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ONTARIO ENERGY BOARD

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 ("LDC Name") 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. EB-2008-0248.

APPLICATION

The Applicant is WEST COAST HURON ENERGY (WCHE). WCHE is an Ontario corporation with its office in the Town of Goderich Ontario. WCHE carries on the business of distributing electricity within the town of Goderich.

WCHE 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.

Except where specifically identified in the Application, WCHE followed Chapter 2 of the Filing Requirements for Transmission and Distribution Applications dated November 14, 2006 (the "Filing Requirements") in order to prepare this application

The Schedule of Rates and Charges proposed in this Application is identified in Exhibit 9; Tab 1; Schedule 6 attached to this Summary.

WCHE requests that the OEB make its Rate Order effective May 1, 2009 in accordance with the Filing Requirements.

WCHE 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;
- (ii) the proposed adjusted rates are necessary to meet WCHE's Market Based Rate of Return and 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 WCHE; and
- (iv) other grounds as may be set out in the material accompanying this Application Summary.

WCHE applies for an Order or Orders approving the proposed distribution rates and other charges set out in this Application to be effective May 1, 2009, or as soon as

possible thereafter. WCHE submits these rates and charges are just and reasonable pursuant to section 78 of the Ontario Energy Board Act, 1998 being Schedule B to the Energy Competition Act, 1998, S.O. 1998, c.15,

The address of service for WCHE is: 64 West Street, Goderich, Ontario N7A 2K4

DATED at Goderich Ontario, this 30th day of September, 2008.

Larry McCabe, President/Secretary
West Coast Huron Energy
lmccabe@goderich.ca

Judy Kay, Treasurer
West Coast Huron Energy
jkay@goderich.ca

Electricity Distribution License

See Appendix A

CONTACT INFORMATION

Larry McCabe
President/Secretary

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Judy Kay
Treasurer

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SPECIFIC APPROVALS REQUESTED

- Approval to charge rates effective May 1, 2009 to recover a revenue deficiency of \$618,459 (Exhibit 7, Tab 1, Schedule 1,)
- Approval of WCHE's proposed change in capital structure, decreasing WCHE's deemed common equity component from 50% to 46.67% (Exhibit 6, Tab 1, Schedule 2,) 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 to continue the following deferral/variance accounts on May 1, 2008 (Exhibit 5, Tab, Schedule):
 - o 1550 LV Variance Account
 - o 1580 RSVA-Wholesale Market Service Charge
 - o 1582 RSVA-One-time Wholesale Market Service
 - o 1584 RSVA-Retail Transmission Network Charge
 - o 1586 RSVA-Retail Transmission Connection Charge
 - o 1588 RSVA-Power
 - o 1562 Deferred Payments in Lieu of Taxes
- Approval of the proposed loss factor of 4.67% Exhibit 4, Tab 2, Schedule 9.

DRAFT ISSUES LIST

1. Smart Metering

West Coast Huron Energy has not included any costs with respect to smart metering in this rate application. In its current rates WCHE has approval for \$0.26 per customer per month to cover the costs for Smart Metering. WCHE was unsure of how these costs were to be handled in this rate process and requests that the Board approve the appropriate change in rates for this initiative.

PROCEDURAL ORDERS/MOTIONS/NOTICES

To be included when received

ACCOUNTING ORDERS REQUESTED

WCHE requests no accounting orders.

NON-COMPLIANCE WITH UNIFORM SYSTEM OF ACCOUNTS

WCHE follows the main categories and accounting guidelines as stated in the Uniform System of Accounts.

MAP OF DISTRIBUTION SYSTEM

Distribution System Maps are located in Appendix B.

LIST OF NEIGHBORING UTILITIES

**LIST OF ADJACENT
DISTRIBUTORS**

Hydro One Networks Inc.
483 Bay St.
Toronto, ON M5G 2P5

Direct line: 416-345-5000
Direct Fax:
Website: www.HydroOne.com

DESCRIPTION OF DISTRIBUTOR

COMMUNITIES SERVED:	Goderich
TOTAL SERVICE AREA	8 sq km
RURAL SERVICE AREA	0 sq km
DISTRIBUTION TYPE	Directly connected
SERVICE AREA POPULATION	7,411
MUNICIPAL POPULATION	7,411
BOUNDARIES	West: Refer to Schedule 1 of distribution License App. A North: Refer to Schedule 1 of distribution License App. A East: Refer to Schedule 1 of distribution License App. A South: Refer to Schedule 1 of distribution License App. A

EXPLANATION OF HOST AND EMBEDDED UTILITIES

West Coast Huron Energy is neither a Host or an Embedded Utility. WCHE is directly connected to the IESO grid.

UTILITY ORGANIZATIONAL CHART

See Appendix C

CORPORATE ENTITIES RELATIONSHIP CHARTS

See Appendix D

PLANNED CHANGES IN CORPORATE AND OPERATIONAL STRUCTURE

West Coast Huron Energy has no planned changes in its corporate and operational structure.

STATUS REPORT ON BOARD DIRECTIVES

West Coast Huron Energy has no Board Directives at this time.

CONDITIONS OF SERVICE

See Appendix E

PLANNED CHANGES IN CONDITIONS OF SERVICE AND SERVICE CHARGES

West Coast Huron Energy reviews its Conditions of Service periodically as required by the Distribution System Code.

West Coast Huron Energy is requesting no changes to its currently approved Specific Service Charges.

LIST OF WITNESSES

To be provided if oral hearing occurs

SUMMARY OF THE APPLICATION

PURPOSE AND NEED

WCHE estimates that its present rates will produce a deficiency in distribution revenue of \$618,459 for the 2009 Test Year. Excluded from this estimate is the impact of energy costs. WCHE therefore seeks the Board's approval to revise its rates applicable to its distribution of electricity. The issues to be reviewed in this case, as WCHE sees them, are discussed below.

Through this Application, WCHE seeks:

- To recover:
 - o Revenue deficiency arising from changes in OM&A, Amortization, Rate Base, Rate of Return and PILS
- To change:
 - o Distribution Loss Factor
- To reflect:
 - o Just and reasonable Distribution Rates that have been filed in accordance with the Ontario Energy Board Filing Requirements for Distribution Rate Applications

The information used in this Application is WCHE's forecasted results for its 2009 Test Year. With the rates presently in effect, WCHE estimates that its revenue for 2009 would not be sufficient to provide a reasonable return. WCHE is also presenting the historical actual information for fiscal 2006 and 2007, information for the current approved test year and six months actual and six months forecast for the fiscal 2008 bridge year.

TIMING

The financial information supporting the test Year for this Application will be WCHE'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 WCHE as needed to enable it to earn a reasonable return for fiscal 2009. For the required revenues to match and appropriately offset the expected costs of service for the Test Year, revised rates reflecting the Board's decision must be effective for volumes consumed on and after May 1, 2009.

Calculation of Revenue Requirement

	2006 EDR	2009 Test
OM&A	\$1,121,583	\$1,821,250
Amortization	\$200,009	\$343,019
Return	\$387,171	\$384,776
PILS	\$41,727	\$84,691
Revenue Offset	-\$114,898	-\$92,696
Revenue Requirement	\$1,635,591	\$2,541,041

CUSTOMER IMPACT

West Coast Huron Energy will not have unacceptable impacts on the total of the customer's bill and therefore WCHE is not proposing any rate mitigation measures.

Residential	UOM	2008	2009	% Change
Service Charge	\$	\$14.0900	\$14.0900	0.00%
Distribution Volumetric Rate	\$/kWh	\$0.0084	\$0.0239	184.24%
Retail Transmission Rate – Network Service Rate	\$/kWh	\$0.0039	\$0.0039	0.00%
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	\$0.0041	\$0.0041	0.00%
Wholesale Market Service Rate	\$/kWh	\$0.0052	\$0.0052	0.00%
Rural Rate Protection Charge	\$/kWh	\$0.0010	\$0.0010	0.00%
Regulated Price Plan – Administration Charge	\$	\$0.2500	\$0.2500	0.00%

In order to adjust the fixed cost recovery through the monthly fixed charge, WCHE is proposing to increase the monthly customer charge by \$0.77 in the 2008 test year. The net impact of these changes is an increase in the revenue-to-cost ratios for Residential customers (from 91.12% to 101.00%).

The impact on a typical residential customer is an increase of 1.9% on the delivery component of the bill. The overall bill impact on a typical Residential customer is shown in detail in Exhibit 9, Tab 1, Schedule 9.

GS<50 kW		2008	2009	% Change
Service Charge	\$	\$33.4600	\$33.4600	0.00%
Distribution Volumetric Rate	\$/kWh	\$0.0052	\$0.0151	190.74%
Retail Transmission Rate – Network Service Rate	\$/kWh	\$0.0036	\$0.0036	0.00%
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	\$0.0037	\$0.0037	0.00%
Wholesale Market Service Rate	\$/kWh	\$0.0052	\$0.0052	0.00%
Rural Rate Protection Charge	\$/kWh	\$0.0010	\$0.0010	0.00%
Regulated Price Plan – Administration Charge	\$	\$0.2500	\$0.2500	0.00%

In order to adjust the fixed cost recovery through the monthly fixed charge, WCHE is proposing to decrease the monthly customer charge by \$8.56 in the 2008 test year. The net impact of these changes is a decrease in the revenue-to-cost ratios for Residential customers (from 144.26% to 101.00%).

The impact on a typical GS<50 kW customer is a decrease of 7.0% on the delivery component of the bill. The overall bill impact on a typical GS<50 kW customer is shown in detail in Exhibit 9, Tab 1, Schedule 9.

GS>50 to 499 kW		2008	2009	% Change
Service Charge	\$	\$402.5600	\$402.5600	0.00%
Distribution Volumetric Rate	\$/kW	\$1.0695	\$1.2645	18.23%
Retail Transmission Rate – Network Service Rate	\$/kW	\$1.4585	\$1.4585	0.00%
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	\$1.4725	\$1.4725	0.00%
Wholesale Market Service Rate	\$/kWh	\$0.0052	\$0.0052	0.00%
Rural Rate Protection Charge	\$/kWh	\$0.0010	\$0.0010	0.00%
Regulated Price Plan – Administration Charge	\$	\$0.2500	\$0.2500	0.00%

In order to adjust the fixed cost recovery through the monthly fixed charge, WCHE is proposing to decrease the monthly customer charge by \$181.81 in the 2008 test year. The net impact of these changes is a decrease in the revenue-to-cost ratios for GS.50 to 999 kW customers (from 117.00% to 101.00%).

The impact on a typical GS>50 to 999 kW customer is a decrease of 1.0% on the delivery component of the bill. The overall bill impact on a typical GS>50 to 999 kW customer is shown in detail in Exhibit 9, Tab 1, Schedule 9.

GS>500 to 4999 kW		2008	2009	% Change
Service Charge	\$	\$3,476.4200	\$2,322.4059	-33.20%
Distribution Volumetric Rate	\$/kW	\$1.4725	\$1.4370	-2.41%
Retail Transmission Rate – Network Service Rate	\$/kW	\$1.5491	\$1.5491	0.00%
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	\$1.6142	\$1.6142	0.00%
Wholesale Market Service Rate	\$/kWh	\$0.0052	\$0.0052	0.00%
Rural Rate Protection Charge	\$/kWh	\$0.0010	\$0.0010	0.00%
Regulated Price Plan – Administration Charge	\$	\$0.2500	\$0.2500	0.00%

In order to adjust the fixed cost recovery through the monthly fixed charge, WCHE is proposing to decrease the monthly customer charge by \$3,993.70 in the 2008 test year. The net impact of these changes is a decrease in the revenue-to-cost ratios for GS>1000 to 2999 kW customers (from 147.47% to 101.00%).

The impact on a typical GS>1000 to 2999 kW customer is a decrease of 3.0% on the delivery component of the bill. The overall bill impact on a typical GS>1000 to 2999 kW customer is shown in detail in Exhibit 9, Tab 1, Schedule 9.

Large Use		2008	2009	% Change
Service Charge	\$	\$8,652.7200	\$8,652.7200	0.00%
Distribution Volumetric Rate	\$/kW	\$0.7592	\$1.8445	142.96%
Retail Transmission Rate – Network Service Rate	\$/kW	\$1.7153	\$1.7153	0.00%
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	\$1.8459	\$1.8459	0.00%
Wholesale Market Service Rate	\$/kWh	\$0.0052	\$0.0052	0.00%
Rural Rate Protection Charge	\$/kWh	\$0.0010	\$0.0010	0.00%
Regulated Price Plan – Administration Charge	\$	\$0.2500	\$0.2500	0.00%

In order to adjust the fixed cost recovery through the monthly fixed charge, WCHE is proposing to decrease the monthly customer charge by \$4,369.37 in the 2008 test year. The net impact of these changes is a decrease in the revenue-to-cost ratios for GS>3000 to 4999 kW customers (from 190.03% to 101.00%).

The impact on a typical GS>3000 to 4999 kW customer is a decrease of 8.0% on the delivery component of the bill. The overall bill impact on a typical GS<50 kW customer is shown in detail in Exhibit 9, Tab 1, Schedule 9

Street Lighting		2008	2009	% Change
Service Charge	\$	\$0.7100	\$1.9458	174.05%
Distribution Volumetric Rate	\$/kW	\$2.6563	\$16.4939	520.94%
Retail Transmission Rate – Network Service Rate	\$/kW	\$1.1000	\$1.1000	0.00%
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	\$1.1384	\$1.1384	0.00%
Wholesale Market Service Rate	\$/kWh	\$0.0052	\$0.0052	0.00%
Rural Rate Protection Charge	\$/kWh	\$0.0010	\$0.0010	0.00%
Regulated Price Plan – Administration Charge	\$	\$0.2500	\$0.2500	0.00%

Explanation; In order to adjust the fixed cost recovery through the monthly fixed charge, WCHE is proposing to decrease the monthly customer charge by \$4,757.79 in the 2008 test year. The net impact of these changes is an increase in the revenue-to-cost ratios for Large Use customers (from 99.29% to 101.00%).

The impact on a typical Large Use customer is an increase of 1.0% on the delivery component of the bill. The overall bill impact on a typical Large Use customer is shown in detail in Exhibit 9, Tab 1, Schedule 9.

Sentinel Lighting		2008	2009	% Change
Service Charge	\$	\$5.6400	\$5.6400	0.00%
Distribution Volumetric Rate	\$/kW	\$4.2206	\$14.4820	243.13%
Retail Transmission Rate – Network Service Rate	\$/kW	\$1.1056	\$1.1056	0.00%
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	\$1.1621	\$1.1621	0.00%
Wholesale Market Service Rate	\$/kWh	\$0.0052	\$0.0052	0.00%
Rural Rate Protection Charge	\$/kWh	\$0.0010	\$0.0010	0.00%
Regulated Price Plan – Administration Charge	\$	\$0.2500	\$0.2500	0.00%

Explanation; In order to adjust the fixed cost recovery through the monthly fixed charge, WCHE is proposing to increase the monthly customer charge by \$3.18 in the 2008 test year. The net impact of these changes is an increase in the revenue-to-cost ratios for Street Lighting connections (from 14.35% to 70.00%).

The impact on a typical Street Lighting connection is an increase of 64.0% on the delivery component of the bill. The overall bill impact on a typical Street Lighting connection is shown in detail in Exhibit 9, Tab 1, Schedule 9.

Unmetered Scattered Load		2008	2009	% Change
Service Charge	\$	\$33.4700	\$33.4700	0.00%
Distribution Volumetric Rate	\$/kWh	\$0.0052	\$0.0338	549.12%
Retail Transmission Rate – Network Service Rate	\$/kWh	\$0.0036	\$0.0036	0.00%
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	\$0.0037	\$0.0037	0.00%
Wholesale Market Service Rate	\$/kWh	\$0.0052	\$0.0052	0.00%
Rural Rate Protection Charge	\$/kWh	\$0.0010	\$0.0010	0.00%
Regulated Price Plan – Administration Charge	\$	\$0.2500	\$0.2500	0.00%

Explanation; In order to adjust the fixed cost recovery through the monthly fixed charge, WCHE is proposing to increase the monthly customer charge by \$3.00 in the 2008 test year. The net impact of these changes is a decrease in the revenue-to-cost ratios for Sentinel Lighting customers (from 55.67% to 101.00%).

The impact on a typical Sentinel Lighting customer is an increase of 36.0% on the delivery component of the bill. The overall bill impact on a typical Sentinel Lighting customer is shown in detail in Exhibit 9, Tab 1, Schedule 9.

Specific Service Charges

West Coast Huron Energy proposes no change to its currently approved Specific Service Charges. The Charges are listed below.

Specific Service Charges

Customer Administration

Arrears Certificate	\$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	\$	30.00
Special meter reads	\$	15.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	\$	30.00

Non-Payment of Account

Late Payment - Per month	%	1.50
Late Payment - Per annum	%	19.56
Collection of account charge-no disconnection	\$	30.00
Disconnect/Reconnect at meter-during regular hours	\$	65.00

Specific Charge for Access to the Power Poles \$/pole/year	\$	22.35
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Allowances

Transformer Allowance for Ownership - per kW of billing demand/month	\$	(0.60)
Primary Metering allowance for transformer losses - applied to measured demand and energy	%	(1.00)

Loss Factors

	2007	2008	% Change
Total Loss Factor - Secondary Metered Customer <5,000 kW	1.0427	1.0436	2.11%
Total Loss Factor - Secondary Metered Customer >5,000 kW	1.0145	1.0145	0.00%
Total Loss Factor - Primary Metered Customer <5,000 kW	1.0322	1.0331	2.80%
Total Loss Factor - Primary Metered Customer >5,000 kW	1.0045	1.0045	0.00%

MAJOR ISSUES

There are a number of issues that, although they may not all be defined as major, are anticipated to be examined in this case. These issues are listed below.

Capital Structure

WCHE is requesting a change in its deemed capital structure. Specifically, WCHE is requesting a decrease in the deemed equity ratio from 50% to 47% consistent with the 3 year phase in of WCHE'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.

Return on Equity

In addition, WCHE has assumed a return on equity of 8.68% consistent with the methodology outlined in Appendix B of the Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario Electricity Distributors dated December 20, 2006. WCHE understands the OEB will be finalizing the return on equity for 2008 rates based on January 2008 market interest rate information.

Capital Expenditures

WCHE continues to expand and reinforce its distribution system in order to meet the demand of new and existing customers in its service territory, and to ensure and enhance its quality of service. This increase in demand comes both from currently un-serviced areas as well as existing areas needing upgrades.

Operating and Maintenance Costs

Operating and maintenance costs have been forecast to reflect the impact of inflation, customer growth, safety, reliability and expected changes in costs.

BUDGET DIRECTIVES

WCHE compiles budget information for the three major components of the budgeting process: revenue forecasts, operating and maintenance expense forecast and capital budgets. This budget information is compiled for both the bridge and test years.

