements)** and submit with their Proposal. This document is not to be changed or altered in any way by prospective Vendors. Only those fields that are left unprotected may be updated by Vendors.

Vendors are asked to complete each Functional Unit based on their CIS system capabilities. The majority of Functional Units have been broken up into three distinct sections:

- Functionality
- Basic Questions
- Other Questions

The exceptions to this rule are Section II and Section III where slight modifications will be noted.

In the first subsection labelled **Functionality**, Vendors are asked to answer each item by marking the appropriate box with an **X** as it relates to their CIS system. If the functionality is anything other than "Core", (Optional, Pending or N/A) please add comments in the Comments field. For example; if the functionality was "Optional", the appropriate Module should be denoted in the Comments field. Further to this, if the functionality is "Pending", please identify if this new functionality will be "Core" or "Optional" and when the new functionality will be available in the Comments field. For any functionality that is "Client Configurable", please place an **X** in the appropriate box.

Functionality	Core	Optional	Pending	N/A	Client Config.	Comments

In the second subsection labelled **Basic Questions**, Vendors will answer each item by marking the appropriate box with an **X** as it relates to their CIS System. If the answer to the question is "No", please provide comments in the Comments Field.

Basic Questions	Yes	No	Comments

In the third subsection labelled **Other Questions**, Vendors will answer all general questions asked in the Answers Field.

Other Questions	Answers

Functionality Coding Key:

Core Indicates that this functionality resides in the Basic CIS Billing & Customer Care Module

Optional The listed functionality does not reside in the Basic CIS Billing & Customer Care Module and is therefore considered an add-on or upgrade to the Core system

Pending This is planned functionality not yet available but will be at some point in the near future. Vendor to advise if this functionality will be Core or Optional

_N/A_ This functionality is not presently available and is not expected anytime in the foreseeable future

Client Configurable This functionality is either "Core", "Optional" or "Pending", and clients have access to configure to meet their business processes

3.5 Source Code

Vendors are required to complete the Source Code spreadsheet located in **Appendix B (Tab 2. Source Code).** This completed spreadsheet and any associated supporting documentation is to be submitted as part of the Proposal. This spreadsheet is not to be changed or altered in any way by prospective Vendors. Only those fields that are left unprotected may be updated by Vendors. Any supporting documentation should be attached to **Appendix C** in PDF format.

3.6 Financial Requirements

3.6.1 Costing / Pricing

The Group requests that all Vendor quotes be all inclusive for all works and services to be provided in the course of completing the Project, and for any facilities used by Vendors outside of those made available by Group Members.

Vendors need to clearly specify any work or services **excluded** from the quoted fixed price. Any exclusion(s) should be noted in **Appendix B (Tab 20. Comments)**.

The Group is asking for multiple costing options for a couple of reasons:

- The Group wishes to explore various costing options as outlined in Section 1.2
- Group Members are currently operating on various databases
- Group Members are currently utilizing various Customer Information and Billing Systems

Vendors are required to complete the costing option templates located in **Appendix B (Tabs 4 to 18)** and submit with their Proposal. These documents are not to be changed or altered in any way by prospective Vendors. Only those fields that are left unprotected may be updated by Vendors.

If a Vendor cannot support any of the costing options presented in Appendix B (Tabs 4 to 18), they are asked not to attempt completion of the applicable costing option and provide comments to this affect in **Appendix B (Tab 20. Comments)**.

If a Vendor is currently providing CIS services to any Group Member(s), they are not required to complete the costing options relative to their own CIS. This pertains to costing options 1 and 2 outlined in Section 1.2. All Vendors should complete their available costing options for option 3 as outlined in Section 1.2.

All offers made in the Vendor Proposals and revised Proposals, pertaining to rates, shall remain valid for a period of **90** days from the due date of Proposals.

3.6.2 Assumptions

Due to Group dynamics, some assumptions are necessary for comparative analysis purposes. It's understood that the complexities of conversions will vary from one CIS to another; therefore every effort has been made to capture all relevant costing scenarios. For further understanding of each costing option, please refer to Appendix B and review the Brief Descriptions.

Option #1: Individual LDC Installation with LDC Defined Set-up. Vendor to Base Costs Wherever Possible on the Assumptions Outlined Below			
LDC Assumptions:			
Account Size:	**30,000**		**Section 3.6.1 states that rates will remain valid for 90 days**
Meter Count:	**29,500**		
End Users:	**22**		
Technical Users:	**3**		
Conversion From Current CIS System:	**ADVANCED**	**Rob Skevington:** Denotes Current CIS for LDC	
Vendor Information			
Name:	**Vendor Name**		
Database Option that Quote is Based on:	**Vendor to Input**	**Rob Skevington:** In Reference to Vendors First Available Database Option	

Further assumptions are being made relative to Hardware and Database Requirements. The assumption is that both of these requirements would be the responsibility of LDC's.

Due to the assumptions outlined within the various costing templates, it's anticipated that short listed Vendors will be asked to revise their costing quotes once Group Members have made a decision on whether or not to proceed. Any requests for revised costing quotes will likely occur during the issuance of the Detailed Project Plan Requirements. It is at this point that LDC's will review Hardware and Database Requirements along with the associated responsibilities. Vendors may be asked to outline additional costs relative to Hardware and Databases in revised pricing quotes.

3.6.3 Warranty

Within the Vendor Proposal it should be outlined what the warranty period will be and what support will be available. Warranty period should be outlined within the Cost Templates located on **Line 63** in **Appendix B (Tabs 4 to 18)**.

3.7 Right of Refusal

The Group reserves the right to reject any or all Proposals in their entirety or to select certain CIS application software from the Proposals received. The Group reserves the right to award the contract(s) in any manner deemed in the best interest of its members.

3.8 Proposal Costs

All costs incurred by the Vendor in the preparation and presentation of the Proposal shall be absorbed entirely by the Vendor. All supporting documentation submitted with this Proposal shall become the property of the Group.

All travel and other expenses incurred by the Vendor related to presenting their Proposal and demonstrating their CIS are the responsibility of the Vendor.

3.9 Evaluations

Evaluation of the Proposals is expected to be completed within **30** days after receipt. An evaluation team will evaluate proposals on a variety of quantitative and qualitative criteria. The Proposal(s) selected shall provide the most cost-effective approach that meets the stated functional requirements. The lowest price Proposal(s) will not necessarily be selected.

The Group reserves the right to:

- Reject any or all Proposals, or to make no award
- Require modifications to initial proposals
- Make partial or multiple awards
- Accept, reject, or modify all or part of the Vendors work plan, resources, and deliverables
- Cancel this RFP at any time without penalty or cost
- Excuse technical defects in a Proposal when, in its sole discretion, such excuse is beneficial to the Group

The Group may award based on initial Proposals received, without discussion of such Proposals. Vendors may be invited to make oral presentations to the evaluation team.

3.10 Demonstrations and Presentations

All short listed Vendors will be required to provide detailed demonstrations of their CIS application software. All short listed Vendors will also be required to make presentations and/or provide written clarifications of their Proposal at the request of the Group. Upon completion of demonstrations and presentations to the Group, Vendors may be short listed again. The Group will make this decision shortly after demonstrations and presentations are completed.

3.11 Customer Site Visits

Each Vendor is being asked to provide customer references. These references must be LDC's operating within the Ontario Electricity Market. Two references are being requested, with two contacts from each reference. It is preferred that a technical and business contact be provided for each reference.

The Group may wish to schedule customer site visits with any or all references. If site visits are conducted, it is presently proposed that these be scheduled during the period of **June 4 – June 8, 2007**. These dates may change at the discretion of the Group.

Vendors are required to complete the Ontario References spreadsheet located in **Appendix B (Tab 19. References)** and submit with their Proposal. This document is not to be changed or altered in any way by prospective Vendors. Only those fields that are left unprotected may be updated by Vendors.

3.12 Proposal Expectations / Checklist

As a checklist for Vendors, the following should be included in their Proposal submission:

- Covering Letter outlining understanding of the requirements presented
- Completed Appendix B (All Tabs) – Excel format
- Supporting Documentation attached to Appendix C – PDF format

The submitted proposal must follow the rules and format established within this RFP. Adherence to these rules will ensure a fair and objective analysis of all proposals. Failure to complete any portion of this request may result in the rejection of a proposal.

3.13 Notification

On or about **May 11, 2007** the Group will short list vendors and request that each be prepared to meet sometime during the week of **May 22 – May 25, 2007** to make a presentation to the Group. These presentation dates may change. It is the intent of the Group to notify short listed Vendors of any presentation date changes as quickly as possible with the understanding that Vendors need the necessary time to prepare. This notification could be in the form of an email or call to the Vendors main contact listed on the Proposals Covering Letter.

Upon completion of presentations the Group will re-evaluate all short list Vendor(s) and will issue Detailed Project Plan Requirements to those Vendor(s) that the Group feels most comfortable in proceeding with. This notification will occur shortly after presentations have completed and will be in the form of a call followed up by an email.

4 PROJECT PLAN

4.1 Broad Project Plan

Vendors are being asked to prepare a document that highlights their philosophical approach to implementing this project. This is the Vendors opportunity to address components of their service offering that sets them apart. Please include your response as part of **<u>Appendix C</u>**, in PDF format, for the following key areas:

- Project Management Requirements
- Project Timelines as referenced in 2.1
- Resource Requirements
- Risk Assessment
- Change Management process
- Gap Analysis
- Assumptions and Issues
- Conversion Plan
- Testing Plan
- Educational and Training Plan
- Implementation Plan

4.2 Detailed Project Plan

Vendors are <u>not</u> being asked to complete and submit a Detailed Project Plan (Plan) as an attachment to their initial Proposal. As stated in Section 3.13, shortly after May 25, 2007, Vendors that have been short listed will be notified and asked to prepare a Plan. Prior to Vendor notification, Group Members will have decided on their preferred path which will serve to assist Vendors in preparing their Plan. In recognizing that the preferred paths for each Group Member may differ and that there could be a number of paths chosen, the Group will provide short listed Vendors with additional guidelines and information prior to issuing the Plan requirements. Vendors will provide their Plan by **June 20, 2007 at 4:00 pm**.

The format of the Detailed Project Plan will be at the discretion of the Vendor. At a minimum, the Detailed Project Plan must address the following:

- Project Charter
- Project Management Requirements
- Detail Project Timelines – Include Gantt Charts or similar graphic depiction to illustrate phases, activities, tasks, comments, milestones, decision points and deliverables
- Resource Requirements
- Risk Assessment

- Change Management Documentation
- Requirements Documentation
- Gap Analysis Documentation
- Assumptions and Issues
- Conversion Plan
- Testing Plan
- Education and Training Plan
- Implementation Plan
- Financial Requirements – Includes Payment Terms and Conditions
- Legal Requirements

5 CONTACT INFORMATION

All **Intent to Respond** forms and **RFP Responses**; should be directed to:

Contact	Address	Contact Details
Rob Skevington	1500 Bishop Street P.O Box 1060 Cambridge, Ontario N1R 5X6	Intent to Respond forms can be emailed to Contact Forward **1** Hard Copy of Proposal and **1** soft copy via CD

All requests for further information, clarification of requirements or general questions should be directed to:

Contact	Email Address	Contact Details
Rob Skevington	rskevington@camhydro.com	Forward any additional requests for information, clarification or general questions

All requests for further information, clarification of requirements or general questions and the associated responses will be forwarded to all Vendors.

6 TERMS AND DEFINITIONS

The Term “Vendor” is in reference to a single organization, if the response to this RFP is from one organization, a combination of organizations, if the response to this RFP is a joint response from more than one organization and an Application Service Provider (ASP) who provides services to LDC’s in the Province of Ontario.

The Term “Customer Information and Billing System (CIS)” is in reference to the system and functionality being sourced by the Group through this RFP Process

The Term “Local Distribution Company (LDC)” is a company as defined in the Ontario Energy Board Act, 1998. Within this document, it’s in reference to the individual members comprising the Working Group.

The Term “CODAC Working Group” (Group) is in reference to the Group of LDC’s who collectively make up the Working Group.

Appendix A

Intent to Respond Template

RECEIPT ACKNOWLEDGEMENT AND CONFIDENTIALITY ACCEPTANCE

A duly qualified representative of the Vendor / Service Provider must provide the information requested below by **April 16, 2007 at 4:00 pm**.

I hereby confirm receipt of the Group RFP. I agree on behalf of my company to comply with the terms and conditions of this RFP that include, but are not limited to:

1. The confidentiality requirements
2. The instructions set out in the RFP

Printed Name: ______________________________

Signature: ______________________________

Title: ______________________________

Date: ______________________________

Tel No: ______________________________

Fax No: ______________________________

E-Mail Address: ______________________________

Company Name: ______________________________

Address: ______________________________

Appendix B

Appendix B is an excel document that must be completed by all prospective Vendors. This excel document contains a total of 20 Tabs. A brief description of each Tab is outlined below:

Tab #	Tab Name	Brief Description
1.	Vendor Background	A brief Questionnaire on the Vendors background. Narrative Responses are required. Additional supporting documentation to be attached to Appendix C.
2.	Source Code	A very brief Questionnaire on Vendor Source Code. Narrative Response required. Additional supporting documentation to be attached to Appendix C.
3.	Functional Requirements	An in depth System functionality Checklist.
4.	Cost_Option 1_DB1_ADV	Costing Sheet: Pertaining to an Individual LDC Installation with **LDC Defined Set-up**, utilizing the Vendors first database choice. LDC's current CIS is Advanced. Be sure to include any Optional Functionality Required from Tab 3.
5.	Cost_Option 1_DB2_ADV	Costing Sheet: Pertaining to an Individual LDC Installation with **LDC Defined Set-up**, utilizing the Vendors second database choice. LDC's current CIS is Advanced. Be sure to include any Optional Functionality Required from Tab 3.
6.	Cost_Option 1_DB1_HTE	Costing Sheet: Pertaining to an Individual LDC Installation with **LDC Defined Set-up**, utilizing the Vendors first database choice. LDC's current CIS is HTE. Be sure to include any Optional Functionality Required from Tab 3.
7.	Cost_Option 1_DB2_HTE	Costing Sheet: Pertaining to an Individual LDC Installation with **LDC Defined Set-up**, utilizing the Vendors second database choice. LDC's current CIS is HTE. Be sure to include any Optional Functionality Required from Tab 3.
8.	Cost_Option 1_DB1_OTHER	Costing Sheet: Pertaining to an Individual LDC Installation with **LDC Defined Set-up**, utilizing the Vendors first database choice. LDC's current CIS is OTHER than Advanced or HTE. Be sure to include any Optional Functionality Required from Tab 3.
9.	Cost_Option 1_DB2_OTHER	Costing Sheet: Pertaining to an Individual LDC Installation with **LDC Defined Set-up**, utilizing the Vendors second database choice. LDC's current CIS is OTHER than Advanced or HTE. Be sure to include any Optional Functionality Required from Tab 3.
10.	Cost_Option 2_DB1_ADV	Costing Sheet: Pertaining to an Individual LDC Installation with **Group Defined Set-up**, utilizing the Vendors first database choice. LDC's current CIS is Advanced. Be sure to include any Optional Functionality Required from Tab 3.
11.	Cost_Option 2_DB2_ADV	Costing Sheet: Pertaining to an Individual LDC Installation with **Group Defined Set-up**, utilizing the Vendors second database choice. LDC's current CIS is Advanced. Be sure to include any Optional Functionality Required from Tab 3.
12.	Cost_Option 2_DB1_HTE	Costing Sheet: Pertaining to an Individual LDC Installation with **Group Defined Set-up**, utilizing the Vendors first database choice. LDC's current CIS is HTE. Be sure to include any Optional Functionality Required from Tab 3.
13.	Cost_Option 2_DB2_HTE	Costing Sheet: Pertaining to an Individual LDC Installation with **Group Defined Set-up**, utilizing the Vendors second database choice. LDC's current CIS is HTE. Be sure to include any Optional Functionality Required from Tab 3.

14.	Cost_Option 2_DB1_OTHER	Costing Sheet: Pertaining to an Individual LDC Installation with **Group Defined Set-up**, utilizing the Vendors first database choice. LDC's current CIS is OTHER than Advanced or HTE. Be sure to include any Optional Functionality Required from Tab 3.
15.	Cost_Option 2_DB2_OTHER	Costing Sheet: Pertaining to an Individual LDC Installation with **Group Defined Set-up**, utilizing the Vendors second database choice. LDC's current CIS is OTHER than Advanced or HTE. Be sure to include any Optional Functionality Required from Tab 3.
16.	Cost_Option 3_DB1_ALL	Costing Sheet: Pertaining to a Single Installation with Multiple Companies **and Group Defined Set-up**, utilizing the Vendors first database choice. Be sure to include any Optional Functionality Required from Tab 3.
17.	Cost_Option 3_DB2_ALL	Costing Sheet: Pertaining to a Single Installation with Multiple Companies and **Group Defined Set-up**, utilizing the Vendors second database choice. Be sure to include any Optional Functionality Required from Tab 3.
18.	Cost_Option 3_DB3_ALL	Costing Sheet: Pertaining to a Single Installation with Multiple Companies and **Group Defined Set-up**, utilizing the Vendors third database choice. Vendor is to define this alternative Database. Be sure to include any Optional Functionality Required from Tab 3.
19.	References	Vendor to provide Ontario Based Utility references.
20.	Comments	An opportunity for the Vendor to provide Freeform information that did not have a placeholder elsewhere in Appendix B.

If a Vendor cannot support any of the costing options presented in Appendix B (Tabs 4 to 18), they are asked not to attempt completion of the applicable costing option and provide comments to this affect in **Appendix B (Tab 20. Comments)**.

The excel file containing Appendix B is called “Appendix B.xls” and is being sent along with this RFP document.

Appendix C

Vendors should attach all Supporting Documentation for their Proposal in a separate PDF document(s) titled "**VendorName_RFPSection_Appendix_C.pdf**".

VendorName to be replaced by prospective Vendors Company Name

RFPSection to be replaced with **ALL** unless Vendor decides to provide individual PDF documents for each Section

Note that this includes the Vendors philosophies of project implementation as outlined in Section 4.1.

Midsize Ontario Utilities to Share a Standardized Customer Information System

Nine hydro distributors commit to implementing streamlined billing processes that are expected to reduce operational costs and benefit customers

Cambridge, ON. – September 25, 2007 – A group of nine midsize Ontario utilities have teamed up to share a solution to effectively manage their meter-to-cash processes as the province moves to smart metering.

The group, collectively known as "CODAC," announced today that its members have signed a memorandum of understanding to configure, deploy and support a standard billing and customer information template for Ontario utilities using SAP® for Utilities software. The solution addresses all activities from receipt of customer's meter data, to processing and billing, and customer payment. The shared template will be configured to meet applicable Ontario market requirements for the CODAC members and will be maintained to keep up with regulatory changes as required.

A common customer information system is expected to result in reduced risk for utilities, provide cost savings and allow for consistent, timely processes that will benefit both business and residential customers. By pooling their efforts, each utility will have a state-of-the-art system that fully supports the changing Ontario electricity market at a lower cost than each would face on its own.

"Ontario local distribution companies are taking the lead in developing innovative, flexible and cost-effective customer information systems. The advantages for the hydro market in the province and ultimately our customers are too large to ignore," said Rob Skevington, Billing & Settlement Supervisor, Cambridge and North Dumfries Hydro Inc., the CODAC group lead. "We all have similar interests and the same business and regulatory requirements, and have found through working together that we can share the same system to better manage our businesses. This will enable each of us to afford the best available system to manage the changing market and provide exceptional service for our customers."

CODAC members include Cambridge and North Dumfries Hydro Inc., COLLUS Power Corp., Greater Sudbury Utilities Inc., Haldimand County Hydro Inc., London Hydro Inc., North Bay Hydro Distribution Limited, Orangeville Hydro Limited, Tillsonburg Hydro Inc. and Wasaga Distribution Inc. They have committed to create the new system and are extending the opportunity to help develop and shape the new systems and processes to other utilities. It is hoped that other utilities will recognize the advantages of such an alliance and will be interested in joining this partnership. Each member organization will commit staff and funds to the project, and can expect to benefit from the synergies and economies of scale that the joint project offers.

The catalyst for this agreement was London Hydro's new customer information system, which is being built on SAP® software and implemented by Wipro Limited. London Hydro has offered the system's blueprint and the SAP® software system configuration that forms the basis of the new standard template to CODAC members. The benefit of leveraging the work already done by London Hydro to the CODAC members is a shorter implementation timeframe and reduced cost.

This proactive initiative was prompted by the ongoing regulatory changes to the operating environment in the Ontario electricity market, which in turn require significant changes to the business processes and supporting systems of Ontario Local Distribution Companies.

"This common business model and cost-sharing approach saves each member utility money and reduces our risks," said Ruth Tyrrell, Manager of Customer Service & Administration, Orangeville Hydro Limited. "What's more, this template model has the flexibility to adapt to changes within a CODAC member company or new participants joining the group."

General Background

- On June 14, 2006, Harris Computer Systems (Harris) announced the purchase of Advanced Utility Systems (Advanced). Advanced clients were assured that Harris would continue to offer the Advanced Customer Information and Billing System (CIS) solution in Ontario.
- On January 31, 2007, Harris announced that they would be discontinuing the Advanced CIS solution in Ontario, effective December 31, 2008. Harris offered their CIS solution as an alternative.
- At the time of this announcement, there were nineteen (19) active Advanced CIS clients in Ontario.
- Rather than immediately accepting the default offering provided by Harris, the majority of the Advanced CIS clients (fifteen of nineteen) decided to explore all alternatives with the hope of procuring the best possible CIS solution.

The CODAC Working Group

Over the past five (5) years, Advanced clients have been working together on numerous initiatives including: standardization, customization and Regulatory report filings. These initiatives have proven to be very productive and have resulted in significant time and cost savings. In light of all previous successes, Advanced clients decided to work together in researching all possible CIS alternatives.

The "CODAC Working Group" (Group) was formed in early February 2007. At the outset, the Group was comprised of Advanced CIS clients only. Word of this Group initiative spread quickly and by mid March 2007 the Group consisted of twenty four (24) LDC's utilizing seventeen (17) separate CIS installations. The Group consisted of fifteen (15) Advanced LDC's, seven (7) Sungard H.T.E. LDC's and two (2) C.O.S. Computer Systems LDC's.

The mandate of the Group was to collectively source out viable CIS alternatives. This approach would serve to help all LDC's in selecting the best CIS alternative. The hope was that the Group could share experiences, expertise and costs relative to this initiative. It was further anticipated that Vendors would also look favorably at this initiative as time, energy and costs would be saved on preparing individual proposals and presentations.

Shortly after the formation of the Group, it became evident that a Group CIS alternative was a distinct possibility. All Group members seemed very supportive of this concept.

CODAC Working Group RFP

During the month of March 2007, the Group spent considerable time developing a Request for Proposal (RFP) with costing options based on:

- Individual CIS procurements with LDC defined set-up
- Individual CIS procurements with Group defined set-up

- Group CIS procurement with Group defined set-up

On March 29, 2007, the RFP was issued to all known CIS Vendors currently active in the Ontario Market. The Group decided against issuing the RFP to Vendor(s) not presently active in Ontario.

The deadline for Vendor Proposals was May 4, 2007 at 12:00 noon. The Group received eleven (11) proposals representing six (6) CIS solutions. All proposal information was disbursed to individual Group members on the afternoon of May 4, 2007. Group members were given until May 9, 2007 to review and provide comments on the proposals received.

A Group meeting was scheduled for May 10, 2007 where the Group hoped to short-list to a maximum of four (4) solutions. The Group managed to meet this deadline and notified four (4) short-listed Vendors on May 11, 2007.

Vendor Presentations

Vendor Presentations were scheduled for the week of May 22 – 25, 2007. During the Vendor Presentations, the Group realized that there were significant gaps relating to functionality, scalability and configurability between systems presented. Furthermore, it was recognized that there were significant gaps in costs relative to the systems presented. This re-affirmed the Group's desire to further explore the possibility of procuring a Group CIS solution.

On May 23, 2007, IBM Canada stated that there may be a fourth option that the Group may want to consider. This option was a "Provincial ASP CIS Solution". This particular CIS option was not expected to be offered until an undetermined date in the future but it was stated that if there was enough interest from the Group, this option may be available earlier than anticipated.

Next Steps

On May 30, 2007, the Group met, via conference call, to discuss the previous week's activities and establish next steps. The possibilities were:

- Each LDC go their own direction
- The formation of Sub Groups based on preferred direction
- Remain unified as we continue down the path of searching for a Group solution

The Group decided to continue looking for a Group solution but expressed a concern regarding timing. Advanced clients have the deadline date of December 31, 2008 looming and were quite concerned about meeting this date if the desired Group procurement strategy went beyond the end of June 2007.

Generic List of Functional Components Reviewed

Multiple Import / Export Formats
Data Archiving
Date & Time Fields
Customized User Screens
Job Scheduler
Standard Interfaces (ie. Banks, Meter Reading, Financial Interfaces,…)
Client Configurability
No System Limitations - Scalability (ie. # of Accounts before degredation)
Split Cycle Billing (ie. SSS vs Retail)
Can Import Usage Profiles (ie. Streetlights)
Can transfer the charges from one account to another account for billing (ie. Transformer Allowance)
No limit on the number of Services that can be maintained
Stores Commodity Pricing within CIS
Supports Multiple Standard Meter Reading Formats
Supports Multiple Interval Meter Reading Formats
Meter Location Code Management
Cycle Reading Scheduler Import Routine
No limit on the # of Cycles / Routes
Static Bill Print
LDC Can Manage Bill Print Changes
Ability to Attach Documents to Accounts
Actions Management
Task Management
Hyperlinks (ie. Postal Codes)
Mass Customer Changes – Adding New Service(s)
Can Automatically Transfer A/R Balances to New Account
Pre-Configured General Address Information (ie. Street Name, Town,…)
Ability to Split Services on

Case Sensitive Fields
Separate Fields for Customer Name Information
Comprehensive Equal Payment Plan Management
Collection Notices can be Configured by Rate Class
Unlimited Collection Status'
Deposits Can be Refunded to 3rd Parties
Deposits By Installment
Ability to Bill Deposits Separate from Regular Billing Process
For Retail Enrolled Customers, IBR Replaces Other Commodity Charges for Deposit Quoting
Exports to External Financials can be either Batch or Real Time
Supports Own Settlement Interface
Supports all Current External Settlement Interfaces Operating in Ontario
Ability to Mass Drop Retail Accounts in the Event of Retailer Default
Streamlined / Efficient Process of Setting up New Retailers
Internal EBT Spoke
Internal EBT Manager
Fully Automated EBT Processes

Supports all Current External EBT Hub / Spoke Interfaces
Actively Participate in EBT Working Group
Automated Processes / Reports for Regulatory Filings
Participate in Ongoing Regulatory Initiatives
On-Line Entity Relationship (ER) Diagrams
Ability to Track Report Versioning
Supports Multiple Inventory Types including: Load Limiters, Meter Base Adaptors, Load Control Switches / Devices
Date and Time for Any Meter Changes / Installs
All Main Inventory ID Fields are Configurable in Length
Linking of Digital Photos (ie. Meter Changes)
On-Line Procedures Manual
Security Can be Configured for as

Low as the Data Field Level
Electronic Approval Path for Transaction Workflows
Mandatory Field Entry
Security Can be Applied at the Service Level
Internal MDM/R Capabilities
Supports ASP Offering
On-Line Documentation
MDM/R Capabilities
Web Services
IVR Capabilities
Mobile Workforce Management
ERP Capabilities
Job Scheduler
Multiple Bill Print Options
Internal Settlement Interface
Financial Interface
Security Down to Data Fields
Online Documentation / Procedure Manual
Deposit Quoting / Refunding (ie. Installments)
Collection Agency
Standard Interface Formats
Consolidated Billing
Standard Regulatory Reporting Templates (ie. DQF)

APPENDIX B 2008 and 2009 - COLLUS Power Corp Capital Budget Summary Schedule

Project or Class No	Asset Category	Project Description	2008 Budgeted	O/H	U/G	P&T	2009 Projected	O/H	U/G	P&T
		DISTRIBUTION PLANT - CUSTOMER DEMAND & RENEWAL CATEGORY : Major Construction Projects								
17011	1&2	Parkside Avenue - 4 kV line rebuild project	$120,000.00	$90,000.00	$18,000.00	$12,000.00				
17012	1&2	First Street Rebuild Project- Hurontario to Balsam Street	$110,000.00	$44,000.00	$44,000.00	$22,000.00				
17015	1&2	Creemore Main Street Replacement Project	$50,000.00		$50,000.00	$0.00				
17016	1&2	Sixth Street High to 6th for new Sub. + 2nd Pine to Birch					$330,000.00	$264,000.00	$49,500.00	$16,500.00
17013	1&2	Georgian Trail & Back Lot Project - New Line Installation	$110,000.00	$47,000.00	$35,000.00	$28,000.00	$0.00			
		DISTRIBUTION PLANT - SECURITY & RELIABILITY CATEGORY : Miscellaneous Projects - Resulting from Annual System Inspections (ESA 22/04)								
17016	3	Rebuild Projects (Poles, Conductor & Hardware) Specifically attributed to the Annual Inspections. Note This amount also includes the system inspection costs. (Increase $20,000 in 09)	$100,000.00	$40,000.00	$40,000.00	$20,000.00	$120,000.00	$48,000.00	$48,000.00	$24,000.00
		DISTRIBUTION PLANT - REGULATORY CATEGORY : Distribution System Boundary Line Expansion (Load Transfers Elimination Project)								
17018	5	New 4kV Polelines - Osler Bluff Road, Long Point Road, Madeline Avenue in Collingwood and 10th Line in Thornbury	$100,000.00	$60,000.00	$20,000.00	$20,000.00	$0.00			
17055/7		DISTRIBUTION PLANT - CUSTOMER METERING CATEGORY : Wholesale Metering Capital Projects (2008 and 10)								
	4	The expected upgrade/replacement work that will be required.	$21,000.00				$0.00			
		DISTRIBUTION PLANT - CAPACITY CATEGORY : Distribution Substation Capital Projects								
17040	6	Construction of new MS#8 Sub-Station in the South West Portion of Collingwood as per 2005 System optimization study results updated in 2008 for current situation.	$0.00				$1,900,000.00			
17050		DISTRIBUTION PLANT - CUSTOMER METERING CATEGORY : Electric Metering Capital Projects (Not part of the Provincial Smart Meter Program)								
	4	Annual replacement program for resid. & comm. hydro meters	$60,000.00				$60,000.00			
		DISTRIBUTION PLANT - CUSTOMER DEMAND & RENEWAL CATEGORY : Distribution Transformer Capital Projects								
17070	1&2	To accommodate any new distribution transformers required for general load growth (Add $20,000 in 09 due to supplier inc.)	$100,000.00			$100,000.00	$120,000.00			$120,000.00
		GENERAL PLANT - COMMUNICATIONS EQUIPMENT CATEGORY : SCADA Capital Projects								
17091	13	New RTU's for Sub-Stations, New Data Radios and Fault Indicators for 44kV feeders	$95,000.00				$40,000.00			
		GENERAL PLANT - TRANSPORTATION EQUIPMENT CATEGORY : Large Vehicles & Equipment Purchases								
17126	12	Replace Existing 1973 Forklift	$50,000.00				$0.00			
		Replace Existing Tr 29	$0.00				$100,000.00			
			$0.00				$0.00			
			$0.00				$0.00			
	12	Replace Existing 1992 Double Bucket Truck	$400,000.00				$0.00			
	12	Replace Existing 1996 1/2 Ton Pickup Truck (Locator)	$0.00				$50,000.00			
		DISTRIBUTION PLANT - CUSTOMER DEMAND & RENEWAL CATEGORY : Collingwood - Overhead & Underground Service Capital Projects								
17170,180, 190,200	1&2	Utility spending on any new o/h & u/g residential & general service as per conditions of service or customer request.	$100,000.00	$40,000.00	$40,000.00	$20,000.00	$112,000.00	$44,800.00	$44,800.00	$22,400.00
		DISTRIBUTION PLANT - CUSTOMER DEMAND & RENEWAL CATEGORY : Thornbury - Overhead & Underground Service Capital Projects								
17401-4	1&2	Utility spending on any new o/h & u/g residential & general service as per conditions of service or customer request.	$60,000.00	$24,000.00	$24,000.00	$12,000.00	$64,500.00	$25,800.00	$25,800.00	$12,900.00
		DISTRIBUTION PLANT - CUSTOMER DEMAND & RENEWAL CATEGORY : Clearview - Overhead & Underground Service Capital Projects								
17301-4	1&2	Utility spending on any new o/h & u/g residential & general service as per conditions of service or customer request.	$38,000.00	$15,200.00	$15,200.00	$7,600.00	$71,000.00	$28,400.00	$28,400.00	$14,200.00
		GENERAL PLANT - COMPUTER SYSTEM CATEGORY : CIS & Accounting Enhancements - Specific for COLLUS Power								
17163	11	Enhancements to the customer information system and general accounting system specifically for COLLUS Power. In particular requirements of changes to the electric market.	$400,000.00				$60,000.00			

APPENDIX B 2008 and 2009 - COLLUS Power Corp Capital Budget Summary Schedule

Project or Class No.	Asset Category	Project Description	2008 Budgeted	O/H	U/G	P&T	2009 Projected	O/H	U/G	P&T
17600		DISTRIBUTION PLANT - CUSTOMER DEMAND & RENEWAL CATEGORY : Economic Evaluations - Portion paid to developers								
	1&2	The portion paid to developers attributed to their original contributed capital calculations.	$120,000.00	$48,000.00	$48,000.00	$24,000.00	$100,000.00	$40,000.00	$40,000.00	$20,000.00
17130		GENERAL PLANT - FACILITIES CATEGORY : Operations Centre - Capital Additions								
	10	Transformer racking added 09. Office Equipment 2008-10	$85,000.00				$90,000.00			
		GROSS TOTAL Before Contributed Capital =	$2,119,000.00				$3,217,500.00			
N/A		NON-CATEGORY ITEM : Rechargeable Mtce Projects & Light Work Re-billed (Not included into totals-used to track utility spending on this non-capital item)								
		Small Mtce Projects and other work recorded to track spending	$60,000.00				$60,000.00			
18000		Rechargeable Capital Work (Used to track utility spending on this item that contributed capital nets against)								
	7	Large Capital Work Projects net impact of $0 to capital	$100,000.00				$100,000.00			
18000		DISTRIBUTION PLANT - CUSTOMER DEMAND & RENEWAL CATEGORY : Contributed Capital (customer portion of utility spending on capital projects listed above)								
	7	Contributions from developers and others for capital work done.	-$350,000.00				-$300,000.00			
(See Schedule B-2 Line 19)		NET CAPITAL SPENDING REQUIREMENT (Net of Contributed Capital) =	$1,869,000.00				$3,017,500.00			

	O/H	U/G	P&T		Supervisory	Meters	Transformers	Supervisory	Vehicles	CIS - Software	Op Ct - Equip	Substation	Total
2008	1	2	Sub 1&2		3	4	5	6	7	8	9	10	
	$ 408,200	$ 334,200	$	165,600	$21,000	$60,000	$100,000	$95,000	$450,000	$400,000	$85,000		$ 2,119,000
	$ 71,800	$ 15,800	$	(165,600)			$78,000						
	$ 480,000	$ 350,000	$	-	$ 21,000	$ 60,000	$ 178,000	$ 95,000	$ 450,000	$ 400,000	$ 85,000	$ -	$ 2,119,000
												Less CC Amt	-$250,000
2009													$ 1,869,000
	$451,000	$236,500		$110,000	$0	$60,000	$120,000	$40,000	$150,000	$60,000	$90,000	$1,900,000	$ 3,217,500
	55000	0		-110000			$55,000.00						
	$ 506,000	$ 236,500	$	-	$ -	$ 60,000	$ 175,000	$ 40,000	$ 150,000	$ 60,000	$ 90,000	$ 1,900,000	$ 3,217,500
													-$200,000
													$ 3,017,500

BARKLEY TECHNOLOGIES INC.
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August 14, 2008

Load Growth and Future Station Requirements for Collingwood

A distribution system model was developed for Collingwood using the following available information:

- Microstation mapping files – 44kv and 4.16kV networks
- Distribution transformer database
- SCADA measurements for Winter and Summer recorded peaks
- Town of Collingwood base map – roads, lots etc.
- Collingwood development maps – known developments with forecasted units
- Municipal Substation – technical specifications

The network model was developed for use with Dromey Design's analysis software for simulation of power flow.

The purpose of this study is to build a working model of Collingwood's distribution system, simulating existing power flow during various peaks and to expand the system to reflect the forecasted load as the result of planned urban development within Collingwood's service boundary.

The following is the existing peak load for 2007 and includes the impact of developments that have been identified in the past.

Existing Summer Peak			
Station	Peak MW	Tx Size	% Loaded
1	5.81	6	97
2	4.78	6	80
3	1.24	3	41
4	2.12	5	42
5	1.23	7.5	16
6	1.36	6	23
7	2.08	5	42
Total	18.62	38.5	48

Following is the forecasted peak load based on known developments, either planned or currently under construction.

Forecasted Summer Peak			
Station	Peak MW	Tx Size	% Loaded
1	7.7	6	128
2	6.5	6	108
3	4.5	3	150
4	5.7	5	114
5	1.2	7.5	16
6	4.1	6	68
7	2.1	5	42
Total	31.8	38.5	83

Using the forecasted load as the main criteria the next step is to look for opportunities to provide relief to the overloaded stations by:

1. Changing existing open points on 4kV feeders that tie with overloaded substations.
2. Build new feeders from existing substations to provide 4kV relief.
3. Increase the size of the substation transformers to absorb the added load.

Adding transformer capacity is only useful if the feeder system can handle the additional load, or if the physical characteristics of the station allow for expansion and a means of distributing more feeders. In the case of M.S. #1 for example, additional transformer capacity will not be beneficial because of the limited feeder options available due to inaccessibility to the station.
Integration of a new substation between MS's 1 and 2 was modeled but provided limited advantages without significant pole line re-construction in an already developed area.