Revenue Forecast

The 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 and Maintenance Expense Forecast

The operating and maintenance expenses for fiscal 2008 bridge year and the 2009 test year have been forecast using a zero based methodology and is strongly influenced by prior year experience. Each item is reviewed account by account for each of the forecast years.

Capital Budget

All capital expenditures are budgeted on a line by line basis based on need and forecasted customer growth. WCHE utilizes an Asset Management tool which weighs the need for new capital projects based on a wide range factors such as reliability, safety, customer growth and economic factors. This tool allows WCHE to weigh all capital projects against these metrics and recommends approval of those projects that best meet the above noted criteria.

CHANGES IN METHODOLOGY

The following is a summary of the changes in methodology requested by WCHE in the current proceeding:

a) Capital Structure

WCHE has applied to change its existing debt equity split to a deemed structure of 53.33% Debt and 46.67% Equity.

b) Return on Equity

WCHE has applied no change to current the methodology in existence for return on equity in this application.

c) Interest Rate Applicable to Deferral/Variance Accounts

WCHE has applied no change to the current methodology in existence for Deferral/Variance Account interest rates in this application.

d) Cost Allocation & Fully Allocated Costing Study

WCHE has applied no change to the current methodology in existence for Cost Allocation & Fully Allocated Costing Study in this application, as per the report of the Board Application of Cost Allocation for Electricity Distributors released November 28th, 2007.

NUMERICAL DETAILS OF CAUSES OF Deficiency
2009 TEST YEAR

	Per Existing Rates				Application Test Year	Revenue Sufficiency or Deficiency
	2006 EDR	IRM Rate Changes	Load Changes	Test Year		
Distribution Expenses	\$1,321,591.92	\$23,788.65	\$216,570.48	\$1,561,951.05	\$2,149,269.50	\$587,318.44
Return on Capital	\$387,170.58	\$6,969.07	\$63,445.99	\$457,585.65	\$384,612.40	-\$72,973.25
PILs	\$41,727.00	\$751.09	\$6,837.84	\$49,315.93	\$84,657.71	\$35,341.78
Total Service Revenues	\$1,750,489.50	\$31,508.81	\$286,854.31	\$2,068,852.63	\$2,618,539.61	\$549,686.98

CAUSES OF REVENUE DEFICIENCY

The increase in WCHE's distribution expenses including depreciation expense in the 2009 Test Year of \$398,726 relative to estimated amount to be collected in existing rates results are from normal operating expenses plus inflation.

The change in WCHE's return on capital in the 2008 Test Year of \$26,844 relative to estimated amount to be collected in existing rates results from the change in the deemed debt equity split.

The change in WCHE's PILs in the 2008 Test Year of \$42,931 relative to estimated amount to be collected in existing rates reflects the change in the tax rates and the change in deemed taxable revenue.

AUDITED FINANCIAL STATEMENTS
AT
DECEMBER 31 2007

See Appendix F

PRO FORMA FINANCIAL STATEMENTS
AT
DECEMBER 31 2008

See Appendix G

PRO FORMA FINANCIAL STATEMENTS
AT
DECEMBER 31 2009

See Appendix H

RECONCILIATION BETWEEN FINANCIAL STATEMENTS AND FINANCIAL RESULTS FILED

West Coast Huron Energy's Financial Statements and Financial Results filed for 2007 match on another. Therefore, no reconciliation is required.

PROPOSED ACCOUNTING TREATMENT

West Coast Huron Energy does not have any projects with a life cycle of greater than one year in this application.

INFORMATION ON PARENT AND SUBSIDIARIES

West Coast Huron Energy's Parent is the Town of Goderich and there are no subsidiaries.

<u>Ex.</u>	<u>Tab</u>	<u>Schedule</u>	<u>Contents of Schedule</u>
<u>2 – Rate Base</u>			
	1		<u>Overview</u>
		1	Rate Base Overview
		2	Rate Base Summary Table
		3	Variance Analysis on Rate Base Table
	2		<u>Gross Assets – Property, Plant and Equipment Accumulated Depreciation</u>
		1	Continuity Statements
		2	Gross Assets Table
		3	Materiality Analysis on Gross Assets
		4	Accumulated Depreciation Table
		5	Materiality Analysis on Accumulated Depreciation
	3		<u>Capital Budget</u>
		1	Capital Budget by Project
		2	Materiality Analysis on Capital Additions
		3	System Expansions
		4	Capitalization Policy
	4		<u>Allowance for Working Capital</u>
		1	Working Capital Allowance calculations by account

RATE BASE OVERVIEW

A projection of West Coast Huron Energy rate base is provided for both the Bridge Year (2008) and the Test Year (2009). Historical data pertaining to rate base is also presented for 2006 Approved through to 2007 Actual.

West Coast Huron Energy's forecast rate base for the test year is \$5,280,630. The rate base underlying the test year revenue requirement includes a forecast of net fixed assets, plus a working capital allowance. Net fixed assets are gross assets in service minus accumulated depreciation and contributed capital. Details for the utility's working capital allowance are provided at Exhibit 2, Tab 4, Schedule 1.

Continuity schedules for Historical Board Approved, Historical Actual, Bridge and Test years are provided at Exhibit 2, Tab 2, Schedule 1.

Gross Asset – Property, Plant and Equipment and Accumulated Depreciation

The bridge and test year's gross asset balance reflects the capital expenditure programs forecast for both years. These programs are described in detail in the company's written evidence at Exhibit 2, Tab 2, Schedule 1, 2, 3, & 4. The justification for capital projects in excess of 1% of the net fixed assets are filed at Exhibit 2, Tab 2, Schedule 2.

Capital Budget

The Bridge year (2008) and Test year (2009) capital budgets are included in Exhibit 2, Tab, 3 Schedule 1.

Allowance for Working Capital

The allowance for working capital follows the board's current methodology of 15% of predetermined account balances, this calculation is detailed in Exhibit 2, Tab 4, Schedule 1.

RATE BASE SUMMARY TABLE

RATE BASE SUMMARY	2006 Board Approved	2006 Actual	Variance from 2006 Board Approved (\$'s)	2006 Actual	2007 Actual	Variance from 2006 Actual (\$'s)	2007 Actual	2008 Bridge	Variance from 2007 Actual (\$'s)	2008 Bridge	2009 Test	Variance from 2008 Bridge (\$'s)
	(\$'s)	(\$'s)	(\$'s)	(\$'s)	(\$'s)	(\$'s)	(\$'s)	(\$'s)	(\$'s)	(\$'s)	(\$'s)	(\$'s)
<u>Gross Asset</u>												
Asset Values at Cost	\$4,464,965	\$4,683,791	\$218,826	\$4,683,791	\$4,880,019	\$196,228	\$4,880,019	\$5,193,610	\$313,592	\$5,193,610	\$5,797,610	\$604,000
<u>Accumulated Depreciation</u>												
Depreciation	-\$748,304	-\$939,201	-\$190,897	-\$939,201	-\$1,193,028	-\$253,827	-\$1,193,028	-\$1,473,165	-\$280,137	-\$1,473,165	-\$1,788,754	-\$315,589
Net Fixed Asset	\$3,716,660	\$3,744,590	\$27,929	\$3,744,590	\$3,686,991	-\$57,599	\$3,686,991	\$3,720,445	\$33,454	\$3,720,445	\$4,008,857	\$288,411
<u>Allowance for Working Capital</u>												
	\$1,048,516	\$1,199,097	\$150,581	\$1,199,097	\$1,137,603	-\$61,495	\$1,137,603	\$1,191,621	\$54,018	\$1,191,621	\$1,274,024	\$82,403
Utility Rate Base	\$4,765,176	\$4,943,687	\$178,511	\$4,943,687	\$4,824,594	-\$119,093	\$4,824,594	\$4,912,066	\$87,472	\$4,912,066	\$5,282,880	\$370,814

VARIANCE ANALYSIS ON RATE BASE SUMMARY TABLE

A summary of utility rate base is presented in Exhibit 2, Tab 1, Schedule 2

2009 Test Year

As shown in Exhibit 2, Tab 1, Schedule 2, the total rate base in the 2009 test year is forecast to be \$5,282,880. Net fixed assets accounts for \$4,008,857 of this total. The allowance for working capital totals \$1,274,024.

Comparison to 2008 Bridge Year

The total rate base is expected to increase by \$370,814 or 7.5% in the 2009 test year than in the 2008 bridge year. This increase is shown in Exhibit 2, Tab 1, Schedule 2. This increase is the result of a \$288,411 increase in net fixed assets due to capital additions and a \$82,403 increase in the working capital allowance which is primarily a result of a \$20,344 increase in working capital allowance related to the cost of power. This increase in cost of power working capital allowance is a direct result of the weather normalized consumption forecast causing an increase in cost of power.

2008 Bridge Year**Comparison to 2007 Actual**

The total rate base is \$87,472 or 1.8% higher in the 2008 bridge year than in 2007 actual. This increase is shown in Exhibit 2, Tab 1, Schedule 2. This increase/decrease is the result of a \$33,454 increase in net fixed assets due to capital additions and a \$54,018 increase in working capital.

2007 Actual**Comparison to 2006 Actual**

The 2006 total rate base is \$-119,093 or 2% lower in 2007 than the 2006 Actual rate base. This decrease is shown in Exhibit 2, Tab 1, Schedule 2. This decrease is the result of a \$57,599 decrease in net fixed assets, and a \$61,495 decrease in working capital.

2006 Actual**Comparison to 2006 Board Approved**

The 2006 total rate base is \$178,511 or 3.7% higher in 2006 than the 2006 Board Approved rate base. This increase is shown in Exhibit 2, Tab 1, Schedule 2. This increase is the result of a \$27,929 increase in net fixed assets, and a \$150,581 increase in working capital. This increase in working capital is primarily related to a \$64,392 increase in working capital directly related to cost of power.

CONTINUITY STATEMENTS

	2006 Actual Gross Asset Value	Accumulated Depreciation	Net Book Value	2007 Actual Gross Asset Value	Accumulated Depreciation	Net Book Value
Land and Buildings						
1805-Land -Opening Balance	\$21,747	\$0	\$21,747	\$21,747	\$0	\$21,747
1805-Land -Additions	\$0		\$0	\$0		\$0
1805-Land -Depreciation		\$0	\$0	\$0	\$0	\$0
1805-Land -Adjustments			\$0	\$0	\$0	\$0
1805-Land -Closing Balance	\$21,747	\$0	\$21,747	\$21,747	\$0	\$21,747
Average	\$21,747	\$0	\$21,747	\$21,747	\$0	\$21,747
1808-Buildings and Fixtures-Opening Balance	\$67,891	-\$10,864	\$57,027	\$70,714	-\$13,580	\$57,134
1808-Buildings and Fixtures-Additions	\$2,822	-\$2,716	\$106	\$225		\$225
1808-Buildings and Fixtures-Depreciation			\$0		-\$2,833	-\$2,833
1808-Buildings and Fixtures -Adjustments			\$0	\$0		\$0
1808-Buildings and Fixtures -Closing Balance	\$70,714	-\$13,580	\$57,134	\$70,939	-\$16,413	\$54,526
Average	\$69,302	-\$12,222	\$57,080	\$70,826	-\$14,997	\$55,830
Total	\$92,460	-\$13,580	\$78,880	\$92,685	-\$16,413	\$76,272
DS						
1820-Distribution Station Equipment Opening Balance	\$151,907	-\$24,304	\$127,603	\$152,252	-\$30,394	\$121,858
1820-Distribution Station Equipment Additions	\$346		\$346	\$346		\$346
1820-Distribution Station Equipment Depreciation		-\$6,090	-\$6,090		-\$6,090	-\$6,090
1820-Distribution Station Equipment Adjustments			\$0	\$0		\$0
1820-Distribution Station Equipment Closing Balance	\$152,252	-\$30,394	\$121,858	\$152,598	-\$36,484	\$116,114
Average	\$152,079	-\$27,349	\$124,730	\$152,425	-\$33,439	\$118,986
Total	\$152,252	-\$30,394	\$121,858	\$152,598	-\$36,484	\$116,114
Poles and Wires						
1830-Poles, Towers and Fixtures-Opening Balance	\$0	\$0	\$0	\$27,035	\$0	\$27,035
1830-Poles, Towers and Fixtures-Additions	\$27,035		\$27,035	\$41,925		\$41,925
1830-Poles, Towers and Fixtures-Depreciation		\$0	\$0		-\$1,920	-\$1,920
1830-Poles, Towers and Fixtures-Adjustments			\$0	\$0		\$0
1830-Poles, Towers and Fixtures-Closing Balance	\$27,035	\$0	\$27,035	\$68,960	-\$1,920	\$67,040
Average	\$13,518	\$0	\$13,518	\$47,998	-\$960	\$47,038
1835-Overhead Conductors and Devices-Opening Balance	\$2,038,965	-\$303,967	\$1,734,998	\$2,173,740	-\$389,897	\$1,783,843
1835-Overhead Conductors and Devices-Additions	\$134,775		\$134,775	\$21,195		\$21,195
1835-Overhead Conductors and Devices-Depreciation		-\$85,930	-\$85,930		-\$87,373	-\$87,373
1835-Overhead Conductors and Devices-Adjustments			\$0	\$0		\$0
1835-Overhead Conductors and Devices-Closing Balance	\$2,173,740	-\$389,897	\$1,783,843	\$2,194,935	-\$477,270	\$1,717,664
Average	\$2,106,353	-\$346,932	\$1,759,421	\$2,184,337	-\$433,584	\$1,750,754
1840-Underground Conduit-Opening Balance	\$0	\$0	\$0	\$2,927	\$0	\$2,927
1840-Underground Conduit-Additions	\$2,927		\$2,927	\$2,927		\$2,927
1840-Underground Conduit-Depreciation		\$0	\$0		-\$139	-\$139
1840-Underground Conduit-Adjustments			\$0	\$0		\$0
1840-Underground Conduit-Closing Balance	\$2,927	\$0	\$2,927	\$5,853	-\$139	\$5,714
Average	\$1,463	\$0	\$1,463	\$4,390	-\$70	\$4,320

1845-Underground Conductors and Devices-Opening Balance	\$889,762	-\$134,197	\$755,565	\$981,813	-\$171,925	\$809,888
1845-Underground Conductors and Devices-Additions	\$92,051		\$92,051	\$74,201		\$74,201
1845-Underground Conductors and Devices-Depreciation		-\$37,728	-\$37,728		-\$40,757	-\$40,757
1845-Underground Conductors and Devices-Adjustments			\$0	\$0		\$0
1845-Underground Conductors and Devices-Closing Balance	\$981,813	-\$171,925	\$809,888	\$1,056,014	-\$212,682	\$843,332
Average	\$935,788	-\$153,061	\$782,727	\$1,018,914	-\$192,303	\$826,610
Total	\$3,185,515	-\$561,822	\$2,623,693	\$3,325,762	-\$692,011	\$2,633,751
Line Transformers						
1850-Line Transformers-Opening Balance	\$681,332	-\$101,207	\$580,125	\$656,835	-\$129,754	\$527,081
1850-Line Transformers-Additions	-\$24,498		-\$24,498	\$116,967		\$116,967
1850-Line Transformers-Depreciation		-\$28,547	-\$28,547		-\$28,613	-\$28,613
1850-Line Transformers-Adjustments			\$0	\$0		\$0
1850-Line Transformers-Closing Balance	\$656,835	-\$129,754	\$527,081	\$773,801	-\$158,367	\$615,435
Average	\$669,083	-\$115,481	\$553,603	\$715,318	-\$144,060	\$571,258
Total	\$656,835	-\$129,754	\$527,081	\$773,801	-\$158,367	\$615,435
Services and Meters						
1855-Services-Opening Balance	\$0	\$0	\$0	\$23,481	\$0	\$23,481
1855-Services-Additions	\$23,481		\$23,481	\$53,849		\$53,849
1855-Services-Depreciation		\$0	\$0		-\$2,016	-\$2,016
1855-Services-Adjustments			\$0	\$0		\$0
1855-Services-Closing Balance	\$23,481	\$0	\$23,481	\$77,331	-\$2,016	\$75,314
Average	\$11,741	\$0	\$11,741	\$50,406	-\$1,008	\$49,398
1860-Meters						
1860-Meters-Opening Balance	\$301,300	-\$46,104	\$255,196	\$389,349	-\$63,418	\$325,931
1860-Meters-Additions	\$88,049		\$88,049	-\$69,241		-\$69,241
1860-Meters-Depreciation		-\$17,314	-\$17,314		-\$14,189	-\$14,189
1860-Meters-Adjustments			\$0	\$0		\$0
1860-Meters-Closing Balance	\$389,349	-\$63,418	\$325,931	\$320,108	-\$77,607	\$242,501
Average	\$345,325	-\$54,761	\$290,564	\$354,729	-\$70,513	\$284,216
Total	\$412,831	-\$63,418	\$349,413	\$397,439	-\$79,623	\$317,816
IT Assets						
1920-Computer Equipment - Hardware-Opening Balance	\$44,191	-\$15,431	\$28,760	\$63,315	-\$19,942	\$43,373
1920-Computer Equipment - Hardware-Additions	\$19,124		\$19,124	\$1,650		\$1,650
1920-Computer Equipment - Hardware-Depreciation		-\$4,511	-\$4,511		-\$6,414	-\$6,414
1920-Computer Equipment - Hardware-Adjustments			\$0	\$0		\$0
1920-Computer Equipment - Hardware-Closing Balance	\$63,315	-\$19,942	\$43,373	\$64,965	-\$26,356	\$38,609
Average	\$53,753	-\$17,687	\$36,067	\$64,140	-\$23,149	\$40,991
1925-Computer Software						
1925-Computer Software-Opening Balance	\$27,606	-\$14,686	\$12,920	\$27,606	-\$24,126	\$3,480
1925-Computer Software-Additions	\$0		\$0	\$0		\$0
1925-Computer Software-Depreciation		-\$9,440	-\$9,440		-\$2,761	-\$2,761
1925-Computer Software-Adjustments			\$0	\$0		\$0
1925-Computer Software-Closing Balance	\$27,606	-\$24,126	\$3,480	\$27,606	-\$26,887	\$719
Average	\$27,606	-\$19,406	\$8,200	\$27,606	-\$25,506	\$2,100
Total	\$90,921	-\$44,068	\$46,853	\$92,571	-\$53,243	\$39,329

Equipment						
1915-Office Furniture and Equipment-Opening Balance	\$50,428	-\$19,863	\$30,565	\$51,442	-\$24,906	\$26,536
1915-Office Furniture and Equipment-Additions	\$1,014		\$1,014	\$13,524		\$13,524
1915-Office Furniture and Equipment-Depreciation		-\$5,043	-\$5,043		-\$7,275	-\$7,275
1915-Office Furniture and Equipment-Adjustments			\$0	\$0		\$0
1915-Office Furniture and Equipment-Closing Balance	\$51,442	-\$24,906	\$26,536	\$64,965	-\$32,181	\$32,784
Average	\$50,935	-\$22,385	\$28,550	\$58,203	-\$28,544	\$29,660
1930-Transportation Equipment-Opening Balance	\$245,849	-\$110,463	\$135,386	\$253,297	-\$142,124	\$111,173
1930-Transportation Equipment-Additions	\$7,448		\$7,448	\$0		\$0
1930-Transportation Equipment-Depreciation		-\$31,661	-\$31,661		-\$63,324	-\$63,324
1930-Transportation Equipment-Adjustments			\$0	\$0		\$0
1930-Transportation Equipment-Closing Balance	\$253,297	-\$142,124	\$111,173	\$253,297	-\$205,448	\$47,849
Average	\$249,573	-\$126,294	\$123,280	\$253,297	-\$173,786	\$79,511
1940-Tools, Shop and Garage Equipment-Opening Balance	\$53,677	-\$40,347	\$13,330	\$60,832	-\$46,904	\$13,928
1940-Tools, Shop and Garage Equipment-Additions	\$7,155		\$7,155	\$8,066		\$8,066
1940-Tools, Shop and Garage Equipment-Depreciation		-\$6,557	-\$6,557		-\$16,216	-\$16,216
1940-Tools, Shop and Garage Equipment-Adjustments			\$0	\$0		\$0
1940-Tools, Shop and Garage Equipment-Closing Balance	\$60,832	-\$46,904	\$13,928	\$68,897	-\$63,120	\$5,777
Average	\$57,254	-\$43,625	\$13,629	\$64,865	-\$55,012	\$9,853
1945-Measurement and Testing Equipment-Opening Balance	\$0	\$0	\$0	\$2,678	\$0	\$2,678
1945-Measurement and Testing Equipment-Additions	\$2,678		\$2,678	\$0		\$0
1945-Measurement and Testing Equipment-Depreciation		\$0	\$0		-\$670	-\$670
1945-Measurement and Testing Equipment-Adjustments			\$0	\$0		\$0
1945-Measurement and Testing Equipment-Closing Balance	\$2,678	\$0	\$2,678	\$2,678	-\$670	\$2,009
Average	\$1,339	\$0	\$1,339	\$2,678	-\$335	\$2,344
Total	\$368,249	-\$213,934	\$154,315	\$389,838	-\$301,419	\$88,419
1995-Contributions and Grants - Credit-Opening Balance	\$0	\$0	\$0	-\$166,135	\$0	-\$166,135
1995-Contributions and Grants - Credit-Additions	-\$166,135		-\$166,135	-\$91,450		-\$91,450
1995-Contributions and Grants - Credit-Depreciation		\$0	\$0		\$8,474	\$8,474
1995-Contributions and Grants - Credit-Adjustments			\$0	\$0		\$0
1995-Contributions and Grants - Credit-Closing Balance	-\$166,135	\$0	-\$166,135	-\$257,585	\$8,474	-\$249,111
Average	-\$83,068	\$0	-\$83,068	-\$211,860	\$4,237	-\$207,623
Total	-\$166,135	\$0	-\$166,135	-\$257,585	\$8,474	-\$249,111
Total Opening Balance	\$4,574,655	-\$821,433	\$3,753,222	\$4,792,927	-\$1,056,970	\$3,735,957
Total Additions	\$218,272	-\$2,716	\$215,556	\$174,183	\$0	\$174,183
Total Depreciation	\$0	-\$232,821	-\$232,821	\$0	-\$272,116	-\$272,116
Total Adjustments	\$0	\$0	\$0	\$0	\$0	\$0
Total Closing Balance	\$4,792,927	-\$1,056,970	\$3,735,957	\$4,967,110	-\$1,329,086	\$3,638,024
Average	\$4,683,791	-\$939,201	\$3,744,590	\$4,880,019	-\$1,193,028	\$3,686,991
Total	\$4,792,927	-\$1,056,970	\$3,735,957	\$4,967,110	-\$1,329,086	\$3,638,024

CONTINUITY STATEMENTS

	2008 Bridge Gross Asset Value	Accumulated Depreciation	Net Book Value	2009 Test Gross Asset Value	Accumulated Depreciation	Net Book Value
Land and Buildings						
1805-Land -Opening Balance	\$21,747	\$0	\$21,747	\$21,747	\$0	\$21,747
1805-Land -Additions	\$0		\$0	\$0		\$0
1805-Land -Depreciation	\$0	\$0	\$0	\$0	\$0	\$0
1805-Land -Adjustments	\$0	\$0	\$0	\$0	\$0	\$0
1805-Land -Closing Balance	\$21,747	\$0	\$21,747	\$21,747	\$0	\$21,747
Average	\$21,747	\$0	\$21,747	\$21,747	\$0	\$21,747
1808-Buildings and Fixtures-Opening Balance	\$70,939	-\$16,413	\$54,526	\$70,939	-\$19,251	\$51,688
1808-Buildings and Fixtures-Additions	\$0		\$0	\$0		\$0
1808-Buildings and Fixtures-Depreciation		-\$2,838	-\$2,838		-\$2,838	-\$2,838
1808-Buildings and Fixtures -Adjustments	\$0		\$0	\$0		\$0
1808-Buildings and Fixtures -Closing Balance	\$70,939	-\$19,251	\$51,688	\$70,939	-\$22,088	\$48,850
Average	\$70,939	-\$17,832	\$53,107	\$70,939	-\$20,669	\$50,269
Total	\$92,685	-\$19,251	\$73,435	\$92,685	-\$22,088	\$70,597
DS						
1820-Distribution Station Equipment Opening Balance	\$152,598	-\$36,484	\$116,114	\$152,598	-\$42,574	\$110,024
1820-Distribution Station Equipment Additions	\$0		\$0	\$30,000		\$30,000
1820-Distribution Station Equipment Depreciation		-\$6,090	-\$6,090		-\$6,690	-\$6,690
1820-Distribution Station Equipment Adjustments	\$0		\$0	\$0		\$0
1820-Distribution Station Equipment Closing Balance	\$152,598	-\$42,574	\$110,024	\$182,598	-\$49,264	\$133,334
Average	\$152,598	-\$39,529	\$113,069	\$167,598	-\$45,919	\$121,679
Total	\$152,598	-\$42,574	\$110,024	\$182,598	-\$49,264	\$133,334
Poles and Wires						
1830-Poles, Towers and Fixtures-Opening Balance	\$68,960	-\$1,920	\$67,040	\$213,960	-\$5,658	\$208,302
1830-Poles, Towers and Fixtures-Additions	\$145,000		\$145,000	\$120,000		\$120,000
1830-Poles, Towers and Fixtures-Depreciation		-\$3,739	-\$3,739		-\$5,300	-\$5,300
1830-Poles, Towers and Fixtures-Adjustments	\$0		\$0	\$0		\$0
1830-Poles, Towers and Fixtures-Closing Balance	\$213,960	-\$5,658	\$208,302	\$333,960	-\$10,958	\$323,002
Average	\$141,460	-\$3,789	\$137,671	\$273,960	-\$8,308	\$265,652
1835-Overhead Conductors and Devices-Opening Balance	\$2,194,935	-\$477,270	\$1,717,664	\$2,334,935	-\$567,868	\$1,767,067
1835-Overhead Conductors and Devices-Additions	\$140,000		\$140,000	\$170,000		\$170,000
1835-Overhead Conductors and Devices-Depreciation		-\$90,597	-\$90,597		-\$96,797	-\$96,797
1835-Overhead Conductors and Devices-Adjustments	\$0		\$0	\$0		\$0
1835-Overhead Conductors and Devices-Closing Balance	\$2,334,935	-\$567,868	\$1,767,067	\$2,504,935	-\$664,665	\$1,840,270
Average	\$2,264,935	-\$522,569	\$1,742,366	\$2,419,935	-\$616,267	\$1,803,668
1840-Underground Conduit-Opening Balance	\$5,853	-\$139	\$5,714	\$5,853	-\$301	\$5,552
1840-Underground Conduit-Additions	\$0		\$0	\$0		\$0
1840-Underground Conduit-Depreciation		-\$162	-\$162		-\$162	-\$162
1840-Underground Conduit-Adjustments	\$0		\$0	\$0		\$0
1840-Underground Conduit-Closing Balance	\$5,853	-\$301	\$5,552	\$5,853	-\$463	\$5,391
Average	\$5,853	-\$220	\$5,633	\$5,853	-\$382	\$5,471

1845-Underground Conductors and Devices-Opening Balance	\$1,056,014	-\$212,682	\$843,332	\$1,056,014	-\$254,922	\$801,092
1845-Underground Conductors and Devices-Additions	\$0		\$0	\$0		\$0
1845-Underground Conductors and Devices-Depreciation		-\$42,241	-\$42,241		-\$42,241	-\$42,241
1845-Underground Conductors and Devices-Adjustments	\$0		\$0	\$0		\$0
1845-Underground Conductors and Devices-Closing Balance	\$1,056,014	-\$254,922	\$801,092	\$1,056,014	-\$297,163	\$758,851
Average	\$1,056,014	-\$233,802	\$822,212	\$1,056,014	-\$276,042	\$779,972
Total	\$3,610,762	-\$828,749	\$2,782,013	\$3,900,762	-\$973,249	\$2,927,513
Line Transformers						
1850-Line Transformers-Opening Balance	\$773,801	-\$158,367	\$615,435	\$898,801	-\$191,819	\$706,983
1850-Line Transformers-Additions	\$125,000		\$125,000	\$135,000		\$135,000
1850-Line Transformers-Depreciation		-\$33,452	-\$33,452		-\$38,652	-\$38,652
1850-Line Transformers-Adjustments	\$0		\$0	\$0		\$0
1850-Line Transformers-Closing Balance	\$898,801	-\$191,819	\$706,983	\$1,033,801	-\$230,471	\$803,331
Average	\$836,301	-\$175,093	\$661,209	\$966,301	-\$211,145	\$755,157
Total	\$898,801	-\$191,819	\$706,983	\$1,033,801	-\$230,471	\$803,331
Services and Meters						
1855-Services-Opening Balance	\$77,331	-\$2,016	\$75,314	\$82,331	-\$5,209	\$77,121
1855-Services-Additions	\$5,000		\$5,000	\$10,000		\$10,000
1855-Services-Depreciation		-\$3,193	-\$3,193		-\$3,493	-\$3,493
1855-Services-Adjustments	\$0		\$0	\$0		\$0
1855-Services-Closing Balance	\$82,331	-\$5,209	\$77,121	\$92,331	-\$8,703	\$83,628
Average	\$79,831	-\$3,613	\$76,218	\$87,331	-\$6,956	\$80,374
1860-Meters						
1860-Meters-Opening Balance	\$320,108	-\$77,607	\$242,501	\$320,108	-\$90,411	\$229,697
1860-Meters-Additions	\$0		\$0	\$0		\$0
1860-Meters-Depreciation		-\$12,804	-\$12,804		-\$12,804	-\$12,804
1860-Meters-Adjustments	\$0		\$0	\$0		\$0
1860-Meters-Closing Balance	\$320,108	-\$90,411	\$229,697	\$320,108	-\$103,216	\$216,893
Average	\$320,108	-\$84,009	\$236,099	\$320,108	-\$96,814	\$223,295
Total	\$402,439	-\$95,621	\$306,818	\$412,439	-\$111,919	\$300,520
IT Assets						
1920-Computer Equipment - Hardware-Opening Balance	\$64,965	-\$26,356	\$38,609	\$64,965	-\$32,853	\$32,113
1920-Computer Equipment - Hardware-Additions	\$0		\$0	\$0		\$0
1920-Computer Equipment - Hardware-Depreciation		-\$6,497	-\$6,497		-\$6,497	-\$6,497
1920-Computer Equipment - Hardware-Adjustments	\$0		\$0	\$0		\$0
1920-Computer Equipment - Hardware-Closing Balance	\$64,965	-\$32,853	\$32,113	\$64,965	-\$39,349	\$25,616
Average	\$64,965	-\$29,604	\$35,361	\$64,965	-\$36,101	\$28,864
1925-Computer Software						
1925-Computer Software-Opening Balance	\$27,606	-\$26,887	\$719	\$27,606	-\$29,647	-\$2,041
1925-Computer Software-Additions	\$0		\$0	\$0		\$0
1925-Computer Software-Depreciation		-\$2,761	-\$2,761		-\$2,761	-\$2,761
1925-Computer Software-Adjustments	\$0		\$0	\$0		\$0
1925-Computer Software-Closing Balance	\$27,606	-\$29,647	-\$2,041	\$27,606	-\$32,408	-\$4,802
Average	\$27,606	-\$28,267	-\$661	\$27,606	-\$31,028	-\$3,421
Total	\$92,571	-\$62,500	\$30,072	\$92,571	-\$71,757	\$20,814

Equipment						
1915-Office Furniture and Equipment-Opening Balance	\$64,965	-\$32,181	\$32,784	\$64,965	-\$40,302	\$24,663
1915-Office Furniture and Equipment-Additions	\$0		\$0	\$0		\$0
1915-Office Furniture and Equipment-Depreciation		-\$8,121	-\$8,121		-\$8,121	-\$8,121
1915-Office Furniture and Equipment-Adjustments	\$0		\$0	\$0		\$0
1915-Office Furniture and Equipment-Closing Balance	\$64,965	-\$40,302	\$24,663	\$64,965	-\$48,423	\$16,543
Average	\$64,965	-\$36,242	\$28,724	\$64,965	-\$44,362	\$20,603
1930-Transportation Equipment-Opening Balance	\$253,297	-\$205,448	\$47,849	\$286,297	-\$272,898	\$13,400
1930-Transportation Equipment-Additions	\$33,000		\$33,000	\$290,000		\$290,000
1930-Transportation Equipment-Depreciation		-\$67,449	-\$67,449		-\$107,824	-\$107,824
1930-Transportation Equipment-Adjustments	\$0		\$0	\$0		\$0
1930-Transportation Equipment-Closing Balance	\$286,297	-\$272,898	\$13,400	\$576,297	-\$380,722	\$195,575
Average	\$269,797	-\$239,173	\$30,624	\$431,297	-\$326,810	\$104,487
1940-Tools, Shop and Garage Equipment-Opening Balance	\$68,897	-\$63,120	\$5,777	\$73,897	-\$80,969	-\$7,072
1940-Tools, Shop and Garage Equipment-Additions	\$5,000		\$5,000	\$0		\$0
1940-Tools, Shop and Garage Equipment-Depreciation		-\$17,849	-\$17,849		-\$18,474	-\$18,474
1940-Tools, Shop and Garage Equipment-Adjustments	\$0		\$0	\$0		\$0
1940-Tools, Shop and Garage Equipment-Closing Balance	\$73,897	-\$80,969	-\$7,072	\$73,897	-\$99,444	-\$25,546
Average	\$71,397	-\$72,045	-\$647	\$73,897	-\$90,207	-\$16,309
1945-Measurement and Testing Equipment-Opening Balance	\$2,678	-\$670	\$2,009	\$2,678	-\$1,339	\$1,339
1945-Measurement and Testing Equipment-Additions	\$0		\$0	\$0		\$0
1945-Measurement and Testing Equipment-Depreciation		-\$670	-\$670		-\$670	-\$670
1945-Measurement and Testing Equipment-Adjustments	\$0		\$0	\$0		\$0
1945-Measurement and Testing Equipment-Closing Balance	\$2,678	-\$1,339	\$1,339	\$2,678	-\$2,009	\$670
Average	\$2,678	-\$1,004	\$1,674	\$2,678	-\$1,674	\$1,004
Total	\$427,838	-\$395,508	\$32,330	\$717,838	-\$530,597	\$187,241
1995-Contributions and Grants - Credit-Opening Balance	-\$257,585	\$8,474	-\$249,111	-\$257,585	\$18,778	-\$238,807
1995-Contributions and Grants - Credit-Additions	\$0		\$0	\$0		\$0
1995-Contributions and Grants - Credit-Depreciation		\$10,303	\$10,303		\$10,303	\$10,303
1995-Contributions and Grants - Credit-Adjustments	\$0		\$0	\$0		\$0
1995-Contributions and Grants - Credit-Closing Balance	-\$257,585	\$18,778	-\$238,807	-\$257,585	\$29,081	-\$228,504
Average	-\$257,585	\$13,626	-\$243,959	-\$257,585	\$23,930	-\$233,656
Total	-\$257,585	\$18,778	-\$238,807	-\$257,585	\$29,081	-\$228,504
Total Opening Balance	\$4,967,110	-\$1,329,086	\$3,638,024	\$5,420,110	-\$1,617,244	\$3,802,866
Total Additions	\$453,000	\$0	\$453,000	\$755,000	\$0	\$755,000
Total Depreciation	\$0	-\$288,158	-\$288,158	\$0	-\$343,019	-\$343,019
Total Adjustments	\$0	\$0	\$0	\$0	\$0	\$0
Total Closing Balance	\$5,420,110	-\$1,617,244	\$3,802,866	\$6,175,110	-\$1,960,264	\$4,214,847
Average	\$5,193,610	-\$1,473,165	\$3,720,445	\$5,797,610	-\$1,788,754	\$4,008,857
Total	\$5,420,110	-\$1,617,244	\$3,802,866	\$6,175,110	-\$1,960,264	\$4,214,847

GROSS ASSET	2006 Board Approved (\$'s)	2006 Actual (\$'s)	Variance form 2006 Board Approved	2006 Actual (\$'s)	2007 Actual (\$'s)	Variance form 2006 Actual
Land and Buildings						
1805-Land	\$21,747	\$21,747	\$0	\$21,747	\$21,747	\$0
1806-Land Rights	\$0	\$0	\$0	\$0	\$0	\$0
1808-Buildings and Fixtures	\$67,891	\$70,714	\$2,822	\$70,714	\$70,939	\$225
1905-Land	\$0	\$0	\$0	\$0	\$0	\$0
1906-Land Rights	\$0	\$0	\$0	\$0	\$0	\$0
1810-Leasehold Improvements	\$0	\$0	\$0	\$0	\$0	\$0
Sub-Total-Land and Buildings	\$89,638	\$92,460	\$2,822	\$92,460	\$92,685	\$225
TS Primary Above 50						
1815-Transformer Station Equipment - Normally Primary above 50 kV	\$0	\$0	\$0	\$0	\$0	\$0
Sub-Total-TS Primary Above 50	\$0	\$0	\$0	\$0	\$0	\$0
DS						
1820-Distribution Station Equipment - Normally Primary below 50 kV	\$151,907	\$152,252	\$346	\$152,252	\$152,252	\$0
Sub-Total-DS	\$151,907	\$152,252	\$346	\$152,252	\$152,252	\$0
Poles and Wires						
1830-Poles, Towers and Fixtures	\$0	\$27,035	\$27,035	\$27,035	\$68,960	\$41,925
1835-Overhead Conductors and Devices	\$2,038,965	\$2,173,740	\$134,775	\$2,173,740	\$2,194,935	\$21,195
1840-Underground Conduit	\$0	\$2,927	\$2,927	\$2,927	\$4,042	\$1,115
1845-Underground Conductors and Devices	\$889,762	\$981,813	\$92,051	\$981,813	\$1,056,014	\$74,201
Sub-Total-Poles and Wires	\$2,928,728	\$3,185,515	\$256,787	\$3,185,515	\$3,323,951	\$138,436
Line Transformers						
1850-Line Transformers	\$681,332	\$656,835	-\$24,498	\$656,835	\$773,801	\$116,967
Sub-Total-Line Transformers	\$681,332	\$656,835	-\$24,498	\$656,835	\$773,801	\$116,967
Services and Meters						
1855-Services	\$0	\$23,481	\$23,481	\$23,481	\$77,331	\$53,849
1860-Meters	\$301,300	\$389,349	\$88,049	\$389,349	\$320,108	-\$69,241
Sub-Total-Services and Meters	\$301,300	\$412,831	\$111,531	\$412,831	\$397,439	-\$15,392