The expanded system was modeled and remodeled to develop a recommended station and feeder configuration strategy to best reflect load growth and the following operational and planning issues.

- Substation transformer loading.
- Substation maintenance.
- Age of substation transformer, switch gear and cables.
- Substation catastrophic failure.
- Substation transformer losses.
- Feeder conductor and equipment capacity.

- Voltage supply stability.
- Protective device coordination
- Ability to feed customers from other feeders using open points during planned or emergency conditions.

The following is a summary of the changes and additions that will best suit all of the design criteria of the expanded model and provide a balance between development and operations. (See DESS model)

1. New Station – Two new substations are required at The Shipyards Development specifically to provide service to the ongoing development. The advantage to the developer is that their supply will be stable because the source is 44,000 volts and not at the 4,160 volts. This means these stations will be dedicated and not subject to effects of surrounding customers outside the development that can cause outages as well as harmonic distortion or power quality issues. The disadvantage to the utility is that it cannot contribute to the existing overload situation of nearby MS's. Based on the load forecast a minimum size transformer of 3 MVA should be used at each station.

2. MS#5 – This substation is in an ideal location to help absorb some of the load from MS#1 and provide feeders to the south for new development. This was completed in 2007 as budgeted. A new 7.5/10 MVA transformer was installed to meet the demand for this area.

3. MS#3 – The station should be upgraded to provide relief to MS#7 and MS#1 and capacity for forecasted load .A 6 or a 10 MVA transformer will allow for back feeding tie line feeders.

4. New Station – To best fill in a system gap at the west a new station should be integrated a load develops. The 44kV feed will come from the M3 approximately 1 km. to a site on the corner of Stewart Road and Sixth Street. This project will be completed by the fall of 2009.

Appendix C - 2

COLLUS Power Corporation

Distribution System Study Update

July 21, 2008

Enclosed with this report is the updated study we had contracted Barkley Technologies Inc. conduct titled "Load Growth and Future Station Requirements for Collingwood". As part of the study we knew that current loading situations would be assessed. As the results indicated, the existing system was under a strain and as noted before, needed immediate addressing. The study makes recommendations that would solve these overload situations and also prepare our system for the growth projections that have been considered.

Current Capacity Concerns:

1. As identified in the Existing Summer Peak Table on the first page of the study, M.S.#'s 1, 2, and 3 are the heaviest loaded within the Collingwood system. The levels of load do not bode well when you consider that these stations back up each other. This situation has existed for years and the problem continues to be that if there is a major occurrence at one of these stations on a peak day, there may well not be adequate load to provide the back up we need. This could result in extended outages for some of our customer base.
2. Recommendation 2, 3 and 4 on page 3 will relieve the concerns that we have in regards to system reliability. With the completion of M.S.#5 in 2007 it will take load off M.S.#1. The M.S.#3 work will do the same as well as relieve some load from M.S.#2.
3. The M.S.#5 work cost 1.1 million . The M.S.#3 upgrade from 3 MVA to 10 MVA will cost approximately 1.5 million.
4. The decision was made to proceed with the upgrade of M.S.#5 and this was completed in 2007. The upgrade of M.S.#3 has been postponed as growth in our south west portion of Collingwood needs to be addressed with the construction of a new station in 2009.

Future Growth Needs:

1. The study carefully considered the growth projection data that we received from developers and others. The study outlined what we needed to know in regards to system expansion requirements so that proper planning could be put in place.

2. The expansion work on M.S.#5 addressed the current overloaded capacity concerns and will also ensure that growth needs are met. Load growth in the south west portion of Collingwood will require the construction of a new sub station (M.S.#9) in 2009.

Recommendations:

1. As noted earlier, we have had concerns for the past few years that the current system is loaded in a way that could severely hamper our ability to deal with a major problem. Even trying to perform work on regular maintenance has been difficult and almost impossible without resulting in extended system outages, because there has been little excess capacity on some of the stations. We recommend, but slightly revise the priority of the study's report (due to the areas of system load concerns and reliability), that it be implemented as outlined.

2. The report recommended the upgrade of M.S.#5. This was completed in 2007. We further recommend the construction of M.S.#9 in 2009 as per item 4 of the report.

3. We recommend that $1.9 million (based on the enclosed sub station schedule) be placed in the 2009 Capital Budget for the M.S.#9 project.

4. In conjunction with the proposed M.S.#9, a 44 KV line extension (distance of 700 meters) will be required from the M3 to feed the station. Electrical Engineering design, 4 KV overhead (distance of 1400 meters), 4 KV underground will also have to be considered for this project. We are estimating the cost at $300,000.00. The overhead construction will be completed in the third quarter in conjunction with the construction of the sub station.

Submitted by: Ray Powell, Hydro Superintendent

__________________ **Date:** July 21/08

Larry Irwin, Director of Operation & I.T. Services

__________________ **Date:** July 21/08

Ed Houghton, President & C.E.O.

__________________ **Date:** July 21/08

Black & McDonald

Ap, .dix C-3

July 23, 2008

Project:	Collingwood tility Services
B&M Project Number	Budget Only
Scope of work:	Substation Construction

Item	Description	Unit of Meas.	Est. Total Quantity	Unit Price	Total Price	Quantities To Date	Quantities Previous	Quantities Period	Payment To Date	Payment Previous	Payment This Period
	Schedule of Quantities and Pricing										
	Budget Pricing Only										
1.0	Mobilization & Demolition of existing station	1	1	$ 55,000.00	$ 55,000.00	0.000	0.000	0.00	$ -	$ -	$ -
2.0	Stripping and restoration of site	1	1	$ 75,000.00	$ 75,000.00	0.000	0.000	0.00	$ -	$ -	$ -
3.0	Civil works - terminal pole concrete base, grounding and restoration	1	1	$ 12,000.00	$ 12,000.00	0.000	0.000	0.00	$ -	$ -	$ -
4.0	Civil works - transformer concrete base	1	1	$ 45,000.00	$ 45,000.00	0.000	0.000	0.00	$ -	$ -	$ -
5.0	Civil works - switchgear concrete base	1	1	$ 55,000.00	$ 55,000.00	0.000	0.000	0.00	$ -	$ -	$ -
6.0	Civil works - Duct banks (primary and secondary)	1	1	$ 118,000.00	$ 118,000.00	0.000	0.000	0.00	$ -	$ -	$ -
7.0	Civil - Electrical maintenance holes (5 units), excavation and restoration	1	1	$ 60,000.00	$ 60,000.00	0.000	0.000	0.00	$ -	$ -	$ -
8.0	Civil - Miscelleneous civil works, clean up and disposal	1	1	$ 49,000.00	$ 49,000.00	0.000	0.000	0.00	$ -	$ -	$ -
9.0	Electrical - 5KV, 1200A main bus, 3P, 3PH, indoor metal enclosed switchgear c/w 5 X 600A feeders	1	1	$ 675,000.00	$ 675,000.00	0.000	0.000	0.00	$ -	$ -	$ -
10.0	Electrical - terminal pole c/w 46KV switch, fuses, spares, lightning arrestors and all accessories	1	1	$ 60,000.00	$ 60,000.00	0.000	0.000	0.00	$ -	$ -	$ -
11.0	Electrical - 10MVA transformer c/w first stage fan cooling	1	1	$ 380,000.00	$ 380,000.00	0.000	0.000	0.00	$ -	$ -	$ -
12.0	Electrical - 46KV copper cables and terminations	1	1	$ 45,000.00	$ 45,000.00	0.000	0.000	0.00	$ -	$ -	$ -
13.0	Electrical - 5KV cables and terminations (5 feeders)	1	1	$ 150,000.00	$ 150,000.00	0.000	0.000	0.00	$ -	$ -	$ -
14.0	Grounding grid and stone cover	1	1	$ 70,000.00	$ 70,000.00	0.000	0.000	0.00	$ -	$ -	$ -
15.0	ESA - Site plan review, inspection permits and fees	1	1	$ 13,000.00	$ 13,000.00	0.000	0.000	0.00	$ -	$ -	$ -
16.0	Final clean up. Preservice testing, commissioning etc.	1	1	$ 38,000.00	$ 38,000.00	0.000	0.000	0.00	$ -	$ -	$ -
	Total Extra Work										
					$1,900,000.00	0	0	0	$0.00	$0.00	$0.00

endix C-4

Black & McDonald

Project: Collingwood Utility Services Sproule Ave.MS#5 — September-07

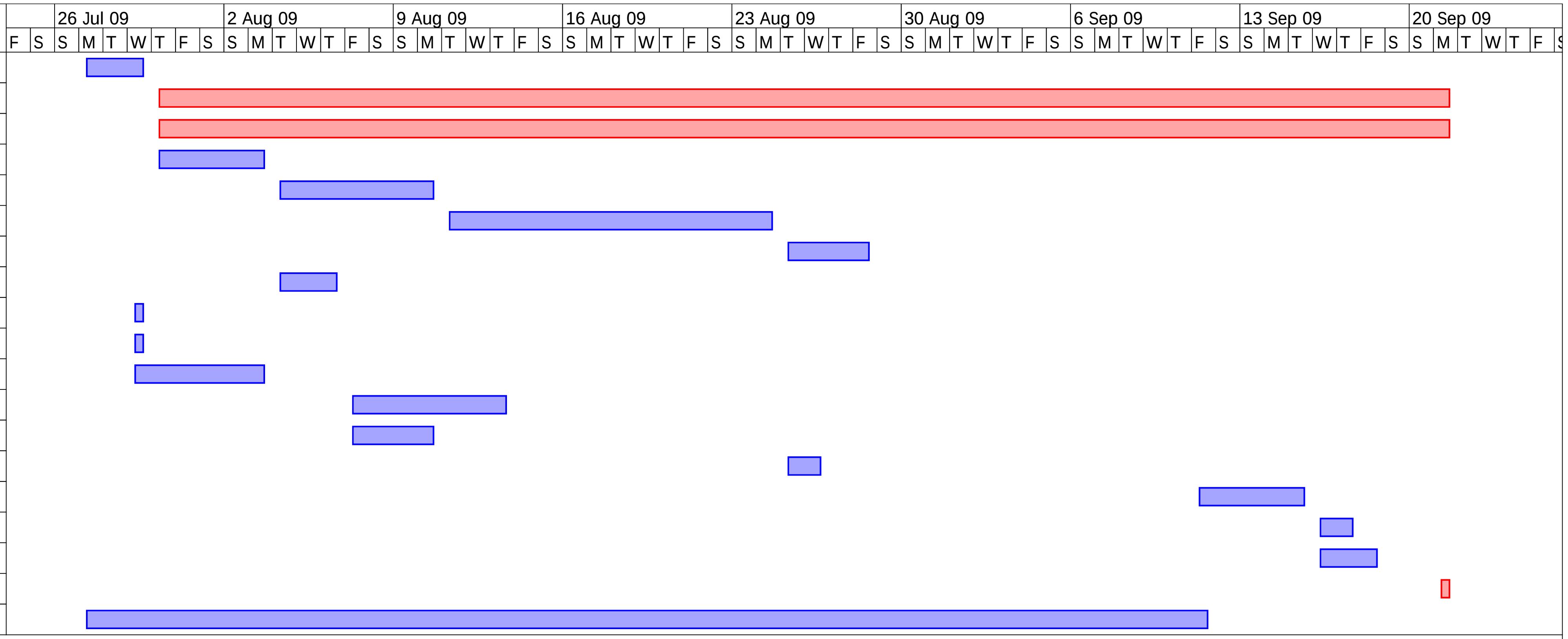
B&M Project Number 70100

Scope of work: Demolition and Reconstruction of existing 44KV/5KV substation

Item	Description	Unit of Meas.	Est. Total Quantity	Unit Price	Total Price	Quantities To Date	Quantities Previous	Quantities Period	Payment To Date	Payment Previous	Payment This Period
	Schedule of Quantities and Pricing										
1.0	Mobilization & Demolition of existing station	1	1	$ 36,000.00	$ 36,000.00	1.000	0.000	0.00	$ 36,000.00	$ -	$ 36,000.00
2.0	Stripping and restoration of site	1	1	$ 13,700.00	$ 13,700.00	1.000	0.000	0.00	$ 13,700.00	$ -	$ 13,700.00
3.0	Front door remove and replacement	1	1	$ 4,600.00	$ 4,600.00	1.000	0.000	0.00	$ 4,600.00	$ -	$ 4,600.00
4.0	Civil works - terminal pole concrete base, grounding and restoration	1	1	$ 8,600.00	$ 8,600.00	1.000	0.000	0.00	$ 8,600.00	$ -	$ 8,600.00
5.0	Civil works - transformer concrete base	1	1	$ 11,500.00	$ 11,500.00	1.000	0.000	0.00	$ 11,500.00	$ -	$ 11,500.00
6.0	Civil works - Duct banks, core drilling of walls and slabs, excavation and restoration	1	1	$ 23,700.00	$ 23,700.00	1.000	0.000	0.00	$ 23,700.00	$ -	$ 23,700.00
7.0	Civil - Electrical maintenance hole, excavation and restoration	1	1	$ 18,600.00	$ 18,600.00	1.000	0.000	0.00	$ 18,600.00	$ -	$ 18,600.00
8.0	Civil - Miscellaneous civil works, clean up and disposal	1	1	$ 7,930.40	$ 7,930.40	1.000	0.000	0.00	$ 7,930.40	$ -	$ 7,930.40
9.0	Electrical - terminal pole c/w 46KV switch, fuses, spares, lightning arrestors and all accessories	1	1	$ 52,000.00	$ 52,000.00	1.000	0.000	0.00	$ 52,000.00	$ -	$ 52,000.00
10.0	Electrical - 7.5/10MVA transformer c/w first stage fan cooling	1	1	$ 246,000.00	$ 246,000.00	1.000	0.000	1.00	$ 246,000.00	$ -	$ 246,000.00
11.0	Electrical - 5KV, 2000A, 3P, 3PH, indoor metal enclosed switchgear	1	1	$ 562,000.00	$ 562,000.00	1.000	0.000	1.00	$ 562,000.00	$ -	$ 562,000.00
12.0	5KV, 2000A, 3P, 3PH, indoor/outdoor bus duct metal enclosed switchgear	1	1	$ 28,500.00	$ 28,500.00	1.000	0.000	0.00	$ 28,500.00	$ -	$ 28,500.00
13.0	Electrical - 46KV copper cables and terminations	1	1	$ 23,700.00	$ 23,700.00	1.000	0.000	0.00	$ 23,700.00	$ -	$ 23,700.00
14.0	Electrical - 5KV terminations and reconnection	1	1	$ 5,600.00	$ 5,600.00	1.000	0.000	0.00	$ 5,600.00	$ -	$ 5,600.00
15.0	Grounding grid	1	1	$ 25,408.00	$ 25,408.00	1.000	0.000	0.00	$ 25,408.00	$ -	$ 25,408.00
16.0	ESA - Site plan review, inspection permits and fees	1	1	$ 7,300.00	$ 7,300.00	1.000	0.000	0.00	$ 7,300.00	$ -	$ 7,300.00
17.0	Final clean up, Preservice testing, commissioning etc.	1	1	$ 6,800.00	$ 6,800.00	1.000	0.000	0.00	$ 6,800.00	$ -	$ 6,800.00
							0.000				
	Total Contract Work			$ 1,081,938.40	$ 1,081,938.40						
	Change Notices										
1.0	Credit for PUC Metering Compartment	1	1	$ (5,500.00)	$ (5,500.00)	1.000	0.000	0.00	$ (5,500.00)	$ -	$ (5,500.00)
2.0	Credit for Drawout feeder breakers	1	1	$ (8,296.00)	$ (8,296.00)	1.000	0.000	0.00	$ (8,296.00)	$ -	$ (8,296.00)
3.0	Sawcut rear building wall and install new door at rear of building	1	1	$ 5,600.00	$ 5,600.00	1.000	0.000	0.00	$ 5,600.00	$ -	$ 5,600.00
4.0		0	0	$ -	$ -	0.000	0.000	0.00	$ -	$ -	$ -
	Total Extra Work			$ (8,196.00)	$ (8,196.00)						
					$ 1,073,742.40				$ 1,073,742.40	$ -	$ 1,073,742.40

PST included
GST Extra

	Name	Duration	Start	Finish
1	Mobilization	3 days	7/27/09 ...	7/29/09 ...
2	Construction	38 days	7/30/09 ...	9/21/09 ...
3	Stripping of Site	38 days	7/30/09 ...	9/21/09 ...
4	Terminal Pole Concrete Base	3 days	7/30/09 ...	8/3/09 5...
5	Transformer Concerte Pad	5 days	8/4/09 8:...	8/10/09 ...
6	Duct Banks (44kV and 4kV)	10 days	8/11/09 ...	8/24/09 ...
7	Maintenance Hole Installation	4 days	8/25/09 ...	8/28/09 ...
8	Terminal Pole Assembly and Installation	3 days	8/4/09 8:...	8/6/09 5...
9	Delivery of 44 Kv Switch & Fuse	1 day	7/29/09 ...	7/29/09 ...
10	44 kV Concrete Pole Delivery	1 day	7/29/09 ...	7/29/09 ...
11	Ground Grid Installation	4 days	7/29/09 ...	8/3/09 5...
12	4 kV Switchgear Installation	5 days	8/7/09 8:...	8/13/09 ...
13	4kV Bus Duct Installation	2 days	8/7/09 8:...	8/10/09 ...
14	46kV Power Cables and Terminataions at Terminal Pole	2 days	8/25/09 ...	8/26/09 ...
15	7.5/10 MVA Transformer Installation	3 days	9/11/09 ...	9/15/09 ...
16	46 kV Power Cables Terminations at Transformer End	2 days	9/16/09 ...	9/17/09 ...
17	Testing and Commissioning of Entire System	3 days	9/16/09 ...	9/18/09 ...
18	ESA Final Inspection and Permission to energize	1 day	9/21/09 ...	9/21/09 ...
19	44kV and 4 kV Pole line Construction	35 days	7/27/09 ...	9/11/09 ...

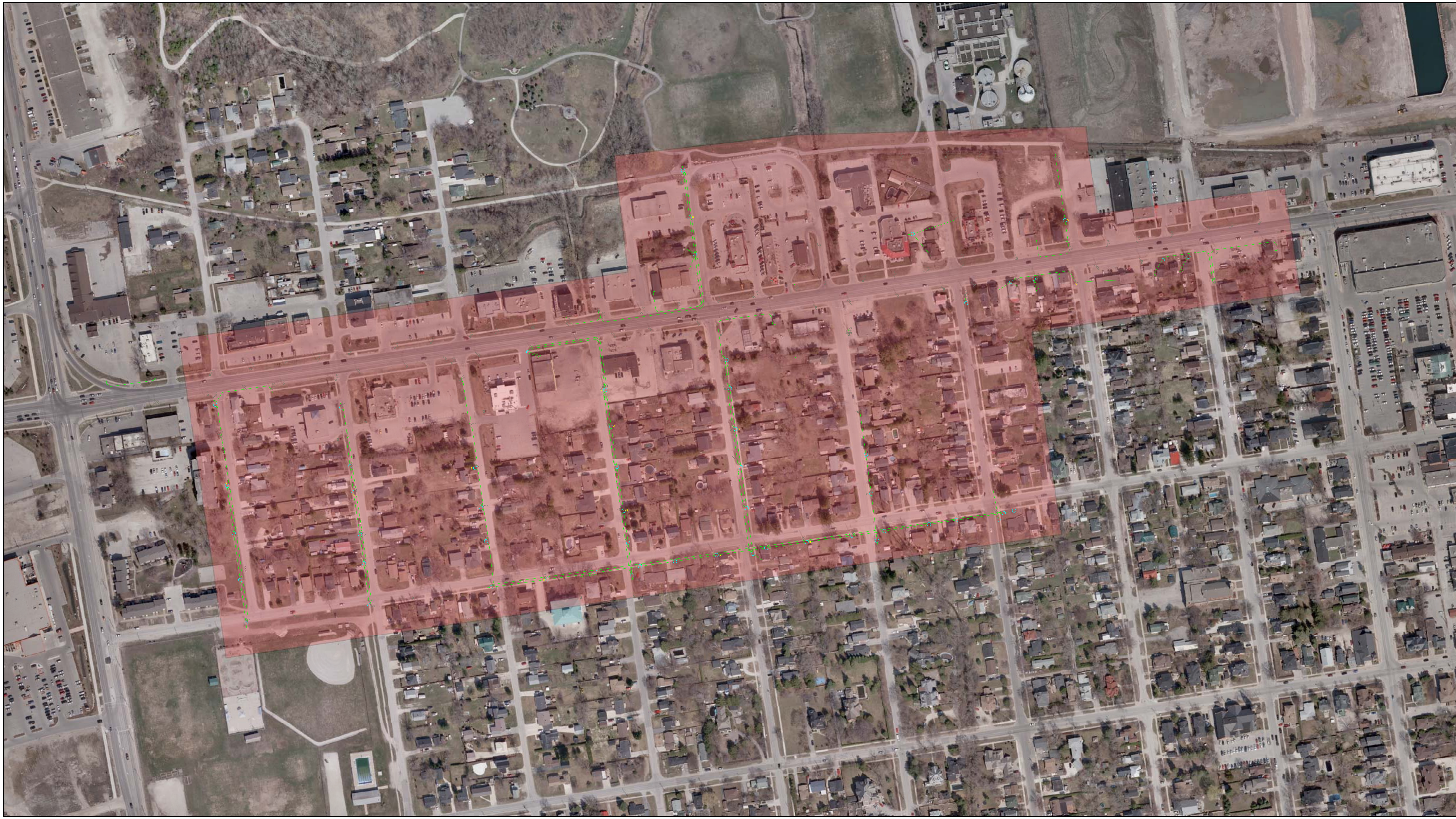


COLLUS Power Corp.

2008 Capital Project Report
Budget No. 17011 Capital Project: Parkside Lane (Georgian Manor Drive) Reconstruction

General Description:	This project is a complete rebuild of the existing hydro asset as a result of the age and undersizing of the existing hydro plant. The project will require that all poles are replaced (approx. 35) and that 1500 metres of new 3/0 ACSR conductor single phase primary will be installed. The majority of transformers will be replaced or relocated to suit the appropriate loads. All secondary services will be replaced with new 4/0 secondary conductor.
Number of Affected Customers:	120 Residential Customers
Estimated Labour Costs:	$80,000
Estimated Material Costs:	$40,000
Expected Project Completion:	First Quarter 2008

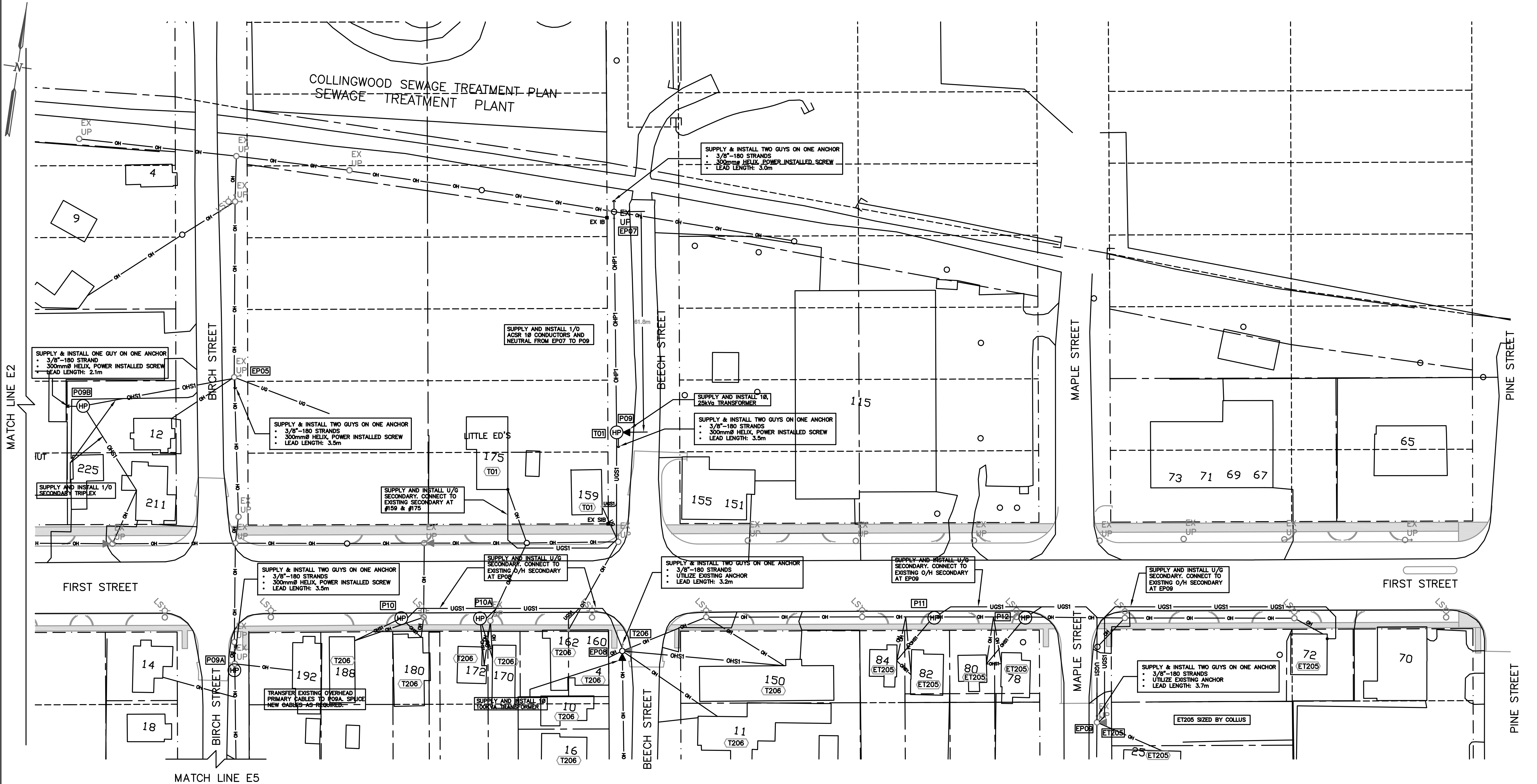
Note: Drawing of works to be completed and typical standard is attached. All drawings have been reviewed and approved by the Electrical Safety Authority.



First Street Re-Build - Hurontario Street to Balsam Street
Georgian Trail and Back Lot Project

0 100 200 400 Metres

N



SEE DRAWING E1 FOR ELECTRICAL LEGEND AND GENERAL NOTES

1. This drawing is the exclusive property of R. J. Burnside & Associates Limited and the reproduction of any part without prior written consent of this office is strictly prohibited.

2. The contractor shall verify all dimensions, levels, and datums on site and report any discrepancies or omissions to this office prior to construction.

3. This drawing is to be read and understood in conjunction with all other plans and documents applicable to this project.

4. Do not scale the drawings.

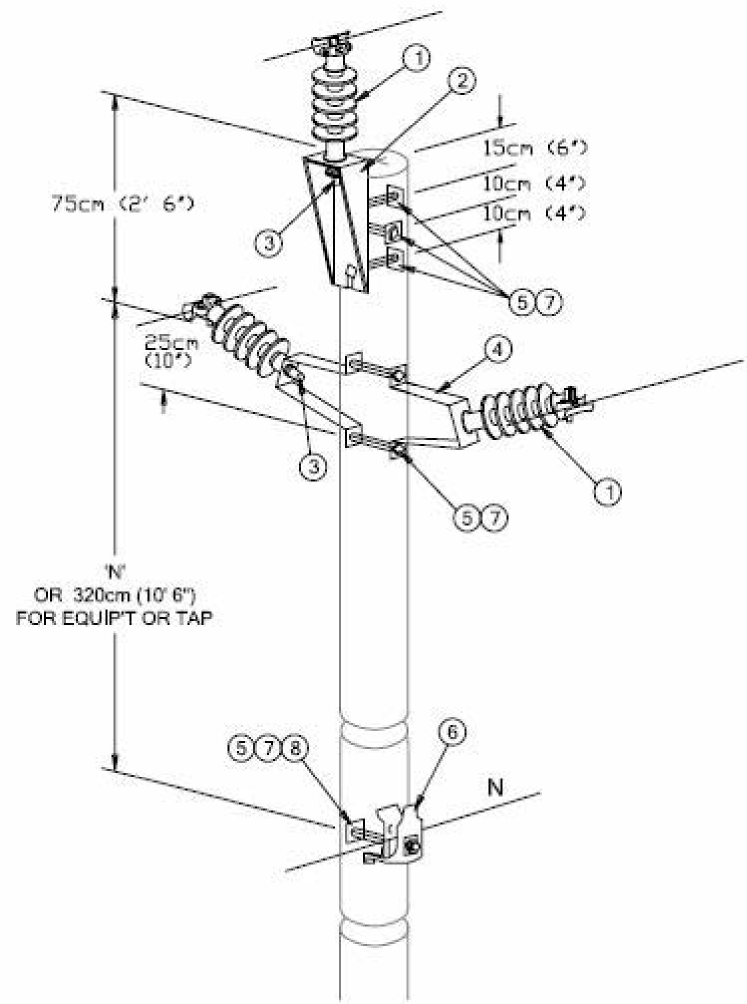
No.	Issue / Revision	Date
1	Issue For Town Of Collingwood, Bell and Rogers Review	March 21, 2007
2	Issue For Bell and Rogers Tender	October 17, 2007
3	Issued For Town of Collingwood Field Review	November 9, 2007
4	Issued For Collus Review	December 4, 2007
5	Issued For Construction	December 18, 2007

BURNSIDE
R. J. Burnside & Associates Limited
3 Ronell Crescent, Collingwood, Ontario
telephone (705) 446-0515 fax (705) 446-2399
web www.rjburnside.com

Client
COLLUS POWER CORPORATION
43 Stewart Rd.,
Collingwood, Ontario
L9Y 3Z5

Drawing Title
FIRST STREET
COLLINGWOOD, ONTARIO
POLE LINE RELOCATION LAYOUT

Drawn By	Checked By	Drawing No.
D.G./H.B./J.R./S.E.	G. Runge	E3
Scale: 1:500	Project No.: XGE 08483.14	



SECTION 1.6

SPAN LENGTH	'N' * MIN CLEARANCE
0-45m	1.5m (5')
46-60m	1.8m (6')
61-70m	2.1m (7')
71-90m	2.4m (8')

SPAN LENGTH	MINIMUM STAND-OFF BRACKET REQUIRED
0-75m	22.5cm (9")
76-90m	45cm (18")

Utilities Standards Forum

USF

Title: PRIMARY 3-PHASE TANGENT
4.16 to 44kV, MAX SPAN 90m

SIZE	FILE NAME:	DWG NO.	REV
A	01-300.DWG	01-300	0

SCALE	DATE:	SHEET
NTS	2006-06-26	1

COLLUS Power Corp.

2008 Capital Project Report
Budget No. 17012 Capital Project: First Street Reconstruction – Hurontario Street to Balsam Street

General Description:	The Town of Collingwood in partnership with the Ministry of Transportation is adding additional lanes to First Street (Highway #26 Connecting Link) to accommodate the significant increase of traffic to the area. This road widening necessitates the relocation of the existing hydro plant along First Street. The project will be a complete rebuild of the existing hydro assets. The project will require that a number of poles be replaced (approx. 25) and that 1500 metres of new 336 ACSR conductor single phase and three phase primary will be installed. The majority of transformers will be replaced or relocated to suit the appropriate loads. All secondary services will be replaced with new 3/0 secondary conductor. This reconstruction project will allow all customers on the south side of First Street to be fed from Second Street.

Number of Affected Customers:	100 Residential Customers and 30 Commercial Customers

Estimated Labour Costs:	$70,000

Estimated Material Costs:	$40,000

Expected Project Completion:	Third Quarter 2008

Note: Drawing of works to be completed and typical standard is attached. All drawings have been reviewed and approved by the Electrical Safety Authority.

COLLUS Power Corp.

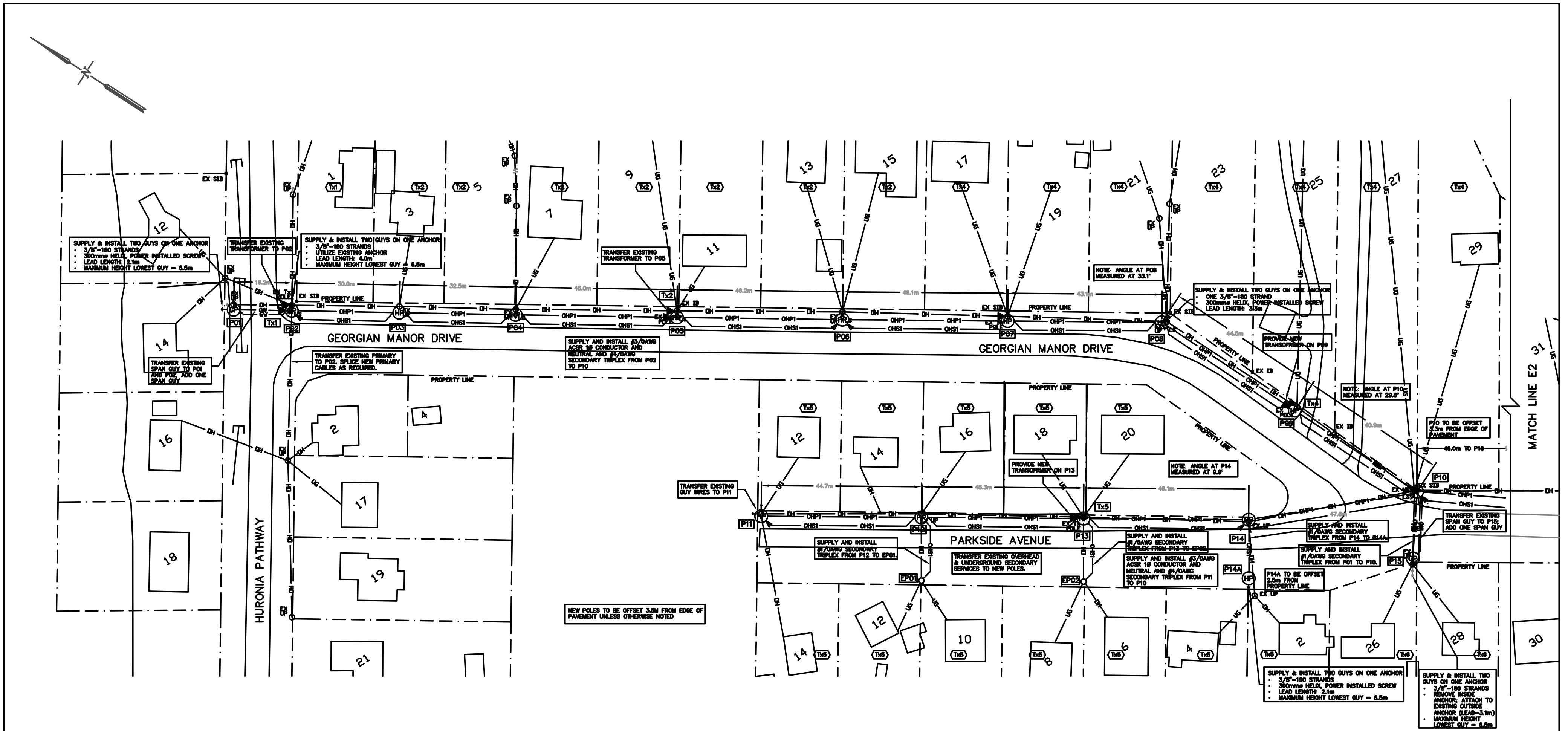
2008 Capital Project Report	
Budget No. 17013 Capital Project: First Street Reconstruction – Georgian Trail and Rear Lot	
General Description:	This project is in conjunction with the Capital Budget No. 17012 Project. The Town of Collingwood in partnership with the Ministry of Transportation is adding additional lanes to First Street (Highway #26 Connecting Link) to accommodate the significant increase of traffic to the area. This road widening necessitates the relocation of the existing hydro plant along First Street. The project will be a complete rebuild of the existing hydro assets. The project will require that a number of poles be replaced (approx. 20) and that 1000 metres of new 336 ACSR conductor single phase and three phase primary will be installed. The majority of transformers will be replaced or relocated to suit the appropriate loads. All secondary services will be replaced with new 3/0 secondary conductor. This reconstruction project will allow all customers on the north side of First Street to be fed from the Georgian Trial and through rear lots.
Number of Affected Customers:	70 Residential Customers and 40 Commercial Customers
Estimated Labour Costs:	$70,000
Estimated Material Costs:	$40,000
Expected Project Completion:	Fourth Quarter 2008

Note: Drawing of works to be completed and typical standard is attached. All drawings have been reviewed and approved by the Electrical Safety Authority.