General Plant

1908-Buildings and Fixtures	\$0	\$0	\$0	\$0	\$0	\$0
1910-Leasehold Improvements	\$0	\$0	\$0	\$0	\$0	\$0
Sub-Total-General Plant	\$0	\$0	\$0	\$0	\$0	\$0

IT Assets

1920-Computer Equipment - Hardware	\$44,191	\$63,315	\$19,124	\$63,315	\$64,965	\$1,650
1925-Computer Software	\$27,606	\$27,606	\$0	\$27,606	\$27,606	\$0
Sub-Total-IT Assets	\$71,797	\$90,921	\$19,124	\$90,921	\$92,571	\$1,650

Equipment

1915-Office Furniture and Equipment	\$50,428	\$51,442	\$1,014	\$51,442	\$64,965	\$13,524
1930-Transportation Equipment	\$245,849	\$253,297	\$7,448	\$253,297	\$253,297	\$0
1935-Stores Equipment	\$0	\$0	\$0	\$0	\$0	\$0
1940-Tools, Shop and Garage Equipment	\$53,677	\$60,832	\$7,155	\$60,832	\$68,897	\$8,066
1945-Measurement and Testing Equipment	\$0	\$2,678	\$2,678	\$2,678	\$2,678	\$0
1950-Power Operated Equipment	\$0	\$0	\$0	\$0	\$0	\$0
1955-Communication Equipment	\$0	\$0	\$0	\$0	\$0	\$0
1960-Miscellaneous Equipment	\$0	\$0	\$0	\$0	\$0	\$0
Sub-Total-Equipment	\$349,953	\$368,249	\$18,296	\$368,249	\$389,838	\$21,589

Other Distribution Assets

1825-Storage Battery Equipment	\$0	\$0	\$0	\$0	\$0	\$0
1970-Load Management Controls - Customer Premises	\$0	\$0	\$0	\$0	\$0	\$0
1975-Load Management Controls - Utility Premises	\$0	\$0	\$0	\$0	\$0	\$0
1980-System Supervisory Equipment	\$0	\$0	\$0	\$0	\$0	\$0
1985-Sentinel Lighting Rental Units	\$0	\$0	\$0	\$0	\$0	\$0
1990-Other Tangible Property	\$0	\$0	\$0	\$0	\$0	\$0
1995-Contributions and Grants - Credit	\$0	-\$166,135	-\$166,135	-\$166,135	-\$257,585	-\$91,450
Sub-Total-Other Distribution Assets	\$0	-\$166,135	-\$166,135	-\$166,135	-\$257,585	-\$91,450

GROSS ASSET TOTAL

\$4,574,655	\$4,792,927	\$218,272	\$4,792,927	\$4,964,953	\$172,026
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GROSS ASSET	2007 Actual (\$'s)	2008 Bridge (\$'s)	Variance form 2007 Actual	2008 Bridge (\$'s)	2009 Test (\$'s)	Variance form 2008 Bridge
Land and Buildings						
1805-Land	\$21,747	\$21,747	\$0	\$21,747	\$21,747	\$0
1806-Land Rights	\$0	\$0	\$0	\$0	\$0	\$0
1808-Buildings and Fixtures	\$70,939	\$70,939	\$0	\$70,939	\$70,939	\$0
1905-Land	\$0	\$0	\$0	\$0	\$0	\$0
1906-Land Rights	\$0	\$0	\$0	\$0	\$0	\$0
1810-Leasehold Improvements	\$0	\$0	\$0	\$0	\$0	\$0
Sub-Total-Land and Buildings	\$92,685	\$92,685	\$0	\$92,685	\$92,685	\$0
TS Primary Above 50						
1815-Transformer Station Equipment - Normally Primary above 50 kV	\$0	\$0	\$0	\$0	\$0	\$0
Sub-Total-TS Primary Above 50	\$0	\$0	\$0	\$0	\$0	\$0
DS						
1820-Distribution Station Equipment - Normally Primary below 50 kV	\$152,252	\$152,252	\$0	\$152,252	\$182,252	\$30,000
Sub-Total-DS	\$152,252	\$152,252	\$0	\$152,252	\$182,252	\$30,000
Poles and Wires						
1830-Poles, Towers and Fixtures	\$68,960	\$213,960	\$145,000	\$213,960	\$333,960	\$120,000
1835-Overhead Conductors and Devices	\$2,194,935	\$2,334,935	\$140,000	\$2,334,935	\$2,504,935	\$170,000
1840-Underground Conduit	\$4,042	\$4,042	\$0	\$4,042	\$4,042	\$0
1845-Underground Conductors and Devices	\$1,056,014	\$1,056,014	\$0	\$1,056,014	\$1,056,014	\$0
Sub-Total-Poles and Wires	\$3,323,951	\$3,608,951	\$285,000	\$3,608,951	\$3,898,951	\$290,000
Line Transformers						
1850-Line Transformers	\$773,801	\$898,801	\$125,000	\$898,801	\$1,033,801	\$135,000
Sub-Total-Line Transformers	\$773,801	\$898,801	\$125,000	\$898,801	\$1,033,801	\$135,000
Services and Meters						
1855-Services	\$77,331	\$82,331	\$5,000	\$82,331	\$92,331	\$10,000
1860-Meters	\$320,108	\$320,108	\$0	\$320,108	\$320,108	\$0
Sub-Total-Services and Meters	\$397,439	\$402,439	\$5,000	\$402,439	\$412,439	\$10,000

General Plant

1908-Buildings and Fixtures	\$0	\$0	\$0	\$0	\$0	\$0
1910-Leasehold Improvements	\$0	\$0	\$0	\$0	\$0	\$0
Sub-Total-General Plant	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>

IT Assets

1920-Computer Equipment - Hardware	\$64,965	\$64,965	\$0	\$64,965	\$64,965	\$0
1925-Computer Software	\$27,606	\$27,606	\$0	\$27,606	\$27,606	\$0
Sub-Total-IT Assets	<u>\$92,571</u>	<u>\$92,571</u>	<u>\$0</u>	<u>\$92,571</u>	<u>\$92,571</u>	<u>\$0</u>

Equipment

1915-Office Furniture and Equipment	\$64,965	\$64,965	\$0	\$64,965	\$64,965	\$0
1930-Transportation Equipment	\$253,297	\$286,297	\$33,000	\$286,297	\$576,297	\$290,000
1935-Stores Equipment	\$0	\$0	\$0	\$0	\$0	\$0
1940-Tools, Shop and Garage Equipment	\$68,897	\$73,897	\$5,000	\$73,897	\$73,897	\$0
1945-Measurement and Testing Equipment	\$2,678	\$2,678	\$0	\$2,678	\$2,678	\$0
1950-Power Operated Equipment	\$0	\$0	\$0	\$0	\$0	\$0
1955-Communication Equipment	\$0	\$0	\$0	\$0	\$0	\$0
1960-Miscellaneous Equipment	\$0	\$0	\$0	\$0	\$0	\$0
Sub-Total-Equipment	<u>\$389,838</u>	<u>\$427,838</u>	<u>\$38,000</u>	<u>\$427,838</u>	<u>\$717,838</u>	<u>\$290,000</u>

Other Distribution Assets

1825-Storage Battery Equipment	\$0	\$0	\$0	\$0	\$0	\$0
1970-Load Management Controls - Customer Premises	\$0	\$0	\$0	\$0	\$0	\$0
1975-Load Management Controls - Utility Premises	\$0	\$0	\$0	\$0	\$0	\$0
1980-System Supervisory Equipment	\$0	\$0	\$0	\$0	\$0	\$0
1985-Sentinel Lighting Rental Units	\$0	\$0	\$0	\$0	\$0	\$0
1990-Other Tangible Property	\$0	\$0	\$0	\$0	\$0	\$0
1995-Contributions and Grants - Credit	-\$257,585	-\$257,585	\$0	-\$257,585	-\$257,585	\$0
Sub-Total-Other Distribution Assets	<u>-\$257,585</u>	<u>-\$257,585</u>	<u>\$0</u>	<u>-\$257,585</u>	<u>-\$257,585</u>	<u>\$0</u>

GROSS ASSET TOTAL

<u>\$4,964,953</u>	<u>\$5,417,953</u>	<u>\$453,000</u>	<u>\$5,417,953</u>	<u>\$6,172,953</u>	<u>\$755,000</u>
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MATERIALITY ANALYSIS CALCULATION

The calculation of the Materiality Threshold for Accumulated Depreciation and Gross Assets is shown in the following table:

Materiality Threshold is 1% of net fixed assets.

	2007 Actual		2008 Bridge		2009 Test
Gross cost	\$4,967,110		\$5,420,110		\$6,175,110
Accumulated Amortization	-\$1,329,086		-\$1,617,244		-\$1,960,264
Net Fixed Assets	\$3,638,024		\$3,802,866		\$4,214,847
1% of Net Fixed Assets	\$36,380		\$38,029		\$42,148

MATERIALITY ANALYSIS ON GROSS ASSET

Asset Account	Bridge Year	Test Year	Variance
1830-Poles Towers and Fixtures	\$213,960	\$333,960	-\$120,000

Explanation: The majority of system improvement projects will impact this account as invariably poles are replaced either due to deterioration or movement of the poles to ease access. There was also a single project for \$80,000 that impacts this account which is WEST COAST's Pole Replacement program. Three of the projects that had dollar amounts impact this account were greater than the materiality threshold for 2008 and they will be explained in Exhibit 2, Tab 3, Schedule 2.

Asset Account	Bridge Year	Test Year	Variance
1835-Overhead Conductors and Devices	\$2,334,935	\$2,504,935	-\$170,000

Explanation: Once again the majority of system improvement projects will impact this account as in any enhancement project there will be additions of conductors and devices utilized in the construction project. Two of the projects that had dollar amounts impact this gl account were greater than the materiality threshold for 2008 and they will be explained in Exhibit 2, Tab 3, Schedule 2.

Asset Account	Bridge Year	Test Year	Variance
1850-Line Transformers	\$898,801	\$1,033,801	-\$135,000

Explanation: The majority of system improvement projects will impact this account as in any enhancement project there will be additions of transformers utilized in the construction project. Two of the projects that had dollar amounts impact this gl account were greater than the materiality threshold for 2008 and they will be explained in Exhibit 2, Tab 3, Schedule 2.

Asset Account	Bridge Year	Test Year	Variance
1930-Transportation Equipment	\$286,297	\$576,297	-\$290,000

Explanation: West Coast Huron Energy is in need of replacing a bucket truck due to a current truck coming to the end of its useful life. This purchase will be explained in Exhibit 2, Tab 3, Schedule 2.

ACCUMULATED DEPRECIATION TABLE

ACCUMULATED DEPRECIATION TABLE	2006 Board Approved (\$'s)	2006 Actual (\$'s)	Variance from 2006 Board Approved	2006 Actual (\$'s)	2007 Actual (\$'s)	Variance from 2006 Actual
Land and Buildings						
1805-Land-Depreciation			\$0	\$0		\$0
1806-Land Rights-Depreciation			\$0	\$0		\$0
1808-Buildings and Fixtures-Depreciation	\$10,864	\$13,580	\$2,716	\$13,580	\$16,413	\$2,833
1905-Land-Depreciation			\$0	\$0		\$0
1906-Land Rights-Depreciation			\$0	\$0		\$0
1810-Leasehold Improvements-Depreciation			\$0	\$0		\$0
Sub-Total-Land and Buildings	\$10,864	\$13,580	\$2,716	\$13,580	\$16,413	\$2,833
TS Primary Above 50						
1815-Transformer Station Equipment - Normally Primary above 50 kV-Depreciation			\$0	\$0		\$0
Sub-Total-TS Primary Above 50	\$0	\$0	\$0	\$0	\$0	\$0
DS						
1820-Distribution Station Equipment - Normally Primary below 50 kV-Depreciation	\$24,304	\$30,394	\$6,090	\$30,394	\$36,484	\$6,090
Sub-Total-DS	\$24,304	\$30,394	\$6,090	\$30,394	\$36,484	\$6,090
Poles and Wires						
1830-Poles, Towers and Fixtures-Depreciation		\$0	\$0	\$0	\$1,920	\$1,920
1835-Overhead Conductors and Devices-Depreciation	\$303,967	\$389,897	\$85,930	\$389,897	\$477,270	\$87,373
1840-Underground Conduit-Depreciation		\$0	\$0	\$0	\$139	\$139
1845-Underground Conductors and Devices-Depreciation	\$134,197	\$171,925	\$37,728	\$171,925	\$212,682	\$40,757
Sub-Total-Poles and Wires	\$438,164	\$561,822	\$123,658	\$561,822	\$692,011	\$130,189
Line Transformers						
1850-Line Transformers-Depreciation	\$101,207	\$129,754	\$28,547	\$129,754	\$158,367	\$28,613
Sub-Total-Line Transformers	\$101,207	\$129,754	\$28,547	\$129,754	\$158,367	\$28,613
Services and Meters						
1855-Services-Depreciation		\$0	\$0	\$0	\$2,016	\$2,016
1860-Meters-Depreciation	\$46,104	\$63,418	\$17,314	\$63,418	\$77,607	\$14,189
Sub-Total-Services and Meters	\$46,104	\$63,418	\$17,314	\$63,418	\$79,623	\$16,205

General Plant

1908-Buildings and Fixtures-Depreciation			\$0	\$0		\$0
1910-Leasehold Improvements-Depreciation			\$0	\$0		\$0
Sub-Total-General Plant	\$0	\$0	\$0	\$0	\$0	\$0

IT Assets

1920-Computer Equipment - Hardware-Depreciation	\$15,431	\$19,942	\$4,511	\$19,942	\$26,356	\$6,414
1925-Computer Software-Depreciation	\$14,686	\$24,126	\$9,440	\$24,126	\$26,887	\$2,761
Sub-Total-IT Assets	\$30,117	\$44,068	\$13,951	\$44,068	\$53,243	\$9,175

Equipment

1915-Office Furniture and Equipment-Depreciation	\$19,863	\$24,906	\$5,043	\$24,906	\$32,181	\$7,275
1930-Transportation Equipment-Depreciation	\$110,463	\$142,124	\$31,661	\$142,124	\$205,448	\$63,324
1935-Stores Equipment-Depreciation			\$0	\$0	\$0	\$0
1940-Tools, Shop and Garage Equipment-Depreciation	\$40,347	\$46,904	\$6,557	\$46,904	\$63,120	\$16,216
1945-Measurement and Testing Equipment-		\$0	\$0	\$0	\$670	\$670
1945-Measurement and Testing Equipment-Depreciation			\$0	\$0	\$0	\$0
1950-Power Operated Equipment-Depreciation			\$0	\$0	\$0	\$0
1955-Communication Equipment-Depreciation			\$0	\$0	\$0	\$0
1960-Miscellaneous Equipment-Depreciation			\$0	\$0	\$0	\$0
Sub-Total-Equipment	\$170,673	\$213,934	\$43,261	\$213,934	\$301,419	\$87,485

Other Distribution Assets

1825-Storage Battery Equipment-Depreciation			\$0	\$0		\$0
1970-Load Management Controls - Customer Premises-Depreciation			\$0	\$0		\$0
1975-Load Management Controls - Utility Premises-Depreciation			\$0	\$0		\$0
1980-System Supervisory Equipment-Depreciation			\$0	\$0		\$0
1985-Sentinel Lighting Rental Units-Depreciation			\$0	\$0		\$0
1990-Other Tangible Property-Depreciation			\$0	\$0		\$0
1995-Contributions and Grants - Credit-Depreciation			\$0	\$0		\$0
Sub-Total-Other Distribution Assets	\$0	\$0	\$0	\$0	-\$8,474	-\$8,474

ACCUMULATED DEPRICIATION TOTAL

\$821,433	\$1,056,970	\$235,537	\$1,056,970	\$1,329,086	\$272,116
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ACCUMULATED DEPRECIATION TABLE			Variance from 2007		Variance from 2008
	2007 Actual (\$'s)	2008 Bridge Actual (\$'s)		2008 Bridge (\$'s)	2009 Test (\$'s)
Land and Buildings					
1805-Land-Depreciation	\$0		\$0	\$0	\$0
1806-Land Rights-Depreciation	\$0		\$0	\$0	\$0
1808-Buildings and Fixtures-Depreciation	\$16,413	\$19,251	\$2,838	\$19,251	\$22,088
1905-Land-Depreciation	\$0		\$0	\$0	\$0
1906-Land Rights-Depreciation	\$0		\$0	\$0	\$0
1810-Leasehold Improvements-Depreciation	\$0		\$0	\$0	\$0
Sub-Total-Land and Buildings	\$16,413	\$19,251	\$2,838	\$19,251	\$22,088
TS Primary Above 50					
1815-Transformer Station Equipment - Normally Primary above 50 kV-Depreciation	\$0		\$0	\$0	\$0
Sub-Total-TS Primary Above 50	\$0	\$0	\$0	\$0	\$0
DS					
1820-Distribution Station Equipment - Normally Primary below 50 kV-Depreciation	\$36,484	\$42,574	\$6,090	\$42,574	\$49,264
Sub-Total-DS	\$36,484	\$42,574	\$6,090	\$42,574	\$49,264
Poles and Wires					
1830-Poles, Towers and Fixtures-Depreciation	\$1,920	\$5,658	\$3,739	\$5,658	\$10,958
1835-Overhead Conductors and Devices-Depreciation	\$477,270	\$567,868	\$90,597	\$567,868	\$664,665
1840-Underground Conduit-Depreciation	\$139	\$301	\$162	\$301	\$463
1845-Underground Conductors and Devices-Depreciation	\$212,682	\$254,922	\$42,241	\$254,922	\$297,163
Sub-Total-Poles and Wires	\$692,011	\$828,749	\$136,738	\$828,749	\$973,249
Line Transformers					
1850-Line Transformers-Depreciation	\$158,367	\$191,819	\$33,452	\$191,819	\$230,471
Sub-Total-Line Transformers	\$158,367	\$191,819	\$33,452	\$191,819	\$230,471
Services and Meters					
1855-Services-Depreciation	\$2,016	\$5,209	\$3,193	\$5,209	\$8,703
1860-Meters-Depreciation	\$77,607	\$90,411	\$12,804	\$90,411	\$103,216
Sub-Total-Services and Meters	\$79,623	\$95,621	\$15,998	\$95,621	\$111,919