Georgain Manor Drive Re-Build

0 135 270 540 Metres

N



STANDARD ELECTRICAL LEGEND

ET01	EXISTING POLE MOUNT TRANSFORMER AND TAG NUMBER
ET02	EXISTING PAD MOUNT TRANSFORMER AND TAG NUMBER
OH	EXISTING OVERHEAD POWER LINE
UG	EXISTING UNDERGROUND POWER LINE
GW	EXISTING OVERHEAD GUY WIRE
EX UP EP05	EXISTING UTILITY POLE WITH TAG NUMBER
LS EX UP	EXISTING HYDRO POLE & LIGHT STANDARD
←	EXISTING GUY WIRE
OHS1 HP OHS1	PROPOSED OVERHEAD SECONDARY OPEN POINT AT POLE
OHP3	PROPOSED OVERHEAD PRIMARY 3Ø POWER LINE(S)
OHP1	PROPOSED OVERHEAD PRIMARY 1Ø POWER LINE(S)
OHS3	PROPOSED OVERHEAD SECONDARY 3Ø POWER LINE(S)
OHS1	PROPOSED OVERHEAD SECONDARY 1Ø POWER LINE(S)
UGP3	PROPOSED UNDERGROUND PRIMARY 3Ø CABLE(S) IN DUCT
UGP1	PROPOSED UNDERGROUND PRIMARY 1Ø CABLE IN DUCT
UGS3	PROPOSED UNDERGROUND SECONDARY 3Ø CABLE(S) IN DUCT
UGS1	PROPOSED UNDERGROUND SECONDARY 1Ø CABLE(S) IN DUCT
Tx#	TRANSFORMER NUMBER PROVIDING SERVICE POWER TO RESIDENCE
T01	PROPOSED POLE MOUNT TRANSFORMER AND TAG NUMBER
T02	PROPOSED PAD MOUNT TRANSFORMER AND TAG NUMBER
P66 GP	PROPOSED GUY POLE WITH TAG NUMBER
P08 HP	PROPOSED POWER POLE WITH TAG NUMBER
P07 CP	NEW POLE BY COLLUS WITH TAG NUMBER (NOT IN CONTRACT)
←	PROPOSED GUY WIRE
USF	UTILITIES STANDARDS FORUM
MAS 2861	MUNICIPAL ADDRESS SYSTEM
Tx	TRANSFORMER

GENERAL NOTES:

1. CONTRACTOR TO REMOVE ALL ABANDONED POLES, WIRES, CABLES AND EQUIPMENT. DELIVER ALL MATERIAL TO COLLUS' YARD IN COLLINGWOOD. COORDNIATE DELIVERY WITH COLLUS.
2. EXISTING STREET LIGHTS TO BE TRANSFERED TO NEW POLES.
3. TRANSFER EXISTING SECONDARY SERVICES TO NEW POLES. PROVIDE NEW SECONDARY CABLES AS REQUIRED. WHERE APPLICABLE, INSTALL SECONDARY O/H SERVICE SPANS AS "SLACK" SPANS (i.e. NO TENSION).
4. FINAL LOCATION OF ALL NEW POLES AND TRANSFORMERS TO BE DETERMINED DURING CONSTRUCTION PHASE. CONTRACTOR TO COORDINATE WITH COLLUS' ENGINEER PRIOR TO INSTALLATION.
5. IT APPEARS THAT A NATURAL GAS PIPELINE IS LOCATED ON THE EAST SIDE OF GEORGIAN MANOR DRIVE. CONTRACTOR TO VERIFY THE LOCATION OF ALL EXISTING UTILITIES PRIOR TO CONSTRUCTION.

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2. The contractor shall verify all dimensions, levels, and datums on site and report any discrepancies or omissions to this office prior to construction.

3. This drawing is to be read and understood in conjunction with all other plans and documents applicable to this project.

4. Do not scale the drawings.

No.	Issue / Revision	Date
1	Issued To Collus For Preliminary Review (50% Design)	September 7, 2007
2	Issued To Collus For Final Review	September 28, 2007
3	Issued For Construction	October 4, 2007

BURNSIDE
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3 Ronell Crescent, Collingwood, Ontario
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web www.rjburnside.com

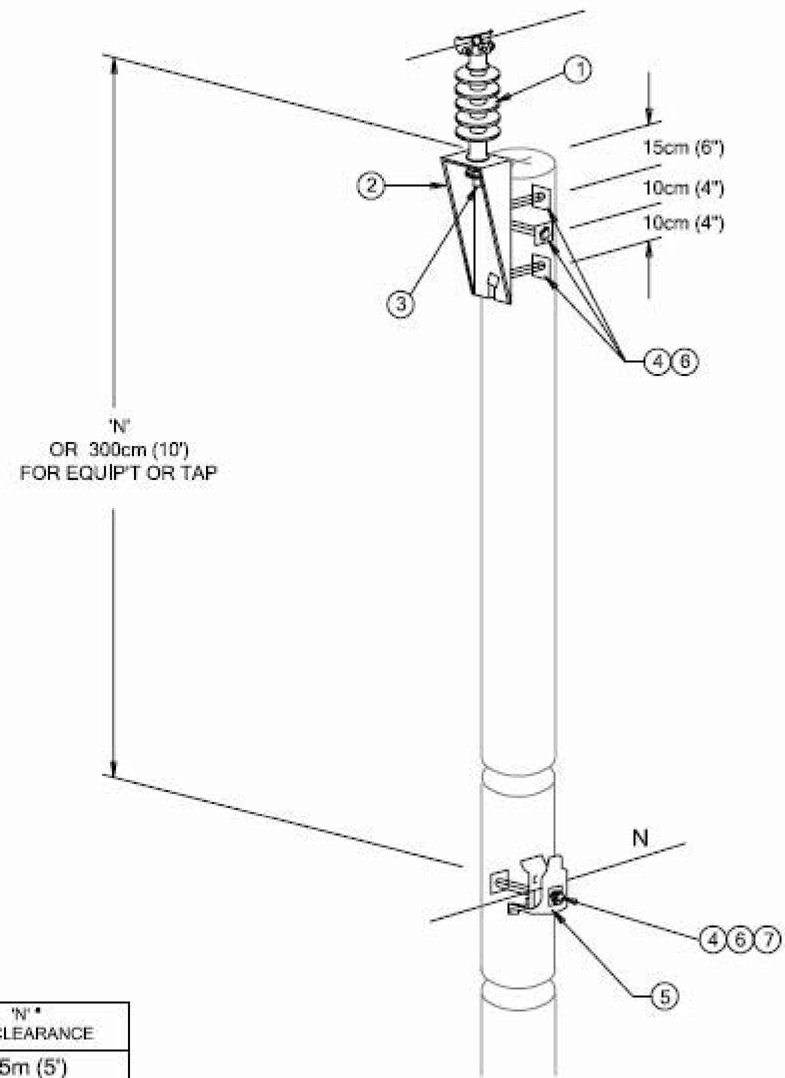
Client
COLLUS POWER CORPORATION
43 Stewart Rd.,
Collingwood, Ontario
L9Y 3Z5

Drawing Title
GEORGIAN MANOR DRIVE
COLLINGWOOD, ONTARIO

POLE LINE EXTENSION LAYOUT

Drawn By	Checked By	Drawing No.
D.G./H.B./S.E.	G. Runge	E1
Scale	Project No.	
1:500	XGE 08483.8	

01-100



SECTION 1.6

SPAN LENGTH	'N' * MIN CLEARANCE
0-45m	1.5m (5')
46-60m	1.8m (6')
61-70m	2.1m (7')
71-90m	2.4m (8')

Utilities Standards Forum USF

Title: PRIMARY 1-PHASE TANGENT 2.4 to 20kV, MAX SPAN 90m

SIZE	FILE NAME:	DWG NO.	REV
A	01-100.DWG	01-100	0

SCALE	DATE:	SHEET
NTS	2006-06-26	1

Collingwood Public Utilities
COLLUS Power Corp
COLLUS Solutions Corp

MEMO

To: Larry

From: Ray

Date: Wednesday, August 13, 2008

Re: Replacement Truck 12

As you are aware our existing 55 foot aerial material handler has become unreliable and through our asset management program is slated to be replaced so as to ensure a safe reliable service to our customers.

The following is pertinent information for the replacement of Truck #93-12

Existing Vehicle:

- Freightliner FL 80 – Year: 1993 – 55' aerial material handler
- The engine hours have the equivalent of 750,000 km.
- The single axle has required spring replacement several times over the past five years with the most recent being June of 2008
- There have been many other repairs but of greatest concern was the need to tow the vehicle on two occasions to Freightliner in Barrie for issues with the gear shift.
- This existing vehicle will not allow us to service hydro poles in excess of height 55 feet. All poles higher than this must be worked manually on spurs.

Proposed Vehicle:

1 - 2008 or 2009 (New) model year 68' Minimum Material Handling Aerial Device, Chassis and Fiberglass Body in accordance with the attached specification.

Regards,
Ray

Ray Powell, Hydro Superintendent
P.O. Box 189, 43 Stewart Road, Collingwood ON L9Y 3Z5 **tel** 705-445-1800 ext 2237 **fax** 705-445-0791 **rpowell@collus.com**

General Vehicle Chassis Specifications			
Item No.	**Description**	**Comply Yes or No**	**Extra Cost If Applicable**
1.	7400 series international / M2 Freightliner or Equivalent State Make____ State Model ____		
	Engine Diesel 310 Hp 950 Lb Ft Torque 1200 Rpm		
	BIO diesel fuel (B5, B20) Compatible (Warranty Approved usage)		
	2008 or 2009 EPA Emission Certification		
	Sba6x4		
	Wheelbase 217		
	150ct , 104 AF		
	Tow Hook Front		
	Frame Rails 120,000 Psi Yield		
	Frame Reinforcement Outer C Channel 120,000 Psi		
	Bumper Front Full Width Aerodynamic		
	Powder Coated Gray Argent Color		
	Axle Front I-Beam Type 18,000 Lb Capacity		
	Shock Absorbers Front		
	Suspension Front Spring Multi-Leaf Shackle Type 18,000 Lb Spring Pins Rubber		
	Bushings Maintenance Free		
	Brake System Air Dual System for Straight Truck Application Air Compressor Air Supply Line		
	Brake Chambers Spring (4) Rear Parking		
	Brake Lines Color Coded Nylon		
	Dust Shield Rear Brakes		
	Dust Shields Front Brake		
	Automatic Slack Adjusters Front & Rear		
	Parking Valve Yellow Knob Dash Mounted Drain Valve Twist Type		
	Spring Brake Modulator Valve		
	Gauge Air Pressure Dash Mounted		
	Brakes Front Air Cam 16.5" X 6"		
	Trailer Connections Four Wheel With Hand Control Valve Tractor Protection Valve		
	Drain Valve Automatic Bendix Dv2		
	Air Brake Abs Full Vehicle Wheel Control System 4 Channel Air Dryer Bendix Ad 9 With Heater		
	Brakes Rear Air Cam 16.5" X 7.0"		

68’ Minimum Material Handling Aerial Device, Chassis and Fiberglass Body

Specifications

General Vehicle Chassis Specifications – Continued			
Item No.	**Description**	**Comply Yes or No**	**Extra Cost If Applicable**
	Brake Chambers Spring Inverted		
	Air Compressor 13.2 Cfm		
	Steering Column Tilting And Telescoping		
	Steering Wheel 18" Diameter		
	Steering Gear Dual Power		
	Exhaust System Single Horizontal After treatment Device Frame Mounted Right Side under Cab Includes Vertical Tailpipe and Guard Provides Clean Ca above and below Rail Tail Pipe Turn Back Type		
	Engine Brake Dlogic		
	Electrical System 12 Volt		
	Battery Box Steel with Fiberglass Cover Mounted Right Side Back Of Cab		
	Turn Signal Switch Self Canceling Headlight Dimmer with Flash to Pass		
	Headlights Sealed Beam Halogen - Daytime Running Lights		
	Horn Electric		
	Parking Light		
	Stop Turn Tail And Back Up Lights Dual Rear		
	Starter Switch Key Operated		
	Turn Signals Front		
	Data Link Connection		
	Windshield Wipers Intermittent Wiring Chassis		
	Power Source Cigar Type		
	Alternator Leece Nevville 200 Amp		
	Body Builder Wiring Back Of Cab at Frame		
	Battery System 12 Volt 1850 Cca Radio		
	Panasonic Cr-W400u - Speaker In Cab With Premium Interior		
	Jump Start Stud Remote Mounted		
	Trailer Connection Socket 7 Way Mounted At Rear Of Frame		
	Air Horn Mounted Behind Bumper On Right Rail		
	Switch Auxiliary Interrupter For Cab And Body Clearance Lights		
	Starting Motor 12 Volt with Thermal Over Crank Protection		
	Indicator Low Coolant Level with Audible Alarm		
	Circuit Breakers		
	Fender Extensions		
	Insulation under Hood		
	Chrome Grille & Bug Screen		
	Insulation Splash Panels		
	Front End Tilting Hood And Fenders		
	Radiator Hoses Silicone		
	Block Heater 120 Volt 1250 Watt Block Heater		

General Vehicle Chassis Specifications – Continued			
Item No.	**Description**	**Comply Yes or No**	**Extra Cost If Applicable**
	Gauge Air Cleaner Restriction Fuel Water Separator		
	Wet Type Cylinder Sleeves		
	Cruise Control		
	Engine Shutdown Key Operated		
	Electronic Road Speed Governor		
	Engine Oil Drain Plug Magnetic		
	Oil Filter Engine Spin On		
	Fan Drive Automatic		
	Radiator 1228 Sq In With Internal Water T Oil Transmission Cooler, Anti Freeze -40f		
	Federal Emissions for 2007 Air Cleaner		
	Throttle hand control engine speed control for PTO - Electronic stationary pre set two speed settings		
	Engine Control Remote Mounted For PTO Controls with Expanded Engine Temp Effects		
	Transmission Automatic Allison 3000 RDS P 5 Speed With Overdrive - Transmission Control Push Button Type		
	Oil Level Sensor		
	PTO Provision		
	Allison Spare Input /Output for Rugged Duty Series RDS PTO Control Dash Mounted		
	Suspension Air Control Valve		
	Axle Rear Tandem Dana Spicer Dd405p/Rd405 Single Reduction 40,000 Lb Capacity Gear Ratio 4.88		
	Driver Controlled Locking Differential In Forward Rear And Rear Axle Power Divider Lock Electric Over Air Operated		
	Rear Axle Drain Plug Magnetic		
	Power Divider Lock		
	Suspension Rear "Blocked"		
	55" Rear Axle Spread 40,000lb Capacity		
	Cab with Air Suspension Ride		
	Fuel Tank - Minimum 50 Us Gallon		
	Fuel Lines Nylon Tubing		
	Fuel Water Separator Fleet guard		
	Cab Conventional Steel Clearance- Marker Lights		
	Arm Rest		
	Floor Covering Rubber Black		
	Grab Handle Passenger Grab Handle		
	2 Entry Steps per Door		
	All Windows Tinted		
	Seat Driver National 2000 Air Ride with Seat Belt 3 Point		
	Seat Passenger National Air Suspension with Seat Belt 3 Point		
	Cab Sound Insulation		
	Power Operated Windows and Door Locks		

General Vehicle Chassis Specifications – Continued			
Item No.		**Comply Yes or No**	**Extra Cost If Applicable**
	Gauge Cluster • Odometer • Warning System • Low Fuel • Low Oil • High Engine Temperature • Low Battery Voltage Engine Oil Pressure • Water Temperature • Tachometer • Fuel • Washer Fluid Level Voltmeter • Transmission Temperature Gauge		
	Mirror Convex Look Down		
	Mirrors Lang Mekra Heated Powered Both Sides Cab		
	Headliner and Dome Light Cab		
	Cab Interior Deluxe Trim with Overhead Console		
	High Capacity Cab Heater and Air Conditioning		
	Wheels Front Disc 22.5 10 Stud Hubs		
	Piloted Wheel Seals Front Oil Lubricated		
	Front Wheels White		
	Wheels Rear Dual Disc 22.5 10 Stud Hub Piloted		
	Rear Wheel Seals Oil Lubricated		
	Rear Wheels White		
	Tire Rear 11r22.5xde M/S tire Front 385/65r22.5 Xzy 3 Michelin 18 Ply tires		
	Color to match fleet (white)		
	Trailer connection socket 7 way mounted at rear of frame		

68’ Minimum Material Handling Aerial Device, Chassis and Fiberglass Body

Specifications

Elevator Specifications			
Item No.	**Description**	**Comply Yes or No**	**Extra Cost If Applicable**
	Unit to Be Designed As A High Capacity Material Handling Aerial Device		
	Unit to Be A Stacked Boom Design		
	Unit Is To Be Mounted With Buckets At Rear With Knuckle Mounted Over Cab		
	Knuckle Is Not To Protrude Past Front Bumper		
	55 ft. from Ground to Bottom Of Platform Elevator Stowed		
	60 ft. Working Height Elevator Stowed		
	70 ft. From Ground To Bottom Of Platform Elevator Raised 75 ft. Working Height Raised		
	360 Degree Continuous Rotation		
	Lower Boom 0 To 105 Degrees		
	Upper Boom 190 Degrees In Relation To Lower Boom		
	With Lower Boom at 0 Degrees and Upper Boom 180 Degrees and Elevator Stowed Min 35’-10” Reach @ 10’ – 2” Height		
	With Lower Boom at 105 Degrees and Upper Boom Parallel to Ground and Elevator Stowed Min 47’-10” Reach @ 36’ – 6” Height		
	Unit Must Comply to the Following Standards • Can Csa C225-00 • Ansi/Sia A92.2-1 990 • W47.1 – 1983 • W59 - M1984 • Can 3 - Z299 4-85 • Sae J343c • Osha Paragraph 1910.67 & 1926.556 • All Federal And Provincial Requirements		
	Steel Structures 3:1 To Yield		
	Steel Structures Used In Fabrication Of Any Load Bearing Element Must Have A Minimum Yield Strength Of 37,000 Psi		
	Main System Pressure Not To Exceed 3000 Psi		
	Self Aligning Bearings or Bronze Sleeve Type to Be Used Throughout Load Bearing Axis Points		
	A Single Speed PTO Continuous Duty Electric Shifted Is To Be Mounted On The Vehicle Transmission		
	PTO Is To Be 6 Bolt Type		
	PTO Is To Be Equipped With Red Warning Light		
	PTO Is To Provide 1000 Rpm On Its Output Shaft With The Vehicle Speed Between 900 And 1200 Rpm		
	When PTO Is Engaged Transmission Is To Automatically Shift To Neutral		
	PTO Switch Is To Be Located In Wire Rite Control Panel Or Chassis Supplied Switch Panel		
	A Variable Volume Or Gear Type Hydraulic Pump Is To Be Close Coupled To the PTO		
	Pump Is To Be Vickers Or Greasen		
	Pump To Be 4000 PSI		
	Pump To Be 10 GPM		
	Hydraulic System To Be Full Pressure Open Center Design 50 Gallon Frame Mount with Reservoir		

68’ Minimum Material Handling Aerial Device, Chassis and Fiberglass Body

Specifications

Elevator Specifications			
Item No.	**Description**	**Comply Yes or No**	**Extra Cost If Applicable**
	Reservoir Is To Be Provided with the following: • Breather • Sump • Drain Plug • Sight Gauge • Thermometer • Clean Out and Hand Hole • Shut Off Valves Tie Wired In The Open Position • Baffles • 100 Mesh Suction Line Strainer • 10 Micron Return Line Filter with Relief • Gate Valves provided on Both Suction and Drain Lines		
	Boom Cylinders Are To Be Equipped With Internal Sun/Type Pilot Operated Adjustable Holding Valves Cartages		
	Outriggers Are To Be Welded To the Sub Frame and Bolted To the Chassis Frame Rail		
	Outriggers Are To Be Radial Type		
	Outrigger Foot Pads Are To Measure A Minimum Of 18" X 18"		
	Outriggers Are To Fit A 100” Wide Body		
	Outriggers Are To Have A Minimum Of 165" Pin To Pin Spread At Ground Level		
	Outriggers Are To Have 10" Of Ground Penetration		
	Outrigger / Machine Selector Valve Is To Be Located At The Lower Control Station		
	Outrigger Control Valves Are To Be Located So To Allow The Operator Clear View Of The Outrigger Operation		
	Outriggers Are Not To Bind Under Full Load During Operation		
	Outriggers Are To Be Marked As Per C.S.A.		
	Outriggers Are To Be Equipped With Holding Valves		
	Qty 4 Outrigger Warning Lights Are To Be Provided		
	Sub Frame Is To Be A Integral Part Of The Aerial Device		
	Sub Frame Is To Be 4" X 4" Rectangular Hollow High Tensile Steel Tubing		
	Sub Frame Is To Be Primed And Finish Painted		
	The Pedestal Is To Be Thoroughly Welded And Braced To The Sub Frame Or Bolt On Design Is Acceptable		
	The Pedestal Is To Be Equipped Access Door		
	The Pedestal Is To Be Manufactured Of H.S.S. Steel		
	The Pedestal Top Plate Is To Be Machined After Welding		
	Rotation Is To Be Accomplished Through A Planetary Gear Or Worm Gear Drive Transmission		
	Rotation Is To Be Field Adjustable For Back Lash		
	An Automatic Spring Applied Hydraulic Release Brake Is To Be Provided With No Pressure Bleed-Off		
	In The Event Of A Hydraulic Failure A Means Of Manual Rotation Is To Be Provided		
	Fiberglass Sections Are To Be Sanded Smooth And Spray Painted		
	Paint Is To Be Waterproof and shall not crack		

68’ Minimum Material Handling Aerial Device, Chassis and Fiberglass Body

Specifications

Elevator Specifications			
Item No.	Description	Comply Yes or No	Extra Cost If Applicable
	Boom to be designed to allow “candle Lighting” of a suspected area if required		
	Lower Boom Insert Manufactured From Bi-Directional Spirally Hand Or Machine Wound Fiberglass		
	Lower Boom Insert to provide Minimum 18” Clear Gap Insulation		
	Lower Boom to be Rectangular in shape		
	Lower Boom to articulate by the means of One Lift Cylinder		
	Lower Boom Lift Cylinder to be double acting type		
	Upper Boom to be manufactured from spirally wound fiberglass		
	Boom deflection to be less than 1/8” / foot		
	Upper Boom to articulate by means of one or two boom cylinders		
	Return to zero boom stow light is to be provided at the boom rest to allow operator to see when the lower boom is lined up in the boom rest for storage		
	An air or Hydraulic operated boom stow latch system is to be provided for both upper and lower booms		
	Two 24” x 30” x 42” deep platforms are to be provided		
	Two platform Liners 70KV rated are to be provided		
	Two platform Scuff Pads c/w Steps are to be provided		
	Two heavy duty vinyl platform covers are to be provided		
	Platform capacity to be 300 Lbs Minimum including Liner		
	Platforms to be supplied with molded in steps		
	Operator & Passenger platforms to rotate 90 degrees		
	Platforms to be provided with a Hydraulic tilt for ease of cleaning out and emergency rescue		
	A “D” Ring attachment is to be provided at the platform area for Lanyard attachment		
	Platform supports are to be supplied		
	Platform tilt control is to be located in the lower control station		
	Platform leveling to be “Chain” Leveling		
	Leveling Chain shall have a average tensile strength of 30,000 Lbs		
	Fiberglass Rods are to used to Maintain rated Dielectric strength		
	The Leveling system is to be enclosed within the booms		
	An Access is to be provided for inspection		
	The leveling system is to have NO tear down inspection and There is to be NO mandatory change required for the leveling system		
	High pressure hydraulic controls are to be located at the platform and below rotation		
	The controls valves are to be spring centering full feathering open center spool valves		
	Aerial Device Is To Be Capable Of Multiple Boom Functions From The Upper Control Station & Lower Control Station		
	Lower Controls Are To Be Located At The Curbside Walkup Area Mounted On Top Of The Outrigger		

68’ Minimum Material Handling Aerial Device, Chassis and Fiberglass Body
Specifications

Elevator Specifications			
Item No.	**Description**	**Comply Yes or No**	**Extra Cost If Applicable**
	Lower Controls Are To Include The Following Functions: • D/C Lowering • Engine Start / Stop • Light for Nighttime operations • Aerial Device / Outrigger / Emergence Stop • Outrigger Controls Curbside • Tool Outlets and Control Selector • Lower Boom - Raise / Lower • Upper Boom - Raise / Lower • Rotation Left / Right • Winch – Raise / Lower • Hydraulic Platform title • Elevator - Raise / Lower • Two Speed Throttle		
	Controls for the Street Side Outriggers to be located Street Side Rear of the Body		
	Upper Controls Are To Include The Following Functions • D/C Lowering • Engine Start / Stop • Light for Nighttime operations • Aerial Device / Outrigger / Emergence Stop • Outrigger Controls Curbside • Tool Outlets and Control Selector • Lower Boom - Raise / Lower • Upper Boom - Raise / Lower • Rotation Left / Right • Winch – Raise / Lower • Platform Rotation • Elevator - Raise / Lower • Jib Rotate Up/Down • Jib Extend / Retract		
	Upper Control Station Is To Have A Joy Stick Control C/W Deadman Trigger		
	D/C Lowering Two Speed Throttle And Engine Stop Start At The Platform Is To Be Controlled Through A Rpm Tess-Iii Control System. No Air Operated System Allowed.		
	Unit Is To Be Designed And Tested As Per Csa 225-00		
	Unit To Be Stability Tested To Csa C225-M88		
	Unit To Be Rated As A Class A 69 Kv Machine As Per Csa C225-00		
	Unit To Be Supplied With Bare Hand Grids		
	Unit To Be Bonded For Bare Hand Application		
	Unit To Be Supplied With Current Leakage Meter And Case		
	Unit To Be Supplied With Current Leakage Monitoring System		
	Unit To Be Supplied With Vacuum Flashover Protection		
	Aerial Device Is To Be Tested At The Factory By Quality Control Personnel		
	An Applicable Check List Is To Be Used And Available For Review If Required		
	All Components Are To Be Given A Visual Inspection Under Operation At Shaft Capacity		
	Hydraulic Components Are To Be Adjusted And Tested		
	All Holding Valves Are To Be Checked And Adjusted To Rated Load		

68’ Minimum Material Handling Aerial Device, Chassis and Fiberglass Body
Specifications

Elevator Specifications			
Item No.	Description	Comply Yes or No	Extra Cost If Applicable
	All Testing Is To Be Documented And A Copy Available If Requested		
	The Following Warning Lights Are To Be Supplied In The Cab • PTO – c/w Hour Meter • Outrigger Warning (Qty 4) • Boom Stow		
	A Heavy Duty H Frame Boom Rest Is To Be Supplied		
	Boom Rest Is To Be Located Between The Cab And The Body		
	Two sets of tool outlets are required at the boom tip		
	One Set of tool outlets are required at the lower control station		
	Tool outlets to match existing COLLUS Power Fleet		
	Tool outlets are to be 9 GPM 1800 PSI		
	A Eight Foot Rectangular In Shape Jib Boom Is To Be Supplied		
	Jib Rotation To Be Achieved By a Worm Gearbox With Hydraulic Brake Assembly And Must Be Serviceable By Not Removing The Boom Tip Leveling Shaft		
	Maximum Output Torque Capacity Shall Be 39,000 In Pounds A Double Acting Hydraulic Extension Is To Be Supplied Maximum Vertical Extension Capacity 2,400 LBS		
	Must Be Able To Extend And Retract Under Full Rated Load		
	Jib Must Rotate 150 Degrees In All Boom Positions		
	Jib Must Rotate Under Full Rated Load		
	A Double Acting Hydraulic Winch Is To Be Supplied		
	Winch To Have 3,000 Lb Bare Drum Rating Winch To Have 2,000 Full Drum Rating		
	Winch To Be Installed Below Or Above Jib Boom Holder		
	Winch Line To Be Yale Maxibraid 0.5" X 85' and a 5 To 1 Safety Factor		
	Winch Line To Have Eye Splice And Thimble At Working End		
	Winch Line To Be Spliced By a Certified Splicer		
	A Removable Double Roller Sheave Head Is To Be Supplied		
	A Top Opening Tilting Conductor Holder Is To Be Supplied with a 725 Lb Rating in all positions		
	A Complete Set Of Fiberglass Guards Are To Be Supplied On The Material Handling Package		
	Grease Zerks For Outrigger And Boom Lubrication Are To Located In Easy To Reach Locations		
	All High Hose To Be Colored Orange And Be Used Above Rotation & Black 100r17 Below Rotation		
	High Pressure Hose to meet SAE 100R7 Rating		
	Main Pressure And Return Line Below Rotation To Be Non Collapsible Sae 100r2 With Oil And Weather Resistant Cover		
	All Hose To Be Rated To 4:1 Minimum		
	All Hoses Routed Close To Exhaust To Be Shielded All High Pressure Tubing		
	All Tube Fittings To Sae J514d		
	All Hydraulic Pipe Fitting To Sae J926		
	Hoses To Be Identified At Both Ends As To Function Hoses To Have Coding Sheet included in Manual		

68’ Minimum Material Handling Aerial Device, Chassis and Fiberglass Body

Specifications

Elevator Specifications			
Item No.	**Description**	**Comply Yes or No**	**Extra Cost If Applicable**
	Lower Boom Articulation To Be Accomplished With A Single Boom Lift Cylinder		
	Upper Boom Articulation To Be Accomplished By Means Of One Or Two Cylinders		
	Include Two Sets Of Operators Parts And Maintenance Manuals		
	Include copy of Warranty Statement		
	Specify Any Additional Cost For a 5 Year Warranty		
	Supply one spare set of filters		
	Supply one spare winch line		
	Material Handling capabilities of 750 LBS		
	Elevator to provide 0 to 90 degree articulation		
	Rotation Is To Be Located At The Top Of The Elevator		
	Elevator To Provide An Additional 15 Feet Of Height		
	No Above Rotation Electrical Wiring Allowed For Any Function		

68’ Minimum Material Handling Aerial Device, Chassis and Fiberglass Body
Specifications

Fiberglass Utility Line Body Specifications			
Item No.	**Description**	**Comply Yes or No**	**Extra Cost If Applicable**
	Body to be Suitable for Mounting on a tandem Axel 150” CT Cab and Chassis		
	Body to be of fiberglass construction		
	Non skid gripstriut aluminum compartment tops		
	Double laminated doors		
	High performance gel coat exterior		
	Separate wheel well sections		
	Wheel wells to be lined		
	Automotive door seal		
	LED Exterior Lights		
	Mid ship turn signal light		
	Protective loom for all wiring		
	Vinyl coated stainless steel door cables		
	Stainless steel nuts and bolts throughout		
	Stainless steel door latches		
	Dual stage rotary door latches with Stainless Steal Hardware		
	All shelving to be aluminum		
	Body to be white gel coat to match fleet colors		
	Overall dimensions 225" long x 48" high x 18" deep x 100" wide		
	Side packs to have 54" high compartments with 12" high top boxes molded one piece construction		
	Street side compartments • # 1- 28" wide to be walkup to deck • #2- 25" wide to have two material rails • #3-24" wide to have 18 swivel hooks • #4-61" wide to be open for tool storage • #5-61" wide with bottom divider shelf • #6- 25" wide to 9 swivel hooks 3 each wall s/s • street side rear to have a hot stick door hot stick shelf to extend from compartment #3 to rear Compartments 2 & 3 to have single door		
	Curbside Compartments • # 1 - 28" wide to be walkup to deck • #2- 25' wide to have 3 adjustable shelves • #3-24" wide to have three adjustable shelves c/w dividers • #4-61" wide to have two shelves c/w dividers on five inch centers. Shelves are to be angled for ease of entry • #5-62 wide to have two shelves c/w dividers • #6- 24" wide to 9 swivel hooks 3 each wall Compartments 2 & 3 to have single door		
	Top opening compartments are not to interfere with the platforms when the aerial device is in the stowed position		
	All top opening compartments to have gas struts		
	Top opening compartments are to stop12" from rear to allow for light bar installation		

Fiberglass Utility Line Body Specifications			
Item No.	**Description**	**Comply Yes or No**	**Extra Cost If Applicable**
	Cargo area is to be lined with aluminum		
	All top opening compartments to have positive mechanical latches		
	One set tow eyes		
	Tubular steel rear bumper		
	One 22 ton army style pintle hitch		
	Access handles at deck access openings		
	Install two model 9200sq mini light bars at left and right rear corners of body		
	Install two model 9200sq mini light bars at right and left hand corners of the 3/4 aluminum cab guard		
	Install 6 Whelan scene lights (qty 3) each side of body		
	Install two go light remote control floodlights at right and left rear corners of cab guard		
	Install platform access steps on top of body compartments.		
	Install deck to compartment top access steps		
	Install two platform supports		
	Install one removable vice bracket and 6 " swivel vice at rear		
	Install outrigger storage bracket as close to outriggers as possible. Storage brackets are to hold two pads each (Pads to be supplied)		
	Install wheel chock cutouts in fender skirts two each skirt (Chocks to be supplied)		
	Install hannie grounding reel on compartment top close to walkup area		
	Install heavy duty boom rest h frame style		
	Install heavy duty 3/4 aluminum cab guard c/w ladder from Deck to cab guard		
	Install front bumper mount tilting cone holder’s qty2		
	All compartments to be equipped lights		
	Supply and Install the following: • sign holder for wind master signs • shovel broom • rake holder • Fire Extinguisher & Bracket • triangle flare kit • Ladder Storage Rack		
	Dash panel switches to include the following functions: • PTO engage/disengage • Rear work lights on / off • Beacons on/off • Compartment lights on / off • PTO hour meter • Outrigger warning lights (qty 4) • Boom out of rest light • Spotlights on/off • Deck lights on /off • Strobe lights c/w 3 position switch		
	Install recessed deck access lighting		
	Install back up alarm		
	Install rear window storage box		

Fiberglass Utility Line Body Specifications			
Item No.	**Description**	**Comply Yes or No**	**Extra Cost If Applicable**
	Install Bosch work lights at rear c/w swivel arms install recessed deck area lighting		
	Install Burndy ground studs front and rear		
	All horizontal compartments to have single drop down doors		
	Traffic Arrow Boards to be supplied		

Tim Fryer

From: Larry Irwin
Sent: Thursday, July 31, 2008 3:41 PM
To: Tim Fryer
Cc: Ray Powell
Subject: Truck # 12 Replacement Status

Tim,

Just thought I would give you a formal status update on this large budget item

- 2008 Budget had $400,000.00 specified for the replacement of our 1992 - 55 ft Double Bucket Truck
- Formal Tenders were created and sent out to the vehicle manufactures at the Beginning of July
- Tenders were received on Thursday July 24th from venders
- After a thorough review of the tenders the successful Vender was Posi Plus Technologies
- Anticipated in service date for this unit will Be Oct 1, 2008

The following is the our projected costs at this point

Item	Amount
One only New 2008 Model Year Freightliner Cab & Chassis	$79,000.00
One only New Posi-Plus 500-55/P68 Aerial Device	$187,691.65
One only New Protek Fiberglass glass Utility Line Body	$45,949.00
Purchase Discount	($3,000.00)
Communication Equipment	$4,000.00
Traffic Control Accessories	$5,000.00
Miscellaneous Storage Bins modifications	$15,000.00
GST @ 5%	$16,682.03
PST @ 8%	$26,691.25
Total =	**$377,013.93**

Sincerely,

Larry

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LARRY IRWIN, Director of Operations & I.T. Services
COLLINGWOOD UTILITY SERVICES (COLLUS).
PO Box 189, 43 Stewart Road,
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OVERVIEW OF OPERATING REVENUE:

This Exhibit provides the details of COLLUS Power Corp'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.

A summary of operating revenues is presented in Exhibit 3, Tab 1, Schedule 2 in Table 1 below.

Throughput Revenue:

Information related to COLLUS Power Corp's throughput revenue includes details such as weather normalized forecasting methodology, normalized volume and customer count forecast tables. Detailed variance analysis on the forecast information is also provided. Detailed information relating to throughput revenue is set out in the Schedules to Exhibit 3, Tab 2.

Other Revenue:

Other revenues include (for example) Late Payment Charges, Miscellaneous Service Revenues and Retail Services Revenues. A summary of these operating revenues together with a materiality analysis of variances is presented in Exhibit 3, Tab 3, Schedules 1 and 2.

TABLE 1

COLLUS Power Corp

SUMMARY OF TOTAL OPERATING REVENUE VARIANCE ANALYSIS

TABLE 1

SUMMARY TOTAL OPERATING 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)
Distribution Revenues									
Residential	3,316,640	2,943,013	-373,627	3,179,122	236,109	***3,302,022***	122,900	***3,875,522***	573,500
GS<50	738,320	667,079	-71,241	731,034	63,956	***721,118***	-9,916	***937,105***	215,987
GS>50-Regular	251,985	333,539	81,554	349,220	15,681	***306,652***	-42,568	***689,991***	383,339
Large User	417,558	444,719	27,161	325,939	-118,780	***171,510***	-154,429	***166,352***	-5,158
Street Light	33,387	26,683	-6,704	32,594	5,911	***36,209***	3,615	***119,863***	83,653
Unmetered Scattered Load	13,349	8,894	-4,455	8,381	-513	***6,488***	-1,894	***20,151***	13,664
Back-up/Standby Power	0	0	0	0	0	***0***	0	***0***	0
Sub-Total	4,771,239	4,423,928	-347,311	4,626,291	202,363	4,544,000	-82,291	5,808,984	1,264,984
Other Distribution Revenue									
Late Payment Charges	60,042	**43,489**	-16,553	**52,179**	8,690	***55,000***	2,821	***55,000***	0
Specific Service Charges	123,623	**138,305**	14,682	**176,904**	38,599	***155,000***	-21,904	***155,000***	0
Other Distribution Revenue	144,077	**329,748**	185,671	**374,839**	45,091	***267,269***	-107,570	***116,000***	-151,269
Sub-Total	327,742	511,542	183,800	603,922	92,380	477,269	-126,653	326,000	-151,269
Total	5,098,981	4,935,470	-163,511	5,230,213	294,743	5,021,269	-208,944	6,134,984	1,113,716

(Sub-Breakdown) Other Distribution Revenue Accounts	06 Apprvd	06 Actual	06 Varnce	07 Actual	07 Varnce	2008 Bridge Yr	08 Varnce	2009 Test Yr	09 Varnce
4082 Retail Service Revenue	$ 51,908	$ 21,678	$ (30,230)	$ 22,598	$ 920	$ 23,000	$ 402	$ 23,000	$ -
4084 Service Transaction Request	$ 7,171	$ 1,585	$ (5,586)	$ 7,381	$ 5,796	$ 8,000	$ 619	$ 8,000	$ -
4210 Rent of Electric Property	$ 57,889	$ 89,400	$ 31,511	$ 83,030	$ (6,370)	$ 85,000	$ 1,970	$ 85,000	$ -
4220 Other Electric Revenues	$ -	$ 26,430	$ 26,430	$ -	$ (26,430)	$ -	$ -	$ -	$ -
4225 Late Payment Charges	$ 60,042	$ 43,489	$ (16,553)	$ 52,179	$ 8,690	$ 55,000	$ 2,821	$ 55,000	$ -
4235 Misc. Service Revenue	$ 3,855	$ 35,695	$ 31,840	$ 31,034	$ (4,661)	$ 34,000	$ 2,966	$ 34,000	$ -
4235-01 Change of Occupancy Charge	$ 45,879	$ 55,047	$ 9,168	$ 63,260	$ 8,213	$ 65,000		$ 65,000	
4235-02 Disconnect/Reconnect Charge	$ 6,000	$ 30,215	$ 24,215	$ 36,140	$ 5,925	$ 38,000		$ 38,000	
4235-03 Collection Services Charge	$ 10,000	$ 14,684	$ 4,684	$ 17,927	$ 3,243	$ 18,000		$ 18,000	
4355 Gain on Disposal of Property	$ -	$ 10,000	$ 10,000	$ 6,600	$ (3,400)	$ -	$ (6,600)	$ -	$ -
4390 Misc. Non-Operating Income	$ -	$ 2,664	$ 2,664	$ 3,828	$ 1,164	$ -	$ (3,828)	$ -	$ -
4405 Interest Income	$ 84,998	$ 180,655	$ 95,657	$ 279,945	$ 99,290	$ 151,269	$ (128,676)	$ 68,856	$ (82,413)
Total (Same as ODR Amount above)	$ 327,742	$ 511,542		$ 603,922		$ 477,269		$ 394,856	

Accounts that exceed the material variance threshold of $40,000 requiring detailed explanation in application.

No materiality threshold requirement but further explanation will be provided in the rate application.

VARIANCE ANALYSIS ON OPERATING REVENUE:

A summary of COLLUS Power Corp's normalized operating revenues is presented in Exhibit 3, Tab 1, Schedule 2.

2006 Board Approved:

COLLUS Power Corp 2006 Board Approved operating revenue was forecast to be $5,098,981, as shown in Exhibit 3, Tab 1, Schedule 2. Distribution revenue totaled $4,771,239 or 91.7% of total revenues. Other operating revenue (net) accounts for the remaining revenue of $327,742.

2006 Actual:

COLLUS Power Corp operating revenue in fiscal 2006 was $4,935,470, as shown in Exhibit 3, Tab 1, Schedule 2. Distribution revenue totaled $4,423,928 or 91.9% of total revenues. Other operating revenue (net) accounts for the remaining revenue of $511,542.

Comparison 2006 Actual to 2006 Board Approved:

As shown in Exhibit 3, Tab 1, Schedule 2, the total operating revenue was $-163,511 lower than the 2006 Board Approved level forecasted. This decrease resulted from lower than forecasted consumption levels, particularly in the residential. Also the 2006 EDR forecast was for 12 months of rates being in place. In 2006 the new rates were only in place for 8 months.

2007 Actual:

COLLUS Power Corp total operating revenue in fiscal 2006 was $5,230,213, as shown in Exhibit 3, Tab 1, Schedule 2. Distribution revenue totaled $4,626,291 or 88.5% of total revenues. Other operating revenue (net) accounts for the remaining revenue of $603,922.

Comparison to 2006 Actual:

As shown in Exhibit 3, Tab 1, Schedule 2, the total operating revenue for 2007 actual was $ 202,363 higher than the 2006 Actual. This increase resulted from the new 2006 EDR rates being applied over a full year rather than only 8 months in 2006.

2008 Bridge Year:

COLLUS Power Corp total operating revenue is forecast to be $ 5,021,269 in fiscal 2008, as shown in Exhibit 3, Tab 1, Schedule 2. Distribution revenue totals $ 4,544,000 or 92% of total revenues. Other operating revenue (net) accounts for the remaining revenue of $ 477,269.

Comparison to 2007 Actual:

As shown in Exhibit 3, Tab 1, Schedule 2, the total operating revenue is expected to be $ -208,944 below the actual year level in fiscal 2006. This decrease was partly due to lower customer rates that more than offset the forecasted normalized growth in customers and consumption. COLLUS Power Corp is also anticipating a decrease in revenues from miscellaneous service charges in this period.

2009 Test Year:

COLLUS Power Corp total operating revenue is forecast to be $ 6,134,984 in fiscal 2009, as shown in Exhibit 3, Tab 1, Schedule 2. Distribution revenue totals $ 5,808,984 or 91.9% of total revenues. Other operating revenue (net) accounts for the remaining revenue of $ 326,000.

Comparison to 2008 Bridge Year:

As shown in Exhibit 3, Tab 1, Schedule 2, the total operating revenue is expected to be $ 1,113,716 above the bridge year level in fiscal 2008. This increase is the result of forecasted normalized growth in customers and consumption and the new rates that are being proposed.

WEATHER NORMALIZED FORECASTING METHODOLOGY:

This exhibit discusses the methodology used to determine COLLUS Power Corp's customer and load forecast. COLLUS Power Corp has provided projections for the number of customers in each customer class for both the 2008 Bridge Year and the 2009 Test Year. Historical data for the annual number of customers in each rate class is available for 2002 through to 2007. COLLUS Power Corp has used a simple trend growth in customer connections, by class, in addition to known applications for subdivision expansions within our service territory and discussions with the Municipal Planning departments to forecast Bridge Year and Test Year customer numbers. Given the slow growth and consistent trend in customer numbers in COLLUS Power Corp's service territory over the past five years, COLLUS Power expects that the resulting customer forecast is likely not materially different than what would result from using more sophisticated time series techniques. In recent history, there has been very little year-to-year variation in customer growth by class. Historical and forecast customer numbers, by class, are displayed in the Exhibit 3, Tab 2, Schedule 2. A planning growth chart of proposed, approved, and pending subdivision applications is displayed in Appendix A of this schedule..

As required by the OEB's Filing Requirements, COLLUS Power Corp is providing normalized historical and forecast (Bridge Year and Test Year) throughput data. Weather normalization (where required) is based on normalized average use per customer ("NAC") calculated from the weather-normalized throughput of the utility from 2004.

COLLUS Power Corp originally contracted with Hydro One to prepare weather normalized data as part of its Cost Allocation filing in March of 2007. Then again to adjust for ALCOA Wheel Products closure in June of 2007. The Hydro One model takes into consideration thirty years of weather related data and translates this into current year normalized data as an annual consumption per customer. The Hydro One model normalized COLLUS Power Corp actual wholesale data for 2004. By using the latest Hydro One forecast that is specific to COLLUS Power Corp, the 2004 weather normalized data has been used to forecast the required information for the 2008 Bridge Year and 2009 Test Year. The process to obtain the weather normal data was an intensive effort for all parties involved, and COLLUS Power Corp is making use of this opportunity to leverage the value of that work by using it for this Application. COLLUS Power Corp submits that three additional years of actual data, being 2005, 2006 and 2007, would not have a significant impact on the existing normalized data from 2004, as the Hydro One forecast takes into consideration 30 years of historical data for COLLUS Power Corp.

COLLUS Power Corp is aware that intervenors in Hydro One's 2008 and 2009 Transmission Revenue Requirement proceeding (OEB File No. EB-2006-0501) raised concerns regarding the accuracy of Hydro One's weather normalization methodology. However, the OEB acknowledged (at p.87 of its August 16, 2008 Decision with Reasons) "that Hydro One's weather-normalization method has been applied consistently over the years and is similar to the methods used by most North American utilities. The Board accepts Hydro One's weather-normal peak load forecast for 2008 and 2009 (before the effects of CDM)."

COLLUS Power Corp submits that COLLUS Power Corp has acted prudently in engaging Hydro One to prepare COLLUS Power Corp's weather normalized data using the current Hydro One methodology.

ECONOMIC AND FORECAST ASSUMPTIONS:

Customer Forecast:

Table 1 below presents historical and forecast customer numbers, by class, for COLLUS Power Corp. Some actual data was smoothed to correct anomalies in data extracted from the Customer Information System database.

Annual percentage change is presented for Residential, GS<50 kW, GS>50 kW and Street Lighting classes. For Residential, GS<50 kW and GS>50 kW customer classes, the 2008 and 2009 customer numbers are forecast based on the average growth rate for the period from 2003 to 2007.

TABLE 1
CUSTOMER and CONNECTIONS BY CLASS

	2002	2003	2004	2005	2006	2007	2008	2009
Residential	11,420	11,756	11,934	12,142	12,242	12,535	12,771	13,011
Per cent chg		*2.94%*	*1.51%*	*1.74%*	*0.82%*	*2.39%*	*1.88%*	*1.88%*
GS<50 kW	1,515	1,524	1,536	1,537	1,554	1,567	1,578	1,588
Per cent chg		*0.59%*	*0.79%*	*0.07%*	*1.11%*	*0.84%*	*0.70%*	*0.63%*
GS>50 kW	108	114	115	119	123	121	124	127
Percent chg		*5.56%*	*0.88%*	*3.48%*	*3.36%*	*-1.63%*	*2.48%*	*2.42%*
Large User	2	2	2	2	1	1	1	1
USL (connections)	150	154	158	100	95	85	76	68
Street Lighting(connections)	2,479	2,517	2,715	2,750	2,806	2,875	2,961	3,051
Percent chg		*1.53%*	*7.87%*	*1.29%*	*2.04%*	*2.46%*	*2.99%*	*3.04%*
Total Customer & Connections	15674	16067	16460	16650	16821	17184	17511	17846
Percent change		*2.51%*	*2.45%*	*1.15%*	*1.03%*	*2.16%*	*1.90%*	*1.91%*

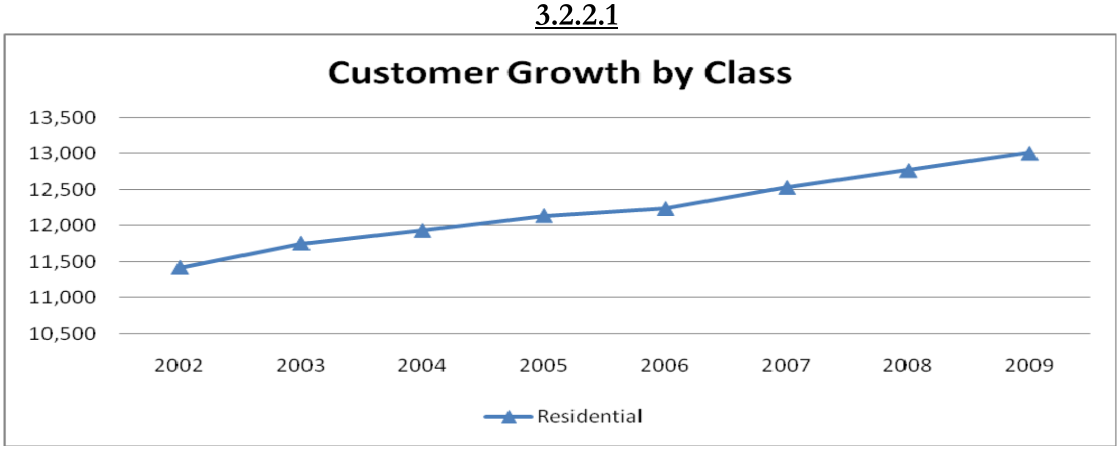
Customer numbers for Street Lighting and Unmetered Scattered Load (“USL”) classes in 2008 also represent current (early 2008) numbers of connections in each of these classes. COLLUS Power Corp expects the number of customers in the USL classes to decrease within the next year, as metering units continue to be added where possible. Customer growth for the Street

Lighting Class is calculated based on the annual average arithmetic mean of growth from 2002 to current year (2008).

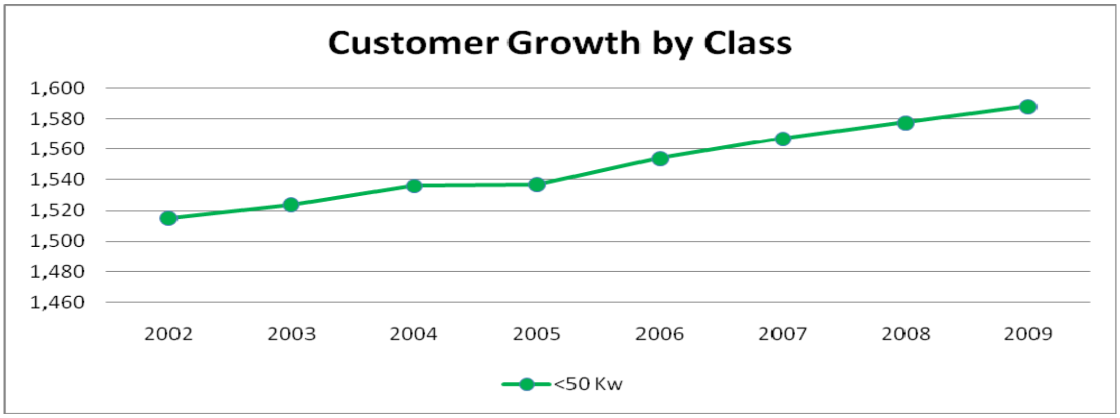
At present, COLLUS Power Corp does not have any customers with Standby rates or charges. COLLUS Power is involved in discussions with a few large commercial customers in the >50 Kw class that are currently investigating generation connections which may lead to Load Displacement generation, however COLLUS Power Corp does not forecast for any change in 2009 and will deal with it on a case by case basis including making the appropriate submission to the Ontario Energy Board.

The Figure 3.2.2-1 below illustrates the historical and forecast customer trend in Residential, GS<50 kW, and GS>50 kW classes.

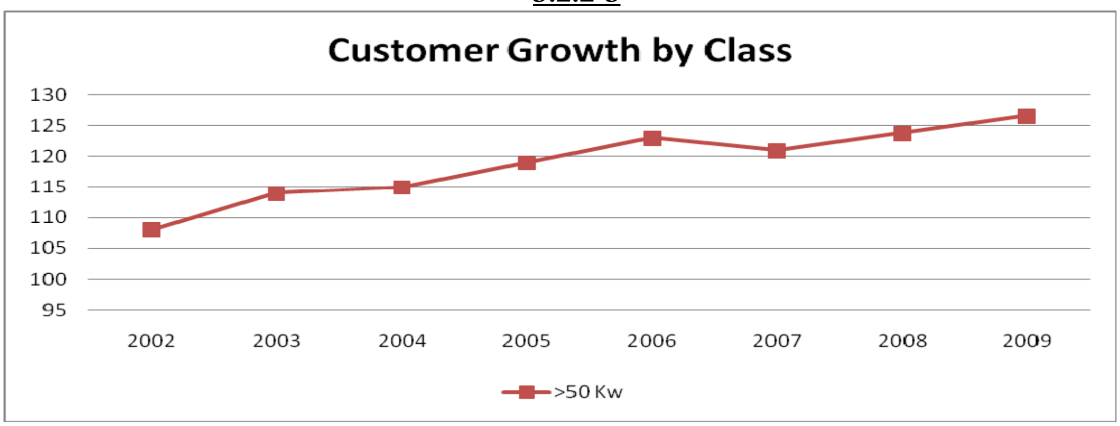
FIGURE 3.2.2.1



<u>FIGURE 3.2.2.2</u>



<u>FIGURE 3.2.2-3</u>



Load Forecast:

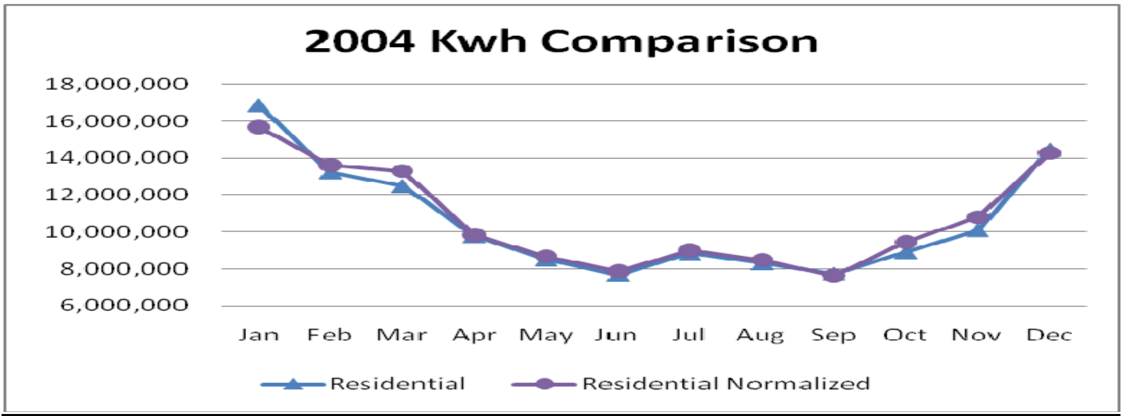
Weather sensitive load (Residential, GS<50 kW, and GS>50 kW classes) is calculated by using retail normalized average use per customer ("retail NAC"). This is calculated by dividing the class weather normal retail kWh for 2004 by the number of customers in class in 2004.

Weather sensitive class wholesale weather normal kWh, number of customers, and retail NAC for 2004 is reported in the Table 2 below.

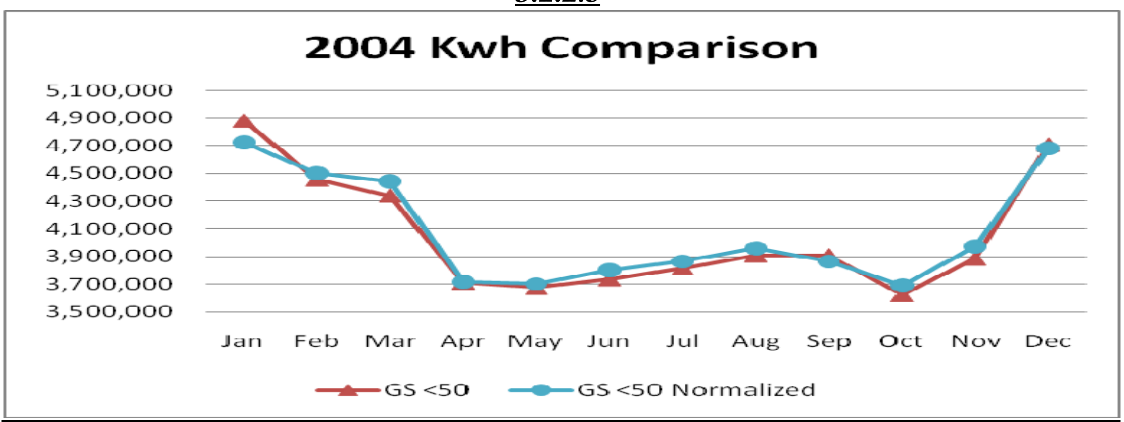
TABLE 2
2004 WEATHER NORMAL WHOLESALE KWH, NUMBER OF CUSTOMERS or CONNECTIONS AND RETAIL NAC

Class	Weather Normal kWh (2004)	Customer Connections (2004)	Retail NAC
Residential	111,105,540	11,934	9310
GS < 50 kW	43,948,032	1,536	28,612
GS > 50 kW	117,066,655	115	101,797

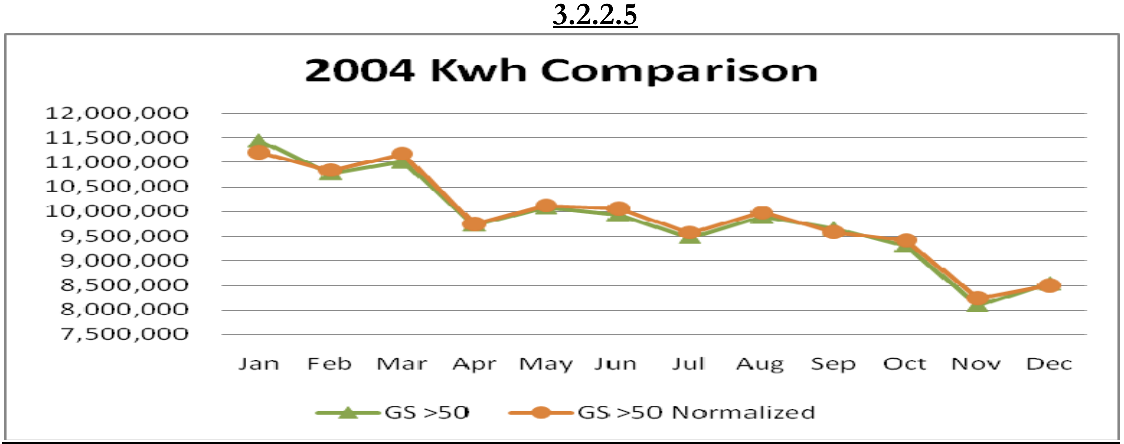
<u>FIGURE 3.2.2.4</u>



<u>FIGURE 3.2.2.5</u>



<u>FIGURE 3.2.2.5</u>



Annual class kWh for weather sensitive load (Residential, GS<50 kW, GS>50 kW) for Bridge Year and Test Year are calculated by multiplying retail NAC by forecast number of customers in class.

Consumption for USL, and Street Lighting are not weather sensitive. A similar methodology is used to calculate an NAC for each of the USL and Street Lighting Classes. Annual class kWh for the Bridge Year and Test Year are calculated by multiplying the NAC by the forecast number of connections in each class.

Specific classes are billed based on demand charges (GS >50 kW, Street Lighting) and require an estimate of billed kW. Billed kW is estimated based on a load factor calculated using a ratio of historical billed kW to historical retail kWh, by class. Table 3, below, summarizes the results of COLLUS Power Corp's customer and load forecast.

TABLE 3
SUMMARY OF COLLUS Power Corp
CUSTOMER AND LOAD FORECAST

COLLUS Power Corp		Historical Actual	Historical Actual Normalized	Historical Actual	Historical Actual Normalized	Bridge Year - Estimated	Bridge Year Forecast Normalized	Test Year Normalized Forecast
Year		2006	2006	2007	2007	2008	2008	2009
Residential	#	12,242	12,242	12,535	12,535	12,771	12,771	13,011
	kWh	110,110,859	113,970,068	113,589,579	116,697,827	115,725,785	118,892,488	121,128,423
GS < 50 kW	#	1,554	1,554	1,567	1,567	1,578	1,578	1,588
	kWh	43,896,761	44,462,361	45,518,571	44,834,311	45,826,838	45,137,944	45,443,633
GS > 50 kW	#	123	123	121	121	124	124	127
	kWh	89,661,262	123,221,061	106,655,296	121,217,467	109,107,536	124,004,523	126,855,660
	kW	231,460	292,104	265,517	287,355	258,647	293,962	300,721
USL	#	95	95	85	85	76	76	68
	kWh	777,240	777,240	579,826	579,826	517,563	510,523	455,702
Street Lights	#	2,806	2,806	2,875	2,875	2,961	2,961	3,051
	kWh	1,838,499	1,838,499	2,005,352	2,005,352	2,065,679	2,000,958	2,061,153
	kW	5,513	5,513	5,594	5,594	6,100	5,909	6,087
Large User	#	1	1	1	1	1	1	1
	kWh	41,277,128	41,277,128	34,974,004	34,974,004	34,974,004	37,423,367	37,423,367
	kW	76,840	76,840	75,942	75,942	70,103	75,012	75,012

VARIANCE ANALYSIS ON VOLUME FORECAST:

Over the last three years, COLLUS Power has incurred the loss of 2 relatively large customers within the GS>50Kw class, as well as 1 Large User >5,000Kw customer from that class.

The Large User had a consistent monthly peak load of over 10Mw. For the purposes of using historical analysis to forecast future loads in the Large User category, calculations were performed by first removing all loads related to the customer that ceased operation. Discussions related to the financial impact on COLLUS Power and the inability to properly collect the full revenue requirement resulting from the loss of this Large Use Customer are appropriately addressed in other sections of this application.

Of the 2 customers ceasing operation that were within the GS>50Kw class, one customer had a consistent load of just over 1Mw, and the second had a consistent load of approximately 4Mw. The loss of these customers has been offset for the most part by the addition of a significant number of Commercial expansions in the service territory (primarily large Box Stores). Although the loss of these two customers could have had significant ongoing impact on future forecasts, COLLUS Power was actively involved in discussions with the municipality’s Economic Development office and had full confidence at the time of the forecast that a new customer would purchase the facility and reach similar levels of energy use to that of the previous customer at the same facility.

The results found in the forecasting of expected load for future years, provided in Exhibit 3 Tab 2 Schedule 7 for the GS>50Kw class, confirm that the variance resulting from the loss of these customers was a temporary and explainable anomaly.

HISTORICAL AVERAGE CONSUMPTION:

The following table sets out historical and average consumption for each of COLLUS Power Corp's customer classes Using Weather Actual Data for all but the forecast years 2008 - 2009:

Residential
*Normalized Forecast

Year	Weather Actual	Average Per Customer	Difference over previous year	% Difference over previous year
2002	115,516,314	10,115	N/A	
2003	110,410,786	9,392	-723	-7.7%
2004	109,804,131	9,201	-191	-2.1%
2005	114,204,151	9,406	205	2.2%
2006	110,110,859	8,995	-411	-4.6%
2007	113,589,579	9,062	67	0.7%
2008*	118,892,488	9,310	248	2.7%
2009*	121,128,423	9,310	0	0.00%

GS<50
*Normalized Forecast

Year	Weather Actual	Average per Customer	Difference over previous year	% Difference over previous year
2002	47,234,711	31,178	N/A	
2003	45,398,302	29,789	-1,389	-4.7%
2004	43,680,631	28,438	-1,351	-4.8%
2005	45,167,195	29,387	949	3.2%
2006	43,896,761	28,248	-1,139	-4.0%
2007	45,518,571	29,048	800	2.8%
2008*	45,137,944	28,612	-436	-1.5%
2009*	45,443,633	28,612	0	0.00%

GS>50-Regular
*Normalized Forecast

Year	Weather Actual	Average per Customer	Difference over previous year	% Difference over previous year
2002	103,940,255	962,410	N/A	
2003	119,278,667	1,046,304	83,894	8.0%
2004	114,739,338	997,733	-48,571	-4.9%
2005	92,896,958	780,647	-217,086	-27.8%
2006	89,661,262	728,953	-51,694	-7.1%
2007	106,655,296	881,449	152,496	17.3%
2008*	124,004,523	1,001,797	120,348	12.0%
2009*	126,855,660	1,001,797	0	0.00%

Street Light
*Normalized Forecast

Year	Weather Actual
2002	1,604,059
2003	1,760,000
2004	1,802,287
2005	1,821,902
2006	1,838,499
2007	2,005,352
2008	2,000,958
2009	2,061,153

Unmetered Scattered Load
*Normalized Forecast

Year	Weather Actual
2002	808,652
2003	906,323
2004	898,587
2005	840,570
2006	777,240
2007	579,826
2008*	510,523
2009*	455,702

Large User (*adjusted for lost customer)
*Normalized Forecast

Year	Weather Actual
2002*	33,943,981
2003*	37,882,859
2004*	37,758,477
2005*	38,703,756
2006*	41,277,128
2007	34,974,004
2008	37,423,367
2009	37,423,367

1

DISTRIBUTION REVENUE DATA BY CLASS:

DISTRIBUTION REVENUE DATA

2006 Board Approved - Normalized

	Customers (Year-End)	Consumption (kWh / KW)	Distribution Revenues ($)	Unit Revenues $/kWh/KW
Residential	11,934	120,960,460	3,316,640	0.0274
GS<50	1,536	43,680,631	738,320	0.0169
GS>50-Regular	115	199,916	251,985	1.2605
Street Light (connections)	2,715	5,463	33,387	6.1115
Unmetered Scattered Load	158	898,587	13,349	0.0149
Large User	2	200,182	417,558	2.0859
TOTAL	16,460	165,945,239	4,771,239	

2006 Actual

	Customers (Year-End)	Consumption (kWh / KW)	Distribution Revenues ($)	Unit Revenues $/kWh/KW
Residential	12,242	110,110,859	2,966,277	0.0269
GS<50	1,554	43,896,761	667,079	0.0152
GS>50-Regular	123	231,460	333,539	1.4410
Street Light	2,806	5,513	26,683	4.8400
Unmetered Scattered Load	439	777,240	8,894	0.0114
Large User	2	212,267	444,719	2.095
TOTAL	17,166	155,234,100	4,447,192	

2007 Actual

	Customers (Year-End)	Consumption (kWh / KW)	Distribution Revenues ($)	Unit Revenues $/kWh/KW
Residential	12,535	113,589,579	3,212,826	0.0283
GS<50	1,567	45,518,571	731,034	0.0161
GS>50-Regular	121	265,517	349,220	1.3152
Street Light (connections)	2,875	5,594	32,594	5.8266
Unmetered Scattered Load	85	579,826	8,381	0.0145
Large User	2	143,254	325,939	2.2753
TOTAL	17,185	160,102,341	4,659,995	

2008 Bridge - Normalized

	Customers (Year-End)	Consumption (kWh / KW)	Distribution Revenues ($)	Normalized Consumption (kWh / KW)	Unit Revenues Normalized $/kWh/KW
Residential	12,771	115,725,785	3,302,023	118,892,488	0.0278
GS<50	1,578	45,826,838	721,118	45,137,944	0.0160
GS>50-Regular	124	258,647	306,652	293,962	1.0432
Street Light (connections)	2,961	6,100	36,209	5,909	6.1278
Unmetered Scattered Load	76	517,563	6,488	510,523	0.0127
Large User	1	70,103	171,510	75,012	2.2864
TOTAL	17,511	162,405,036	4,544,000	164,915,838	

2009 Test - Normalized

	Customers (Year-End)	Consumption (kWh / KW)	Distribution Revenues ($)	Normalized Consumption (kWh / KW)	Unit Revenues $/kWh/KW
Residential	13,011	121,128,423	3,730,836	121,128,423	0.0308
GS<50	1,588	45,443,633	996,473	45,443,633	0.0219
GS>50-Regular	127	300,721	746,513	300,721	2.4824
Street Light (connections)	3,051	6,087	137,208	6,087	22.5412
Unmetered Scattered Load	68	455,702	21,449	455,702	0.0471
Large User	1	75,012	176,507	75,012	2.3531
TOTAL	17,846	167,409,578	5,808,986	167,409,578	

SUMMARY OF OTHER DISTRIBUTION REVENUE

Excerpt from Exhibit 3 Tab 1 Schedule 2 (TABLE 1)

(Sub-Breakdown) Other Distribution Revenue Accounts	06 Apprvd	06 Actual	06 Varnce	07 Actual	07 Varnce	2008 Bridge Yr	08 Varnce	2009 Test Yr	09 Varnce
4082 Retail Service Revenue	$ 51,908	$ 21,678	$ (30,230)	$ 22,598	$ 920	$ 23,000	$ 402	$ 23,000	$ -
4084 Service Transaction Request	$ 7,171	$ 1,585	$ (5,586)	$ 7,381	$ 5,796	$ 8,000	$ 619	$ 8,000	$ -
4210 Rent of Electric Property	$ 57,889	$ 89,400	$ 31,511	$ 83,030	$ (6,370)	$ 85,000	$ 1,970	$ 85,000	$ -
4220 Other Electric Revenues	$ -	$ 26,430	$ 26,430	$ -	$ (26,430)	$ -	$ -	$ -	$ -
4225 Late Payment Charges	$ 60,042	$ 43,489	$ (16,553)	$ 52,179	$ 8,690	$ 55,000	$ 2,821	$ 55,000	$ -
4235 Misc. Service Revenue	$ 3,855	$ 35,695	$ 31,840	$ 31,034	$ (4,661)	$ 34,000	$ 2,966	$ 34,000	$ -
4235-01 Change of Occupancy Charge	$ 45,879	$ 55,047	$ 9,168	$ 63,260	$ 8,213	$ 65,000		$ 65,000	
4235-02 Disconnect/Reconnect Charge	$ 6,000	$ 30,215	$ 24,215	$ 36,140	$ 5,925	$ 38,000		$ 38,000	
4235-03 Collection Services Charge	$ 10,000	$ 14,684	$ 4,684	$ 17,927	$ 3,243	$ 18,000		$ 18,000	
4355 Gain on Disposal of Property	$ -	$ 10,000	$ 10,000	$ 6,600	$ (3,400)	$ -	$ (6,600)	$ -	$ -
4390 Misc. Non-Operating Income	$ -	$ 2,664	$ 2,664	$ 3,828	$ 1,164	$ -	$ (3,828)	$ -	$ -
4405 Interest Income	$ 84,998	$ 180,655	$ 95,657	$ 279,945	$ 99,290	$ 151,269	$ (128,676)	$ 68,856	$ (82,413)
Total (Same as ODR Amount above)	$ 327,742	$ 511,542		$ 603,922		$ 477,269		$ 394,856	

Accounts that exceed the material variance threshold of $40,000 requiring detailed explanation in application.

No materiality threshold requirement but further explanation will be provided in the rate application.

MATERIALITY 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 2 below. The OM&A cost threshold was used because other distribution revenues, like OM&A costs, are recorded in Income Statement accounts.

TABLE 2

Summary of Operating Costs

Description	2006 Board Approved	2006 Actual	2007 Actual	2008 Bridge	2009 Test
OM&A expenses					
Operation	$ 260,626	$ 285,179	$ 245,331	$ 274,300	$ 291,300
Maintenance	$ 1,163,605	$ 1,263,888	$ 1,322,165	$ 1,500,825	$ 1,628,325
Billing and Collections	$ 538,249	$ 592,333	$ 655,645	$ 722,109	$ 762,093
Community Relations	$ 88,563	$ 154,243	$ 157,924	$ 100,085	$ 107,389
Administrative and General Expenses	$ 1,200,627	$ 952,430	$ 904,732	$ 932,991	$ 1,008,741
Taxes Other Than Income Taxes	$ 990	$ 5,025	$ 8,256	$ 8,916	$ 8,916
Amortization Expenses	$ 843,197	$ 767,646	$ 782,359	$ 886,997	$ 983,056
Total Operating Costs	$ 4,095,857	$ 4,020,744	$ 4,076,412	$ 4,426,223	$ 4,789,820
Determination of Variance Amount (1%)	$ 40,959	$ 40,207	$ 40,764	$ 44,262	$ 47,898

To allow for the most detailed review of materiality on Other Distribution Revenue, COLLUS Power Corp has selected the lowest materiality threshold rounding it to $40,000. COLLUS

Power Corp has provided explanations for the following variances, which exceed the materiality threshold.

There is only the one (1) account 4405 Interest Income that exceeds the threshold in 2006 and 2007. The chart below summarizes the variances in the account over the four (4) years.

(Sub-Breakdown) Other Distribution Revenue Accounts	06 Apprvd	06 Actual	06 Varnce	07 Actual	07 Varnce	2008 Bridge Yr	08 Varnce	2009 Test Yr	09 Varnce
4405 Interest Income	$ 84,998	$ 180,655	$ 95,657	$ 279,945	$ 99,290	$ 151,269	$ (128,676)	$ 68,856	$ (82,413)

Explanation:

The variance in 2006 and 2007 reflects the changing position of interest on regulatory deferral accounts between the two periods. Regulatory deferral accounts that were in a receivable position in 2006 resulted in interest revenue. These accounts are forecasted to be in a net liability position in 2008 and 2009 with resulting interest expense.

In regards to the Interest Income forecasted for 2008 and 2009 there is no material variance threshold requirement but further explanation should be provided. The expected reduced average net bank balance (Cash on Hand) in 2008 and then further in 2009 results in estimated interest revenue lower than in previous years. The expected interest rate that has been used to make the calculations is the 4.08% rate that the Ontario Energy Board has advised COLLUS Power Corp to use in calculating carrying charge impact on the Retail Service Variance Account balances.

The aforementioned note explains the difference in estimated interest revenue but additional information should be provided regarding the non-inclusion of interest revenue in the 2009 Revenue offset figures. The estimated $ $ 68,856 has not been included because of the following submission by COLLUS Power Corp.

At the beginning of 2008 the balance in Retained Earnings was $ 1,587,358.76 and the expected Net Income to be transferred to Retained Earnings is $ 237,248.24. COLLUS Power Corp submits that interest revenue earned due to Retained Earnings should not be considered as a revenue offset as it is separate from normal operations. The Retained Earnings have resulted from operations throughout the year and should be allowed to earn interest revenue that would not be treated as a revenue offset.

Since it is expected that in 2009 the Retained Earnings noted above, if the 4.08% rate is applicable, will result in Interest Earned of in excess $70,000, and since this is in excess of the forecasted 2009 interest revenue an amount of $0 has been used in calculating the total revenue offset for the 2009 test year. Therefore the total revenue offset that has been used in further calculations is $ 326,000 and not $ $ 394,856 estimated in the 2009 trial balance.

DESCRIPTION OF REVENUE SHARING:

COLLUS Power Corp does not have a revenue sharing practice in place.