General Plant

1908-Buildings and Fixtures-Depreciation	\$0	\$0	\$0	\$0	\$0	\$0
1910-Leasehold Improvements-Depreciation	\$0	\$0	\$0	\$0	\$0	\$0
Sub-Total-General Plant	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>

IT Assets

1920-Computer Equipment - Hardware-Depreciation	\$26,356	\$32,853	\$6,497	\$32,853	\$39,349	\$6,497
1925-Computer Software-Depreciation	\$26,887	\$29,647	\$2,761	\$29,647	\$32,408	\$2,761
Sub-Total-IT Assets	<u>\$53,243</u>	<u>\$62,500</u>	<u>\$9,257</u>	<u>\$62,500</u>	<u>\$71,757</u>	<u>\$9,257</u>

Equipment

1915-Office Furniture and Equipment-Depreciation	\$32,181	\$40,302	\$8,121	\$40,302	\$48,423	\$8,121
1930-Transportation Equipment-Depreciation	\$205,448	\$272,898	\$67,449	\$272,898	\$380,722	\$107,824
1935-Stores Equipment-Depreciation	\$0	\$0	\$0	\$0	\$0	\$0
1940-Tools, Shop and Garage Equipment-Depreciation	\$63,120	\$80,969	\$17,849	\$80,969	\$99,444	\$18,474
1945-Measurement and Testing Equipment-	\$670	\$1,339	\$670	\$1,339	\$2,009	\$670
1945-Measurement and Testing Equipment-Depreciation	\$0	\$0	\$0	\$0	\$0	\$0
1950-Power Operated Equipment-Depreciation	\$0	\$0	\$0	\$0	\$0	\$0
1955-Communication Equipment-Depreciation	\$0	\$0	\$0	\$0	\$0	\$0
1960-Miscellaneous Equipment-Depreciation	\$0	\$0	\$0	\$0	\$0	\$0
Sub-Total-Equipment	<u>\$301,419</u>	<u>\$395,508</u>	<u>\$94,089</u>	<u>\$395,508</u>	<u>\$530,597</u>	<u>\$135,089</u>

Other Distribution Assets

1825-Storage Battery Equipment-Depreciation	\$0	\$0	\$0	\$0	\$0	\$0
1970-Load Management Controls - Customer Premises-Depreciation	\$0	\$0	\$0	\$0	\$0	\$0
1975-Load Management Controls - Utility Premises-Depreciation	\$0	\$0	\$0	\$0	\$0	\$0
1980-System Supervisory Equipment-Depreciation	\$0	\$0	\$0	\$0	\$0	\$0
1985-Sentinel Lighting Rental Units-Depreciation	\$0	\$0	\$0	\$0	\$0	\$0
1990-Other Tangible Property-Depreciation	\$0	\$0	\$0	\$0	\$0	\$0
1995-Contributions and Grants - Credit-Depreciation	-\$8,474	-\$18,778	-\$10,303	-\$18,778	-\$29,081	-\$10,303
Sub-Total-Other Distribution Assets	<u>-\$8,474</u>	<u>-\$18,778</u>	<u>-\$10,303</u>	<u>-\$18,778</u>	<u>-\$29,081</u>	<u>-\$10,303</u>

ACCUMULATED DEPRICIATION TOTAL

<u>\$1,329,086</u>	<u>\$1,617,244</u>	<u>\$288,158</u>	<u>\$1,617,244</u>	<u>\$1,960,264</u>	<u>\$343,019</u>
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MATERIALITY ANALYSIS ON ACCUMULATED DEPRICIATION

Asset Account	Bridge Year	Test Year	Variance
1835-Overhead Conductors and Devices - Depreciation	\$567,868	\$664,665	\$96,797

Explanation: The accumulated depreciation increased by more than materiality for Overhead Conductors and Devices due to the fact that the associated asset account represents a large portion of the Distribution Assets in service for WEST COAST. The associated asset account is \$2,504,935 of WEST COAST's total gross asset base and consequently will generate a large amount of amortization as a result. It is important to note that amortization rates have not changed on this account throughout the whole timeframe of the application.

Asset Account	Bridge Year	Test Year	Variance
1845-Underground Conductors and Devices-Depreciation	\$254,922	\$297,163	\$42,241

Explanation: The accumulated depreciation increased by more than materiality for Underground Conductors and Devices due to the fact that the associated asset account represents a large portion of the Distribution Assets in service for WEST COAST. The associated asset account is \$1,056,014 of WEST COAST's total gross asset base and consequently will generate a large amount of amortization as a result. It is important to note that amortization rates have not changed on this account throughout the whole timeframe of the application.

Asset Account	Bridge Year	Test Year	Variance
1850-Line Transformers-Depreciation	\$191,819	\$230,471	\$38,652

Explanation: The accumulated depreciation increased by more than materiality for Line Transformers due to the fact that the associated asset account represents a large portion of the Distribution Assets in service for WEST COAST. The associated asset account is \$1,033,801 of WEST COAST's total gross asset base and consequently will generate a large amount of amortization as a result. It is important to note that amortization rates have not changed on this account throughout the whole timeframe of the application.

Asset Account	Bridge Year	Test Year	Variance
1930-Transportation Equipment- Depreciation	\$272,898	\$380,722	\$107,824

Explanation: The accumulated depreciation increased by more than materiality for Transportation Equipment as a direct result of the fact that vehicles amortize quickly coupled by the fact that a new Bucket Truck is being added in service in 2009 which will explained in the explanation of capital additions in Exhibit 2, Tab 3, Schedule 2.

CAPITAL BUDGET BY PROJECT

Project Description	USoA Account	Expansion or Enhancement	Amount	Spend Year
27KV Conversion and Feeder Operating Enhancements	1830, 1835, 1850	Enhancement	\$175,000	Bridge
Replace Danger Poles within Distribution System	1830, 1835	Enhancement	\$95,000	Bridge
Upgrade Poles and Conductor on M3 6 spans from TS	1830, 1836	Enhancement	\$80,000	Bridge
Cost of Connecting New Customers	1850, 1855	Expansion	\$50,000	Bridge
Tools and equipment purchases	1940	Enhancement	\$5,000	Bridge
Transformer purchases for Inventory	1850	Enhancement	\$15,000	Bridge
purchase truck	1930	Enhancement	\$33,000	Bridge
			\$453,000	

Project Description	USoA Account	Expansion or Enhancement	Amount	Spend Year
Release 31M3 27.6kv Constraints on South Loop by	1830, 1835, 1850	Enhancement	\$305,000	Test
Introducing 31M4 27.6 Circuit	1830, 1835	Enhancement	\$50,000	Test
Replace Danger Poles within Distribution System	1820	Enhancement	\$30,000	Test
Fencing & Grounding and station overhaul	1850, 1855	Expansion	\$60,000	Test
Cost of Connecting New Customers	1850	Enhancement	\$20,000	Test
Transformer purchases for Inventory	1930	Enhancement	\$290,000	Test
New Bucket Truck Ordered in 2008			\$755,000	

MATERIALITY ANALYSIS ON CAPITAL BUDGETS**West Coast Huron Energy (WCHE) Capital Additions Explanations.****Project ID 2009, “New Bucket Truck”**

WCHE has a current fleet of only one bucket truck. The existing bucket truck is a 1990 50' aerial device over 18 years old and has exceeded its end of life expectation. Most bucket truck fleets have a life cycle of 10-15 years maximum. With some of the distribution system configurations that will be posed in coming years a larger 55' unit will be required to perform some of the day to day functions required. With the constraint of only one bucket truck it is imperative that the utilities fleet maintains in good operational standing and not to jeopardize worker safety while working aloft.

Project ID 1126, “Replace Danger Poles”:

In 2007 WCHE had contractor a company to come in a perform pole testing on $\frac{1}{4}$ of the poles in the distribution system. The results of testing have been evaluated and prioritized to mitigate the utilities risks. Funding is required over a two year period (2008, 2009) to deal with the asset condition.

Project ID 1129, “Cost of Connecting New Customers”:

Starting in 2007 WCHE has seen a rise in new capital commercial additions as a result of big box stores being attracted to the community. System expansions/enhancements have been taken to accommodate the new connections. Local municipal planners have indicated the trend to continue into 2009.

Project ID 1124, 1132, 1134, “M3 & M4 Feeder Enhancements”:

In 2007 Sifto Salt announced an expansion to the plant which was cause for concern for the existing distribution infrastructure. WCHE retained an engineering firm to conduct a distribution system feeder assessment and report back on their findings and recommendations.

Report Summary

Goderich Hydro (the LDC) has two feeders, the M3 which peaks at 17 MW or 475 A and the M4 which peaks at 9.5 MW or 215 A. The feeders are 336 conductor which has a maximum current rating of 450 A. Refer to Section 5 for discussion. The load on the M3 is primarily one customer, Sifto Salt, whose load characteristic has a low power factor of about 0.78. Since at peak the 336 conductor exceeds its rating, the LDC has no operating flexibility or redundancy for the loss of critical feeder elements. Sifto has expansion plans and the LDC is concerned that a critical situation is going to get worse.

This report assesses the status quo and works through a number of potential options to reinforce supply, lower operating currents and provide operating flexibility and redundancy.

There are two approaches with some similar and some alternate options. The first is to maximize the facility of the two existing feeders. The second and preferred option is to add a third feeder.

The components of the approaches can be mixed and matched for interim relief providing the end point is kept in focus and to some extent the order of activities depending on the opportunity to do work, the timing

available and working with Sifto's plans to integrate the upgrades to ensure the least disruption to the town's customers and Sifto.

In summary the upgrade recommendations have been considered and WCHE has determined the best solution to be:

Add a Third Feeder

- Build tie line between M3 and M4 circuits MS 1 to MS 2.
- Add breaker position to TS.
- Build 3rd circuit from TS to MS2. Increase M3 conductor size to 556 from TS to MS2.
- Split Sifto load by double circuiting into plant
- Add ties between TS and splits for M3, M4 and 3rd feeder to increase operating flexibility.
- Upgrade M4 egress from 750 kCMil Al to 1000 kCMil Cu.

This solution will require significant investment over the next five years. Once completed the results will relieve constraints, reduce system losses, and provide safe, reliable power for the customers served.

Complete report can be viewed in Appendix I and Appendix J attached to this application.

West Coast Huron Energy Inc. (WCHE) Asset Management Plan

WCHE has developed a number of processes and work flow procedures necessary to manage and maintain the distribution assets within its licensed service territory. The asset investment strategy for WCHE is illustrated within Appendix L.

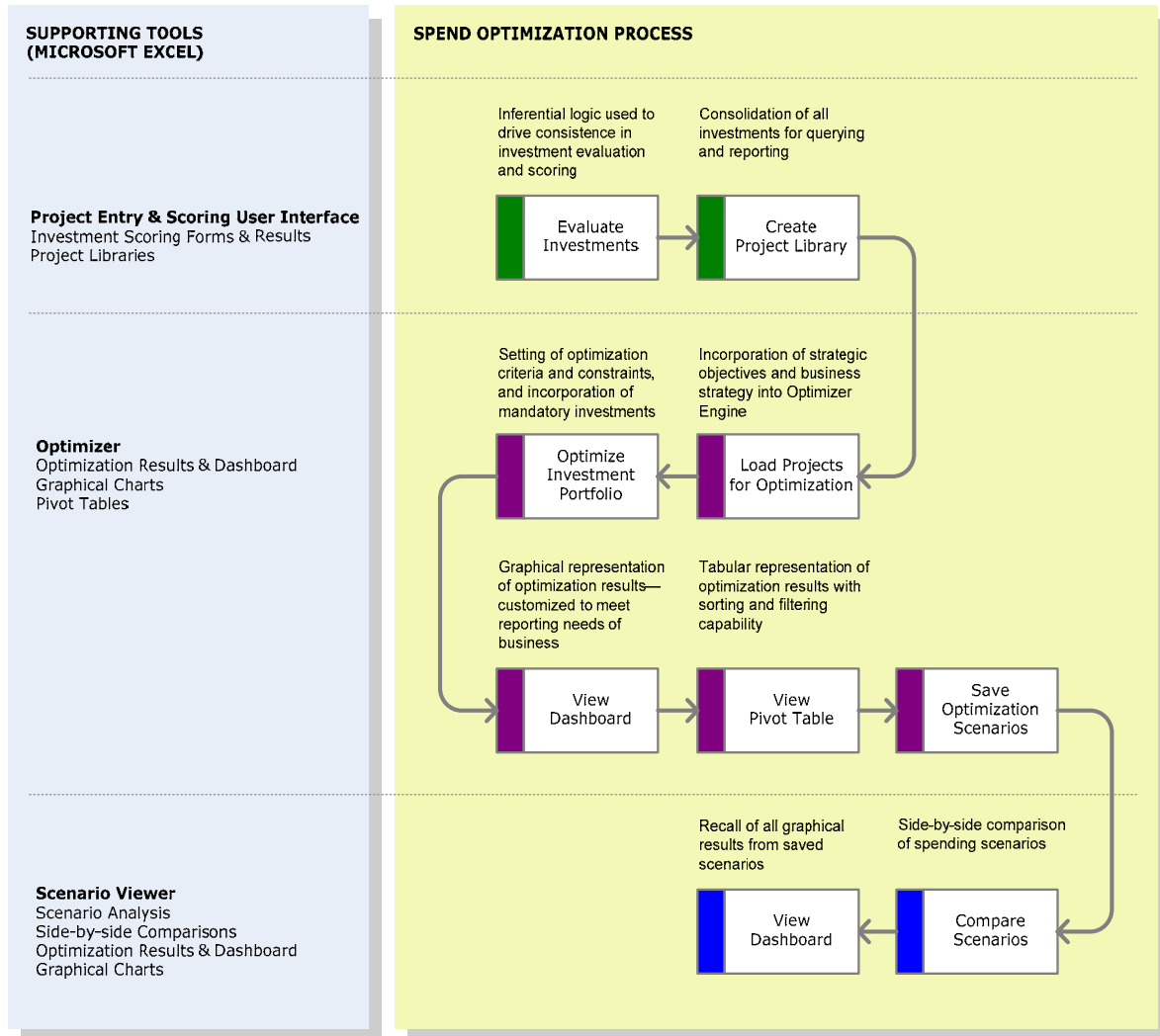
Embedded with in the plan is the requirement for needs assessments. Ongoing assessments are done on a continue basis through annual inspections, work flow processes and trouble report procedures. In addition it is imperative for WCHE to participate and communicate with local developers along with municipal planners to assess future requirements for the distribution system. Attachments for these processes are detailed below.

1. Appendix J describes the annual process for annual inspection and maintenance of the distribution system. In addition to the annual inspection requirement for WCHE staff, contractors are used to perform yearly infrared scans on the entire distribution system along with bi annual pole testing on $\frac{1}{4}$ of the distribution system. Through this process information is gathered pertinent to the condition and state of the distribution system in its current state that lend to the needs assessment process to support capex and opex spending decisions.
2. Appendix K describes the day to day work flow methods which also lend itself to the needs assessment process.
3. Appendix M illustrates another method of gathering data for both OEB reporting requirements and outage information that trend ongoing issues with the distribution system. This information is evaluated on an ongoing basis and used to support capex and opex spending decisions.
4. Customer requests, participation in municipal planning and development meetings, market rules (Electrical Safety Authority requirements) all form part of the needs assessment process as well.
5. Distribution System analysis (feeder studies) – WCHE has recently undergone a feeder study which has determined that its 27kv distribution system (loop) circuits M3 and M4 are very constrained and it lacks operational flexibility and the ability to support new load growth. Results of such studies and their recommendations along with priorities of needs over the next 5 years have been included within the portfolio.

Elements listed above held identify areas of need which will form projects that become part of a portfolio which is developed throughout the year. The projects are then analyzed for their validity before being entered into our project library and optimized for the best outcome.

With the optimization process employed the projects that bring the greatest value along with accelerated plans for projects that pose the greatest risk will be executed first. When all drivers are thoroughly and equally evaluated “reactive” situations can be avoided.

Optimization Process



1.1 FUNCTIONAL Walkthrough

Optimizer Toolset is designed to facilitate the asset planning and budgeting processes through portfolio optimization. Portfolio optimization takes a holistic view of all expenditures by project/program and enables the determination of a spending portfolio that fits any given budget constraint and produces the highest cumulative weighted benefit across all nominated strategic objectives of the business.

Put another way, investment optimization focuses on selecting the optimum bundle of projects/programs that maximizes the strategic value with an acceptable risk exposure and for minimum cost. The contribution of individual projects is measured within the bundle. What portfolio optimization avoids, therefore, is the trap of budget entitlements. That is, budget allocation based primarily on subjective or organization political considerations, rather than to meet strategic objectives (maximize value) or to minimize risk for the least cost. The Optimizer toolset incorporates the latest techniques and mathematical algorithms, and the functionality fits the realities of today's operating requirements.

The overall Optimizer toolset is comprised of six components: Strategic Objectives, Project Entry and Scoring User Interface, Project Library, Optimizer Engine, Optimization Results Dashboard, and Scenario Viewer.

1.2 Strategic Objectives

A unique set of strategic business objectives is incorporated into the Optimizer. Business leaders outline the strategic value and risk frameworks you want to use to influence spend decisions. The strategic objectives and sub-criteria making up this framework need to be aligned with your business strategies and mission.

The screenshot shows the 'Strategic Objectives' window in the UMS Optimizer. It features a 'WEIGHTINGS' section on the left with five sliders, each set to 20.0%. The main area displays a grid of criteria: Financial & Risk Management, Operational Effectiveness, Customer Focus, Human Resource Management, and Strategic Relationships. A preference consistency check at the top shows $\lambda = 0.00$. A 3D pie chart at the bottom visualizes the weightings. Four numbered callouts provide context:

1. As a business you develop the criteria you want to use in the "optimizer". These need to be aligned with the business objectives and have a common translation into the day to day decision making process
2. Appropriate percentile weightings are calculated for each criterion to reflect their relative importance in selecting an overall "best value" alternative. This tool calculates weights by aggregating a series of systematic one-vs-one comparisons between each pair of criteria.
3. The criteria can be changed and /or their relative weightings altered at any point in time in response to Board or Regulatory requests e.g. a focus on safety, etc.
4. The decision-maker is asked to decide which item in each pair of criteria is more important or preferred, and how strongly preferred (if at all) all other criteria being equal.

Scoring Matrices

Subject Matter Experts (SMEs) facilitate the development of scoring matrices for all strategic objectives and decision parameters (both value and risk). Each proposed investment will be analyzed across these defined value parameters and risk domains. For our purposes, value is assessed as the benefit (or detriment) that would result if the investment were funded, whereas the risk is assessed in terms of the risk of deferral, or what could potentially happen (consequence and probability) for any investment not funded.

1.3 Project Entry and Scoring User Interface

Consistency, accuracy, and precision are all important in ensuring effective evaluation of investments. However, in our experience, consistency is the most important because, at its root, investment optimization is a relative comparison process. Accuracy, although secondary in importance, is also necessary to achieve a clear and truthful depiction of the value and risk associated with each investment. Precision is tertiary in importance and is to be achieved when consistency and accuracy are not jeopardized. To this end, the Optimizer offers an inferential Project Entry and Scoring User Interface that dramatically facilitates the task of assembling the data needed to evaluate investments. "Data input" is the program-guided and user-executed process by which all data and assumptions relevant to the evaluation of work, projects or investments are queried for, responded to and collected as program inputs.

1.4 Project Library

The Project Library functions as a database of all investment information. All CAPEX and OPEX spend is stored in the Library. The Library is divided into four major categories of information:

- Demographics – where basic information about each investment, such as year, location, and budget process data is captured,
- Cost – where the investment cost information is broken down,

The screenshot displays the 'Investment Description' form, which is a comprehensive data entry interface. It features a top navigation bar with the 'Investment Description' and 'Summary' tabs. The form is organized into several sections, each with a yellow header: 'Business Unit', 'Line of Business', 'Investment ID # (PID)', 'Investment Name - Project Name', 'Investment Description', 'Select "Root Project"', 'Companion Project ID', 'Companion Project Name', 'Companion Project Description', 'Budget Schedule', 'Owner Center', 'Location', 'Owner Corp', 'State (if applicable)', 'Bulk/Submission (if applicable)', 'Blanket / Specific type Project', 'Work Type', 'Type Code Description', 'Justification Code Description', 'P/E Group Code', 'Planned Start Date', 'Planned In-service Date', 'Estimated Total Project Cost (Fully Loaded Dollars)', 'What Percent of the Investment Cost Has Already Been Spent?', 'Project Initiation', 'Project Sponsor', 'Department Manager', 'How many Units of Work are included in this investment?', 'Does this investment have a mutually exclusive relationship with any other submitted investments?', 'Is this investment dependent on another investment?', 'Is this investment mandatory?', and 'Current status of this investment'. Each section contains various input fields, including dropdown menus, text boxes, and checkboxes. A 'Submit Investment' button is located in the top right corner, and a 'Complete' button is at the bottom right. The form also includes a 'Check here when the Investment Description Page is complete' checkbox and a 'Load Demographics' button.

- Value – where the results of the investment scorings are captured, and
- Risk – where the results of the risk assessment are captured.

The Project Library is created from the Project Entry and Scoring User Interface. This relationship between the Project Entry and Scoring User Interface and the Project Library allows for both the information needed for analysis and the additional information required for value determination to be retained for audit, detailed analysis and historical/ reference purposes.

The decision-maker has the ability to "force select" certain projects – e.g. new

Project Identifier	Project Name	Budget Year	Cost Category	Project Type	Business Unit	Estimated Start Date	Program	Business Case Prepared By	Business Case Reviewed By	Project Manager	Project Status
2003-0001	Here to There Tie	2003	Capital	Reliability	Network Planning & Operations	Anytime	Betterments	R. Abdullah	R. Abdullah		Pls
2003-0002	Station Betterments-Tap changer Fite	2003	Capital	Reliability	Network Planning & Operations	Anytime	Minor Station Works	R. Abdullah	R. Abdullah		Pls
2003-0003	Relocate poles for 3rd party	2003	Capital	Demand	Network Planning & Operations	February	Distribution System Program	R. Abdullah	R. Abdullah		Pls
2003-0004	Limebank Reconst - 7F4	2003	Capital	Demand	Network Planning & Operations	May	Road Reconstruction Projects	R. Abdullah	R. Abdullah		Pls
2003-0005	Smithville U/G Improvements	2003	Capital	Reliability	Network Planning & Operations	July	Betterments	R. Abdullah	R. Abdullah		Pls
2003-0006	Padmountd SV/G	2003	Capital	Reliability	Network Planning & Operations	October	Distribution Automation	R. Abdullah	R. Abdullah		Pls
2003-0007	Angtown F1/F5	2003	Capital	Reliability	Network Planning & Operations	June	Betterments	R. Abdullah	R. Abdullah		Pls
2003-0008	Hwy 7 Reconstruction	2003	Capital	Demand	Network Planning & Operations	August	Road Reconstruction Projects	R. Abdullah	R. Abdullah		Pls
2003-0009	Upgrade BRDF2 cable to oct. Capacity	2003	Capital	Reliability	Network Planning & Operations	August	Betterments	R. Abdullah	R. Abdullah		Pls
2003-0010	Splice Replacement	2003	Capital	Reliability	Network Planning & Operations	July	Distribution System Program	R. Abdullah	R. Abdullah		Pls
2003-0011	Pole Mounted SV/G	2003	Capital	Reliability	Network Planning & Operations	January	Distribution Automation	R. Abdullah	R. Abdullah		Pls
2003-0012	Residential Developments	2003	Capital	Demand	Network Planning & Operations	Anytime	Metering	R. Abdullah	R. Abdullah		Pls
2003-0013	SV/ Vault removal	2003	Capital	Reliability	Network Planning & Operations	August	Betterments	R. Abdullah	R. Abdullah		Pls
2003-0014	New RTU's	2003	Capital	Reliability	Network Planning & Operations	August	SCADA	R. Abdullah	R. Abdullah		Pls
2003-0015	Minor SCADA upgrades	2003	Capital	Reliability	Network Planning & Operations	June	SCADA	R. Abdullah	R. Abdullah		Pls
2003-0016	Line extension Program-Russel	2003	Capital	Reliability	Network Planning & Operations	Anytime	Minor Station Works	R. Abdullah	R. Abdullah		Pls
2003-0017	ASIM 44 kV Improvements	2003	Capital	Reliability	Network Planning & Operations	December	Betterments	R. Abdullah	R. Abdullah		Pls
2003-0018	Commercial Developments	2003	Capital	General Plant	Network Planning & Operations	Anytime	Metering	J. Smith	J. Smith		Pls
2003-0019	Transformer Replacement	2003	Capital	Demand	Network Planning & Operations	January	Distribution System Program	J. Smith	J. Smith		Pls
2003-0020	Station Betterments-Bagshore D.S. up	2003	Capital	Reliability	Network Planning & Operations	Anytime	Minor Station Works	J. Smith	J. Smith		Pls
2003-0021	Bow Conversion	2003	Capital	Reliability	Network Planning & Operations	October	SCADA	J. Smith	J. Smith		Pls
2003-0022	Transformer Replacements	2003	Capital	Reliability	Network Planning & Operations	March	Distribution System Program	J. Smith	J. Smith		Pls
2003-0023	Jack Bus Replacement	2003	Capital	Reliability	Network Planning & Operations	Anytime	Betterments	J. Smith	J. Smith		Pls
2003-0024	Unplanned PLC Cable replacement	2003	Capital	Demand	Network Planning & Operations	March	Distribution System Program	J. Smith	J. Smith		Pls
2003-0025	service upgrades	2003	Capital	Demand	Network Planning & Operations	Anytime	Residential Development	J. Smith	J. Smith		Pls
2003-0026	Goulbourn Stat. Monitoring	2003	Capital	Reliability	Network Planning & Operations	September	SCADA	J. Smith	J. Smith		Pls
2003-0027	4th Line Reconstruction	2003	Capital	Demand	Network Planning & Operations	July	Road Reconstruction Projects	J. Smith	J. Smith		Pls
2003-0028	Minor commercial upgrades	2003	Capital	Demand	Network Planning & Operations	July	Commercial Development	J. Smith	J. Smith		Pls
2003-0029	Laurel Bridge Reconstruction	2003	Capital	Demand	Network Planning & Operations	March	Road Reconstruction Projects	J. Smith	J. Smith		Pls
2003-0030	DNF1 Conver. remote Sw's	2003	Capital	Reliability	Network Planning & Operations	August	SCADA	J. Smith	J. Smith		Pls
2003-0031	Angtown F3/F4	2003	Capital	Reliability	Network Planning & Operations	Anytime	Betterments	J. Smith	J. Smith		Pls
2003-0032	SCADA Upgrades	2003	Capital	Reliability	Network Planning & Operations	July	SCADA	J. Smith	J. Smith		Pls

1.5 Optimizer Engine

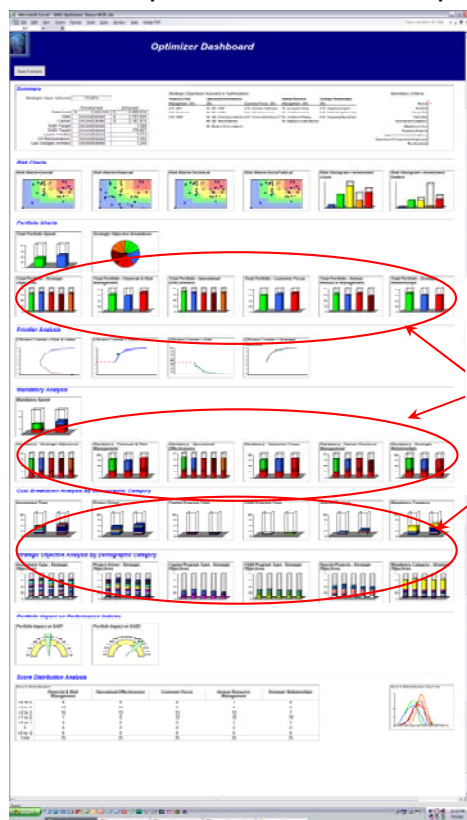
The Optimizer Engine brings all of the decision parameters together for rapid analysis and easy business studies of multiple issues, including complete flexibility for scenario analysis.

The user is in total control over the analysis parameters. The Optimizer allows the user to designate the investment cost type and budget limits that they wish to analyze (OPEX, CAPEX, or both). In addition to budgetary constraints, users are able to apply any combination of target constraints (e.g., safety performance, plant reliability, resource availability, remediation cost, etc), or any other operational program targets to a given optimization scenario. Likewise, complete flexibility is provided to the user over the optimization parameters. The default analysis is an optimization across all the strategic objectives, however, any combination of the strategic objectives or sub-objectives or risk parameters can be selected or unselected for more targeted

analysis. In addition to the optimization criteria, the Optimizer allows the user to further enhance the analysis by designating investments as mandatory or discretionary. Investments can be marked as mandatory either individually or by category. The Optimizer also allows for inclusion of dependencies and exclusivities among investments.

1.6 Optimization Results Dashboard

The Optimizer provides both graphical and tabular outputs. The graphical outputs are provided in a thumbnail “Dashboard” as well as full screen charts. This approach allows for quick scanning across all parameters and still provides for detailed analysis where appropriate.



There are many standard charts included in the dashboard – Risk Breakdowns, Cost Breakdowns, Value Breakdowns, and Frontier Analysis (allowing users to compare the selected portfolio against the efficient frontier, or maximum achievable value or risk mitigation at any spending level). If desired, all of the Optimizer’s graphical outputs can be customized on the engagement to meet the needs. You can choose to include additional Target Analysis (allowing the direct impact of portfolio spend to be calculated in terms of performance targets reliability, availability, emissions limits. The primary limitation on the graphical outputs is the availability of your data inputs.

The tabular outputs take advantage of Excel’s pivot table capabilities to provide complete sorting, filtering, and report printing control. These results are easily saved and archived for scenario analysis or incorporation into the budgeting systems.

CAPITALIZATION POLICY

Appendix N

WORKING CAPITAL ALLOWANCE CALCULATION BY ACCOUNT	2006 Actual	15%	Allowance for Working Capital	2007 Actual	15%	Allowance for Working Capital
Operation (Working Capital)						
5005-Operation Supervision and Engineering	\$1,121.00	15%	\$168.15	\$340.80	15%	\$51.12
5010-Load Dispatching	\$628.00	15%	\$94.20	\$2,810.67	15%	\$421.60
5012-Station Buildings and Fixtures Expense	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
5014-Transformer Station Equipment - Operation Labour	\$16,314.00	15%	\$2,447.10	\$19,366.34	15%	\$2,904.95
5015-Transformer Station Equipment - Operation Supplies and Expenses	\$100.00	15%	\$15.00	\$50.00	15%	\$7.50
5016-Distribution Station Equipment - Operation Labour	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
5017-Distribution Station Equipment - Operation Supplies and Expenses	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
5020-Overhead Distribution Lines and Feeders - Operation Labour	\$259,058.00	15%	\$38,858.70	\$158,282.14	15%	\$23,742.32
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
5030-Overhead Sub transmission Feeders - Operation	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
5035-Overhead Distribution Transformers- Operation	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
5040-Underground Distribution Lines and Feeders - Operation Labour	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	\$5,593.00	15%	\$838.95	\$0.00	15%	\$0.00
5050-Underground Sub transmission Feeders - Operation	\$68,461.00	15%	\$10,269.15	\$85,654.13	15%	\$12,848.12
5075-Customer Premises - Materials and Expenses	\$1,026.00	15%	\$153.90	\$0.00	15%	\$0.00
Sub-Total	\$352,301.00		\$52,845.15	\$266,504.08		\$39,975.61
Maintenance (Working Capital)						
5105-Maintenance Supervision and Engineering	\$15,616.00	15%	\$2,342.40	\$2,376.32	15%	\$356.45
5110-Maintenance of Buildings and Fixtures - Distribution Stations	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
5112-Maintenance of Transformer Station Equipment	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
5114-Maintenance of Distribution Station Equipment	\$5,229.00	15%	\$784.35	-\$15,793.14	15%	-\$2,368.97
5120-Maintenance of Poles, Towers and Fixtures	\$8,957.00	15%	\$1,343.55	\$319.92	15%	\$47.99
5125-Maintenance of Overhead Conductors and Devices	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
5130-Maintenance of Overhead Services	\$11,593.00	15%	\$1,738.95	\$18,644.33	15%	\$2,796.65
5135-Overhead Distribution Lines and Feeders - Right of Way	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
5145-Maintenance of Underground Conduit	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
5150-Maintenance of Underground Conductors and Devices	\$27,773.00	15%	\$4,165.95	\$26,989.57	15%	\$4,048.44
5155-Maintenance of Underground Services	\$290.00	15%	\$43.50	\$453.53	15%	\$68.03
5160-Maintenance of Line Transformers	\$5,910.00	15%	\$886.50	\$4,971.82	15%	\$745.77
5165-Maintenance of Street Lighting and Signal Systems	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
5170-Sentinel Lights - Labour	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
5172-Sentinel Lights - Materials and Expenses	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
5175-Maintenance of Meters	\$39,204.00	15%	\$5,880.60	\$4,800.00	15%	\$720.00
5178-Customer Installations Expenses- Leased Property	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
5185-Water Heater Rentals - Labour	\$42.00	15%	\$6.30	\$0.00	15%	\$0.00
5186-Water Heater Rentals - Materials and Expenses	\$1,358.00	15%	\$203.70	\$432.68	15%	\$64.90
Sub-Total	\$115,972.00		\$17,395.80	\$43,195.03		\$6,479.25

Billing and Collections

5305-Supervision	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
5310-Meter Reading Expense	\$77,860.00	15%	\$11,679.00	\$3,364.68	15%	\$504.70
5315-Customer Billing	\$249,860.00	15%	\$37,479.00	\$22,556.84	15%	\$3,383.53
5320-Collecting	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
5325-Collecting- Cash Over and Short	\$110.00	15%	\$16.50	\$0.00	15%	\$0.00
5330-Collection Charges	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
5335-Bad Debt Expense	\$575.00	15%	\$86.25	\$0.00	15%	\$0.00
5340-Miscellaneous Customer Accounts Expenses	\$0.00	15%	\$0.00	\$4,875.00	15%	\$731.25
Sub-Total	\$328,405.00		\$49,260.75	\$30,796.52		\$4,619.48

Community Relations

5405-Supervision	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
5410-Community Relations - Sundry	\$36,360.00	15%	\$5,454.00	\$3,364.68	15%	\$504.70
5415-Energy Conservation	\$17,011.00	15%	\$2,551.65	\$22,556.84	15%	\$3,383.53
5420-Community Safety Program	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
5425-Miscellaneous Customer Service and Informational Expenses	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
5505-Supervision	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
5510-Demonstrating and Selling Expense	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
5515-Advertising Expense	\$3,262.00	15%	\$489.30	\$4,875.00	15%	\$731.25
5520-Miscellaneous Sales Expense	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
Sub-Total	\$56,633.00		\$8,494.95	\$30,796.52		\$4,619.48

Administrative and General Expenses

5605-Executive Salaries and Expenses	\$47,701.00	15%	\$7,155.15	\$47,841.08	15%	\$7,176.16
5610-Management Salaries and Expenses	\$47,615.00	15%	\$7,142.25	\$47,555.76	15%	\$7,133.36
5615-General Administrative Salaries and Expenses	\$138,572.00	15%	\$20,785.80	\$150,364.50	15%	\$22,554.68
5620-Office Supplies and Expenses	\$5,353.00	15%	\$802.95	\$3,612.99	15%	\$541.95
5625-Administrative Expense Transferred Credit	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
5630-Outside Services Employed	\$192,738.00	15%	\$28,910.70	\$174,341.92	15%	\$26,151.29
5635-Property Insurance	\$27,667.00	15%	\$4,150.05	\$28,773.12	15%	\$4,315.97
5640-Injuries and Damages	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
5645-Employee Pensions and Benefits	\$0.00	15%	\$0.00	\$0.65	15%	\$0.10
5650-Franchise Requirements	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
5655-Regulatory Expenses	\$15,491.00	15%	\$2,323.65	\$12,946.97	15%	\$1,942.05
5660-General Advertising Expenses	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
5665-Miscellaneous General Expenses	\$32,128.00	15%	\$4,819.20	\$44,451.12	15%	\$6,667.67
5670-Rent	\$26,400.00	15%	\$3,960.00	\$26,400.00	15%	\$3,960.00
5675-Maintenance of General Plant	\$58,422.00	15%	\$8,763.30	\$115,899.89	15%	\$17,384.98
5680-Electrical Safety Authority Fees	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
5685-Independent Market Operator Fees and Penalties	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
Sub-Total	\$592,087.00		\$88,813.05	\$652,188.00		\$97,828.20