End of Exhibit 3 (Operating Revenue)

Development Activity

Town of Collingwood - May 2008

1:15,000

LEGEND

●	APPLICATION RECEIVED - UNDER REVIEW
⬤	APPROVED - UNDER CONSTRUCTION

MAJOR DOCUMENTS

	COMMERCIAL POLICY REVIEW	
	INDUSTRIAL POLICY REVIEW	
	COMPREHENSIVE ZONING BY-LAW	

INSTITUTIONAL

NUMBER	NAME	PHASE
1	PRETTY RIVER ACADEMY	⬤

COMMUNITY FACILITY

NUMBER	NAME	PHASE
2	LIBRARY/FUTURE PARKING	●
3	ANIMAL SHELTER	⬤
4	SOUTH SERVICE PUMPING STATION	⬤
5	YMCA	●

ENVIRONMENTAL

NUMBER	NAME	PHASE
6	EXPROPRIATION OF SILVER CREEK WETLANDS	●

COMMERCIAL

NUMBER	NAME	PHASE
7	COMMERCIAL OPA/ZONING (Landex)	●
8	NEW HOTEL CONDO	●
9	HEARING CLINIC	●
10	PHARMACY/MEDICAL CLINIC	●
11	COMMERCIAL DEVELOPMENT (Holborn)	●
12	COMMERCIAL WITH ADDITIONAL USES	●
13	HOME HARDWARE	●
14	CRANBERRY VILLAGE MARKET	⬤
15	CRANBERRY HARBOUR	⬤
16	SIERRA HOME TEMPORARY SALES OFFICE	⬤
17	GEORGIAN MANOR RESORTS	⬤
18	SOBEY'S GROCERY STORE	⬤
19	BLUE SHORES CLUBHOUSE	⬤
20	TSC STORE	●

INDUSTRIAL

NUMBER	NAME	PHASE
21	RAGLAN INDUSTRIAL BUILDING PHASE 1	●
22	2095780 ONTARIO INC.	●
23	EDEN OAK INDUSTRIAL BUSINESS PARK	●
24	CONTEMPORY BUSINESS PARK	●
25	COLLINGWOOD ETHANOL	⬤
26	SHERTINE CONSTRUCTION	⬤
27	RONA	⬤
28	SELF STORAGE FACILITY	⬤
29	COLLUS RENOVATIONS	⬤
30	95 & 115 SANDFORD FLEMING	●

RESIDENTIAL

APPLICATION RECEIVED (Subdivisions and Site Plans)

NUMBER	NAME	UNITS (SINGLE & SEMI)	UNITS (MULTI)	COMMERCIAL (sq.m.)
31	593 HURONTARIO ST	n/a	12	n/a
32	NORDARLA ENTERPRISES INC	71	18	n/a
33	ANCHORAGE DEVELOPMENTS	n/a	28	n/a
34	MAIR MILLS VILLAGE	112	94	n/a
35	HELEN COURT HOMES	74	189	n/a
36	EDEN OAK (McNabb)	336	n/a	n/a
37	THE VICTORIA ANNEX	10	9	n/a
38	ST. PAUL STREET	n/a	36	n/a
39	ADMIRAL COLLINGWOOD PLACE	n/a	140	4100 sq.m. G.F.A.
40	GEORGIAN TRADITIONS	n/a	36	n/a
41	BALSAM STREET TOWNHOUSES	n/a	3	n/a
42	CRANBERRY MARSH ESTATES	n/a	32	n/a
43	REGENCY HEIGHTS HOMES	n/a	32	n/a
44	WATERSTONE DEVELOPMENTS	n/a	55	n/a
45	AFFORDABLE HOUSING / WALK UP APTS	n/a	30	n/a
	TOTAL UNITS	**603**	**714**	

DRAFT APPROVED (Subdivisions)

NUMBER	NAME	UNITS (SINGLE & SEMI)	UNITS (MULTI)	COMMERCIAL (sq.m.)
46	BRANDY LANE HOMES	n/a	136	n/a
47	MAIR MILLS ESTATES PHASE 2	59	n/a	n/a
48	MAIR MILLS ESTATES PHASE 3	14	n/a	n/a
49	CRANBERRY (Future Blocks)	n/a	750	n/a
50	TANGLEWOOD (Cranberry Block 10A)	n/a	122	n/a
51	CHARIS DEVELOPMENTS	24	n/a	n/a
52	TODCOE DEVELOPMENT	109	80	n/a
53	BLACK ASH MEADOWS	200	64	n/a
54	DENBOK - CHARLESTON HOMES	84	n/a	n/a
55	TEPCO HOLDINGS	374	n/a	n/a
56	PRETTY RIVER ESTATES	217	n/a	n/a
57	EDEN OAK - SUN VISTA HOMES	72	n/a	n/a
58	THE SHIPYARDS	n/a	697	3200 sq.m. G.F.A.
59	CONSULATE DEVELOPMENTS	71	289	n/a
60	GEORGIAN MEADOWS PHASE 5	46	n/a	n/a
61	GEORGIAN MEADOWS PHASE 6	56	n/a	n/a
62	GEORGIAN MEADOWS (Future Development)			n/a
	TOTAL UNITS	**1326**	**2138**	

REGISTERED (Subdivisions and Site Plans)

NUMBER	NAME	UNITS (SINGLE & SEMI)	UNITS (MULTI)	COMMERCIAL (sq.m.)
63	GEORGIAN GREEN	n/a	184	n/a
64	GEORGIAN MEADOWS PHASE 4	75	n/a	n/a
65	RIVERSIDE SUBDIVISION	140	340	n/a
66	THE SHIPYARDS (MINNESOTA BLOCK)	n/a	23	n/a
67	RAGLAN VILLAGE SENIORS	n/a	182	n/a
68	BLUE SHORES	149	n/a	n/a
69	GEORGIAN MEADOWS PHASE 3	94	n/a	n/a
70	MAIR MILLS ESTATES PHASE 1	48	28	n/a
	TOTAL UNITS	**506**	**757**	

	UNITS (SINGLE)	UNITS (MULTI)	UNITS (COMBO)
RESIDENTIAL TOTALS	**2435**	**3609**	**6044**

Revision Date : May 2008 (KB)
Produced by the Town of Collingwood Planning Services Department.
The information contained herein is believed to be correct, however,
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OVERVIEW OF OPERATING COSTS:

Operating Costs:

The operating costs presented in this Exhibit represent the annual expenditures required to sustain COLLUS Power Corps' distribution operations. COLLUS Power Corp follows the OEB's Accounting Procedures Handbook (the "APH") in distinguishing work performed between operations and maintenance. A summary of COLLUS Power Corp' 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

Summary of Operating Costs

Description	2006 Board Approved	2006 Actual	2007 Actual	2008 Bridge	2009 Test
OM&A expenses					
Operation	$ 260,626	$ 285,179	$ 245,331	$ 274,300	$ 291,300
Maintenance	$ 1,163,605	$ 1,263,888	$ 1,322,165	$ 1,500,825	$ 1,628,325
Billing and Collections	$ 538,249	$ 592,333	$ 655,645	$ 722,109	$ 762,093
Community Relations	$ 88,563	$ 154,243	$ 157,924	$ 100,085	$ 107,389
Administrative and General Expenses	$ 1,200,627	$ 952,430	$ 904,732	$ 932,991	$ 1,008,741
Taxes Other Than Income Taxes	$ 990	$ 5,025	$ 8,256	$ 8,916	$ 8,916
Amortization Expenses	$ 843,197	$ 767,646	$ 782,359	$ 886,997	$ 983,056
Total Operating Costs	$ 4,095,857	$ 4,020,744	$ 4,076,412	$ 4,426,223	$ 4,789,820
Determination of Variance Amount (1%)	$ 40,959	$ 40,207	$ 40,764	$ 44,262	$ 47,898

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. COLLUS Power Corp has adopted a variance analysis threshold of $40,000, being the lowest of the variances among the years under review.

OM&A Costs:

OM&A costs in this Exhibit represent COLLUS Power Corp' integrated set of asset maintenance and customer activity needs to meet public and employee safety objectives; to comply with the DSC, 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 COLLUS Power Corp' 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.

COLLUS Power Corp is proposing recovery of 2009 Test Year OM&A costs, including amortization, totaling $ $ 4,789,820 .

OM&A Budgeting Process Used by COLLUS Power Corp:

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, it does not change, but provides a plan against which actual results may be evaluated.

The operating budget is a component of the overall budget process described in Exhibit B, Tab 1, Schedule 1.

- **Operating Work plans:**

Each department Manager is responsible for the preparation of the departmental budget. The following directives are provided to each manager and director:

- All department budgets are to be built using a "bottom up" approach, which requires each functional area, within COLLUS Power Corp, to build work plans that identify resources, including labour, vehicles, materials and other third party costs that are required to execute the work plans. This approach ensures that budgets are developed based on the actual work to be completed during the fiscal year, as opposed to a historical costing approach;

- Where applicable, Activity Based Costing ("ABC") work order methodology is to be used in the creation of work plans; and
- Significant variances from prior year must be explained and documented.
- **Payroll-specific procedure:**

Each department manager completes the following payroll budget items:

- Review the headcount of the department for accuracy and include projected overtime, vacation payouts or pay differentials for each employee;
- The Director responsible reviews all templates before submitting to Finance.
- All payroll templates are consolidated into a payroll database where the employee information is fully costed and incorporated into the budget database.
- A Payroll Cost Analysis is prepared along with a final Employee Complement Report to summarize and compare to the previous year highlighting changes.

The budget review process and subsequent review/forecasting process follow the processes outlined in Exhibit B, Tab 1, Schedule1.

Income Tax, Large Corporation Tax and Ontario Capital Taxes:

COLLUS Power Corp 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 2 below provides a summary of 2006 OEB Approved, 2008 Bridge and 2009 Test Year income taxes.

Table 2
Summary of Income Taxes

Summary of Income Taxes

Description	2006 Board Approved	2006 Actual	2007 Actual	2008 Bridge	2009 Test
Income Taxes	361,729	223,436	260,037	20,729	234,628
Large Corporation Tax				0	0
Ontario Capital Tax	11,436	5,025	8,256	0	2,174
Total Taxes	373,165	228,461	268,293	20,729	236,801

CORPORATE OM&A DEPARTMENT ACTIVITIES REVIEW:

The following outlines the various departments within COLLUS Power Corp:

1. LINE OPERATONS DEPARTMENT:

The expenses for this department include all costs relating to maintenance of the COLLUS Power Corp electrical system. This includes both labor costs and non-capital material spending to support both scheduled and reactive maintenance events.

COLLUS Power Corp' maintenance strategy is, to the extent possible, to minimize reactive and emergency-type work through an effective planned maintenance program (including predictive and preventative actions).

COLLUS Power Corp' customer responsiveness and system reliability are monitored continually to ensure that its maintenance strategy is effective. This effort is coordinated with COLLUS Power Corp' capital project work, so that where maintenance programs have identified matters the correction of which require capital investments, COLLUS Power Corp may adjust its capital spending priorities to address those matters.

> Predictive Maintenance:

Predictive maintenance activities involve the testing of elements of the COLLUS Power Corp distribution system. These activities include infrared thermography testing, planned visual inspections and pole testing. These evaluation tools are administered across the service territory with appropriate frequency levels. Any identified deficiencies found are prioritized and addressed within a suitable time frame.

> Preventative Maintenance:

Preventative maintenance activities include inspection, servicing and repair of distribution components. This includes overhead and pad-mount load break switch maintenance, insulator inspection and tree/brush clearing. This work is scheduled across the service territory with appropriate frequencies.

> Corrective Maintenance:

The bulk of this work is repair work that has been identified during the predictive and preventative work described previously and is of a nature that can be scheduled over time. This also includes funding to repair minor vandalism.

> Emergency Maintenance:

This item includes unexpected system repairs to the electrical system that must be addressed immediately. The costs include those related to repairs caused by storm damage, emergency tree trimming and on-call premiums. COLLUS Power Corp constantly evaluates its maintenance data to adjust predictive and preventative actions. The ultimate objective is to reduce this emergency maintenance.

> Reactive Maintenance:

Reactive maintenance covers costs necessary to evaluate, troubleshoot and correct system problems related to a customer request. This would include minor adjustments and repairs to the system such as voltage adjustments, replacement of lightning arrestors and other similar work.

> Service Work:

The majority of costs related to this work pertain to service upgrades requested by customers, and requests to provide safety coverage for work (overhead line cover ups). This includes service connection, disconnections and reconnections by COLLUS Power Corp for all service classes; assisting contractors; the making of final connections after Electrical Safety Authority ("ESA") inspection for service upgrades; and changes of service locations.

> Asset Maintenance:

COLLUS Power Corp carries out capacity and reliability planning; maintenance program design; capital project development; and determination of distribution system capital requirements. COLLUS Power Corp develops and maintains the construction and material standards for the organization, and complies with public safety regulation O. Reg. 22/04 (Electrical Distribution Safety).

> Network Operating:

Network operating costs are related to the 24-hour monitoring and operation of the distribution system through COLLUS Power Corp' control room in the Operations Center on Stewart Road in Collingwood. The control room at the Operations Center is staffed only on weekdays, during regular business hours. Monitoring of the system is performed through remote communications during non-business hours remotely by the SCADA Systems Coordinator and the Load Management & Regulatory Coordinator. The control room is linked to the distribution system by a 900Mhz data communications network and information is processed by a Supervisory Control and Data Acquisition ("SCADA") system. Real-time breaker status, and voltage and current readings from most of the 12 substations along with real time Voltage and Current information from three 44 Kv supply feeders are sent to the control room and displayed on the SCADA system. The SCADA system continuously monitors the distribution system and automated notification of abnormal conditions and outages are sent to management, supervisors and on-call repair crews, as required, to manage equipment failures and outages in a timely manner.

> Substation Services:

Substation services activities address the maintenance of all equipment at COLLUS Power Corp' 12 substations (becoming 13 in 2009). This includes both labor costs and non-capital material spending to support both scheduled and emergency maintenance events. As with the maintenance activities conducted by the Design and Construction Department, COLLUS Power Corp' substation maintenance strategy focuses on minimizing, to the extent possible, emergency-type work by improving the effectiveness of COLLUS Power Corp' planned maintenance program (including predictive and preventative actions) for its substations.

> Substation Predictive Maintenance:

The predictive maintenance activities include the costs to perform the following testing programs: storage battery testing, infrared thermography, partial discharge testing, and transformer oil analysis. These evaluation tools are administered using a combination of time-based and condition-based methodology. Repair work that is identified through this testing is prioritized and repaired in the corrective maintenance category below.

> Substation Preventative Maintenance:

Preventative maintenance involves activities scheduled regularly to inspect, service and repair substation components. These activities include maintenance of metal clad switchgear, breakers, relays and ancillary equipment. The work is performed using a combination of time and condition based methodologies. Review of information related to feeder loading recorded by the SCADA system on a minute by minute basis is also used to assist in evaluating station transformer conditions.

> Substation Corrective Maintenance:

The bulk of this work is repair work that has been identified by the predictive and preventative programs described previously and is of a nature that can be scheduled over time. This program also includes funding to repair minor vandalism and substation enclosure building repairs as identified during regular inspections at the substations.

> Substation Emergency Maintenance:

This work includes unexpected repairs to substation assets and related equipment that must be addressed immediately. The costs include repairs caused by storm damage, and on-call premiums for this work. COLLUS Power Corp constantly evaluates its maintenance data to adjust predictive and preventative actions. The ultimate objective is to reduce this emergency maintenance.

2. CUSTOMER METER MEASUREMENT DEPARTMENT:

The Metering department operates from the COLLUS Power Corp Operations Center.

COLLUS Power Corp has outsourced its required MSP services and liaison with the MSP is coordinated by the Metering Department.

The department is also responsible for all interval and non-interval meters for COLLUS Power Corp.

The Meter Department is responsible for the verification of complex Instrument Transformer - CT/PT type meter installations. The focus is on ensuring the accuracy of meter multipliers for billing purposes through the inspection of each installation as meters are changed or when new complex metering installations are installed.

The Metering Department will also be participating in AMI activities including planning, installation and meter verification for the smart meter program.

Revenue Protection is another key activity performed by the Metering Department. By proactively investigating potential diversion and theft of power COLLUS Power Corp continues to be committed to protecting the best interests of the company, employees, customers, and the general public by promoting safety while in the pursuit of the prevention, detection, correction, restitution and prosecution for theft of power.

Interval Meter Reading & Wholesale Settlement Services:

Interval Meter Reading & Wholesale Settlement services are contracted out to a non-affiliated third party (Utilismart Corp) under a service level agreement for the COLLUS Power Corp service territory. The contractor reads 60 Retail interval meters along with 18 Registered Wholesale Interval meters on a daily basis. Data for all Interval and Wholesale Meters is made available to COLLUS Staff and some customers through a secured web site. The current meter contract was originally negotiated in 2002, after the completion of a competitive bid process, through a collective review by COLLUS Power Corp and 16 other LDC members of the Cornerstone Hydro Electric Concepts (CHEC) group. The initial contract was a for a three year term with a provision for three year extensions upon mutual agreement. Service levels are tracked daily and the contractor maintains a 99.99% accuracy rate and a 99.9% read rate. The COLLUS Power Corp Meter Department maintains and arranges for repairs as required when communications to Interval Meters experience faults.

Retail HUB Services:

COLLUS Power Corp has outsourced the required HUB services to a non-affiliated third party (SPi Group) under service level agreement for the COLLUS Power Corp service territory. The initial contract was for a three year term with a provision for three year extensions upon mutual agreement. Service levels are tracked monthly and the contractor maintains a 99% service rate. Appendix A with this schedule is the latest Customer Report which matches previous reports for providing evidence of an extremely high rate of accuracy for completion of this important function.

COLLUS Power Corp is currently re-negotiating the agreement with a third party and will be including the “Spoke” services as well into the new contract. This is required due to the migration to a new CIS system, the Harris Billing system. COLLUS Power Corp will be undertaking the negotiating of the new agreement in conjunction with five other LDC members of the Utility Collaborative Services group, a cooperative undertaking of joint ownership of a Harris Billing System.

STORES DEPARTMENT

Department staff provides support to COLLUS Power Corp in areas such as strategic sourcing, field purchasing, materials and inventory management, maintenance management, fleet management and asset management.

> Procurement:

The focus for 2009 will be on reviewing the negotiation of master agreements, and identify opportunities for volume pooling and continuous process improvements. As always there are many opportunities afforded to COLLUS Power Corp staff because of its affiliation with the Cornerstone Hydro-Electric Concepts group of LDC's. The CHEC group achieves opportunities to receive preferred pricing by combining together and forming a pool.

> Stores (Warehouse):

Stores staff is accountable for managing the control and movement of materials within COLLUS Power Corp' service centre. The staff focus for 2009 will be on process improvements, inventory reduction, material standardization and preparation of COLLUS Power Corp' warehouse to support the new processes involved with the CIS system.

3. INFORMATION TECHNOLOGY/ENGINEERING DEPARTMENT:

> Applications:

COLLUS Power Corp' Information Technology (IT) and Engineering staff work with users and departmental staff to effectively manage information services systems and programming resources. This results in the implementation, maintenance, and enhancements of high quality and cost effective business applications.

IT and Engineering staff are responsible for the daily operations of an application server, file servers, web server (COLLUS Power Corp' internal and external websites are hosted internally), Financial System server, and CIS Database Server. Currently supporting over 20 users, troubleshooting of application and system errors is critical in keeping all application systems performing. Daily backups and regular disaster recovery tests are performed., and staff maintain and update disaster recovery plans and procedures in case of a disaster. Finally, COLLUS Power Corp' customized application programs are written, tested and implemented by IT and Engineering staff.

> **Network/PC Support:**

Network/PC support staff currently support 30 desktop devices and 3 network servers. responsibilities include:

- design, deployment, support and maintenance of the end-user desktop environment and the network application servers necessary to deliver applications to the desktop environment;
- ensuring network availability and inter-site connectivity, providing end-user support, configuring and deploying desktop computers, laptops, and servers;
- providing help desk, hardware, software, cell phone and PDA support services to end users; and
- performing the many departmental hardware/software moves, adds, changes and deletes that occur on a regular basis.

> **Network Security:**

The Information Technology department is responsible for the security of all business system applications utilized by the utility in its operations. These include the customer information, financial management and work management systems.

> **Engineering Services**

Departmental Staff provide the engineering service required to meet all standards. Engineering staff oversee the compliance of COLLUS Power Corp and development agents to ensure that the safety, reliability and integrity of the distribution system is maintained and enhanced. Engineering staff also compile and maintain distribution system mapping information for the COLLUS Power Corp service territory.

5. CUSTOMER SERVICE DEPARTMENT:

The Customer Service group is responsible for the customer care activities for the approximately 14,500 customers in COLLUS Power Corp' service area. These activities include meter reading, billing, call centre, collections, and other back office functions. COLLUS Power Corp staff ensure that all customer needs are met in the most efficient and effective process possible. Excellence in customer service is the primary focus of all of the staff.

> Meter Reading:

Meter reading services are contracted out to a non-affiliated third party under a service level agreement for the COLLUS Power Corp service territory. On average the contractor reads 700 to 800 electric service meters per day. The third party service also provides collection of accounts services that include but don't fully consist of: delivery of collection notices, meter reading verification calls, collection calls contact with customers, disconnect and reconnect of services.

The meter contract was re-negotiated in June 2004 after the completion of a competitive bid process. The contract is renewed upon mutual consent and has had no change in rates over the past 3 years.

Reports are generated regularly that provide an indication of the service levels. The contractor must maintain and does a 99.5% accuracy rate and a 95% read rate.

> Billing:

COLLUS Power Corp invoices its full customer base monthly thereby issuing 175,000 invoices annually to customers. In addition to this there are customer account terminations for customer move ins and outs that result in approximately 1,000 final bill invoices annually.

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 approximately 2,000 retailer accounts; account adjustments; processing meter changes; and other various account related field service orders and mailing services.

COLLUS Power Corp offers customers a number of billing and payment options including an equal payment plan; a preauthorized payment plan; and will soon provide paperless billing from COLLUS Power Corp' website. Customers will also have the ability to view their account history, invoices and transactions online and self service on a "24/7" basis from COLLUS Power Corp' website, once all of the new Customer Information System processes are installed.

> Collections:

Collections involve a combination of activities, including the collection of overdue active accounts, security deposits and final bills for service termination. On average 12,000 collection notices are issued annually. This and the diligent follow-up of staff help to keep bad debt write down to a minimum. Recently COLLUS Power Corp purchased credit risk insurance to provide additional protection and reduce overall risk. This initiative was also in conjunction with the CHEC group of LDC's, which not only helped provide a reduced cost but the insurance itself would not have been made available to a utility of this size. In an effort to minimize credit losses, COLLUS Power Corp 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.

The estimate in the 2009 Test Year expense is for $70,000 of bad debt expense. On estimated gross sales of $30,000,000 the bad debt expense rate is approximately a very low 0.2%. Collections staff work very closely with all customers that have problems or difficulties keeping their account completely current. They are in constant contact with the various social agencies that can provide assistance in certain circumstances, and work to help make sure all customers have options to maintain continuous service.

> Customer Care:

Customer care is responsible for back office functions such as payment processing; web inquiries; move in and out requests; and all call centre activities for the COLLUS Power Corp service territory. Back office functions are performed in COLLUS Power Corp by in-house staff and the customer care centre is located in COLLUS Power Corp at 43 Stewart Road. Customer call levels continue to increase particularly in relation to Retailer activity, and are expected to grow even more dramatically in future with the introduction of smart meters.

The SQI tracking requirements for the OEB's service quality reporting provides the information that COLLUS Service Corp supervisory staff require to monitor customer care performance. As reported in Exhibit 1 Tab2 Schedule 1 of this application the SQI results for the past years have been excellent and the targets are set to maintain these high levels.

> **Education – Energy Conservation:**

Building a conservation culture in Ontario continues to be an important objective for COLLUS Power Corp. COLLUS Power Corp is very active in the community promoting conservation initiatives. COLLUS Staff participate in a number of community events each year, distributing compact florescent light bulbs and energy conservation handbooks, and provide information to encourage acceptance of the new smart meters and time of use pricing. COLLUS Power Corp 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.

Conservation program assistance is provided to commercial/industrial customers to assist in helping develop an understanding of the long-term major benefits of achieving cost avoidance or savings. This will include providing information to educate business's staff of the complicated rules and regulations in the Ontario marketplace regarding items such as selling electricity into the grid and solar energy implementation.

COLLUS Power Corp has also resurrected their Demand Side Management tool through a partnership with the Ontario Power Authority. The system currently has the capacity to manage the peak loading contribution of over 1,600 electric water heaters in the COLLUS Service territory. COLLUS Power Corp is actively working with two other LDC's in sharing the capabilities of the existing DSM system in an effort to help all three LDC's reduce costs of system ownership and operation.

> **Public Relations:**

In the interest of being accessible to customers, improving the quality of its services, and making it easy for customers to do business with it, COLLUS Power Corp produces public service notices on energy and other electricity related topics that would be useful to the public. COLLUS Power Corp also maintains a web site that contains up-to-date energy conservation tips, data about smart meters, company info & contacts, bill payment info, account services, and retailer information. COLLUS Power Corp staff has also put in place a weekly communications practice with key Industries, the local radio, television, and newspaper media, as well as local councils. This activity has been well received and provides for a regular conduit of information to the local communities.

> SAFETY AND HEALTH:

COLLUS Power Corp is committed to maximizing productivity and reducing risk of injury by initiating safety and health measures that focus on preventative actions. The internal safety program focuses on maximizing safety performance by measuring, reporting and managing positive safety behaviors. The commitment to safety and health is significant, and involves documenting unsafe behaviors, monitoring conformance to established standards and policies, determining the effectiveness of safety training and monitoring the resolution of safety recommendations/audits; commitment to continuous improvement in training; and identifying and correcting root causes for system deficiencies.

COLLUS Power Corp also recognizes that a healthy workplace is integral to the health and well-being of staff, and drives successful quality practices. Managing health within the workplace is an important management function and the results of these efforts directly affects employees' perceptions of their work; customer service; corporate productivity; competitiveness and costs. For instance ergonomic studies are done regularly to ensure all employees having work environment that maximize their effectiveness and efficiency.

Over the past six years, COLLUS Power Corp' accident frequency and severity rates have dropped while its audit and safety performance have risen, providing proof that COLLUS Power Corp' safety and health programs make good business sense by reducing risk and building a supportive safety culture. COLLUS Power Corp continuously strives to be a leading and innovative safety organization, both within and outside of the industry.

6. ADMINISTRATIVE & GENERAL SERVICES DEPARTMENT:

Administrative and general services include duties incurred in connection with the general administration of the utility's operations. Within COLLUS Power Corp, 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:

- Certain members of the Executive Management Team;
- Corporate Services, including Human Resources, Communications, Health & Wellness and Facilities; and
- Financial Services, including Finance, Regulatory Services and where applicable Information Technology Services.

➢ **Executive Costs:**

President & CEO

➢ **Human Resources**

Human Resources/Executive Assistant for the utility operations.

> **Financial Services:**

The Finance department is responsible for the preparation of Statutory, Management, and Board of Directors financial reporting in accordance with GAAP; all daily accounting functions, including accounts payable, accounts receivable, and general accounting; treasury functions including cash management, risk management, accounting systems and internal control processes; preparation of consolidated budgets and forecasts; and supporting tax compliance.

> **Regulatory Services:**

The Regulatory Services department is responsible for all regulatory reporting and compliance with applicable Codes, Market Rules, Regulations, and Legislation governing COLLUS Power Corp. Regulatory reporting includes development and preparation of rate filings, performance reporting, IESO monthly settlement reporting, and market 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 Schedule 7 (Employee Compensation Plans), below.

2. Outside services employed include, but are not limited to specialized services, 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. COLLUS Power Corp 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 employee future benefits provided to eligible COLLUS Power Corp employees in accordance with company policy and as provided in the collective bargaining agreement between COLLUS Power Corp 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 Ontario Energy Board 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 COSTS (INCLUDING ACCOUNT VARIANCE YEAR TO YEAR DATA) 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	58,975	69,738	10,763	70,082	344	73,300	3,218	76,800	3,500
5010-Load Dispatching	78,457	41,714	(36,743)	40,932	(782)	43,500	2,568	46,500	3,000
5012-Station Buildings and Fixtures Expense	18,889	14,403	(4,485)	19,782	5,379	18,000	(1,782)	19,000	1,000
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		0	0	0	0	0	0	0	0
5017-Distribution Station Equipment - Operation Supplies and Expenses	7,158	63,013	**55,855**	(15,622)	**(78,635)**	6,000	21,622	10,000	4,000
5020-Overhead Distribution Lines and Feeders - Operation Labour		410	410	13,088	12,678	22,000	8,912	26,000	4,000
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses		104	104	12,150	12,046	0	(12,150)	0	0
5030-Overhead Subtransmission Feeders - Operation		0	0	0	0	0	0	0	0
5035-Overhead Distribution Transformers- Operation		2,726	2,726	1,456	(1,271)	3,000	1,544	3,500	500
5040-Underground Distribution Lines and Feeders - Operation Labour		0	0	0	0	0	0	0	0
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses		0	0	0	0	0	0	0	0
5050-Underground Subtransmission Feeders - Operation		0	0	0	0	0	0	0	0
5055-Underground Distribution Transformers - Operation	1,752	0	(1,752)	0	0	0	0	0	0
5060-Street Lighting and Signal System Expense		0	0	0	0	0	0	0	0
5065-Meter Expense	105	753	649	1,550	796	1,500	(50)	1,500	0
5070-Customer Premises - Operation Labour		0	0	0	0	0	0	0	0
5075-Customer Premises - Materials and Expenses		0	0	0	0	0	0	0	0
5085-Miscellaneous Distribution Expense	67,791	64,818	(2,973)	71,913	7,095	77,000	5,087	78,000	1,000
5090-Underground Distribution Lines and Feeders - Rental Paid		0	0	0	0	0	0	0	0
5095-Overhead Distribution Lines and Feeders - Rental Paid		0	0	0	0	0	0	0	0
5096-Other Rent	27,500	27,500	0	30,000	2,500	30,000	0	30,000	0
Sub-Total	**260,626**	**285,179**	**24,553**	**245,331**	**(39,849)**	**274,300**	**28,969**	**291,300**	**17,000**
Maintenance									
5105-Maintenance Supervision and Engineering	51,617	63,093	11,477	59,223	(3,871)	60,000	777	62,000	2,000
5110-Maintenance of Buildings and Fixtures - Distribution Stations	12,192	5,514	(6,678)	23,103	17,589	25,000	1,897	26,000	1,000
5112-Maintenance of Transformer Station Equipment		0	0	0	0	0	0	0	0
5114-Maintenance of Distribution Station Equipment	232,640	58,133	**(174,507)**	59,921	1,788	38,100	(21,821)	59,600	21,500
5120-Maintenance of Poles, Towers and Fixtures	32,907	82,222	**49,315**	44,397	(37,825)	72,725	28,328	68,225	(4,500)
5125-Maintenance of Overhead Conductors and Devices	174,210	236,540	**62,330**	217,058	(19,482)	247,500	30,442	263,500	16,000
5130-Maintenance of Overhead Services	97,704	232,107	**134,404**	138,066	**(94,042)**	170,500	32,434	189,000	18,500
5135-Overhead Distribution Lines and Feeders - Right of Way	148,287	193,455	**45,168**	178,169	(15,286)	218,000	39,831	244,000	26,000
5145-Maintenance of Underground Conduit		0	0	0	0	0	0	0	0
5150-Maintenance of Underground Conductors and Devices	74,419	57,625	(16,794)	99,113	**41,488**	110,000	10,887	120,000	10,000
5155-Maintenance of Underground Services	114,893	45,799	**(69,094)**	187,822	**142,023**	201,500	13,678	236,500	35,000
5160-Maintenance of Line Transformers	14,081	130,216	**116,134**	81,061	**(49,154)**	111,000	29,939	100,000	(11,000)
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	210,655	159,183	**(51,473)**	234,232	**75,049**	246,500	12,268	259,500	13,000
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	**1,163,605**	**1,263,888**	**100,283**	**1,322,165**	**58,277**	**1,500,825**	**178,660**	**1,628,325**	**127,500**

OM&A COSTS TABLE (INCLUDING ACCOUNT VARIANCE YEAR TO YEAR DATA) CONTINUED

Billing and Collections									
5305-Supervision	29,892	31,990	2,099	34,315	2,325	46,000	11,685	49,000	3,000
5310-Meter Reading Expense	72,121	77,385	5,264	80,380	2,996	82,000	1,620	85,000	3,000
5315-Customer Billing	337,771	409,197	**71,426**	426,328	17,131	459,109	32,781	489,093	29,984
5320-Collecting	39,811	54,419	14,608	53,525	(894)	65,000	11,475	69,000	4,000
5325-Collecting- Cash Over and Short	866	270	(596)	461	191	0	(461)	0	0
5330-Collection Charges	(9,910)	0	9,910	0	0	0	0	0	0
5335-Bad Debt Expense	67,707	19,072	**(48,635)**	60,636	**41,564**	70,000	9,364	70,000	0
5340-Miscellaneous Customer Accounts Expenses		0	0	0	0	0	0	0	0
Sub-Total	**538,258**	**592,333**	**54,075**	**655,645**	**63,312**	**722,109**	**66,464**	**762,093**	**39,984**
Community Relations									
5405-Supervision		0	0	0	0	0	0	0	0
5410-Community Relations - Sundry		0	0	0	0	0	0	0	0
5415-Energy Conservation		100,646	**100,646**	71,280	(29,366)	0	**(71,280)**	0	0
5420-Community Safety Program		0	0	0	0	0	0	0	0
5425-Miscellaneous Customer Service and Informational Expenses	88,563	53,597	(34,966)	86,644	33,047	100,085	13,441	107,389	7,304
5505-Supervision		0	0	0	0	0	0	0	0
5510-Demonstrating and Selling Expense		0	0	0	0	0	0	0	0
5515-Advertising Expense		0	0	0	0	0	0	0	0
5520-Miscellaneous Sales Expense		0	0	0	0	0	0	0	0
Sub-Total	**88,563**	**154,243**	**65,680**	**157,924**	**3,681**	**100,085**	**(57,839)**	**107,389**	**7,304**
Administrative and General Expenses									
5605-Executive Salaries and Expenses	139,979	163,872	23,893	198,380	34,508	221,296	22,916	230,611	9,315
5610-Management Salaries and Expenses	172,776	169,862	**(2,914)**	154,925	(14,937)	173,700	18,775	192,500	18,800
5615-General Administrative Salaries and Expenses	137,921	272,171	**134,250**	280,631	8,460	308,695	28,064	324,130	15,435
5620-Office Supplies and Expenses	4,029	0	(4,029)	0	0	0	0	0	0
5625-Administrative Expense Transferred Credit		0	0	0	0	0	0	0	0
5630-Outside Services Employed	231,000	237,750	**6,750**	244,500	6,750	191,300	(53,200)	181,500	(9,800)
5635-Property Insurance	7,595	1,929	(5,666)	1,490	(439)	2,000	510	2,000	0
5640-Injuries and Damages	1,735	533	(1,202)	234	(299)	1,000	766	1,000	0
5645-Employee Pensions and Benefits	7,099	0	(7,099)	0	0	0	0	0	0
5650-Franchise Requirements		0	0	0	0	0	0	0	0
5655-Regulatory Expenses	59,875	15,822	**(44,053)**	1,960	(13,862)	2,750	790	43,000	**40,250**
5660-General Advertising Expenses		5,533	5,533	5,780	247	7,250	1,470	7,500	250
5665-Misc General Exp	402,351	51,892	**(350,459)**	0	**(51,892)**	4,750	4,750	5,000	250
5670-Rent		0	0	0	0	0	0	0	0
5675-Maintenance of General Plant (05	34,095	33,067	(1,028)	16,832	(16,235)	20,250	3,418	21,500	1,250
5680-Electrical Safety Authority Fees	2,172	0	(2,172)	0	0	0	0	0	0
5685-Independent Market Operator Fees and Penalties		0	0	0	0	0	0	0	0
6205-Charitable Donations	0		0		0		0		0
Sub-Total	**1,200,627**	**952,430**	**(248,197)**	**904,732**	**(47,698)**	**932,991**	**28,259**	**1,008,741**	**75,750**
Taxes Other Than Income Taxes									
6105-Property Taxes	990	5,025	4,036	8,256	3,231	8,916	660	8,916	0
Sub-Total	**990**	**5,025**	**4,036**	**8,256**	**3,231**	**8,916**	**660**	**8,916**	**0**
Total Operating, Maintenance and Administration Expenses	**3,252,668**	**3,253,098**	**430**	**3,294,053**	**40,955**	**3,539,226**	**245,173**	**3,806,764**	**267,538**
Amortization Expenses									
5705-Amortization Expense - Property, Plant, and Equipment	843,197	767,646	**(75,552)**	782,359	14,713	886,997	**104,638**	983,056	**96,059**
Sub-Total	**843,197**	**767,646**	**(75,552)**	**782,359**	**14,713**	**886,997**	**104,638**	**983,056**	**96,059**
Total Distribution Expense Before Income Taxes	4,095,866	4,020,744	(75,122)	4,076,412	55,668	4,426,223	349,811	4,789,820	363,597
Variance Determined as 1% of Total Distribution Expense before Taxes		40,207		40,764		44,262		47,898	
Materiality		**40,207**							

VARIANCE ANALYSIS ON OM&A COSTS:

COLLUS Power Corp has provided a detailed OM&A (Table 1 above) cost analysis in 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 & 3, above.

Variance Analysis:

As calculated above, and noted earlier, the variance that triggers required analysis is $40,000, representing less than 1% of COLLUS Power Corp' total distribution expenses before PILs. COLLUS Power Corp has reviewed the Total Variance of each major group of accounts, as well as individual OEB USoA accounts in determining where explanations were necessary. Table 1 analysis is for every account and it also identifies the accounts exceeding the variance amount and requiring explanations.

Before identifying the accounts that require further explanation a general statement about variance between 2006 Board Approved (Board) amounts and 2006 Actual should be made. The 2006 Board total OM&A expense was $3,252,668 and the 2006 Actual was only $430 more. But there are factors that impact both of these totals that should be considered before making an overall "apples to apples" comparison. These items are:

1. **Low Voltage Amount in account #5665-Misc. General Exp**: The OEB approved amount allowed for recovery in rates of $398,421 was placed into this account, but the actual accounting treatment used account #4750-Low Voltage Charges. This is not an account in OM& A listing.

2. **Energy Conservation Account #5415**: This account was used to record the 2006 expenses incurred in following the OEB directive of "3rd Tranche spending". The 2006 actual amount in #5415 encompasses this but the 2006 Board amount was $0 for that account.

A portion of Table 2 below provides a reconciliation of these items thereby allowing for a calculation of the net impact of **10.3%** as the percentage difference between 2006 EDR and 2006 Actual results. Since the 2006 Actual OM&A expenses were in line with the 2006 EDR Board approved amounts, when inflation is taken into account, no analysis of this difference is specifically done. Later in this exhibit an account by account analysis is performed when applicable.