Amortization Expenses

5705-Amortization Expense - Property, Plant, and Equipment	\$205,406.00	0%	\$0.00	\$212,970.00	0%	\$0.00
5710-Amortization of Limited Term Electric Plant	\$0.00	0%	\$0.00	\$0.00	0%	\$0.00
5715-Amortization of Intangibles and Other Electric Plant	\$2,280.00	0%	\$0.00	\$2,280.00	0%	\$0.00
5720-Amortization of Electric Plant Acquisition Adjustments	\$0.00	0%	\$0.00	\$0.00	0%	\$0.00
5725-Miscellaneous Amortization	\$0.00	0%	\$0.00	\$0.00	0%	\$0.00
5730-Amortization of Unrecovered Plant and Regulatory Study Costs	\$0.00	0%	\$0.00	\$0.00	0%	\$0.00
5735-Amortization of Deferred Development Costs	\$0.00	0%	\$0.00	\$0.00	0%	\$0.00
5740-Amortization of Deferred Charges	\$0.00	0%	\$0.00	\$0.00	0%	\$0.00
Sub-Total	\$207,686.00		\$0.00	\$215,250.00		\$0.00

6105-Taxes other than Income Taxes	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
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Cost of Power

4705-Power Purchased	\$4,679,585.00	15%	\$701,937.75	\$4,780,362.46	15%	\$717,054.37
4708-Charges-WMS	\$352,951.00	15%	\$52,942.65	\$350,056.61	15%	\$52,508.49
4710-Cost of Power Adjustments	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
4712-Charges-One-Time	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
4714-Charges-NW	\$767,821.00	15%	\$115,173.15	\$708,898.12	15%	\$106,334.72
4716-Charges-CN	\$661,464.00	15%	\$99,219.60	\$633,021.39	15%	\$94,953.21
4730-Rural Rate Assistance Expense	\$86,764.00	15%	\$13,014.60	\$88,200.82	15%	\$13,230.12
5685-Independent Market Operator Fees and Penalties	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
Sub-Total	\$6,548,585.00		\$982,287.75	\$6,560,539.40		\$984,080.91

WORKING CAPITAL ALLOWANCE TOTAL

\$1,199,097.45

\$1,137,602.93

WORKING CAPITAL ALLOWANCE CALCULATION BY ACCOUNT	2008 Bridge	15%	Allowance for Working Capital	2009 Test	15%	Allowance for Working Capital
Operation (Working Capital)						
5005-Operation Supervision and Engineering	\$2,000.00	15%	\$300.00	\$2,000.00	15%	\$300.00
5010-Load Dispatching	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
5012-Station Buildings and Fixtures Expense	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
5014-Transformer Station Equipment - Operation Labour	\$0.00	15%	\$0.00	\$5,000.00	15%	\$750.00
5015-Transformer Station Equipment - Operation Supplies and Expenses	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
5016-Distribution Station Equipment - Operation Labour	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
5017-Distribution Station Equipment - Operation Supplies and Expenses	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
5020-Overhead Distribution Lines and Feeders - Operation Labour	\$135,000.00	15%	\$20,250.00	\$221,725.00	15%	\$33,258.75
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	\$0.00	15%	\$0.00	\$22,425.00	15%	\$3,363.75
5050-Underground Sub transmission Feeders - Operation	\$100,000.00	15%	\$15,000.00	\$124,600.00	15%	\$18,690.00
5070-Customer Premises - Operation Labour	\$0.00	15%	\$0.00	\$5,000.00	15%	\$750.00
Sub-Total	\$237,000.00		\$35,550.00	\$380,750.00		\$57,112.50
Maintenance (Working Capital)						
5105-Maintenance Supervision and Engineering	\$4,000.00	15%	\$600.00	\$4,000.00	15%	\$600.00
5110-Maintenance of Buildings and Fixtures - Distribution Stations	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
5112-Maintenance of Transformer Station Equipment	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
5114-Maintenance of Distribution Station Equipment	\$35,500.00	15%	\$5,325.00	\$10,000.00	15%	\$1,500.00
5120-Maintenance of Poles, Towers and Fixtures	\$15,000.00	15%	\$2,250.00	\$27,000.00	15%	\$4,050.00
5125-Maintenance of Overhead Conductors and Devices	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
5130-Maintenance of Overhead Services	\$18,000.00	15%	\$2,700.00	\$15,000.00	15%	\$2,250.00
5135-Overhead Distribution Lines and Feeders - Right of Way	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
5145-Maintenance of Underground Conduit	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
5150-Maintenance of Underground Conductors and Devices	\$20,000.00	15%	\$3,000.00	\$15,000.00	15%	\$2,250.00
5155-Maintenance of Underground Services	\$7,000.00	15%	\$1,050.00	\$5,000.00	15%	\$750.00
5160-Maintenance of Line Transformers	\$0.00	15%	\$0.00	\$6,000.00	15%	\$900.00
5175-Maintenance of Meters	\$6,000.00	15%	\$900.00	\$6,000.00	15%	\$900.00
5178-Customer Installations Expenses- Leased Property	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
5185-Water Heater Rentals - Labour	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
5186-Water Heater Rentals - Materials and Expenses	\$3,800.00	15%	\$570.00	\$3,800.00	15%	\$570.00
Sub-Total	\$109,300.00		\$16,395.00	\$91,800.00		\$13,770.00

Billing and Collections

5305-Supervision	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
5310-Meter Reading Expense	\$88,000.00	15%	\$13,200.00	\$100,750.00	15%	\$15,112.50
5315-Customer Billing	\$301,324.00	15%	\$45,198.60	\$326,050.00	15%	\$48,907.50
5320-Collecting	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
5325-Collecting- Cash Over and Short	\$10,000.00	15%	\$1,500.00	\$10,000.00	15%	\$1,500.00
5330-Collection Charges	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
5335-Bad Debt Expense	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
5340-Miscellaneous Customer Accounts Expenses	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
Sub-Total	\$399,324.00		\$59,898.60	\$436,800.00		\$65,520.00

Community Relations

5405-Supervision	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
5410-Community Relations - Sundry	\$10,000.00	15%	\$1,500.00	\$13,000.00	15%	\$1,950.00
5515-Advertising Expense	\$10,000.00	15%	\$1,500.00	\$13,000.00	15%	\$1,950.00
5520-Miscellaneous Sales Expense	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
Sub-Total	\$20,000.00		\$3,000.00	\$26,000.00		\$3,900.00

Administrative and General Expenses

5605-Executive Salaries and Expenses	\$56,100.00	15%	\$8,415.00	\$59,300.00	15%	\$8,895.00
5610-Management Salaries and Expenses	\$47,200.00	15%	\$7,080.00	\$49,900.00	15%	\$7,485.00
5615-General Administrative Salaries and Expenses	\$150,500.00	15%	\$22,575.00	\$244,750.00	15%	\$36,712.50
5620-Office Supplies and Expenses	\$6,500.00	15%	\$975.00	\$6,700.00	15%	\$1,005.00
5625-Administrative Expense Transferred Credit	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
5630-Outside Services Employed	\$230,000.00	15%	\$34,500.00	\$361,400.00	15%	\$54,210.00
5635-Property Insurance	\$32,000.00	15%	\$4,800.00	\$33,900.00	15%	\$5,085.00
5655-Regulatory Expenses	\$15,300.00	15%	\$2,295.00	\$16,250.00	15%	\$2,437.50
5660-General Advertising Expenses	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
5665-Miscellaneous General Expenses	\$42,100.00	15%	\$6,315.00	\$42,100.00	15%	\$6,315.00
5670-Rent	\$27,200.00	15%	\$4,080.00	\$31,600.00	15%	\$4,740.00
5675-Maintenance of General Plant	\$35,000.00	15%	\$5,250.00	\$40,000.00	15%	\$6,000.00
5680-Electrical Safety Authority Fees	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
5685-Independent Market Operator Fees and Penalties	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
Sub-Total	\$641,900.00		\$96,285.00	\$885,900.00		\$132,885.00

Amortization Expenses

5705-Amortization Expense - Property, Plant, and Equipment	\$288,158.00	0%	\$0.00	\$343,019.50	0%	\$0.00
5710-Amortization of Limited Term Electric Plant	\$0.00	0%	\$0.00	\$0.00	0%	\$0.00
5715-Amortization of Intangibles and Other Electric Plant	\$0.00	0%	\$0.00	\$0.00	0%	\$0.00
5720-Amortization of Electric Plant Acquisition Adjustments	\$0.00	0%	\$0.00	\$0.00	0%	\$0.00
5725-Miscellaneous Amortization	\$0.00	0%	\$0.00	\$0.00	0%	\$0.00
5730-Amortization of Unrecovered Plant and Regulatory Study Costs	\$0.00	0%	\$0.00	\$0.00	0%	\$0.00
5735-Amortization of Deferred Development Costs	\$0.00	0%	\$0.00	\$0.00	0%	\$0.00
5740-Amortization of Deferred Charges	\$0.00	0%	\$0.00	\$0.00	0%	\$0.00
Sub-Total	\$288,158.00		\$0.00	\$343,019.50		\$0.00

6105-Taxes other than Income Taxes	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
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Cost of Power

4705-Power Purchased	\$4,807,363.52	15%	\$721,104.53	\$4,913,262.91	15%	\$736,989.44
4708-Charges-WMS	\$458,684.23	15%	\$68,802.63	\$468,788.39	15%	\$70,318.26
4710-Cost of Power Adjustments	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
4712-Charges-One-Time	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
4714-Charges-NW	\$576,994.97	15%	\$86,549.25	\$585,765.20	15%	\$87,864.78
4716-Charges-CN	\$605,363.61	15%	\$90,804.54	\$614,273.53	15%	\$92,141.03
4730-Rural Rate Assistance Expense	\$88,208.51	15%	\$13,231.28	\$90,151.61	15%	\$13,522.74
5685-Independent Market Operator Fees and Penalties	\$0.00	15%	\$0.00	\$0.00	15%	\$0.00
Sub-Total	\$6,536,614.83		\$980,492.22	\$6,672,241.64		\$1,000,836.25

WORKING CAPITAL ALLOWANCE TOTAL	\$1,191,620.82	\$1,274,023.75
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<u>Ex.</u>	<u>Tab</u>	<u>Schedule</u>	<u>Contents of Schedule</u>
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3 - Operating Revenue

1	1	Overview of Operation Revenue
	2	Summary of Operating Revenue Table
	3	Variance Analysis on Operating Revenue
2		Throughput Revenue
	1	Weather Normalized Forecasting Methodology
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	5	Variance Analysis on Customer Count Forecast
3		Other Revenue
	1	Other Distribution Revenue
	2	Materiality Analysis on Other Distribution Revenue
	3	Rate of Return on Other Distribution Revenue
	4	Distribution Revenue Data
4		Revenue Sharing
	1	Description of Revenue Sharing

OVERVIEW OF OPERATING REVENUE

This exhibit provides the details on West Coast Huron Energy operating revenue for Historical, Historical Board Approved, Bridge and Test years. This exhibit also provides a detailed variance analysis by rate class of the operating revenue components.

Distribution revenues have been calculated using the most recently approved rates from EB-2007-0892 approved on April 17th, 2008. Distribution revenues do include PILS Revenue Recovery amounts. A summary of normalized operating revenues is presented in Exhibit 3, Tab 3, and Schedule 4.

Throughput Revenue

Information related to the utility's throughput revenue include details such as weather normalized forecasting methodology, normalized volume and customer counts forecast tables. Detailed variance analysis on the forecast information is also provided.

Other Revenue

Other revenues include revenues such as Late Payment Charges, Miscellaneous Service Revenues and Retail Services Revenues. A summary of these operating revenues is presented in Exhibit 3, Tab 3, and Schedule 1.

Revenue Sharing

West Coast Huron Energy and its employees do not participate in revenue sharing.

SUMMARY OF OPERATING REVENUE TABLE

SUMMARY OF OPERATING REVENUE	2006 Board Approved (\$'s)	2006 Actual (\$'s)	Variance from 2006 Board Approved (\$'s)	2006 Actual (\$'s)	2007 Actual (\$'s)	Variance from 2006 Actual (\$'s)	2007 Actual (\$'s)	2008 Bridge (\$'s)	Variance from 2007 Actual (\$'s)	2008 Bridge (\$'s)	2009 Test (\$'s)	Variance from 2008 Bridge (\$'s)
<u>Distribution Revenues</u>												
Residential	\$683,400	\$737,012	\$53,612	\$737,012	\$765,738	\$28,726	\$765,738	\$796,994	\$31,256	\$796,994	\$804,908	\$7,915
GS<50	\$250,721	\$263,743	\$13,022	\$263,743	\$268,268	\$4,525	\$268,268	\$292,289	\$24,021	\$292,289	\$295,116	\$2,827
GS>50 to 499	\$261,989	\$251,715	-\$10,275	\$251,715	\$268,181	\$16,467	\$268,181	\$315,398	\$47,217	\$315,398	\$335,111	\$19,712
GS>500 to 4999	\$202,701	\$194,751	-\$7,949	\$194,751	\$207,492	\$12,740	\$207,492	\$230,468	\$22,977	\$230,468	\$230,468	\$0
Large Use	\$339,295	\$250,792	-\$88,504	\$250,792	\$209,117	-\$41,675	\$209,117	\$203,315	-\$5,802	\$203,315	\$203,315	\$0
Street Lighting	\$3,983	\$3,986	\$3	\$3,986	\$3,987	\$1	\$3,987	\$4,481	\$493	\$4,481	\$4,481	\$0
Sentinel Lighting	\$1,036	\$1,216	\$180	\$1,216	\$1,190	-\$26	\$1,190	\$1,154	-\$36	\$1,154	\$1,154	\$0
Unmetered Scattered Load	\$17,191	\$22,383	\$5,192	\$22,383	\$23,121	\$738	\$23,121	\$18,439	-\$4,682	\$18,439	\$18,439	\$0
	\$1,760,317	\$1,725,599	-\$34,718	\$1,725,599	\$1,747,094	\$21,496	\$1,747,094	\$1,862,538	\$115,444	\$1,862,538	\$1,892,992	\$30,454
<u>Other Distribution Revenue</u>												
Late Payment Charges	\$13,206	\$12,646	-\$560	\$12,646	\$13,221	\$575	\$13,221	\$13,000	-\$221	\$13,000	\$13,647	\$13,221
Specific Service Charges	\$40,115	\$18,480	-\$21,635	\$18,480	\$23,625	\$5,145	\$23,625	\$23,000	-\$625	\$23,000	\$24,145	\$23,625
Other Distribution Revenue	\$30,748	\$56,837	\$26,089	\$56,837	\$47,266	-\$9,571	\$47,266	\$52,300	\$5,034	\$52,300	\$54,904	\$47,266
	\$84,069	\$87,963	\$3,894	\$87,963	\$84,112	-\$3,851	\$84,112	\$88,300	\$4,188	\$88,300	\$92,696	\$84,112
Total Operating revenue	\$1,844,386	\$1,813,562	-\$30,824	\$1,813,562	\$1,831,207	\$17,645	\$1,831,207	\$1,950,838	\$119,632	\$1,950,838	\$1,985,688	\$114,566

VARIANCE ANALYSIS ON OPERATING REVENUE

West Coast Huron Energy distribution revenue has been calculated using the most recently approved rates. In particular, delivery rates are based on EB-2007-0892. Distribution revenue does not include commodity related revenue.

2009 Test Year

West Coast Huron Energy operating revenue is forecast to be \$1,985,688 in Fiscal 2009, as shown in Exhibit 3, Tab 1, and Schedule 2. Distribution revenue totals \$1,892,992 or 95% of total revenues. Other operating revenue (net) accounts for the remaining revenue of \$92,696.

Comparison to 2008 Bridge Year

As shown in Exhibit 3, Tab 1, Schedule 2, the total operating revenue is expected to be \$114,566 above the bridge year level in fiscal 2008. This increase is the result of the change in debt equity split for deemed revenue requirement, an increase in operating expenses, and the change in PILS revenue.

2008 Bridge Year**Comparison to Fiscal 2007 Actual**

As shown in Exhibit 3, Tab 1, Schedule 2, the total operating revenue is expected to be \$119,632 above the 2006 Actual level in fiscal 2007. This increase is the result the use of normalized consumption levels for 2008 distribution revenue.

2007 Actual**Comparison to 2006 Actual**

As shown in Exhibit 3, Tab 1, Schedule 2, the increase in total operating revenue was \$17,645 . This increase is the result of the timing of the approval of the 2006 EDR coupled with changes in consumption patterns year over year.

2006 Actual**Comparison to 2006 Board Approved**

As shown in Exhibit 3, Tab 1, Schedule 2, the change in total operating revenue was a \$30,824 reduction . This increase is the result of the timing of the approval of the 2006 EDR coupled with changes in consumption patterns year over year.

WEATHER NORMALIZED FORECASTING METHODOLOGY

This exhibit discusses the methodology used to determine West Coast Huron Energy customer and load forecast. A projection for the number of customers in each customer class is provided for both the Bridge Year (2008) and the Test Year (2009). As a result of the limited amount of data available, time series techniques that are often used to help estimate forecast values cannot be used. Rather, the Applicant has used a simple trend growth in customer connections, by class, to forecast Bridge and Test Year customer numbers. Given the consistent trend in customer numbers in WCHE's service territory over the past five years, 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 next section.

As required by the OEB Filing Requirements for Transmission and Distribution Applications, we are 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. This weather-normalized throughput was generated by Hydro One using their weather normalization model for the Cost Allocation process previously undertaken by the Board. The process to obtain these weather normal data was an intensive effort for all parties involved, and we are leveraging the value of this work by using it for this process.

Customer Forecast

Table 1 below presents historical and forecast customer numbers, by class, for West Coast Huron Energy.

CUSTOMER COUNT FORECAST TABLE	2006 Board Approved	2006 Actual	Variance from 2006 Board Approved	2006 Actual	2007 Actual	Variance from 2006 Actual	2007 Actual	2008 Bridge	Variance from 2007 Actual	2008 Bridge	2009 Test	Variance from 2008 Actual
Residential	3,214	3,257	1.34%	3,257	3290	1.01%	3290	3323	1.00%	3323	3356	0.99%
GS<50	496	508	2.42%	508	512	0.79%	512	517	0.98%	517	522	0.97%
GS>50 to 499 kW	43	41	-4.65%	41	46	12.20%	46	48	4.35%	48	51	6.25%
GS>500 kW to 4999 kW	4	4	0.00%	4	4	0.00%	4	4	0.00%	4	4	0.00%
Large Use	1	1	0.00%	1	1	0.00%	1	1	0.00%	1	1	0.00%
Unmetered Scattered Load	9	9	0.00%	9	9	0.00%	9	9	0.00%	9	9	0.00%
Sentinel Lighting	13	13	0.00%	13	13	0.00%	13	13	0.00%	13	13	0.00%
Street Lighting	1,334	1,333	-0.07%	1,333	1333	0.00%	1333	1333	0.00%	1333	1333	0.00%
	5,114	5,166		5,166	5208		5,208	5,248		5,248	5,289	

Annual percentage change is presented for Residential, and GS<50. For Residential and GS<50 customer classes, the percentage change for 2008 represents the annual average growth rate for 2002 to 2007. The annual trend growth rate is used to project customer growth into 2008 and 2009. For the GS>500 to 4999 customer classes, an annual growth rate of 0% was assumed for 2007 and 2008.