TABLE 2

COMPARATIVE ANALYSIS OF OPERATING COSTS FROM 2006 TO 2009

	2006 Board Approved	2006 Actual	2007 Actual	2008 Bridge	2009 Test	% Change 2009 to 2006 Actuals
ADJUSTED OM&A FOR COMPARISON						
Total Operating Costs	$ 4,136,815	$ 4,060,951	$ 4,117,176	$ 4,470,485	$ 4,837,718	
less: Amortization Expenses	$ 843,197	$ 767,646	$ 782,359	$ 886,997	$ 983,056	
less: Low Voltage Charges in 2006 EDR	$ 398,421					
less: Energy Conservation in 2006 Actual		$ 100,646				
Net Operation, Maintenance & Admin Exp.	**$ 2,895,197**	**$ 3,192,660**	**$ 3,334,817**	**$ 3,583,488**	**$ 3,854,662**	
	% Differ to 06EDR>	**10.3%**				
OM & A Wages & Benefits (Table 2 EC&C)		$ 1,613,096	$ 1,722,311	$ 1,919,358	$ 2,172,162	**34.7%**
OM & A Other Expenses		$ 1,579,564	$ 1,612,506	$ 1,664,131	$ 1,682,500	**6.5%**
Net Operation, Maintenance & Admin Exp.		**$ 3,192,660**	**$ 3,334,817**	**$ 3,583,488**	**$ 3,854,662**	**20.7%**

Table 2 also provides further general analysis of the change in cost from 2006 Actual to the proposed 2009 Test Year. It identifies that over the 3 years OM&A has increased by **20.7%**, with a **34.7%** increase of OM&A Wages & Benefit Expense (from Table 4 in Exhibit 4 Tab 2 Schedule 3 "Employee Complement and Compensation") and an increase of **6.5%** on OM&A Other Expense.

The EC&C table noted above provides detailed information the approximately 18% growth in Full-time Equivalent employee complement. This would account for the major portion of wages and benefit expense increases and the remaining approximately 13% would equate to around a 4% per year increase. This amount is in line with industry trends in yearly wage increase.

In regards to employee contingent it is important to note here that over the past few decades COLLUS Power Corp and its' former municipal hydro company Collingwood Public Utilities Commission-Hydro Department was the leader in Number of Customers per Employee. Recent comparative analysis by one of our associations for 2007 indicates this continues. In these comparisons all sizes of utilities are considered. These results continue to bode well to support the goal of providing superior customer service at the most reasonable rates possible.

A closing statement on this general overall analysis of the past 3 years would be that the approximately 10% increase in OM&A Other Expense is also generally due to the impact of inflationary increases. This is a very important statistic because of the many regulatory burdens that have been placed upon COLLUS Power Corp over the past 3 years. Every effort is to try to ensure that these burdens do not negatively impact overall cost or service reliability to the customers.

<u>VARIANCE ANALYSIS – ACCOUNTS in Excess of Materiality Threshold (2006 thru 2009)</u>

In providing the required analysis of material differences this section is partitioned into 3 parts:

PART A – OPERATION & MAINTENANCE (O&M) EXPENSES:

- **ACCOUNT #'s – 5120, 5125, 5130, 5135, 5150, 5155 & 5160:**

TABLE 3

ACCOUNT	2006 EDR	2006 ACTUAL	2006 Variance	2007 ACTUAL	2007 Variance	2008 BRIDGE	2008 Variance	2009 TEST	2009 Variance
5120-Mtce P T & F	32,907	82,222	**49,315**	44,397	(37,825)	72,725	28,328	68,225	(4,500)
5125-Mtce OH Con&Dev	174,210	236,540	**62,330**	217,058	(19,482)	247,500	30,442	263,500	16,000
5130-Mtce OH Services	97,704	232,107	**134,403**	138,066	(94,041)	**170,500**	32,434	189,000	18,500
5135-OH D L&F-R of W	148,287	193,455	**45,168**	178,169	(15,286)	218,000	39,831	244,000	26,000
5145-Mtce UG Conduit		0	0		0	0	0	0	0
5150-Mtce UG Con&Dev	74,419	57,625	(16,794)	99,113	41,488	**110,000**	10,887	120,000	10,000
5155-Mtce UG Services	114,893	45,799	**(69,094)**	187,822	142,023	**201,500**	13,678	236,500	35,000
5160-Mtce Transformers	14,081	130,216	**116,135**	81,061	(49,155)	**111,000**	29,939	100,000	(11,000)
Total 5120 thru 2160	***656,501***	***977,964***	***321,463***	***945,686***	***(32,278)***	***1,131,225***	***185,539***	***1,221,225***	***90,000***
% change to previous			**49.0%**		**-3.3%**		**19.6%**		**8.0%**

Variance Explanation 2006 EDR approved to 2006 Actual:

Table 3 is an excerpt from the full account by account Table 1 earlier in the Schedule. To properly perform the variance analysis all of these accounts are reviewed together given the Line Department time worked varies from year to year between these accounts. The 2006 Board approved total for these accounts was $656,501 whereas actual spending totaled $977,964. In 2005 and 2006 COLLUS Power Corp undertook a tree maintenance program to ensure that poles, overhead lines and transformers had proper clearance for safety and reliability reasons. Spending in 2004 had been minimal due to COLLUS Power Corp's constrained spending because of the incorrect return that was later recognized by the OEB with the Tier 2 approval. The cost of this work in 2005 and 2006 totaled $82,800, for an average of $41,400 per year.

Additionally, maintenance of the distribution system that had also been curtailed because of the constrained spending up to 2005 took precedent over the line staff working on Capital programs in 2006.

2006 was a low Capital investment year as evidenced in the 2006 Continuity Schedule provided in Exhibit 2 Tab 2 Schedule 1. Account #5160 was one of the main accounts to have increased spending as both internal staff and external third party expenses increased. The work was to ensure the integrity of the line transformation portion of the distribution system including work on PCB elimination and repairs when necessary. Expenditures with Black & MacDonald totaled over $43,000 and Westburne was over $21,000. The majority of the remaining difference for 2006 was the line department staff increased labor expense.

Variance Explanation 2007 actual to 2006 Actual:

As indicated in Table 3 above the net difference in 2007 of these accounts was a decrease of 3.3%. Accounts #5150 and #5155 indicate material differences that are more than offset by the large credit variances in the other accounts in the table. As noted above there were some expenses such as the B&M and Westburne spending that wouldn't be duplicated in 2007. Removing $63,000 from 2006 total for comparison purposes would result in 2007 indicating an increased spending of approximately 3% which is right in line with inflationary and wage change rates.

Variance Explanation 2008 Bridge to 2007 Actual

Table 4 is presented to provide information regarding Employee Complement and Compensation. It can be used in explaining the overall impact on these accounts forecasted for 2008. Although there are not any material threshold variances all of the accounts contribute to indicate an approximate increase of 20%.

For the first half of 2008 the line department staff were short-staffed as 2 journey linepersons were absent on sick leave. This situation created a double burden as short–term sick leave is funded directly, and their absence required an increase in overtime for the rest of the line staff to ensure all required maintenance work was completed to prevent a lapse in system reliability. The total cost impact is forecasted to be approximately $30,000 by year end.

In July, two additional journey linepersons were hired and one of the other journey lineperson returned from sick leave. The cost of the 2 new journey linepersons, who are an integral part of the succession plans for COLLUS Power Corp, will be approximately $90,000 in 2008. Additional information on succession plans is provided in Table 5 in this Exhibit and also in Exhibit 4, Tab 2, Schedule 7.

Table 4
Employee Complement And Compensation

	ACTUAL	ACTUAL	BRIDGE	TEST YEAR
Number of Employees (FTEs)	2006	2007	2008	2009
Executive	0.5	0.5	0.525	0.55
Management	0.5	0.5	0.525	0.55
Non-Union (Superv, Bill&Collect, Accting, RegSCADA)	8.4	8.6	9	9.5
Union	8.5	8.75	9.5	11
Total	17.9	18.35	19.55	21.6
Number of Part Time Employees (NONE)	2006	2007	2008	2009
Executive	0	0	0	0
Management	0	0	0	0
Non-Union (Superv, Bill&Collect, Accting, RegSCADA)	0	0	0	0
Union	0	0	0	0
Total	0	0	0	0
Total Compensation	2006	2007	2008	2009
Executive	115,481	126,483	134,400	145,024
Management	63,220	68,573	73,920	79,552
Non-Union (Superv, Bill&Collect, Accting, RegSCADA)	699,805	735,210	806,400	876,736
Union	734,590	792,044	904,638	1,070,850
Total	1,613,096	1,722,311	1,919,358	2,172,162
Compensation - Average Yearly Base Wages	2006	2007	2008	2009
Executive	184,770	197,630	200,000	206,000
Management	101,152	107,146	110,000	113,000
Non-Union (Superv, Bill&Collect, Accting, RegSCADA)	66,648	66,789	70,000	72,100
Union	62,942	65,557	66,000	70,000
Compensation - Average Yearly Overtime	2006	2007	2008	2009
Executive	0	0	0	0
Management	0	0	0	0
Non-Union (Superv, Bill&Collect, Accting, RegSCADA)	0	0	0	0
Union	8,417	7,708	10,745	7,750
Compensation - Average Yearly Incentive (NONE)	2006	2007	2008	2009
Executive	0	0	0	0
Management	0	0	0	0
Non-Union (Superv, Bill&Collect, Accting, RegSCADA)	0	0	0	0
Union	-	-	-	-
Compensation - Average Yearly Benefits	2006	2007	2008	2009
Executive	23,096	27,668	29,400	31,724
Management	12,644	15,000	16,170	17,402
Non-Union (Superv, Bill&Collect, Accting, RegSCADA)	16,662	18,701	19,600	20,188
Union	15,063	17,255	18,480	19,600
	2006	2007	2008	2009
Total Salary, Wages & Benefits Charged to O&M	609,590	631,954	734,638	800,850
Add in Supervision that is in FTE's on Non-Union #'s.	187,190	196,375	204,800	211,200
Total SW&B Charged to O&M Union and N-U (Supervis.)	796,780	828,329	939,438	1,012,050

Variance Explanation 2009 Test Year to 2008 Bridge:

As indicated in Table 4 the impact of the 2 new journey linepersons hired in 2008 will be applied for the whole year through 2009. Most of the 9% change for these accounts is due to this impact. Still COLLUS Power Corp does not expect to see material variances impact on any of these accounts in this section.

- ## ACCOUNT #'s 5017 & 5114:

For these accounts there was a material debit variance in account 5017 for 2006 Actual compared to 2006 EDR approved. As noted earlier in Exhibit 4 Tab 2 Schedule 3 (Item 4) all of the $200,000 approved substation spending was allocated to account #5114. Spending should have been planned into both accounts with $50,000 in #5017 and $150,000 in #5114. Prudent financial management prevented the entire $200,000 from being spent in 2006, as COLLUS Power Corp only started to record the funds from the customer rates as of May 1/06 and actually receive funds beginning in June. Staged spending of the $200,000 expenses on sub-stations stretched into 2007. COLLUS Power Corp's has provided quarterly reports to the OEB Audit Department which is a requirement of the Accounting Procedures Handbook to summarize spending under this plan. This investment in sub-stations was part of the Tier 2 approved expenses established to help alleviate the incorrect rate of return which COLLUS Power Corp was limited to in previous years.

- ## ACCOUNT # 5175: Maintenance of Meters

There was a large credit variance in this account for 2006 Actual compared to 2006 EDR Approved. Thru to 2005 COLLUS Power Corp had a single meter technician on staff and assistance was provided when needed by the lines staff. Significant effort was required to meet Measurement Canada metering requirements in the acquired service territory areas (the Towns of Stayner, Creemore and Thornbury). In 2006, as a result of succession planning and the need for line staff to dedicate their activities to their own duties, COLLUS Power Corp committed to hire an additional meter technician. The hiring process was completed on Oct. 30/06 as evidenced in Table 5 below. The resulting material variance between 2007 Actual to 2006 Actual, is explained by the cost of the additional Meter Technician.

TABLE 5

LINE STAFF BREAKDOWN OF AGE AND YEARS OF EXPERIENCE

COLLUS Power Corp - Unionized Line Staff		30-Jun-08		
Employee Name	**Position**	**Current Age**	**Years of Service**	**Age+Years of Service**
	Journey Linesperson Lead Hand	53.5	15.08	68.58
	Meter Technician Lead Hand	53.5	27	80.5
	Journey Linesperson	52.5	34	86.5
	Journey Linesperson	49.7	32	81.7
	Journey Linesperson	43.7	16	59.7
	Journey Linesperson Lead Hand	43.5	13.5	57
	Inspector/Locator	41.3	1.25	42.55
	Journey Linesperson	30.3	11.083	41.383
	Journey Linesperson	29.7	6	35.7
	Meter Technician	24.9	2.173	27.073
	Journey Linesperson	23.3	5	28.3

The hiring of the additional Meter Technician was partly to cover the increased work load after the expansion of COLLUS Power Corp's service territory and also to set up a succession plan as the Meter Technician Lead Hand is due for retirement in 2010.

Succession planning and a review of employee demographics is provided and further reviewed at Exhibit 4 Tab 2 Schedule 7.

PART B – Billing, Community Relations and Administration Expenses:

As with Table 2 earlier in this section and Table 3 in Part A the following Table 6 is provided for analysis of the overall changes to this department from 2006 to 2009. It should be noted that the 2006 EDR approved is based on 2004 costs. The table takes the totals of each department and determines the total administration (non-O&M) costs.

TABLE 6

COMPARATIVE ANALYSIS OF ADMINISTRATION (B&C, CR and G&A) COSTS FROM 2006 TO 2009

	2006 Board Approved	2006 Actual	2007 Actual	2008 Bridge	2009 Test	% Change 2009 to 2006 Actuals
ADJUSTED OM&A FOR COMPARISON						
Billing and Collections	$ 538,249	$ 592,333	$ 655,645	$ 722,109	$ 762,093	
Community Relations	$ 88,563	$ 154,243	$ 157,924	$ 100,085	$ 107,389	
Administrative and General Expenses	$ 1,200,627	$ 952,430	$ 904,732	$ 932,991	$ 1,008,741	
Taxes & Other Related	$ 990	$ 5,025	$ 8,256	$ 8,916	$ 8,916	
SUB-TOTAL	$ 1,828,428	$ 1,704,031	$ 1,726,557	$ 1,764,101	$ 1,887,139	
less: Low Voltage Charges in 2006 EDR	$ 398,421					
less: Energy Conservation in 2006 Actual		$ 100,646				
TOTAL	$ 1,430,007	$ 1,603,385	$ 1,726,557	$ 1,764,101	$ 1,887,139	
	% Differ to 06EDR>	**12.1%**				
Admin. Wage & Benefits (Table 2 EC&C)		$ 878,506	$ 930,267	$ 1,014,720	$ 1,101,312	**25.4%**
Administration Other Expenses		$ 724,878	$ 796,290	$ 749,381	$ 785,827	**8.4%**
Net Administration Expense		$ 1,603,385	$ 1,726,557	$ 1,764,101	$ 1,887,139	**17.7%**

As indicated in Table 4 above there has been an overall increase of **17.7%** in Administration Expense from 2006 to 2009. The wage related change has been a **25.4%** increase and the remaining portion has been an **8.4%** increase in Other Expenses. The wage change is reviewed in Table 2 Employee Complement and Compensation, and the remaining portion is an inflationary impact that would be expected. COLLUS Power Corp continues to attempt to provide a superior level of customer service while dealing with the upward pressure on cost of the regulatory and legislative burden in the Ontario marketplace. When reviewing the comparative statistics available, to determine how these controllable costs equate to other LDC's for Administration Expense, the indication is COLLUS Power Corp continues to have one of the lowest Cost per Customer ratings. This is an important comparator for COLLUS Power Corp in monitoring that costs are both fair and reasonable.

1. BILLING AND COLLECTIONS VARIANCE-Accounts #5315 and 5330:

Account #5315 indicates an increase of $71,426 between 2006 Board Approved at a total of $337,771 (which is based on 2004 actual) and 2006 Actual at a total of $409,197. This variance is reduced by $33,965 if a correcting allocation entry had been made between this account and #5330. The Bad Debt Account should have a year end balance of $53,307 and account #5315 would be $375,232. This would leave a variance of $37,461 which is explained by the two year inflationary impact.

The correction noted above would mean that the variance of account #5335 indicated as $41,564 would be reduced to $7,599 which is only a minor increase in Bad Debt Expense over the previous year. The variance of 2007 Actual to 2006 Actual (adjusted) in account #5315 would increase from $17,131 to $51,096. This material variance is due to a reallocation of labor expense between account #5320 and #5315. There was also an increase of a .5 FTE in this department which was expensed to #5315 which contributed to the resulting variance by $22,500. The remaining variance was due to normal increase expense pressures.

Unfortunately the Collections Department has been particularly impacted by economic pressures within the community. The closure of our largest industrial customer, ALCOA Wheel Products, not only had a direct impact on COLLUS Power Corp's ability to collect a significant portion of its revenue requirement, it was also the largest employer in the community and its closure had a significant impact on the ability of people to meet their financial commitments. Although the Distribution Code has an in-depth process for managing deposits, the rules limit the ability of COLLUS Power Corp to minimize bad debt risk in such circumstances resulting in more accounts written off as bad debt.

2. COMMUNITY RELATIONS (ENERGY CONSERVATION) VARIANCE:

The variance of account #5415 for 2006 Actual compared to 2006 EDR was explained earlier in the general explanation statement. This also explains the material credit variance of $71,280 between 2008 Bridge year forecast and the 2007 Actual.

3. ADMINISTRATIVE & GENERAL EXPENSE VARIANCE-Accounts #5610, 5615&5655:

The 2006 Board Approved amounts in these accounts anticipated $370,572 but the actual expense was $417,605. This variance of $47,033 is partly explained by spending of $36,350 for the Regulatory guidance and assistance of Energy Concepts Management Inc. The assistance was required to set up processes to complete various OEB regulatory reporting requirements. This service was expensed to account #5615 when it should have been expensed to account #5655 which would eliminate the large credit variance.

The other material difference in 2006 is account #5665 and part of that was explained earlier in the general explanation of variance. The other material portion of variance is the $51,892 for expensing future employee benefits. This had not been anticipated in the 2006 EDR approved amount for this account. The actuarial study of this category of expense is done every 3 years. 2006 was an adjustment year and the yearly estimate was inadequate. Typically the yearly estimate is applied as an overhead charge but the yearend adjustment had to be applied directly to an account. COLLUS Power Corp anticipates the yearly estimate to be the total expense when the 3 year period is up in 2009. Since there was no year end adjustment in 2009 the account #5665 is $0 for 2007. That further explains the reason for the major credit variance of $51,892 in 2007 actual.

Another material variance is in account #5655 between the 2009 Test year and 2008 Bridge amount. The $40,250 is almost totally due to the placement of $160,000 for recovery over a four year period, of the estimated cost of the 2009 Cost of Service Rate Application Process. This estimate is based on discussion with 2008 COS applicants who have incurred incremental costs over the past year. COLLUS Power Corp has also incorporated into the calculation anticipated costs for the oral component of the 2009 COS process.

Those are the accounts with material differences for 2006 thru 2009.

PART C – AMORTIZATION EXPENSE:

Explanation of Variance 2008 Bridge to 2007 Actual:

A material variance for account #5705 occurred in 2008 Bridge compared to 2007 Actual as there was an increase of $104,638. The reason for the increase is the depreciation estimate for the new Customer Information System software purchase and installation beginning in 2008. It is straight line depreciation for a 5 year term which is equal to $80,000 per year. This is because the estimated software investment cost is $400,000 and this will be amortized over a 5 year period. Explanation of the CIS purchase has been provided in Exhibit 2 in the discussion of capital projects for 2008.

Explanation of Variance 2009 Test to 2008 Bridge:

A material increase in depreciation expense estimated for 2009 Test year of $96,059 is related to the depreciation of the new substation estimated at $50,000 per year. The balance of the variance is related to new project depreciation.

SHARED SERVICES:

Introduction:

The following discussion of shared services will outline the 3 distinct areas that COLLUS Power Corp considers to be involved in this aspect of the operations:

1. CORNERSTONE HYDRO ELECTRIC CONCEPTS (CHEC):

As noted earlier COLLUS Power Corp is a member of the CHEC Group of LDC's. As a participant in this successful co-operative enterprise COLLUS Power Corp shares certain services that it would have to develop internally or use a commercial third party at a higher cost to otherwise complete the work.

- **Finance Coordinator Services**

For the past 3 years the member LDC's of the CHEC group collectively hired the services of a Finance Coordinator that efficiently and effectively provides guidance on important financial, rate related, and other regulatory matters. The CHEC group members share the cost for this service based on a pro-rata method of cost allocation. Currently the number of customers is the basis for this.

- **Establishment of Services**

COLLUS Power Corp individually reviews participation in any shared purchase of services for even though there may be an initial appearance that cost will be lower, when decisions are being made to undertake certain initiatives, proper purchasing practices are still utilized and the optimum choices are made. This is because cost cannot be the only factor, overall quality of service is also a key determinant. COLLUS Power Corp values this extremely important allegiance and sharing of services.

- **Electricity Customer Bad Debt Expense Insurance**

Another important shared initiative within the CHEC membership was the recent establishment of Bad Debt Expense Insurance at a highly reduced cost. Initially in order to remove some of the risk that the Ontario Market places on LDC's in regards to cost of power, COLLUS Power Corp investigated both the availability and the cost of this type of insurance. The rates quoted would have resulted in excessive cost and it was determined to be unacceptable. By working cooperatively with other CHEC members an acceptable rate was negotiated, at roughly 30% the original single quoted rate, and an important risk aversion tool is now in place.

- **Customer Information System Functions**

A recent initiative, that is probably one of the most important COLLUS Power Corp will take on, is the previously mentioned (in Exhibit 2) decision to set up the new CIS system on a shared basis with 5 other CHEC members. This is potentially a stepping stone towards full billing services being shared through the UCS group. Customer billing expense is one of the highest expense centers for all LDC's and this is the same for COLLUS Power Corp. The ability to share the provision of all billing services will assist COLLUS Power Corp with succession planning while maintaining the current high quality billing services it provides at the best cost possible is maintained.

- **Future Considerations**

There are other major initiatives, such as accounting, safety coordination, staff training and regulatory reporting services, being considered by the CHEC members. This is part of the on-going study process that COLLUS Power Corp uses to ensure that its current costs for administrative services are as economical as possible and are key to COLLUS Power Corp future for succession planning. Whenever initiatives are undertaken there is constant communication with the Ontario Energy Board to ensure that all aspects of the Affiliate Relationship Code are considered and met.

2. THIRD PARTY SUPPLIERS:

- **Overview**

COLLUS Power Corp purchases services from numerous non-affiliated third party suppliers. COLLUS Power Corp purchasing policy processes are followed to ensure maximum value is realized when deciding in regards to using third party suppliers.

➢ Specialized Services

In order to meet market requirements, services such as wholesale settlements verification had to be either developed in-house, or acquired externally. As an example COLLUS Power Corp chose to utilize the services of Utilismart Inc for wholesale settlement verification. Information is provided earlier in this Exhibit that explains that service quality and reliability are key components in the on-going process of measuring whether or not the cost of a service is competitive.

➢ Professional Services

Also in order to cover the aspect of regulatory requirements additional professional services have to be utilized. For example in order to complete the 2009 Cost of Service rate application both legal and rate consultation services had to be employed. Another example is external audit services that require becoming familiar with the OEB's regulatory accounting requirements.

3. AFFILIATED SERVICES:

➢ Overview

There are also shared services amongst affiliates of COLLUS Power Corp. Appropriate agreements are structured that serve to properly adhere to all regulatory requirements, such as the Affiliate Relationship Code. The Services Agreement mentioned in Exhibit 1, Tab 1, Schedule 14 is provided and includes information on the services provided to COLLUS Power Corp by its affiliate COLLUS Solutions Corp. The services affiliate, which only has non-unionized administrative and supervision employees, also provides certain services to the shareholder (Town of Collingwood) and also to their municipal service board the Collingwood Public Utilities.

➢ Cost of Service Agreement Allocation

There are labor related and other expenses applied to perform the services considered in the Services Agreement. Table 1 provides an outline of the allocators used to apply labor related costs.

The Service Agreement is a cost based related agreement. The other related expenses are generally allocated on a pro-rata basis, generally with time allocated to the service as a guideline.

TABLE 1
SUMMARY OF INTRA-COMPANY COST ALLOCATIONS

ACTIVITY	% To COLLUS Power	% To COLLUS Solutions	% To Collingwood Public Utilities
Operations- Supervison	95	5	0
Opertions - SCADA & Load Management	50	5	45
Operatons - Miscellaneous Distribution Expense*	0	0	0
Maintenance - Supervison	95	5	0
Customer Billing	58	5	37
Collections & Reconnects	50	5	45
Customer Service & Information Expenses	50	5	45
Meter Reading Expense*	0	0	0
Executive Salaries & Expenses	55	5	40
Management Salaries & Expenses	50	5	45
General & Administration Salaries & Expenses	50	5	45
Outside Services Employed	0	0	0
Maintenance of General Plant*	0	0	0
Ovehead Accounts - Vehicle Expense Engineering & IT Expense	55	5	40

*** No Labour component (Costs are applied between each company on a pro-rata calculation)**

- **Shared Facilities Lease Agreement**

Currently COLLUS Power Corp houses its operations at the Collingwood Public Utilities facilities at 43 Stewart Road in Collingwood. Appendix A provided with this Schedule is the Shared Facilities Lease (SFL) agreement that incorporates the terms of the lease. As indicated in the terms a determination has been made as to the area utilized by COLLUS Power Corp. The rental rates that are utilized to determine the value of the lease have been provided through independent study by Gaviller & Company, COLLUS Power Corp's external independent audit firm. These terms are studied annually during the annual external audit process to determine that they are at the appropriate levels.

- **Computer Rental Agreement**

Currently COLLUS Power Corp utilizes the Intellectual Technology hardware and software resources owned by the Collingwood Public Utilities. The agreement is also based on an estimated usage factor and rates that have been studied by the independent audit firm. The terms of the agreement are reviewed annually to ensure they are still applicable. Initial review of the impact of the purchase of a new CIS by COLLUS Power Corp does not indicate any major variance from the current agreement amounts. A copy of the current agreement is provided with this schedule as Appendix B.

EMPLOYEE COMPENSATION REVIEW:

Overview:

COLLUS Power Corp is facing many of the same challenges as other LDCs throughout the electricity distribution sector. In the next five years, 36.3% of COLLUS Power Corp' employees are eligible for retirement. COLLUS Power Corp' total employee average age is slightly lower than the national electricity distribution sector at 43.0 years.

The challenge COLLUS Power Corp faces is effectively bridging the gap in maintaining sufficient talent to meet the current needs of the utility while planning for the 'new' future. Table 1 below illustrates COLLUS Power Corp' current employee demographics.

Table 1
COLLUS Power Corp Employee Demographics

COLLUS Power Employees		
Line Department: Sub-Category	**Avg Age**	**Avg. Yrs Service**
Line Operations - Supervision	48.5	14.3
Line Operations - Operations	39.0	16.8
Line Operations - Inspection	41.3	1.3
Meter Measurement - Super.	53.5	27.0
Meter Measurement - Operations	24.9	2.2
Totals	41.4	12.3

COLLUS Power Corp continues to be proactive and strategic in its approach to workforce planning. Using the demographic profile, including risks and gaps that have been identified by skills and trades, COLLUS Power Corp is in the process of identifying where its knowledge reserves are and what areas are at risk for knowledge loss in the future. This will continue to direct COLLUS Power Corp' retention and recruitment strategies and practices.

Beginning in 2009, Managers and Supervisors will review and recommend those employees with potential to move up or laterally within the organization. Recognized frontline unionized leaders will be invited to participate in industry Leadership Development program preparing them for supervisory roles.

COLLUS Power Corp' strategy to retain and develop in-house talent combined with developing competent leaders, rewarding employees and remaining competitive through its compensation plans is aimed at attracting and retaining the skills and talent required going forward.

Staying ahead of the competition for talent through progressive recruitment and retention strategies and continually focusing on increasing employee engagement will help to make COLLUS Power Corp an employer of choice in a shrinking employee market.

COLLUS Power Corp' Performance Analysis:

- **Supervisory 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.

COLLUS Power Corp' performance management 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 supervisors, 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.

COLLUS Power Corp' Total Compensation System:

- **Introduction:**

COLLUS Power Corp' 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.

- **Benefits:**

A comprehensive and competitive benefits package exists which includes medical 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 COLLUS Power Corp employees.

- **Employee Compensation and Benefits:**

COLLUS Power Corp' employee and full-time equivalent complement, compensation and benefits are set out in Table 2, 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 2
COLLUS Power Corp' Employee Complement And Compensation

	ACTUAL	ACTUAL	BRIDGE	TEST YEAR
Number of Employees (FTEs)	2006	2007	2008	2009
Executive	0.5	0.5	0.525	0.55
Management	0.5	0.5	0.525	0.55
Non-Union (Superv, Bill&Collect, Accting, RegSCADA)	8.4	8.6	9	9.5
Union	8.5	8.75	9.5	11
Total	17.9	18.35	19.55	21.6
Number of Part Time Employees (NONE)	2006	2007	2008	2009
Executive	0	0	0	0
Management	0	0	0	0
Non-Union (Superv, Bill&Collect, Accting, RegSCADA)	0	0	0	0
Union	0	0	0	0
Total	0	0	0	0
Total Compensation	2006	2007	2008	2009
Executive	115,481	126,483	134,400	145,024
Management	63,220	68,573	73,920	79,552
Non-Union (Superv, Bill&Collect, Accting, RegSCADA)	699,805	735,210	806,400	876,736
Union	734,590	792,044	904,638	1,070,850
Total	1,613,096	1,722,311	1,919,358	2,172,162
Compensation - Average Yearly Base Wages	2006	2007	2008	2009
Executive	184,770	197,630	200,000	206,000
Management	101,152	107,146	110,000	113,000
Non-Union (Superv, Bill&Collect, Accting, RegSCADA)	66,648	66,789	70,000	72,100
Union	62,942	65,557	66,000	70,000
Compensation - Average Yearly Overtime	2006	2007	2008	2009
Executive	0	0	0	0
Management	0	0	0	0
Non-Union (Superv, Bill&Collect, Accting, RegSCADA)	0	0	0	0
Union	8,417	7,708	10,745	7,750
Compensation - Average Yearly Incentive (NONE)	2006	2007	2008	2009
Executive	0	0	0	0
Management	0	0	0	0
Non-Union (Superv, Bill&Collect, Accting, RegSCADA)	0	0	0	0
Union	-	-	-	-
Compensation - Average Yearly Benefits	2006	2007	2008	2009
Executive	23,096	27,668	29,400	31,724
Management	12,644	15,000	16,170	17,402
Non-Union (Superv, Bill&Collect, Accting, RegSCADA)	16,662	18,701	19,600	20,188
Union	15,063	17,255	18,480	19,600
	2006	2007	2008	2009
Total Salary, Wages & Benefits Charged to O&M	609,590	631,954	734,638	800,850
Add in Supervision that is in FTE's on Non-Union #'s.	187,190	196,375	204,800	211,200
Total SW&B Charged to O&M Union and N-U (Supervis.)	796,780	828,329	939,438	1,012,050

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, COLLUS Power Corp 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.

COLLUS Power Corp 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”.

COLLUS Power Corp submits that its methodology for calculating amortization meets this objective.

Details of COLLUS Power Corp’ depreciation by asset group are provided in the Accumulated Depreciation Table at Exhibit 2, Tab 2, Schedule 4. Details of COLLUS Power Corp’ amortization and depletion by asset group are provided in the Fixed Asset Continuity Schedules at Exhibit 2, Tab 2, Schedule 1.

DETERMINATION OF LOSS ADJUSTMENT FACTORS:

- **Total Loss Factor:**

COLLUS Power Corp has calculated the total loss factor to be applied to customers' consumption based on the average wholesale and retail kWh for the years 2005 thru 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 Generation	***369,942,976***	***376,054,075***	***381,935,042***	***363,932,933***	***349,841,198***	***342,462,009***	2,184,168,233
B	"Wholesale" kWh for Large Use customer(s)	85,553,496	86,793,405	96,595,869	98,014,141	91,431,798	34,974,002	493,362,711
C	Net "Wholesale" kWh (A)-(B)	284,389,480	289,260,670	285,339,173	265,918,792	258,409,400	307,488,007	1,690,805,522
D	"Retail" kWh (Distributor)	353,595,657	364,621,938	367,636,669	353,069,346	338,274,830	331,005,952	2,108,204,392
E	"Retail" kWh for Large Use Customer(s)	84,697,961	85,925,471	95,629,910	97,034,000	90,517,480	34,624,262	488,429,084
F	Net "Retail" kWh (D)-(E)	268,897,696	278,696,467	272,006,759	256,035,346	247,757,350	296,381,690	1,619,775,308
G	Loss Factor [(C)/(F)]	105.76%	103.79%	104.90%	103.86%	104.30%	103.75%	104.39%
H	Distribution Loss Adjustment Factor (current 3 years)							**103.97%**
	Supply Facility Loss Factor	103.40%	103.40%	103.40%	103.40%	103.40%	103.40%	**103.40%**
	Supply Facility Loss Adjustment Factor (3 year avg.)							**103.40%**
	Total Loss Factor							**1.0750498**

As noted in the table calculations average distribution loss adjustment factor (G) is 104.39% which is the average for the six years of actual data. The DLAF (H) is based on the most current 3 years of data and has been used in establishing the factor of **103.97%** which is being submitted for approval with this rate application. COLLUS Power Corp submits that the use of the 3 years rather than 6 is more appropriate due to the recent major impact of the largest customer ceasing operation. Upon approval of the proposed Loss Factor COLLUS Power Corp Customers will have benefited from a reduction in two consecutive rate applications.

- **Supply Facility Loss Factor:**

The supply facility loss factor (the "SFLF") is calculated in Table 2 and represents the losses on supply to COLLUS Power Corp. 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 2002	Full Year 2003	Full Year 2004	Full Year 2005	Full Year 2006	Full Year 2007	Total
"Wholesale" kWh IMO With Losses	**382,521,037**	**388,839,914**	**394,920,833**	**376,306,653**	**361,735,798**	**354,105,717**	2,258,429,952
"Wholesale" kWh IMO No Losses	*369,942,976*	*376,054,075*	*381,935,042*	*363,932,933*	*349,841,198*	*342,462,009*	2,184,168,233
Supply Facility Loss Factor	0.03400	0.03400	0.03400	0.03400	0.03400	0.03400	0.03400

- **Total Loss Factor by Class:**

Table 3 sets out the class-specific Total Loss Factors used by COLLUS Power Corp in the calculation of commodity and other non-distribution charges for bill impact and other applicable comparison that it required to reach the proposed rates.

Table 3
Total Loss Factor by Class

Total Utility Loss Adjustment Factor		LAF
Supply Facility Loss Factor		1.0340
Distribution Loss Factor		
Distribution Loss Factor - Secondary Metered Customer < 5,000kW		1.0397
Distribution Loss Factor - Primary Metered Customer < 5,000kW		1.0293
Total Loss Factor		
Total Loss Factor - Secondary Metered Customer < 5,000kW		1.0750
Total Loss Factor - Primary Metered Customer < 5,000kW		1.0643

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- **Materiality Analysis on Distribution Losses:**

COLLUS Power Corp' proposed distribution loss factor is 3.97%. Pursuant to the Filing Requirements, as the Distribution Loss Factor is less than 5%, COLLUS Power Corp is not required to provide an explanation of, or justification for, its loss adjustment factor.

TAX CALCULATIONS: COLLUS Power Corp' detailed tax calculations are provided in the following:

Table 1
Tax Calculations

Description	2006 Board Approved	2008 Bridge	2009 Test
Determination of Taxable Income			
Utility Income Before Taxes	301,675	117,240	827,097
Book to Tax Adjustments			
Additions to Accounting Income:			
Depreciation and amortization	743,840	974,716	1,101,668
Income or Loss for tax Purposes-joint ventures or partnerships		0	0
Employee Benefit Plans - accrued, not paid	55,192		
Meals & entertainment / Mileage	2,195	0	0
Non-deductible club fees and dues		0	0
Taxable Capital Gains	5,530	0	0
Tax reserves beginning of year		81,654	81,654
Reserves from financial statements -balance at year end		0	0
Regulatory asset write-downs and recoveries			
Debt financing expenses for book purposes		0	0
Total Additions	**806,757**	**1,056,370**	**1,183,322**
Deductions from Accounting Income:			
Capital Cost Allowance	593,320	979,370	1,170,614
Gain on disposal of assets per financial statements	29,260	0	0
Cumulative eligible capital deduction	67,785	50,707	47,158
Tax reserves end of year		81,654	81,654
Amortization of Deferred Asset	39,475	0	0
Adj for Employee Future Benefits.	28,841	0	0
Net Capital Loss from Preceding Year	5,530	0	0
Total Deductions	**764,211**	**1,111,731**	**1,299,426**
Regulatory Taxable Income	**344,221**	**61,879**	**710,993**
Corporate Income Tax Rate	0	0	0
Subtotal	**124,333**		
<u>Less:</u> R&D ITC (0.3)			
Regulatory Income Tax	**124,333**	**20,729**	**234,628**
Calculation of Utility Income Taxes			
Income Taxes	124,333	20,729	234,628
Large Corporation Tax	0	0	0
Ontario Capital Tax	11,456	0	2,174
Total Taxes	**135,788**	**20,729**	**236,801**
Tax Rates			
Federal Tax	0.221	0.195	0.190
Federal Surtax			
Provincial Tax	0.140	0.140	0.140
Total Tax Rate	**0.361**	**0.335**	**0.330**
Calculation of Large Corporation Tax			
Total Rate Base	13,818,524	14,271,703	15,966,037
<u>Less:</u> Exemption	50,000,000		
Taxable Capital	**(36,181,476)**		
LCT Rate	0.0013	0	0
Subtotal	(45,227)	0	0
Federal Surtax	0	0	0
Large Corporation Tax	**0**	**0**	**0**
Calculation of Ontario Capital Tax			
Total Rate Base	13,818,524	14,271,703	15,966,037
Less Exemption	10,000,000	15,000,000	15,000,000
Taxable Capital /Deemed taxable capital	**3,818,524**	**0**	**966,037**
OCT Rate	0.00300	0	0.00225
Ontario Capital Tax	**11,456**	**0**	**2,174**

Summary of Income Taxes

Description	2006 Board Approved	2008 Bridge	2009 Test
Income Taxes	124,333	20,729	234,628
Large Corporation Tax	0	0	0
Ontario Capital Tax	11,456	0	2,174
Total Taxes	**135,788**	**20,729**	**236,801**

CAPITAL COST ALLOWANCE:

COLLUS Power Corp 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	8,202,521	0	0	8,202,521	0	0	8,202,521	0	8,202,521	4%	328,101	7,874,420
2	Distribution System - pre 1988	0	0	0	0	0	0	0	0	0	6%	0	0
6	Buildings (No footings below ground)	0	0	0	0	0	0	0	0	0	10%	0	0
8	General Office/Stores Equip	206,315	0	0	206,315	*85,000*	0	291,315	42,500	248,815	20%	49,763	241,552
10	Computer Hardware/ Vehicles	300,697	0	0	300,697	*450,000*	0	750,697	225,000	525,697	30%	157,709	592,988
10.1	Certain Automobiles	0	0	0	0	*0*	0	0	0	0	30%	0	0
12	Computer Software	2,633	0	0	2,633	*400,000*	0	402,633	200,000	202,633	100%	202,633	200,000
13 1	Lease # 1	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	0	0	0	0	*0*	0	0	0	0	45%	0	0
45.1	Computers & Systems Hardware acq'd post Mar 19/07	0	0	0	0	*0*	0	0	0	0	55%	0	0
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	2,547,547			2,547,547	*934,000*	0	3,481,547	467,000	3,014,547	8%	241,164	3,240,383
	SUB-TOTAL - UCC	**11,259,713**	**0**	**0**	**11,259,713**	**1,869,000**	**0**	**13,128,713**	**934,500**	**12,194,213**		**979,370**	**12,149,343**
		verified											

CEC	Goodwill	724,386	0	0	724,386
CEC	Land Rights		0	0	0
CEC	FMV Bump-up		0	0	0
	SUB-TOTAL - CEC	**724,386**	**0**	**0**	**724,386**
		From T2 2007 taxes			

Cumulative Eligible Capital Calculation

Cumulative Eligible Capital				724,386
<u>Additions:</u>				
Cost of Eligible Capital Property Acquired during the year	0			
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday December 31, 2002	0	x 1/2 =	0	
			0	724,386
Amount transferred on amalgamation or wind-up of subsidiary	0			0
Subtotal				724,386
<u>Deductions:</u>				
Projected proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during the year				
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	724,386
Cumulative Eligible Capital Balance				724,386
CEC Deduction	7%			50,707
Cumulative Eligible Capital - Closing Balance				673,679

2009 Test Year:

CCA Continuity Schedule (2009)

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	7,874,420	0	0	7,874,420	0	0	7,874,420	0	7,874,420	4%	314,977	7,559,443
2	Distribution System - pre 1988	0	0	0	0	0	0	0	0	0	6%	0	0
6	Buildings (No footings below ground)	0	0	0	0	0	0	0	0	0	10%	0	0
8	General Office/Stores Equip	241,552	0	0	241,552	*90,000*	0	331,552	45,000	286,552	20%	57,310	274,242
10	Computer Hardware/ Vehicles	592,988	0	0	592,988	*150,000*	0	742,988	75,000	667,988	30%	200,396	542,592
10.1	Certain Automobiles	0	0	0	0	*0*	0	0	0	0	30%	0	0
12	Computer Software	200,000	0	0	200,000	*60,000*	0	260,000	30,000	230,000	100%	230,000	30,000
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	0	0	0	0	*0*	0	0	0	0	45%	0	0
45.1	Computers & Systems Hardware acq'd post Mar 19/07	0	0	0	0	*0*	0	0	0	0	55%	0	0
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	3,240,383			3,240,383	*2,717,500*	0	5,957,883	1,358,750	4,599,133	8%	367,931	5,589,953
	SUB-TOTAL - UCC	**12,149,343**	**0**	**0**	**12,149,343**	**3,017,500**	**0**	**15,166,843**	**1,508,750**	**13,658,093**		**1,170,614**	**13,996,229**

CEC	Goodwill	673,679	0	0	673,679
CEC	Land Rights	0	0	0	0
CEC	FMV Bump-up	0	0	0	0
	SUB-TOTAL - CEC	**673,679**	**0**	**0**	**673,679**

Cumulative Eligible Capital Calculation

Cumulative Eligible Capital				673,679
<u>Additions:</u>				
Cost of Eligible Capital Property Acquired during the year	0			
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday December 31, 2002	0	x 1/2 =	0	
			0	673,679
Amount transferred on amalgamation or wind-up of subsidiary	0			0
Subtotal				673,679
<u>Deductions:</u>				
Projected proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during the year				
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	673,679
Cumulative Eligible Capital Balance				673,679
CEC Deduction	7%			47,158
Cumulative Eligible Capital - Closing Balance				626,521

Customer Report

Date Issued:	August 1st, 2008
Bulletin No.:	CR 080801-01
Issue:	Customer Report for July 2008

Availability Report

The availability report records hub service availability derived from the duration, in minutes, for a specific month that the service is accessible to customers, excluding any scheduled maintenance outages and Force Majeure factors outside of The SPi Group's control.

July	QTD	YTD
100%	100%	99.721%

EBT Delivery Time

The EBT delivery time is the time it takes for a document to be uploaded to our system, parsed and validated, made available for download by the recipient (if the document is valid), and acknowledged by the hub to the sender (that is, creating a Functional Acknowledgement available for download by the sender). The performance measure takes into consideration all documents across our customer base for the month. Our target service level for delivery time is four hours, with a threshold of eight hours.

The EBT delivery time report for July 2008 is as follows:

Less than Four Hours	Four to Six Hours	Six to Eight Hours	More than Eight Hours
100%	0%	0%	0%

Confidentiality Statement

In accordance with The SPi Group's EBT Hub Service Agreement, this report is intended exclusively for you, and should not be forwarded to any other individuals or parties. Unauthorized access to this information is a violation of federal law. Violators will be prosecuted.

NOTE: If you wish to make any changes to our distribution list (i.e. change your email address or add/delete other e-mail recipients), please let us know.

For More Information, Please Contact:

Technical Support Line:	416. 408. 3974
Technical Support E-mail:	hubsupport@thespigroup.com
Technical Support Pager:	647. 407. 3800

AMENDING AGREEMENT

THIS AMENDING AGREEMENT is made this 19TH day of DECEMBER, 2007.

BETWEEN:

COLLUS Power Corp. a corporation incorporated pursuant to the laws of the Province of Ontario

(Hereinafter referred to as "**WIRESCO**")

-and-

Collingwood Public Utilities a service board of the Town of Collingwood incorporated pursuant to the laws of the Province of Ontario

(Hereinafter referred to as "**CPU**")

WHEREAS WIRESCO and **CPU** (collectively the "**Parties**") have entered into an amended agreement (the "**Shared Facilities Lease**") dated as of January 1, 2007 whereby **CPU** has agreed to lease office & industrial space to **WIRESCO** as provided in the original Shared Facilities Lease dated January 1, 2004; and

WHEREAS the lease rates are outlined in the first part Section 3 ($14.00 per sq. ft. for office space and $6.50 per sq. ft. for industrial space); and

WHEREAS the Shared Facilities Lease indicates that WIRESCO's uses 70%(2007 change of %) of the office (13,100 sq. ft.) & industrial space (7,500 sq. ft.); and

WHEREAS the Effective Date of the Shared Facilities Lease is defined as January 1, 2007; and

WHEREAS the lease charge includes the use of the 43 Stewart Road property other than the Operations Center Building; (approximately 150,000 sq. ft. of open area of an estimated value $450,000.00); and

WHEREAS the current charges (2007) equate to a total annual amount of $171,500.00 (66.7% of (10,000 X $14.00) + (6,000 X $6.50) + ($450,000 X 10%)) + $43,400/2(this was 3,100 sq. ft of addition @ $14.00 per sq for ½ of a year of use);

NOW THEREFORE THIS AMENDING AGREEMENT WITNESSETH that, in consideration of the mutual covenants and agreements herein contained and subject to the terms and conditions hereinafter set out, the Parties hereto agree as follows:

(a) The lease rates will remain at $14.00 per sq. ft for office space and $6.50 per sq. ft. for industrial space:

(b) The annual lease charge is 70% of (13,100 sq. ft. at $14.00 per sq. ft) plus 70% of (7,500 sq. ft at $6.50 per sq. ft) plus 70% of ($450,000 at 10%) = $194,000.00

(c) The Effective Date of the newly amended Shared Facilities Lease is January 1, 2008;

(d) Except as varied in this Amending Agreement the terms and conditions set forth in the Shared Facilities Lease shall remain in full force and effect.

(e) Capitalize terms not defined herein shall have the meanings ascribed thereto in the Shared Facilities Lease.

IN WITNESS WHEREOF this Amending Agreement has been executed by the parties hereto as of the date written above.

COLLUS Power Corp.

By: Dean Muncaster
Name: Mr. Dean Muncaster
Title: Chair of the Board of Directors

Collingwood Public Utilities

By: D Garbutt
Name: Mr. Doug Garbutt
Title: Vice-Chair of the CPU

AMENDING AGREEMENT

THIS AMENDING AGREEMENT is made this 19TH day of DECEMBER 2007.

BETWEEN:

COLLUS Power Corp., corporation incorporated pursuant to the laws of the Province of Ontario

(Hereinafter referred to as "**WIRESCO**")

-and-

Collingwood Public Utilities a service board of the Town of Collingwood incorporated pursuant to the laws of the Province of Ontario

(Hereinafter referred to as "**CPU**")

WHEREAS WIRESCO and **CPU** (collectively the "**Parties**") have entered into an amended agreement (the "**Computer Rental Agreement**") dated as of January 1, 2007 whereby **CPU** (formerly Collingwood Public Utilities Commission) has agreed to rent their computer hardware and software to **WIRESCO** as provided in the Computer Rental Agreement; and

WHEREAS the rental rate outlined in the Computer Rental Agreement results in a current total charge of $117,000 per year for 2007; and

WHEREAS the basis for the rental rate is that **WIRESCO's** share is 60%of the estimated value of said computer hardware and software of $975,000.00, at a 20% straight-line amortization rate; and

WHEREAS the Effective Date of the original Computer Rental Agreement is defined as January 1, 2004; and

NOW THEREFORE THIS AMENDING AGREEMENT WITNESSETH that, in consideration of the mutual covenants and agreements herein contained and subject to the terms and conditions hereinafter set out, the Parties hereto agree as follows:

(a) The rental rate will be **WIRESCO's** share of 60% of the estimated replacement value of $975,000.00 based on an amortization rate of 20% = $117,000.00 per year for computer hardware and software, thereby replacing the current rates;

(b) The Effective Date of the amended Computer Rental Agreement is January 1, 2008;

(c) Except as varied in this Amending Agreement the terms and conditions set forth in the Computer Rental Agreement shall remain in full force and effect.

(d) Capitalize terms not defined herein shall have the meanings ascribed thereto in the Computer Rental Agreement.

IN WITNESS WHEREOF this Amending Agreement has been executed by the parties hereto as of the date written above.

COLLUS Power Corp.

By: Dean Muncaster

Name: Dean Muncaster
Title: Chair of the Board of Directors

Collingwood Public Utilities

By: D Garbutt

Name: Doug Garbutt
Title: Vice-Chair of the CPU

Exhibit	Tab	Schedule	Appendix	Contents
5 – Deferral and Variance Accounts				
	1	1		Proposed treatment of Account #2405 Other Regulatory Credits
				Table 1(Large Use Class Rev. 2006-09)
				RSVA, RCVA & Other Variance Deferral Accounts Balances 2008-09

DEFERRAL AND VARIANCE ACCOUNTS:

The OEB has indicated in the decision for Norfolk Power (EB-2007-0753) and other distributors, that the Board is of the view that it is appropriate to defer the disposition of RSVA and RCVA accounts until the completion of the announced generic review of these accounts. The Board further indicated that any LDC could file a proposal as to disposition of any of the accounts, if they deemed it necessary, and it would be considered.

COLLUS Power Corp submits a proposal in regards to variance account #2405 Other Regulatory Credits for the OEB's consideration.

Background:

COLLUS Power Corp has incurred a material impact, since July 2007, on the ability to earn the rate of return anticipated in the 2006 EDR rate approval. The impact combines with the original negative impact on COLLUS Power Corp of the OEB's decision to use a "floor" of $0 mechanism in the original establishment of distribution rates in 2001. The current negative impact continues to be incurred and will be until a new re-based rate approval is provided. In 2006 COLLUS Power Corp's largest customer announced its pending closure. The company's operation continued through 2006 but it began to "wind down" in 2007 with closure significantly occurring in July. ALCOA Wheel Products, which formerly utilized over 20% of the monthly utility peak load, reduced its consumption and therefore demand requirement and over 5.88% of the yearly base Distribution Service Revenue Requirement was lost from Aug. 2007 forward. The customer was part of the Large Use class customer base.

The following chart is an excerpt of the Operating Revenue table utilized in Exhibit 3 for Rate Base explanation purposes. It only includes information regarding the Large Use customer class for use in calculating the overall dollar impact on COLLUS Power Corp after closure.

Table 1

SUMMARY of LARGE USE CLASS REVENUE

From 2006 EDR Board APPROVED to 2009 TEST

SUMMARY TOTAL OPERATING 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	2009 Test ($'s)	Variance from 2008 Actual ($'s)
Large User	417,558	444,719	27,161	325,939	-118,780	***171,510***	-154,429	***166,352***	-5,158

Taking the Board approved amount of $417,558 and considering it for a period of 40 months the expected revenue from the Large Use customer class would total $ 1,390,468 . The total of actual revenue received or estimated to be received in 2006, 2007, 2008 and 4 months of 2009 totals to only $ 997,619 . The difference between the expected revenue and actual revenue is approximately $400,000 of lost opportunity to earn the 2006 approved revenue requirement and this has substantially impacted COLLUS Power Corp.

COLLUS Power Corp submits that this second instance of lost opportunity to earn the appropriate rate of return should be recoverable because of the material impact on earned income from a major component of base revenue requirement. As agreed to by the OEB in their previous rulings COLLUS Power Corp needs to earn their deemed rate of return in order to have the resources to continue to provide superior customer service and reliability in the future.

Further background information on this matter which COLLUS Power Corp believes affords the opportunity for recovery of the amount noted above is the accounting treatment of the 2006 EDR approved rates for a Tier 2 adjustment rate rider. The 2006 EDR approval EB-2005-0353 dated April 12, 2006 approved COLLUS Power Corp's Tier 2 adjustments proposal subject to the reporting requirements set out in the Handbook.

$200,000 was included as additional Distribution Substation Maintenance, to be recovered and expended over a 12 month period. It was only allowed to be considered income for one year. Therefore over the next 24 months or 2 year period the income generated from the rate rider has been placed into account #2405 Other Regulatory Credits. Additionally the account has been recording carrying charge impact as per the same treatment as the RSVA accounts.

It is estimated that approximately $25,000.00 of carrying charge interest will have accumulated by May 1, 2009. Adding the $25,000 to the 2 years of $200,000 brings the total in the account to approximately $425,000.

COLLUS Power Corp submits that the amount in the account #2405 equals the second instance of lost opportunity to earn the approved rate of return due to the ALCOA plant closure and request approval to transfer the total credit from #2405 into Distribution Service Revenue in 2008.

RSVA, RCVA & OTHER VARIANCE ACCOUNTS 2008 and 2009 FORECAST:

For purposes of projected year end balances in these accounts for 2008 Bridge and 2009 Test years the assumption has been that the balances in the accounts in the 2007 Actual will be the same in 2008 and 2009. There may be some changes to carrying charges in certain accounts but there are credit and debit principal balances so the assumption is that there will be no net change.

The only accounts that reflect change in 2008 and 2009 are Account #1590 Recovery of Regulatory Assets because there is a rate rider impacting this account so an estimate for 2008 and 2009 was made. The other set of accounts that reflect change are Account #1555 Smart Meter Recovery and 1556 Smart Meter O& M Costs. There is a rate rider charge that affects most of the change forecasted.

End of Exhibit #5 (Deferral and Variance Accounts)

OVERVIEW:

The purpose of this evidence is to summarize the method and cost of financing COLLUS Power Corp's capital requirements for the 2009 test year.

Capital Structure:

COLLUS Power Corp has a current capital structure of 53.3% debt, 46.7% equity, and a return on equity of 9.00%, consistent with the capital structure and return specified in the OEB's Decision in EB-2007-0856, dated 14th March, 2006. COLLUS Power Corp is requesting Board approval of a capital structure of 52.7% Long-Term and 4% Short-Term debt, 43.3% equity including an equity return of 8.57%.

COLLUS Power Corp is requesting this change in capital structure and associated return on equity primarily to comply 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 6, Tab 1, Schedule 2 as to the impact on 2009 Test Year structure. COLLUS Power Corp believes the requested capital structure and equity return will provide continued access to long-term debt at reasonable rates.

Return on Equity:

COLLUS Power Corp is requesting an equity return for the 2009 Test year of 8.57% in accordance with the information filed at Exhibit 6, Tab 1, Schedule 4. COLLUS Power Corp understands that the OEB will be finalizing the return on equity for 2009 rates based on January 2009 market interest rate information. COLLUS Power Corp's use of an ROE of 8.57% is without prejudice to any revised ROE that may be adopted by the OEB in early 2009.

Cost of Debt:

Exhibit 6, Tab 1, Schedule 3 provides the details of COLLUS Power Corp's forecasted long-term debt cost of 5.79% for 2009. Long-term debt cost information for the 2006 Board

Approved, 2007 Actual, 2008 Bridge Year and 2009 Test Year periods are also filed at Exhibit 6, Tab 1, Schedule 2 (Table 1). The Exhibit 6, Tab 1, Schedule 2 also provides the details of the short-term debt cost of 4.47% regarding the 2009 Test Year calculation.

Part of the calculation in Exhibit 6, Tab 1, Schedule 3 (Table 2) COLLUS Power Corp has incorporated the intention to replace the current CIBC loan. When the loan comes due on January 7, 2009, at an estimated principal balance of $790,000, a new loan of $1,100,000 for a 5 year term will be issued. The calculations anticipate an equal monthly principal payment of $18,333.33 for 60 months.

To determine the appropriate interest rate of this new loan, information was located from Infrastructure Ontario regarding their OSIFA Loan Program for Municipal Corporations. The loan interest rate has been forecasted as 5.08% based on OSIFA information. This has been incorporated into the overall Long-term debt rate calculations for the 2009 test year.

TABLE 1

DEEMED CAPITAL STRUCTURE

2006 EDR Approved

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	6,455,989	50.00%	5.88%	379,866.09
Unfunded Short Term Debt				
Total Debt	6,455,989	50.00%		379,866.09
Common Share Equity	6,455,989	50.00%	9.00%	581,038.97
Total equity	6,455,989	50.00%		581,038.97
Total Rate Base	12,911,977	100%	7.44%	960,905.05

2007 Actual

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	6,686,244	50.00%	6.25%	418,039.00
Unfunded Short Term Debt				
Total Debt	6,686,244	50.00%		418,039.00
Common Share Equity	6,686,244	50.00%	9.00%	601,761.94
Total equity	6,686,244	50.00%		601,761.94
Total Rate Base	13,372,488	100%	7.63%	1,019,800.95

2008 Bridge

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	7,606,818	53.30%	6.26%	475,917.07
Unfunded Short Term Debt				
Total Debt	7,606,818	53.30%		475,917.07
Common Share Equity	6,664,885	46.70%	9.00%	599,839.67
Total equity	6,664,885	46.70%		599,839.67
Total Rate Base	14,271,703	100%	7.54%	1,075,756.74

2009 Test

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	8,414,101	52.70%	5.79%	487,346.49
Unfunded Short Term Debt	638,641	4.00%	4.47%	28,547.27
Total Debt	9,052,743	56.70%		515,893.76
Common Share Equity	6,913,294	43.30%	8.57%	592,469.29
Total equity	6,913,294	43.30%		592,469.29
Total Rate Base	15,966,037	100%	6.94%	1,108,363.05

TABLE 2

COST OF DEBT

Debt & Capital Cost Structure

Weighted Debt Cost

Description	Debt Holder	Affliated with LDC?	Date of Issuance	Principal at end of 2004	Term (Years)	Rate%	Year Applied to	Interest Cost
1.Demand Loan	CIBC	No	February 7, 2002	2,315,654	7	5.47%	2009	126,666
2. Promissory Note	Town Cwood	Yes	1-Nov-01	**1,710,170**	None	6.25%	None	**106,886**
3. Debenture	Usborne & H	No	June 5 1992	86,000	15	9.75%	2006	8,385
4. Demand Loan(renew 1)	OSIFA	No	January 7, 2009	**1,100,000**	5	5.08%	2013	**55,880**
								0
								0

Total Long Term Debt Outstanding at end of 2004 used for 2006 EDR calc	4,111,824	**Total Interest Cost in 2004 for 06 calc**	241,937
not 297,817 from 2006 this is the 04 balance			
		Weighted Debt Cost Rate from 2006 EDR	5.88%
Total Long Term Debt Outstanding 2007	3,151,736	**Total Interest Cost for 2007**	197,054
		Weighted Debt Cost Rate for 2007	6.25%
Total Long Term Debt Outstanding 2008	2,827,522	**Total Interest Cost for 2008**	176,903
		Weighted Debt Cost Rate for 2008	6.26%
Total Long Term Debt Outstanding 2009	**2,810,170**	**Total Interest Cost for 2009**	**162,766**

(Long Term Debt Outstanding at end of 2009 expected to have $220,000 reduction of starting debt noted above for prinicipal payments on re-newed Debt)

Weighted Debt Cost Rate for 2009	5.79%

RETURN ON EQUITY:

The calculations used to determine the ROE and the return on debt are consistent with the returns approved in the recent 2008 cost of service applications and are consistent with the OEB's "Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors" issued August 15, 2006.

Debt Rate Calculations:

COLLUS Power Corp's calculations of its Long-Term debt rate for the years 2006 to 2009 are as follows:

TABLE 3

SUMMARY of LONG_TERM DEBT DATA

Long-Term Debt Cost

	2006 EDR	2007	2008	2009
Debt Service Costs	241,937	197,054	176,903	162,766
Long Term Debt	4,111,824	3,151,736	2,827,522	2,810,170
Effective debt rate	5.88%	6.25%	6.26%	5.79%

Deemed ROE Calculation:

COLLUS Power Corp has followed the OEB deemed ROE as follows:

Return on Equity	**8.57%**

End of Exhibit 6 (Cost of Capital and Rate of Return)

REVENUE DEFICIENCY - OVERVIEW:

COLLUS Power Corp has provided detailed calculations supporting its 2009 revenue deficiency.

The net revenue deficiency is calculated as $ **654,390** and when grossed up for PILs

COLLUS Power Corp's revenue deficiency is $ **976,701**.

Table 1 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.

Table 1

Calculation of Revenue Deficiency or Surplus

	2009 Test Existing Rates	2009 Test Proposed Rates
Revenue		
Suff/ Def From Below.		$976,701
Distribution Revenue	$4,832,283	$4,832,283
Other Operating Revenue (Net)	$326,000	$326,000
Total Revenue	$5,158,283	$6,134,984
Distribution Costs		
Operation, Maintenance, and Administration	$3,806,764	$3,806,764
Depreciation & Amortization	$983,056	$983,056
Capital Taxes	$2,174	$2,174
Interest- Deemed Interest	$515,894	$515,894
Total Costs and Expenses	$5,307,887	$5,307,887
Utility Income Before Income Taxes	-$149,604	$827,097
Net Adjustments per 2008 Pils	-$116,104	-$116,104
Taxable Income	-$265,708	$710,993
Income Tax (Tax Rate 33.0%)	-$87,684	$234,628
Utility Income	-$61,920	$592,469
Rate Base	$15,966,037	$15,966,037
Equity	43.30%	43.30%
Equity Component Rate Base	$6,913,294	$6,913,294
Income / Equity Rate Base %	-0.896%	8.57%
Target Return -Equity on Rate Base	8.57%	8.57%
Return- Equity on Rate Base	$592,469	$592,469
Revenue Deficiency	$654,390	
Revenue Deficiency (Gross-up)	$976,701	

End of Exhibit 7 (Calculation of Revenue Deficiency)

COST ALLOCATION OVERVIEW:

Introduction:

On September 29, 2006, the Ontario Energy Board (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. COLLUS Power Corp prepared a cost allocation information filing consistent with COLLUS Power Corp's understanding of the Directions, the Guidelines, the Model and the Instructions. COLLUS Power Corp submitted this filing to the OEB in January 2007.

One of the main objectives of the filing, based on the OEB's Model was to determine and provide the information to the OEB on the Revenue to Cost ratios 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 COLLUS Power Corp's cost data that supported its 2006 OEB-approved distribution rates. Consistent with the Guidelines, COLLUS Power Corp 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 all LDCs, 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 COLLUS Power Corp in January 2007. The calculations are based on COLLUS Power Corp's OEB-approved 2006 electricity distribution rates.

Table 1
Revenue to Cost Ratios as Filed in COLLUS Power Corp
(INITIAL)Cost Allocation Informational Filing

Rate Classification	Revenue (A)	Allocated Cost (B)	Revenue to Cost Ratio (A)/(B)
Residential	$3,545,358	$3,056,930	115.98%
GS <50 kW	$798,452	$805,706	99.1%
GS>50 kW	$342,951	$744,219	46.08%
Large User	$546,816	$415,472	131.61%
Street Lighting	$38,137	$246,216	15.49%
Unmetered Scattered Load	$14,997	$18,168	82.54%
Total	**$5,286,711**	**$5,286,711**	**100.00**

UPDATED COST ALLOCATION STUDY RESULTS:

In early 2006 ALCOA Wheel Products, COLLUS Power Corp's largest distribution customer, announced that the Collingwood operation would be closed within one (1) year. This resulted in a loss of almost 6% of total distribution revenue for COLLUS Power Corp and this issue has been earlier addressed in Exhibit 5 of this application. For this Exhibit purposes there is a need to consider the impact from a Cost Allocation Study basis. Since ALCOA was a single customer from within the Large Use Class it was determined that the previous study should be updated. Although COLLUS Power Corp's management believed that the load data for the model that was provided by HONI as per the approved calculation procedures, would only change for the Large Use customer class, staff decided to request a re-run. HONI completed this re-run and it confirmed that the only class of customer that had changes was the Large Use, when ALCOA's information was not included.

Upon inserting the load data into the CA model to replace the former information some of the other outcomes did change. It should be noted here that the reason for re-running the CA model was to determine what the Revenue to Cost ratios were without ALCOA in the numbers. COLLUS Power Corp decided this would be the better starting point for any consideration of adjustment during the 2009 Cost of Service rate application process. The results of the update run of the CA model are provided in Table 2 below:

Table 2
Revenue to Cost Ratios as Filed in COLLUS Power Corp
UPDATED Cost Allocation Information

Rate Classification	Revenue (A)	Allocated Cost (B)	Revenue to Cost Ratio (A)/(B
Residential	$3,547,823	$3,168,443	111.97%
GS <50 kW	$799,284	$843,291	94.78%
GS>50 kW	$344,599	$819,903	42.03%
Large User	$231,042	$190,239	121.45%
Street Lighting	$38,142	$246,413	15.48%
Unmetered Scattered Load	$15,004	$18,422	81.45%
Total	**$4,975,894**	**$5,286,711**	**94.12%**

In comparing the revenues in Table 2 with Table 1, the Large Use class has decline from $546,816 to $231,042 which is a difference of $310,817. This represents the annual lost revenue associated with

ALCOA. The revenues in the other classes are slightly different between Table 2 and Table 1 since the miscellaneous revenue is allocated to the various classes differently when ALCOA is removed.

In comparing the costs in Table 2 with Table 1, the total costs have not changed but in some classes allocation of these costs has significantly changed since the costs associated with ALCOA have been redistributed to the remaining customers. While COLLUS Power Corp failed to recover the revenue requirement from ALCOA the total costs of providing distribution service remained the same.

As a result, the revenue to cost ratios shown in Table 2 not only recognize the issue of cross subsidization between classes but also reflect how revenues should be adjusted to collect the on-going inability to collect the revenue requirement from ALCOA. For example, in Table 1, the revenue to cost ratio for the GS < 50 kW class is 99.10% which suggests in order to fully address cross subsidization this class should have its revenue increase by 0.9%. However in Table 2 the comparable revenue to cost ratio is 94.78%. This suggests revenues should increase by 5.22% to address cross subsidization as well as the loss of revenue from ALCOA. In order to collect the lost revenue the GS < 50 kW class should have their revenues increased by 4.32% (i.e. 5.22% - 0.9%).

It also should be noted here that COLLUS Power Corp determined that the 2006 CA model data in all other respects was still very accurate in its' calculations and that it would be appropriate to utilize the results of the recent cost allocation filing for rate setting proposals in the 2009 COS filing.

<u>Proposed Adjustment to Cost Allocation:</u>

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. As can be seen from the table, COLLUS Power Corp's Cost Allocation Filing Results, the Residential and Large User classes currently appear to be subsidizing the rest of the other classes. Additionally the Large User class is higher than the upper limit of the parameters. Of the subsidized classes of customer the General Service < 50 kW and Unmetered Scattered Load are within the revenue to cost ratio ranges established by the OEB. But both the GS > 50 kW and Street Light classes are well below the lower parameter in their class range.

Table 3 also provides COLLUS Power Corp's Proposed 2009 R/C ratios for ease of comparison purposes. The proposed R/C ratios reflect adjustments to revenue to address cross subsidization measures and the collection of lost revenue from ALCOA's departure.

Table 3
OEB Proposed Revenue to Cost Ratio Ranges & COLLUS Power Corp Results

Customer Class	OEB Low	OEB High	COLLUS Power Corp Cost Allocation Filing Results	COLLUS Power Corp Proposed 2009 Revenue to Cost Ratios
Residential	85%	115%	111.97%	**109.52%**
GS <50 kW	80%	120%	94.78%	**100.00%**
GS>50 kW	80%	180%	42.03%	**80.00%**
Large User	80%	180%	121.45%	**100.00%**
Street Lighting	70%	120%	15.48%	**42.74%**
Unmetered Scattered Load	80%	180%	81.45%	**100.00%**

COLLUS Power Corp is proposing in the 2009 COS rate filing to re-align its revenue to cost ratios by adjusting the allocations of revenue among certain rate classes in order to reduce some of the cross-subsidization that is occurring. The re-alignment will attempt to move all classes to a 100% (revenue and cost are equal) ratio, while bearing in mind: overall rate impact to each class; the parameters of the class; and what has possibly been occurring over the past few years. The revenue split by rate class needed to achieve the proposed revenue to cost ratios is outline in Table 4 below.

Table 4

Revenue Split by Rate Class to Achieve Proposed Revenue to Cost Ratios

Class	Proposed Revenue Split for 2009 Rate Application
Residential	66.71600%
GS <50 kW	16.13200%
GS>50 kW	11.87800%
Large Use >5MW	2.86370%
Street Light	2.06340%
Unmetered Scattered Load	0.34690%
TOTAL	**100.00000%**

The 2009 rate application made by COLLUS Power Corp proposes rates that will achieve levels that will fall within the OEB's standards for 5 of the 6 customer classes. Of the 5 within the parameters the forecast is that 3 will be at a 100% level which means that neither subsidization or over recovery occur. The other 2 are the Residential and General Service > 50 kW classes. COLLUS Power Corp believes that the level of movement, from 42.03% up to 80% creates a sufficient impact on the GS > 50kW class. Also it does move to within the OEB's target range. COLLUS Power Corp is determined to continue to reduce the apparent subsidization by the Residential class, as it has with these proposed rates, but will wait until the next stage of adjustment, most likely the next Cost of Service application, to take the final steps.

The remaining customer class that falls outside the OEB target range with the proposed rate changes is the Street Light class. The proposed rates will achieve movement that equates to a 50% change between an existing 15.48% and the 70% lower level of the OEB's target range for this class. The rate impacts are substantial for the Street Light class customer and COLLUS Power Corp submits that it is also better to wait until the next stage of adjustment to take the final steps.

Cost Allocation Summary:

The discussion and tables above support COLLUS Power Corp'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. COLLUS Power Corp 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;

End of Exhibit 8 (Cost Allocation)

Exhibit	Tab	Schedule	Appendix	Contents
9 – Rate Design				
	1	1		Rate Design Overview
				Table 1 (Base Revenue Requirement)
				Table 2 (Class Revenue Proportions)
				Table 3(Base Rev. Req. Class Allocation)
				Table 4 (Current Fixed Charge Ratio)
				Table 5 (Current Fixed/Variable Ratio)
				Table 6 (Proposed Fixed Charge Ratio)
				Table 7 (Proposed Volumetric Chg Ratio)
				Table 8 (Low Voltage Costs Allocation)
				Table 9 (Adjusted LV Costs Allocation)
				Table 10(Proposed El. Distribution Rates)
		2		Rate Mitigation
		3		Retail Transmission Rates–(Not required)
		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 Table 11 (Dist. Revenue Reconciliation)
		9		Rate and Bill Impacts
			A	Table of Rate and Bill Impacts

RATE DESIGN OVERVIEW:

This exhibit documents the calculation of COLLUS Power Corp's proposed distribution rates by rate class for the 2009 test year, based on rate design as proposed in this Exhibit.

COLLUS Power Corp has determined its total 2009 service revenue requirement to be $ **6,134,984** . The total revenue offsets in the amount of $ 326,000 reduce COLLUS Power Corp's total service revenue requirement to a base revenue requirement to $ **5,808,984.43**, which is used to determine the proposed distribution rates. The base revenue requirement is derived from COLLUS Power Corp's 2009 capital and operating forecasts, weather normalized usage, forecasted customer counts, and COLLUS Power Corp's regulated return on rate base. The revenue requirement is summarized in Table 1 below:

TABLE 1

Calculation of Base Revenue Requirement

OM&A, Capital Tax & Deemed Interest Exp.	4,324,831
Amortization Expenses	983,056
Total Distribution Expenses	**5,307,887**
Regulated Return On Capital	**592,469**
PILs (with gross-up)	234,628
Service Revenue Requirement	**6,134,984**
Less: Revenue Offsets	326,000
Base Revenue Requirement	**5,808,984.43**

(Note: The amounts in the above table are provided in more detail at Table 1 Ex7, Tab1, Sch 1)

The outstanding base revenue requirement is allocated to the various rate classes using the following proposed apportionment of revenue as outlined in Exhibit 8 – Cost Allocation.

TABLE 2

Proposed Apportionment of Revenue to Rate Classes

Rate Classification	Proposed Proportion of Revenue
Residential	66.71600%
General Service Less Than 50 kW	16.13200%
General Service Greater Than 50 kW	11.87800%
Large Use	2.86370%
Street Lights	2.06340%
Unmetered Scattered Load	0.34690%
Total	100.00000%

The following Table 3 outlines the results of this allocation.

TABLE 3

Allocation of Outstanding Base Revenue Requirement

Rate Classification	Proposed Revenue
Residential	3,875,522.05
General Service Less Than 50 kW	937,105.37
General Service Greater Than 50 kW	689,991.17
Large User	166,351.89
Street Lights	119,862.58
Unmetered Scattered Load	20,151.37
Total	5,808,984.43

Determination of Monthly Fixed Charges:

COLLUS Power Corp's current OEB-approved monthly fixed charges based on its 2008 IRM application by customer class are summarized in Table 4 below.

TABLE 4

Current Monthly Fixed Charges

Rate Class (Customer or Connection)	Current Monthly Fixed Charge ($)
Residential (per Customer)	9.26
General Service Less Than 50 kW (Cust.)	16.26
General Service Greater Than 50 kW (Cust.)	54.14
Large Use (Customer)	6,908.18
Street Lights (per connection)	0.6100
Unmetered Scattered Load	No Fixed Rate

Using the existing approved fixed charges applied to the forecasted number of customers for 2009, the following Table 5 outlines the current split between fixed and variable distribution revenue.

TABLE 5

Current Fixed and Variable Proportions

Rate Class	Fixed Revenue Proportion	Variable Revenue Proportion
Residential	41.12%	58.88%
General Service Less Than 50 kW	40.55%	59.45%
General Service Greater Than 50kW	20.47%	79.53%
Large Use	36.55%	63.45%
Street Lights	58.18%	41.82%
Unmetered Scattered Load	0.00%	100.00%

COLLUS Power Corp submits that it is appropriate for 2009 to maintain the same fixed/variable proportions assumed in the current rates. This matter is discussed further below.

In its November 28, 2007 Report on Application of Cost Allocation for Electricity Distributors, referred to in Exhibit 8 , 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". COLLUS Power Corp's MSCs exceed that floor amount. With respect to the upper bound for the MSC, the OEB considered it to be inappropriate to make changes to the MSC ceiling at this time, given the number of issues that remain to be examined within the scope of the OEB's Rate Review proceeding (EB-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.

COLLUS Power Corp confirms that it is making no changes to the current fixed and variable proportions of its rates. Any changes in MSCs are due solely to changes in the total base revenue requirement attributable to each customer class. The following Table 6 provides COLLUS Power Corp's calculations of its proposed monthly fixed distribution charges for the 2009 Test Year assuming the fixed/variable split supporting the current approved rates.

TABLE 6

Proposed Monthly Fixed Distribution Charge

Customer Class	Fixed Portion of Total Base Revenue Requirement $	2009 Test Year Customers	Proposed Fixed Distribution Charge $
Residential	$ 1,593,672	13,011	10.21
General Service Less Than 50 kW	$ 379,955	1,588	19.94
General Service Greater Than 50 kW	$ 141,270	127	92.97
Large Use	$ 60,804	1	5,067.00
Street Lights (connections)	$ 69,739	3,051	1.91
Unmetered Scattered Load	$ -	68	0.00
Total	**$ 2,245,440**		

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 7 provides COLLUS Power Corp'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, and includes the proposed adjustment for the Transformer Allowance as discussed below.

TABLE 7

Variable Distribution Charge Calculation

Customer Class	Yearly Variable Portion of Base Revenue Requirement $	2009 Test Yearly Volumetric Billing Determinant	Unit of measure	Proposed Volumetric Distribution Charge
Residential	$ 2,281,850	*121,128,423*	kWh	$0.0188
General Service Less Than 50 kW	$ 557,150	*45,443,633*	kWh	$0.0123
General Service Greater Than 50 kW	$ 548,722	*300,721*	kW	$1.9736
Large Use	$ 105,548	*75,012*	kW	$1.4071
Street Lights	$ 50,124	*6,087*	kW	$8.2349
Unmetered Scattered Load	$ 20,151	*455,702*	KWh	$0.0442
Total	**$ 3,563,545**			

Proposed Adjustment to Transformer Allowance:

Currently, COLLUS Power Corp provides a Transformer Allowance to those customers that own their transformation facilities. The current approved Transformer Allowance is $0.60 per kW. The Transformer Allowance is intended to reflect the costs to COLLUS Power Corp of providing step down transformation facilities to the customer's utilization voltage. Since COLLUS Power Corp provides electricity at utilization voltage, the cost of COLLUS Power Corp' transformers are captured in and recovered through the distribution rates. However, the distribution rates only reflect the cost of COLLUS Power Corp transformers and not the cost associated with transformers owned by the customer. Therefore the rate should reflect every customer using COLLUS Power Corp transformers and the Transformer Allowance should be applied to this rate for those customers that own their transformers. To accomplish this, the amount of Transformer Allowance should be added back to the volumetric rate to produce a rate that assumes every customer is using COLLUS Power Corp transformers. Then the customer that owns its transformer will receive a credit for their transformer and COLLUS Power Corp will collect sufficient revenue to cover the cost of providing transformation to the customer using COLLUS Power Corp transformers.

Based on the information provided in the Cost Allocation Model results (Worksheet O3.1 Line Tran Unit Cost, Cell F28) COLLUS Power Corp proposes to reduce the current approved transformer ownership allowance to $ (0.3500) per kW for GS>50 kW.

COLLUS Power Corp proposes that the amount of Transformer Allowance expected to be provided to those General Service Greater than 50 kW customers that own their transformers has been included in the General Service Greater Than 50 kW volumetric charge. This means that the proposed General Service Greater than 50 kW

volumetric charge has been increased by $ **0.1489** per kW and has been included in the volumetric rate of $ $1.9736 per kW to recover the amount of the Transformer Allowance over all kWs in the General Service Greater Than 50 kW rate class. Once the Transformer Allowance is applied to this charge the resulting revenue will recover the full base revenue requirement for the General Service Greater than 50 kW rate class.

Based on the same Cost Allocation Study it is proposed that the Transformer Allowance for the Large Use class be eliminated. The Large Use customer class is supplied from COLLUS Power Corp primary distribution system and therefore has a share of the associated costs of the primary distribution system allocated accordingly. However, by virtue of being primary fed, the Large Use class does not have an allocation of transformation or secondary costs assigned to it. The OEB's cost allocation model allocated costs correctly for primary fed customers. The Model also correctly eliminates the provision of a Transformer Allowance for primary fed customer classes, as there are no related transformation costs assigned to this class. The Large Use customer class will no longer receive the Transformer Allowance effective May 1, 2009, when COLLUS Power Corp proposes to begin implementing the results of its cost allocation study.

Recovery of Low Voltage Costs:

Consistent with the approach in the Board's 2006 EDR model, LV costs of $ **550,000.00** have been allocated to each rate class based on the proportion of retail transmission connection revenue collected from each class. The amount of forecasted LV charges in 2009 is based on calculating the 2008 costs. This is based on actual data for the first 6 months of 2008 and then estimating the last 6 months, based on the applicable rates and utilizing historical loads from 2007 actual. The applicable rates are the newly approved HONI charges. The estimated monthly load levels that HONI will charge are based on historical data. After 2008 is estimated the same load data is used with the applicable rates for all of 2009. The calculation to proportionally spread out the LV 2009 amount is outlined in the following Table 8:

TABLE 8

Allocation of LV Costs

Rate Classification	**2009 Test Year Retail Transmission Connection Revenue $**	**RTC Class Allocation Percentages**	**Allocated 2009 Test Year Low Voltage Revenue $**
Residential	351,272.43	39.78%	218,815.04
General Service Less Than 50 kW	118,153.45	13.38%	73,600.28
General Service 50 to 4,999 kW	310,403.71	35.16%	193,357.04
Large Use	97,065.74	10.99%	60,464.31
Street Lights	4,856.59	0.55%	3,025.27
Unmetered Scattered Load	1,184.82	0.13%	738.05
Total	**882,936.74**	**100.00%**	**550,000.00**

These proposed LV costs by rate class are then divided by the projected volumes and this produces the proposed adjustments to the distribution volumetric charges set out in the Table 9 below:

TABLE 9

LV-Related Adjustments to Volumetric Charges

Rate Classification	**LV Adjustment ($ per kWh)**	**LV Adjustment ($ per kW)**
Residential	0.0018	
General Service Less Than 50 kW	0.0016	
General Service 50 to 4,999 kW		0.6430
Large Use		0.8061
Street Lights		0.4970
Unmetered Scattered Load	0.0016	

Proposed Distribution Rates:

The following Table 10 sets out COLLUS Power Corp's proposed 2009 electricity distribution rates based on the foregoing calculations, including adjustments for the recovery of transformer allowance.

TABLE 10

Proposed 2009 Electricity Distribution Rates

Customer Class	$ Per Connection	$ Per Customer	$ per kW	$ per kWh
Residential	0.0000	10.2100	0.0000	0.0206
GS <50 kW	0.0000	19.9400	0.0000	0.0139
GS>50 kW	0.0000	92.9700	2.6166	0.0000
Large Use >5MW	0.0000	5,067.0000	2.2132	0.0000
Street Light	1.9051	0.0000	8.7319	0.0000
	0.0000	0.0000	0.0000	0.0000
Unmetered Scattered Load	0.0000	0.0000	0.0000	0.0458
0	0.0000	0.0000	0.0000	0.0000

NOTE: The 2009 proposed rate schedule outlined below will reflect the above rates plus the smart meter rate adder of $0.26 per customer per month for metered customers.

RATE MITIGATION:

COLLUS Power Corp submits that the bill impacts of its proposed 2009 electricity distribution rates are not so significant as to warrant any mitigation measures.

EXISTING RATE CLASSES:

Residential:

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separate 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. All customers are single-phase.

General Service Less Than 50kW:

This classification applies to a non residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW, subject to an annual review.

General Service Greater Than 50 kW:

This classification applies to a non-residential account whose average monthly maximum demand for billing purposes is equal to or greater than, or is forecast to be greater than 50 kW, subject to an annual review.

Large Use (Greater than 5,000 kW):

This classification applies to a non-residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be greater than 5,000 kW, subject to annual review.

Unmetered Scattered Load:

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption.

Street Lighting:

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

EXISTING RATE SCHEDULE: MONTHLY RATES AND CHARGES

Residential

Service Charge	$	9.52
Distribution Volumetric Rate	$/kWh	0.0184
Retail Transmission Rate – Network Service Rate	$/kWh	0.0047
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0029
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	$	16.52
Distribution Volumetric Rate	$/kWh	0.0111
Retail Transmission Rate – Network Service Rate	$/kWh	0.0043
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0026
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 Greater Than 50 kW

Service Charge	$	54.40
Distribution Volumetric Rate	$/kW	1.4435
Retail Transmission Rate – Network Service Rate	$/kW	1.7399
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.0322
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)	$	0.0000
Distribution Volumetric Rate	$/kWh	0.0162
Retail Transmission Rate – Network Service Rate	$/kWh	0.0043
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0026
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)	$	0.61
Distribution Volumetric Rate	$/kW	2.9941
Retail Transmission Rate – Network Service Rate	$/kW	1.3122
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.7979
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Large Use

Service Charge	$	6,908.44
Distribution Volumetric Rate	$/kW	2.4860
Retail Transmission Rate – Network Service Rate	$/kW	2.0461
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2940
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		
Charge to certify cheque	$	15.00
Arrears certificate	$	15.00
Statement of account	$	15.00
Pulling post dated cheque	$	15.00
Duplicate invoice for previous billing	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Legal letter Charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	15.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Special meter reads	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	20.00
Collection of account charge – no disconnection - after regular hours	$	165.00
Disconnect/Reconnect Charge - At Meter during Regular Hours	$	40.00
Disconnect/Reconnect Charge - 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
Service call - after regular hours	$	165.00
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	$ (0.6000)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

Retail Service Charges (if applicable)

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing, charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction 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 Factor

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0838
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0443
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0730
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0340

PROPOSED RATE CLASSES:

Residential:

This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separate 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 townhouse complex or apartment building also qualify as residential customers. All customers are single-phase.

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, subject to an annual review.

General Service Greater Than 50 kW:

This classification refers to a non-residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than 50 kW, subject to an annual review.

Large Use (Greater than 5,000 kW):

This classification applies to a non-residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be greater than 5,000 kW, subject to annual review.

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, 50kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information / documentation with regard to electrical demand / consumption of the proposed unmetered load.

Street Lighting:

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

COLLUS Power Corp
Schedule of Proposed Tariff of Rates and Charges
Effective May 1, 2009

Monthly Rate and Charges

Residential

Service Charge	$	10.47
Distribution Volumetric Rate	$/kWh	0.0206
Deferral and Variance Account Rider	$/kWh	0.0000
Retail Transmission Rate – Network Service Rate	$/kWh	0.0047
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0029
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administrative Charge	$	0.25

General Service Less Than 50 kW

Service Charge	$	20.20
Distribution Volumetric Rate	$/kWh	0.0139
Deferral and Variance Account Rider	$/kWh	0.0000
Retail Transmission Rate – Network Service Rate	$/kWh	0.0043
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0026
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administrative Charge	$	0.25

General Service Greater Than 50 kW

Service Charge	$	93.23
Distribution Volumetric Rate	$/kW	2.6166
Deferral and Variance Account Rider	$/kW	0.0000
Retail Transmission Rate – Network Service Rate	$/kW	1.7399
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.0322
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administrative Charge (if applicable)	$	0.25

Large Use

Service Charge	$	5067.26
Distribution Volumetric Rate	$/kW	2.2132
Deferral and Variance Account Rider	$/kW	0.0000
Retail Transmission Rate – Network Service Rate - Interval Metered	$/kW	2.0461
Retail Transmission Rate – Line and Transformation Connection Service Rate - Interval Metered	$/kW	1.2940
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administrative Charge (if applicable)	$	0.25

Street Lighting

Service Charge (per connection)	$	1.9051
Distribution Volumetric Rate	$/kW	8.7319
Deferral and Variance Account Rider	$/kW	0.0000
Retail Transmission Rate – Network Service Rate	$/kW	1.3122
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.7979
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge (per customer)	$	0
Distribution Volumetric Rate	$/kW h	0.0458
Deferral and Variance Account Rider	$/kW h	0.0000
Retail Transmission Rate – Network Service Rate	$/kW	0.0043
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.0026
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administrative Charge (if applicable)	$	0.25

Specific Service Charges

Charge to certify cheque	$	15.00
Arrears certificate	$	15.00
Statement of account	$	15.00
Pulling post dated cheque	$	15.00
Duplicate invoice for previous billing	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Legal letter Charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	15.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Special meter reads	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	20.00
Collection of account charge – no disconnection - after regular hours	$	165.00
Disconnect/Reconnect Charge - At Meter during Regular Hours	$	40.00
Disconnect/Reconnect Charge - 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
Service call - after regular hours	$	165.00
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	(0.3500)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

Retail Service Charges (if applicable)

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing, charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction 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 Factor

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0750
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0397
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0643
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0340

RECONCILIATION OF RATE CLASS REVENUE:

The following Table 11 is used to examine the revenue expected to be generated with the proposed rates. Due to rounding, especially for the Fixed Charges, there will be a difference to the Total Distribution Revenue that was expected.

TABLE 11

2009 Test Year Distribution Revenue Reconciliation

Customer Class	Fixed Distribution Revenue	Variable Distribution Revenue	Transformer Allowance Credit	Total Distribution Revenue	Expected
Residential	$ 1,594,097	$ 2,495,246		$ 4,089,342	$ 4,094,337
GS <50 kW	$ 380,048	$ 631,667		$ 1,011,714	$ 1,010,706
GS>50 kW	$ 141,271	$ 786,865	($44,787.75)	$ 883,349	$ 883,348
Large Use >5MW	$ 60,804	$ 166,017	$0.00	$ 226,821	$ 226,816
Street Light	$ 69,740	$ 53,149		$ 122,889	$ 122,888
Sentinel	$ -	$ -		$ -	$ -
Unmetered Scattered Load	$ -	$ 20,871		$ 20,871	$ 20,889
Back-up/Standby Power	$ -	$ -		$ -	$ -
Total	**$ 2,245,959**	**$ 4,153,814**	**($44,787.75)**	**$ 6,354,986**	**$ 6,358,984**

Difference Due to Rate Rounding
$ 3,999

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 Deferral and Variance Accounts if applicable) and proposed 2009 Retail Transmission Service 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 IMPACT

End of Exhibit 9 (Rate Design)

BILL IMPACTS *(Monthly Consumptions)*

RESIDENTIAL

Consumption 100 kWh

	2008 BILL			2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			9.26			10.21	0.95	10.26%	4.72%
Distribution (kWh)	100	0.0184	1.84	100	0.0206	2.06	0.22	11.96%	1.09%
Smart Meter Rider (per month)			0.26			0.26	0.00	0.00%	0.00%
LRAM & SSM Rider (kWh)	100			100	0.0000	0.00	0.00	#DIV/0!	0.00%
Regulatory Assets (kWh)	100	0.0000	0.00	100	0.0000	0.00	0.00	#DIV/0!	0.00%
Sub-Total			**11.36**			**12.53**	**1.17**	**10.30%**	**5.81%**
Other Charges (kWh)	108	0.0208	2.25	108	0.0208	2.24	(0.02)	(0.81%)	(0.09%)
Cost of Power Commodity (kWh)	108	0.0500	5.42	108	0.0500	5.38	(0.04)	(0.81%)	(0.22%)
Total Bill			**19.03**			**20.14**	**1.11**	**5.82%**	**5.50%**

RESIDENTIAL

Consumption 250 kWh

	2008 BILL			2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			9.26			10.21	0.95	10.26%	2.74%
Distribution (kWh)	250	0.0184	4.60	250	0.0206	5.15	0.55	11.96%	1.59%
Smart Meter Rider (per month)			0.26			0.26	0.00	0.00%	0.00%
LRAM & SSM Rider (kWh)	250			250	0.0000	0.00	0.00	#DIV/0!	0.00%
Regulatory Assets (kWh)	250	0.0000	0.00	250	0.0000	0.00	0.00	#DIV/0!	0.00%
Sub-Total			**14.12**			**15.62**	**1.50**	**10.62%**	**4.33%**
Other Charges (kWh)	271	0.0208	5.64	269	0.0208	5.59	(0.05)	(0.81%)	(0.13%)
Cost of Power Commodity (kWh)	271	0.0500	13.55	269	0.0500	13.44	(0.11)	(0.81%)	(0.32%)
Total Bill			**33.30**			**34.65**	**1.35**	**4.04%**	**3.88%**

RESIDENTIAL

Consumption 500 kWh

	2008 BILL			2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			9.26			10.21	0.95	10.26%	1.61%
Distribution (kWh)	500	0.0184	9.20	500	0.0206	10.30	1.10	11.96%	1.87%
Smart Meter Rider (per month)			0.26			0.26	0.00	0.00%	0.00%
LRAM & SSM Rider (kWh)	500			500	0.0000	0.00	0.00	#DIV/0!	0.00%
Regulatory Assets (kWh)	500	0.0000	0.00	500	0.0000	0.00	0.00	#DIV/0!	0.00%
Sub-Total			**18.72**			**20.77**	**2.05**	**10.95%**	**3.48%**
Other Charges (kWh)	542	0.0208	11.27	538	0.0208	11.18	(0.09)	(0.81%)	(0.15%)
Cost of Power Commodity (kWh)	542	0.0500	27.10	538	0.0500	26.88	(0.22)	(0.81%)	(0.37%)
Total Bill			**57.09**			**58.83**	**1.74**	**3.05%**	**2.96%**

RESIDENTIAL

Consumption 750 kWh

	2008 BILL			2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			9.26			10.21	0.95	10.26%	1.12%
Distribution (kWh)	750	0.0184	13.80	750	0.0206	15.45	1.65	11.96%	1.94%
Smart Meter Rider (per month)			0.26			0.26	0.00	0.00%	0.00%
LRAM & SSM Rider (kWh)	750			750	0.0000	0.00	0.00	#DIV/0!	0.00%
Regulatory Assets (kWh)	750	0.0000	0.00	750	0.0000	0.00	0.00	#DIV/0!	0.00%
Sub-Total			**23.32**			**25.92**	**2.60**	**11.15%**	**3.06%**
Other Charges (kWh)	813	0.0208	16.91	806	0.0208	16.77	(0.14)	(0.81%)	(0.16%)
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)	213	0.0590	12.56	206	0.0590	12.17	(0.39)	(3.08%)	(0.46%)
Total Bill			**82.79**			**84.86**	**2.08**	**2.51%**	**2.45%**

RESIDENTIAL

Consumption 1,000 kWh

	2008 BILL			2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			9.26			10.21	0.95	10.26%	0.85%
Distribution (kWh)	1,000	0.0184	18.40	1,000	0.0206	20.60	2.20	11.96%	1.97%
Smart Meter Rider (per month)			0.26			0.26	0.00	0.00%	0.00%
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			**27.92**			**31.07**	**3.15**	**11.28%**	**2.83%**
Other Charges (kWh)	1,084	0.0208	22.54	1,075	0.0208	22.36	(0.18)	(0.81%)	(0.16%)
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)	484	0.0590	28.54	475	0.0590	28.03	(0.52)	(1.81%)	(0.46%)
Total Bill			**109.01**			**111.46**	**2.45**	**2.25%**	**2.20%**

RESIDENTIAL

Consumption		2008 BILL			2009 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
1,500 kWh	Monthly Service Charge			9.26			10.21	0.95	10.26%	0.58%
	Distribution (kWh)	1,500	0.0184	27.60	1,500	0.0206	30.90	3.30	11.96%	2.00%
	Smart Meter Rider (per month)			0.26			0.26	0.00	0.00%	0.00%
	LRAM & SSM Rider (kWh)	1,500			1,500	0.0000	0.00	0.00	#DIV/0!	0.00%
	Regulatory Assets (kWh)	1,500	0.0000	0.00	1,500	0.0000	0.00	0.00	#DIV/0!	0.00%
	Sub-Total			**37.12**			**41.37**	**4.25**	**11.45%**	**2.58%**
	Other Charges (kWh)	1,626	0.0208	33.81	1,613	0.0208	33.54	(0.27)	(0.81%)	(0.17%)
	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)	1,026	0.0590	60.52	1,013	0.0590	59.74	(0.77)	(1.28%)	(0.47%)
	Total Bill			**161.45**			**164.65**	**3.20**	**1.98%**	**1.95%**

RESIDENTIAL

Consumption		2008 BILL			2009 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
2,000 kWh	Monthly Service Charge			9.26			10.21	0.95	10.26%	0.44%
	Distribution (kWh)	2,000	0.0184	36.80	2,000	0.0206	41.20	4.40	11.96%	2.02%
	Smart Meter Rider (per month)			0.26			0.26	0.00	0.00%	0.00%
	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			**46.32**			**51.67**	**5.35**	**11.55%**	**2.46%**
	Other Charges (kWh)	2,168	0.0208	45.09	2,150	0.0208	44.72	(0.36)	(0.81%)	(0.17%)
	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)	1,568	0.0590	92.49	1,550	0.0590	91.46	(1.03)	(1.12%)	(0.47%)
	Total Bill			**213.89**			**217.85**	**3.95**	**1.85%**	**1.81%**

GENERAL SERVICE < 50 kW

Consumption		2008 BILL			2009 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
1,000 kWh	Monthly Service Charge			16.26			19.94	3.68	22.63%	3.27%
	Distribution (kWh)	1,000	0.0111	11.10	1,000	0.0139	13.90	2.80	25.23%	2.49%
	Smart Meter Rider (per month)			0.26			0.26	0.00	0.00%	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			**27.62**			**34.10**	**6.48**	**23.46%**	**5.77%**
	Other Charges (kWh)	1,084	0.0201	21.78	1,075	0.0201	21.61	(0.18)	(0.81%)	(0.16%)
	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)	334	0.0590	19.69	325	0.0590	19.18	(0.52)	(2.62%)	(0.46%)
	Total Bill			**106.60**			**112.39**	**5.79**	**5.43%**	**5.15%**

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			16.26			19.94	3.68	22.63%	1.74%
	Distribution (kWh)	2,000	0.0111	22.20	2,000	0.0139	27.80	5.60	25.23%	2.65%
	Smart Meter Rider (per month)			0.26			0.26	0.00	0.00%	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			**38.72**			**48.00**	**9.28**	**23.97%**	**4.39%**
	Other Charges (kWh)	2,168	0.0201	43.57	2,150	0.0201	43.22	(0.35)	(0.81%)	(0.17%)
	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)	1,418	0.0590	83.64	1,400	0.0590	82.61	(1.03)	(1.23%)	(0.49%)
	Total Bill			**203.43**			**211.32**	**7.90**	**3.88%**	**3.74%**

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			16.26			19.94	3.68	22.63%	0.72%
	Distribution (kWh)	5,000	0.0111	55.50	5,000	0.0139	69.50	14.00	25.23%	2.76%
	Smart Meter Rider (per month)			0.26			0.26	0.00	0.00%	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			**72.02**			**89.70**	**17.68**	**24.55%**	**3.48%**
	Other Charges (kWh)	5,419	0.0201	108.92	5,375	0.0201	108.04	(0.88)	(0.81%)	(0.17%)
	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)	4,669	0.0590	275.47	4,625	0.0590	272.89	(2.58)	(0.94%)	(0.51%)
	Total Bill			**493.91**			**508.13**	**14.22**	**2.88%**	**2.80%**

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			16.26			19.94	3.68	22.63%	0.37%
	Distribution (kWh)	10,000	0.0111	111.00	10,000	0.0139	139.00	28.00	25.23%	2.79%
	Smart Meter Rider (per month)			0.26			0.26	0.00	0.00%	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			**127.52**			**159.20**	**31.68**	**24.84%**	**3.16%**
	Other Charges (kWh)	10,838	0.0201	217.84	10,750	0.0201	216.09	(1.76)	(0.81%)	(0.18%)
	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)	10,088	0.0590	595.19	10,000	0.0590	590.03	(5.16)	(0.87%)	(0.51%)
	Total Bill			**978.06**			**1,002.81**	**24.76**	**2.53%**	**2.47%**

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			16.26			19.94	3.68	22.63%	0.25%
	Distribution (kWh)	15,000	0.0111	166.50	15,000	0.0139	208.50	42.00	25.23%	2.80%
	Smart Meter Rider (per month)			0.26			0.26	0.00	0.00%	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			**183.02**			**228.70**	**45.68**	**24.96%**	**3.05%**
	Other Charges (kWh)	16,257	0.0201	326.77	16,126	0.0201	324.13	(2.64)	(0.81%)	(0.18%)
	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)	15,507	0.0590	914.91	15,376	0.0590	907.17	(7.74)	(0.85%)	(0.52%)
	Total Bill			**1,462.20**			**1,497.50**	**35.30**	**2.41%**	**2.36%**

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			54.14			92.97	38.83	71.72%	2.47%
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	1.4434	86.60	60	2.6166	157.00	70.39	81.28%	4.47%
	Smart Meter Rider (per month)			0.26			0.26	0.00	0.00%	0.00%
	Regulatory Assets (kW)	60	0.0000	0.00	60	0.0000	0.00	0.00	#DIV/0!	0.00%
	Sub-Total			**141.00**			**250.23**	**109.22**	**77.46%**	**6.94%**
	Other Charges (kWh)	16,257	0.0132	214.59	16,126	0.0132	212.86	(1.73)	(0.81%)	(0.11%)
	Other Charges (kW)	60	2.7721	166.33	60	2.7721	166.33	0.00	0.00%	0.00%
	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)	15,507	0.0590	914.91	15,376	0.0590	907.17	(7.74)	(0.85%)	(0.49%)
	Total Bill			**1,474.34**			**1,574.08**	**99.75**	**6.77%**	**6.34%**

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			54.14			92.97	38.83	71.72%	1.10%
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	1.4434	144.34	100	2.6166	261.66	117.32	81.28%	3.31%
	Smart Meter Rider (per month)			0.26			0.26	0.00	0.00%	0.00%
	Regulatory Assets (kW)	100	0.0000	0.00	100	0.0000	0.00	0.00	#DIV/0!	0.00%
	Sub-Total			**198.74**			**354.89**	**156.15**	**78.57%**	**4.41%**
	Other Charges (kWh)	43,352	0.0132	572.25	43,002	0.0132	567.63	(4.62)	(0.81%)	(0.13%)
	Other Charges (kW)	100	2.7721	277.21	100	2.7721	277.21	0.00	0.00%	0.00%
	Cost of Power Commodity (kWh)	0	0.0545	0.00	0	0.0545	0.00	0.00	#DIV/0!	0.00%
	Cost of Power Commodity (kWh)	43,352	0.0545	2,362.68	43,002	0.0545	2,343.61	(19.08)	(0.81%)	(0.54%)
	Total Bill			**3,410.88**			**3,543.33**	**132.45**	**3.88%**	**3.74%**

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			54.14			92.97	38.83	71.72%	0.42%
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	1.4434	505.19	350	2.6166	915.81	410.62	81.28%	4.44%
	Smart Meter Rider (per month)			0.26			0.26	0.00	0.00%	0.00%
	Regulatory Assets (kW)	350	0.0000	0.00	350	0.0000	0.00	0.00	#DIV/0!	0.00%
	Sub-Total			**559.59**			**1,009.04**	**449.45**	**80.32%**	**4.86%**
	Other Charges (kWh)	108,380	0.0132	1,430.62	107,505	0.0132	1,419.07	(11.55)	(0.81%)	(0.12%)
	Other Charges (kW)	350	2.7721	970.24	350	2.7721	970.24	0.00	0.00%	0.00%
	Cost of Power Commodity (kWh)	0	0.0545	0.00	0	0.0545	0.00	0.00	#DIV/0!	0.00%
	Cost of Power Commodity (kWh)	108,380	0.0545	5,906.71	107,505	0.0545	5,859.02	(47.69)	(0.81%)	(0.52%)
	Total Bill			**8,867.15**			**9,257.36**	**390.21**	**4.40%**	**4.22%**

GENERAL SERVICE > 50 kW

Consumption
- 400,000 kWh
- 1,400 kW

	2008 BILL			2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			54.14			92.97	38.83	71.72%	0.11%
Distribution (kWh)	400,000	0.0000	0.00	400,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Distribution (kW)	1,400	0.8434	1,180.76	1,400	2.2666	3,173.24	1,992.48	168.75%	5.50%
Smart Meter Rider (per month)			0.26			0.26	0.00	0.00%	0.00%
Regulatory Assets (kW)	1,400	0.0000	0.00	1,400	0.0000	0.00	0.00	#DIV/0!	0.00%
Sub-Total			**1,235.16**			**3,266.47**	**2,031.31**	**164.46%**	**5.60%**
Other Charges (kWh)	433,520	0.0132	5,722.46	430,020	0.0132	5,676.26	(46.20)	(0.81%)	(0.13%)
Other Charges (kW)	1,400	2.7721	3,880.94	1,400	2.7721	3,880.94	0.00	0.00%	0.00%
Cost of Power Commodity (kWh)	0	0.0545	0.00	0	0.0545	0.00	0.00	#DIV/0!	0.00%
Cost of Power Commodity (kWh)	433,520	0.0545	23,626.84	430,020	0.0545	23,436.09	(190.75)	(0.81%)	(0.53%)
Total Bill			**34,465.40**			**36,259.76**	**1,794.35**	**5.21%**	**4.95%**

GENERAL SERVICE > 50 kW

Consumption
- 1,000,000 kWh
- 2,800 kW

	2008 BILL			2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			54.14			92.97	38.83	71.72%	0.04%
Distribution (kWh)	1,000,000	0.0000	0.00	1,000,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Distribution (kW)	2,800	0.8434	2,361.52	2,800	2.2666	6,346.48	3,984.96	168.75%	4.58%
Smart Meter Rider (per month)			0.26			0.26	0.00	0.00%	0.00%
Regulatory Assets (kW)	2,800	0.0000	0.00	2,800	0.0000	0.00	0.00	#DIV/0!	0.00%
Sub-Total			**2,415.92**			**6,439.71**	**4,023.79**	**166.55%**	**4.63%**
Other Charges (kWh)	1,083,800	0.0132	14,306.16	1,075,050	0.0132	14,190.66	(115.50)	(0.81%)	(0.13%)
Other Charges (kW)	2,800	2.7721	7,761.88	2,800	2.7721	7,761.88	0.00	0.00%	0.00%
Cost of Power Commodity (kWh)	0	0.0545	0.00	0	0.0545	0.00	0.00	#DIV/0!	0.00%
Cost of Power Commodity (kWh)	1,083,800	0.0545	59,067.10	1,075,050	0.0545	58,590.21	(476.89)	(0.81%)	(0.55%)
Total Bill			**83,551.06**			**86,982.46**	**3,431.40**	**4.11%**	**3.94%**

LARGE USER (> 5000 kW)

Consumption
- 3,118,000 kWh
- 6,250 kW

	2008 BILL			2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			6,908.18			5,067.00	(1,841.18)	(26.65%)	(0.71%)
Distribution (kWh)	3,118,000	0.0000	0.00	3,118,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Distribution (kW)	6,250	1.8860	11,787.50	6,250	2.2132	13,832.50	2,045.00	17.35%	0.79%
Smart Meter Rider (per month)			0.26			0.26	0.00	0.00%	0.00%
Regulatory Assets (kW)	6,250	0.0000	0.00	6,250	0.0000	0.00	0.00	#DIV/0!	0.00%
Sub-Total			**18,695.94**			**18,899.76**	**203.82**	**1.09%**	**0.08%**
Other Charges (kWh)	3,224,012	0.0132	42,556.96	3,224,012	0.0132	42,556.96	(0.00)	(0.00%)	(0.00%)
Other Charges (kW)	6,250	3.3401	20,875.63	6,250	3.3401	20,875.63	0.00	0.00%	0.00%
Cost of Power Commodity (kWh)	0	0.0545	0.00	0	0.0545	0.00	0.00	#DIV/0!	0.00%
Cost of Power Commodity (kWh)	3,224,012	0.0545	175,708.65	3,224,012	0.0545	175,708.65	(0.00)	(0.00%)	(0.00%)
Total Bill			**257,837.18**			**258,041.00**	**203.82**	**0.08%**	**0.08%**

LARGE USER (> 5000 kW)

Consumption
- 10,000,000 kWh
- 11,000 kW

	2008 BILL			2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			6,908.18			5,067.00	(1,841.18)	(26.65%)	(0.24%)
Distribution (kWh)	10,000,000	0.0000	0.00	10,000,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Distribution (kW)	11,000	1.8860	20,746.00	11,000	2.2132	24,345.20	3,599.20	17.35%	0.47%
Smart Meter Rider (per month)			0.26			0.26	0.00	0.00%	0.00%
Regulatory Assets (kW)	11,000	0.0000	0.00	11,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Sub-Total			**27,654.44**			**29,412.46**	**1,758.02**	**6.36%**	**0.23%**
Other Charges (kWh)	10,340,000	0.0132	136,488.00	10,340,000	0.0132	136,488.00	(0.00)	(0.00%)	(0.00%)
Other Charges (kW)	11,000	3.3401	36,741.10	11,000	3.3401	36,741.10	0.00	0.00%	0.00%
Cost of Power Commodity (kWh)	0	0.0545	0.00	0	0.0545	0.00	0.00	#DIV/0!	0.00%
Cost of Power Commodity (kWh)	10,340,000	0.0545	563,530.00	10,340,000	0.0545	563,530.00	(0.00)	(0.00%)	(0.00%)
Total Bill			**764,413.54**			**766,171.56**	**1,758.02**	**0.23%**	**0.23%**

Street Lighting

Billing Determinants
- 1,964 Connections
- 96,667 kWh
- 290 kW

	2008 BILL			2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge	1,964	0.6100	1,198.04	1,964	1.9051	3,741.62	2,543.58	212.31%	18.27%
Distribution (kWh)	96,667	0.0000	0.00	96,667	0.0000	0.00	0.00	#DIV/0!	0.00%
Distribution (kW)	290	2.9941	868.29	290	8.7319	2,532.25	1,663.96	191.64%	11.95%
Regulatory Assets (kW)	290	0.0000	0.00	290	0.0000	0.00	0.00	#DIV/0!	0.00%
Sub-Total			**2,066.33**			**6,273.87**	**4,207.54**	**203.62%**	**30.22%**
Other Charges (kWh)	104,767	0.0132	1,382.93	103,921	0.0132	1,371.76	(11.17)	(0.81%)	(0.08%)
Other Charges (kW)	290	2.1101	611.93	290	2.1101	611.93	0.00	0.00%	0.00%
Cost of Power Commodity (kWh)	750	0.0545	40.88	750	0.0545	40.88	0.00	0.00%	0.00%
Cost of Power Commodity (kWh)	104,017	0.0545	5,668.94	103,171	0.0545	5,622.85	(46.10)	(0.81%)	(0.33%)
Total Bill			**9,771.01**			**13,921.28**	**4,150.27**	**42.48%**	**29.81%**

Street Lighting

Billing Determinants
- 672 Connections
- 48,333 kWh
- 145 kW

	2008 BILL			2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge	672	0.6100	409.92	672	1.9051	1,280.23	870.31	212.31%	13.66%
Distribution (kWh)	48,333	0.0000	0.00	48,333	0.0000	0.00	0.00	#DIV/0!	0.00%
Distribution (kW)	145	2.9941	434.14	145	8.7319	1,266.13	831.98	191.64%	13.06%
Regulatory Assets (kW)	145	0.0000	0.00	145	0.0000	0.00	0.00	#DIV/0!	0.00%
Sub-Total			**844.06**			**2,546.35**	**1,702.29**	**201.68%**	**26.72%**
Other Charges (kWh)	52,384	0.0132	691.46	51,961	0.0132	685.88	(5.58)	(0.81%)	(0.09%)
Other Charges (kW)	145	2.1101	305.96	145	2.1101	305.96	0.00	0.00%	0.00%
Cost of Power Commodity (kWh)	750	0.0545	40.88	750	0.0545	40.88	0.00	0.00%	0.00%
Cost of Power Commodity (kWh)	51,634	0.0545	2,814.03	51,211	0.0545	2,790.99	(23.05)	(0.82%)	(0.36%)
Total Bill			**4,696.40**			**6,370.06**	**1,673.66**	**35.64%**	**26.27%**

Street Lighting

Billing Determinants
352 Connections
21,667 kWh
65 kW

	2008 BILL			2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge	352	0.6100	214.72	352	1.9051	670.60	455.88	212.31%	15.44%
Distribution (kWh)	21,667	0.0000	0.00	21,667	0.0000	0.00	0.00	#DIV/0!	0.00%
Distribution (kW)	65	2.9941	194.62	65	8.7319	567.57	372.96	191.64%	12.63%
Regulatory Assets (kW)	65	0.0000	0.00	65	0.0000	0.00	0.00	#DIV/0!	0.00%
Sub-Total			**409.34**			**1,238.17**	**828.83**	**202.48%**	**28.07%**
Other Charges (kWh)	23,482	0.0132	309.97	23,293	0.0132	307.46	(2.50)	(0.81%)	(0.08%)
Other Charges (kW)	65	2.1101	137.16	65	2.1101	137.16	0.00	0.00%	0.00%
Cost of Power Commodity (kWh)	750	0.0545	40.88	750	0.0545	40.88	0.00	0.00%	0.00%
Cost of Power Commodity (kWh)	22,732	0.0545	1,238.91	22,543	0.0545	1,228.58	(10.33)	(0.83%)	(0.35%)
Total Bill			**2,136.25**			**2,952.24**	**816.00**	**38.20%**	**27.64%**

UNMETERED SCATTERED LOAD

Consumption
18,000 kWh
0 kW

	2008 BILL			2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			0.00			0.00	0.00	#DIV/0!	0.00%
Distribution (kWh)	18,000	0.0162	291.60	18,000	0.0458	824.40	532.80	182.72%	24.96%
Distribution (kW)	0	0.0000	0.00	0	0.0000	0.00	0.00	#DIV/0!	0.00%
Smart Meter Rider (per month)			0.00			0.26	0.26	#DIV/0!	0.01%
Regulatory Assets (kW)	0	0.0000	0.00	0	0.0000	0.00	0.00	#DIV/0!	0.00%
Sub-Total			**291.60**			**824.66**	**533.06**	**182.81%**	**24.97%**
Other Charges (kWh)	19,508	0.0132	257.51	19,351	0.0132	255.43	(2.08)	(0.81%)	(0.10%)
Other Charges (kW)	0	2.7721	0.00	0	2.7721	0.00	0.00	#DIV/0!	0.00%
Cost of Power Commodity (kWh)	750	0.0545	40.88	750	0.0545	40.88	0.00	0.00%	0.00%
Cost of Power Commodity (kWh)	18,758	0.0545	1,022.33	18,601	0.0545	1,013.75	(8.58)	(0.84%)	(0.40%)
Total Bill			**1,612.32**			**2,134.72**	**522.40**	**32.40%**	**24.47%**