The large use and GS>3000 kW to 4999 kW classes contains only one customer each. The 2008 customer number is the current actual number of customers in this class. The Applicant does not expect the number of customers in this class to change within the next year to 18 months, and has used this for the number of customers expected at Bridge Year end and Test Year.

Customer numbers for Sentinel Lighting, Street Lighting, and USL classes in 2007 also represent current number of connections in each of these classes. The Applicant does not expect the number of customers in the Sentinel and USL classes to change within the next year and the 2007 current figures are used for 2008. Customer growth for the Street Lighting Class is calculated based on the actual addition of street lights in 2007 and 2008.

Load Forecast

Weather sensitive load (Residential, GS<50, and GS>50 classes) is calculated by using a 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. Class weather normal retail kWh for 2004 is determined by dividing the class weather normal wholesale kWh for 2004 reported in the Hydro One weather normalization analysis by the class loss factor. The class loss factor is calculated for 2004 by dividing the class weather actual wholesale consumption for 2004 (Hydro One file) by the class weather actual retail consumption (utility data). Weather sensitive class weather actual wholesale and retail kWh and associated loss factors are reported in the following table below.

Load Forecast

Normalized Average Consumption kWh

	2002	2003	2004	2005	2006	2007	2008	2009
<u>RESIDENTIAL</u>								
Regular	8,460	8,548	8,477	8,593	8,358	8,107	8,424	8,424
GENERAL SERVICE								
Less than 50 kW	31,709	32,189	31,717	32,391	30,785	30,248	31,507	31,507
Greater than 50 to 499 kW	680,289	457,856	441,598	477,658	508,942	448,818	502,527	502,527
Greater than 500 to 4,999 kW	3,363,890	5,415,840	4,518,279	4,773,579	4,965,117	4,912,540	4,658,208	4,658,208
Large Use	54,488,795	65,970,074	69,093,771	66,538,600	62,522,031	62,029,064	63,440,389	63,440,389
Unmetered Scattered Load	16,631	17,409	18,138	19,162	19,931	19,720	18,499	18,499
Sentinel Lighting	1,178	1,765	1,778	1,799	1,870	1,790	1,697	1,697
Street Lighting	438	789	800	801	809	793	738	738

Normalized Average Consumption kWh

	2002	2003	2004	2005	2006	2007	2008	2009
<u>RESIDENTIAL</u>								
Regular	26,784,344	27,326,993	27,244,635	27,719,584	27,222,139	26,672,783	27,992,952	28,270,944
GENERAL SERVICE								
Less than 50 kW	15,442,483	15,708,056	15,731,386	16,195,748	15,638,855	15,487,130	16,289,119	16,446,654
Greater than 50 to 499 kW	25,170,704	19,229,948	18,988,710	20,061,647	20,866,610	20,645,650	24,121,296	25,628,877
Greater than 500 to 4,999 kW	10,091,669	16,247,520	18,073,115	19,094,317	19,860,467	19,650,161	18,632,832	18,632,832
Large Use	54,488,795	65,970,074	69,093,771	66,538,600	62,522,031	62,029,064	63,440,389	63,440,389
Unmetered Scattered Load	149,678	156,678	163,238	172,462	179,382	177,482	166,491	166,491
Sentinel Lighting	14,133	22,939	23,119	23,382	24,313	23,275	22,061	22,061
Street Lighting	566,866	1,047,521	1,067,640	1,063,727	1,078,742	1,057,613	983,754	983,754
	132,708,672	145,709,729	150,385,614	150,869,467	147,392,539	145,743,158	151,648,894	153,592,002

Normalized Average Consumption kW

	2002	2003	2004	2005	2006	2007	2008	2009
<u>RESIDENTIAL</u>								
Regular								
GENERAL SERVICE								
Less than 50 kW								
Greater than 50 to 499 kW	2,296	1,656	1,574	1,670	1,691	1,544	1,627	1,627
Greater than 500 to 4,999 kW	7,563	12,563	10,080	10,447	10,323	10,580	10,798	10,798
Large Use	118,775	127,223	132,381	124,517	133,199	137,861	131,036	131,036
Unmetered Scattered Load	0	0	0	0	0	0	0	0
Sentinel Lighting	5	5	5	5	5	5	5	5
Street Lighting	2	2	2	2	2	2	2	2

Normalized Average Consumption kW

	2002	2003	2004	2005	2006	2007	2008	2009
<u>RESIDENTIAL</u>								
Regular								
GENERAL SERVICE								
Less than 50 kW								
Greater than 50 to 499 kW	84,939	69,572	67,680	70,148	69,316	71,037	78,096	82,977
Greater than 500 to 4,999 kW	22,688	37,688	40,318	41,789	41,292	42,318	43,192	43,192
Large Use	118,775	127,223	132,381	124,517	133,199	137,861	131,036	131,036
Unmetered Scattered Load	0	0	0	0	0	0	0	0
Sentinel Lighting	64	64	64	64	64	64	65	65
Street Lighting	2,897	2,904	2,930	2,940	2,916	2,842	2,666	2,666
	229,363	237,451	243,373	239,458	246,787	254,122	255,055	259,936

Annual class kWh for weather sensitive load (Residential, GS<50, GS>50) for Bridge Year and Test Year are calculated by multiplying retail NAC by forecast number of customers in class. Class kWh for the Large User ("LU") class, Unmetered Scattered Load ("USL"), and Sentinel Lighting is not weather sensitive and is not expected to differ in 2008 from current 2007 levels. Utility budgeted throughput for these classes based on year-to-date consumption is used to estimate Bridge Year and Test Year values for these classes. Consumption for Street Lighting is not weather sensitive and has been projected based on historical consumption patterns for the street light class.

Several classes are billed based on demand charges (GS>50 to 999, GS>1000 to 2999, GS>3000 to 4999, Large Use, Sentinel, and 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. The following table summarizes the results of The Applicant's customer and load forecast.

		Board Approved	Historical Actual	Historical Normalized	Historical Actual	Historical Normalized	Bridge Year Estimate	Bridge Year Normalized	Test Year Normalized
Year		2004	2006	2006	2007	2007	2008	2008	2009
Customer Class									
Residential	#	3,214	3,257	3,257	3,290	3,290	3,323	3,323	3,356
	kWh	27,302,454	27,222,139	27,436,968	26,672,783	27,714,960	28,668,883	27,992,952	28,270,944
GS<50 kW	#	496	508	508	512	512	522	522	522
	kWh	15,808,273	15,638,855	16,005,556	15,638,855	16,131,584	16,686,818	16,289,119	16,446,654
GS>50 to 4999 kW	#	43	41	41	46	46	48	48	51
	kWh	22,642,985	20,866,610	20,603,607	20,866,610	23,116,242	23,911,881	20,645,650	25,628,877
	kW	79,207	70,148	66,707	71,037	74,842	77,418	71,037	82,977
GS> 500 to 4999	#	4	4	4	4	4	4	4	4
	kWh	17,730,678	19,860,467	18,632,832	19,860,467	18,632,832	19,274,156	18,632,832	18,632,832
	kW	40,273	41,789	43,192	42,318	43,192	44,679	42,318	43,192
Large Use >5000 kW	#	1	1	1	1	1	1	1	1
	kWh	63,184,213	62,522,031	63,440,389	62,522,031	63,440,389	65,623,947	63,440,389	63,440,389
	kW	126,126	124,517	131,036	137,861	131,036	135,546	137,861	131,036
Unmetered Scattered Load	#	9	9	9	9	9	9	9	9
	kWh	156,531	179,382	166,491	179,382	166,491	172,221	166,491	166,491
Sentinel Lighting	#	13	13	13	13	13	13	13	13
	kWh	20,456	24,313	22,061	24,313	22,061	22,820	22,061	22,061
	kW	66	64	65	64	65	67	64	65
Street Lighting	#	1,334	1,333	1,333	1,333	1,333	1,333	1,333	1,333
	kWh	901,277	1,078,742	983,754	1,078,742	983,754	1,017,614	983,754	983,754
	kW	2,944	2,940	2,666	2,842	2,666	2,758	2,842	2,666

NORMALIZED VOLUME FORECAST TABLE

NORMALIZED VOLUME FORECAST

	2006 Board Approved (kWh)	2006 Board Approved (kW)	2006 Actual (kWh)	2006 Actual (kW)	Variance from 2006 Board Approved
(Volumetric + Monthly Service Charge)					
Rate Classes					
Residential	27,302,454		27,222,139	0	80,315
GS<50	15,808,273		15,638,855	0	169,418
GS>50 to 499 kW	22,642,985	79,207	20,866,610	70,148	9,059
GS>500 kW to 4999 kW	17,730,678	40,273	19,860,467	41,789	-1,516
Large Use	63,184,213	126,126	62,522,031	124,517	1,609
Unmetered Scattered Load	156,531	0	179,382	0	0
Sentinel Lighting	20,456	66	24,313	64	2
Street Lighting	901,277	2,944	1,078,742	2,940	-177,465

2006 Actual (kWh)	2006 Actual (kW)	2007 Actual (kWh)	2007 Actual (kW)	Variance from 2006 Actual
27,222,139	0	26,672,783	0	549,356
15,638,855	0	15,487,130	0	151,725
20,866,610	70,148	20,645,650	71,037	-889
19,860,467	41,789	19,650,161	42,318	-529
62,522,031	124,517	62,029,064	137,861	-13,344
179,382	0	177,482	0	0
24,313	64	23,275	64	0
1,078,742	2,940	1,057,613	2,842	21,129

	2007 Actual (kWh)	2007 Actual (kW)	2008 Bridge (kWh)	2008 Bridge (kW)	Variance from 2007 Actual
(Volumetric + Monthly Service Charge)					
Rate Classes					
Residential	26,672,783		27,992,952	0	-1,320,169
GS<50	15,487,130		16,289,119	0	-801,989
GS>50 to 499 kW	20,645,650	71,037	24,121,296	78,096	-7,059
GS>500 kW to 4999 kW	19,650,161	42,318	18,632,832	43,192	-874
Large Use	62,029,064	137,861	63,440,389	131,036	6,825
Unmetered Scattered Load	177,482	0	166,491	0	0
Sentinel Lighting	23,275	64	22,061	65	-1
Street Lighting	1,057,613	2,842	983,754	2,666	73,859

2008 Bridge (kWh)	2008 Bridge (kW)	2009 Test (kWh)	2009 Test (kW)	Variance from 2008 Bridge
27,992,952		28,270,944	0	-277,992
16,289,119		16,446,654	0	-157,535
24,121,296	78,096	25,628,877	82,977	-4,881
18,632,832	43,192	18,632,832	43,192	0
63,440,389	131,036	63,440,389	131,036	0
166,491	0	166,491	0	0
22,061	65	22,061	65	0
983,754	2,666	983,754	2,666	0

VARIANCE ANALYSIS ON NORMALIZED VOLUME FORECAST

The purpose of the evidence contained in Schedules 1, 2 and 4, Tab 2, of Exhibit 3, is to provide the Board with a review of West Coast Huron Energy actual and forecasted customers, consumption and revenues for the historical, bridge and test years. Test year revenues have been calculated using the approved rate order EB-2007-0892 dated April 17th, 2008.

Exhibit 3, Tab 2, Schedule 3, provides a summary of the normalized throughput numbers from the schedules noted above.

Fiscal 2009 Test Year

Comparison to Fiscal 2008 Bridge Year

Due the use of 2004 weather normalized consumptions per customer the variance in consumption for 2008 Bridge Year to 2009 Test Year is attributable to the forecast change in customer growth.

2008 Bridge Year

Comparison to Fiscal 2007 Actual

Due the use of 2004 weather normalized consumptions per customer the variance in consumption for 2007 Actual to 2008 Bridge Year is attributable to the forecast change in customer growth.

CUSTOMER COUNT FORECAST TABLE

CUSTOMER COUNT FORECAST TABLE	2006 Board Approved	2006 Actual	Variance from 2006 Board Approved	2006 Actual	2007 Actual	Variance from 2006 Actual	2007 Actual	2008 Bridge	Variance from 2007 Actual	2008 Bridge	2009 Test	Variance from 2008 Actual
Residential	3,214	3,257	43	3,257	3290	33	3290	3323	33	3323	3356	33
GS<50	496	508	12	508	512	4	512	517	5	517	522	5
GS>50 to 499 kW	43	41	- 2	41	46	5	46	48	2	48	51	3
GS>500 kW to 4999 kW	4	4	-	4	4	-	4	4	-	4	4	-
Large Use	1	1	-	1	1	-	1	1	-	1	1	-
Unmetered Scattered Load	9	9	-	9	9	-	9	9	-	9	9	-
Sentinel Lighting	13	13	-	13	13	-	13	13	-	13	13	-
Street Lighting	1,334	1,333	- 1	1,333	1333	-	1333	1333	-	1333	1333	-
	5,114	5,166	52	5,166	5208	42	5,208	5,248	40	5,248	5,289	41

VARIANCE ANALYSIS ON CUSTOMER COUNT FORECAST

The purpose of the evidence contained in Schedules 1, 2 and 4, Tab 2, of Exhibit 3, is to provide the Board with a review of West Coast Huron Energy actual and forecasted customers, consumption and revenues for the historical, bridge and test years. Test year revenues have been calculated using the approved rate order EB-2007-0892 dated April 17th, 2008.

Exhibit 3, Tab 2, Schedule 4, provides a summary of the normalized customer numbers from the schedules noted above.

Fiscal 2009 Test Year

Comparison to Fiscal 2008 Bridge Year

2008 increases are based on the forecasted number of connections based on our capital projects and historical customer growth for residential and GS<50 kW classes. For GS>50 to 499 kW WCHE utilized our historical customer growth for that class of approximately 6%. We have projected no change for 2008 in the GS>500 to 4999 kW, Large Use, Unmetered Scattered Load, Sentinel Lighting and Street Lighting classes.

2008 Bridge Year

Comparison to Fiscal 2007 Actual

For all rate classes we have updated our customer numbers as of the end of June YTD and applied the resulting growth factor for the remainder of the year. No change was experienced or forecast for the GS>500 to 4999 kW, Large Use, Unmetered Scattered Load, Sentinel Lighting, and Street Lighting classes.

OTHER DISTRIBUTION REVENUE

	2006 Board Approved	2006 Actual	Variance from 2006 Board Approved	2006 Actual	2007 Actual	Variance from 2006 Actual	2007 Actual	2008 Bridge	Variance from 2007 Actual	2008 Bridge	2009 Test	Variance from 2008 Bridge
OTHER DISTRIBUTION REVENUE	(\$'s)	(\$'s)	(\$'s)	(\$'s)	(\$'s)							
Other Distribution Revenue												
Retail Services Revenues	\$960	\$2,700	\$1,740	\$2,700	\$2,940	\$240	\$2,940	\$3,300	\$360	\$3,300	\$3,464	\$164
Service Transaction Requests (STR) Revenues	\$187	\$2,734	\$2,548	\$2,734	\$6,339	\$3,605	\$6,339	\$7,000	\$661	\$7,000	\$7,349	\$349
Electric Services Incidental to Energy Sales			\$0	\$0		\$0	\$0		\$0	\$0	\$0	\$0
Rent from Electric Property	\$9,112	\$13,232	\$4,120	\$13,232	\$10,821	-\$2,411	\$10,821	\$14,000	\$3,179	\$14,000	\$14,697	\$697
Other Utility Operating Income			\$0	\$0		\$0	\$0		\$0	\$0	\$0	\$0
Other Electric Revenues			\$0	\$0		\$0	\$0		\$0	\$0	\$0	\$0
Late Payment Charges	\$13,206	\$12,646	-\$560	\$12,646	\$13,221	\$575	\$13,221	\$13,000	-\$221	\$13,000	\$13,647	\$647
Sales of Water and Water Power	\$20,489	\$38,171	\$17,682	\$38,171	\$27,166	-\$11,005	\$27,166	\$28,000	\$834	\$28,000	\$29,394	\$1,394
Miscellaneous Service Revenues	\$40,115	\$18,480	-\$21,635	\$18,480	\$23,625	\$5,145	\$23,625	\$23,000	-\$625	\$23,000	\$24,145	\$1,145
TOTAL	\$84,069	\$87,963	\$3,894	\$87,963	\$84,112	-\$3,851	\$84,112	\$88,300	\$4,188	\$88,300	\$92,696	\$4,396

MATERIALITY ANALYSIS ON OTHER DISTRIBUTION REVENUE

Materiality of 1% of 2006 board approved distribution expenses of \$2,149,269 is \$21,493.

There are no changes in other distribution revenue greater than the materiality threshold.

RATE OF RETURN ON OTHER DISTRIBUTION ACTIVITIES

In this application West Coast Huron Energy has applied for the same Specific Service Charges schedule previously approved in the 2008 Tariffs of Rates and Charges from EB-2007-0892 approved on April 17th, 2008.

DISTRIBUTION REVENUE DATA
2006 Board Approved

	Customers (Year-End)	Consumption (kWh / KW)	Distribution Revenues (\$)	Unit Revenues \$/kWh
Residential	3,214	27,302,454	\$683,400	\$0.0250
GS<50	496	15,808,273	\$250,721	\$0.0159
GS>50 to 499 kW	43	79,207	\$261,989	\$3.3076
GS>500 kW to 4999 kW	4	40,273	\$202,701	\$5.0332
Large Use	1	126,126	\$339,295	\$2.6901
Unmetered Scattered Load	9	156,531	\$3,983	\$0.0254
Sentinel Lighting	13	20,456	\$1,036	\$0.0507
Street Lighting	1,334	2,944	\$17,191	\$5.8397
TOTAL	5,114		\$1,760,317	

2006 Actual

	Customers (Year-End)	Consumption (kWh / KW)	Distribution Revenues (\$)	Unit Revenues \$/kWh
Residential	3,257	27,222,139	\$737,012	\$0.0271
GS<50	508	15,638,855	\$263,743	\$0.0169
GS>50 to 499 kW	41	73,325	\$251,715	\$3.4328
GS>500 kW to 4999 kW	4	37,283	\$194,751	\$5.2237
Large Use	1	133,199	\$250,792	\$1.8828
Unmetered Scattered Load	9	154,854	\$3,986	\$0.0257
Sentinel Lighting	13	64	\$1,216	\$19.0050
Street Lighting	1,333	2,916	\$22,383	\$7.6760
TOTAL	5,166		\$1,725,599	

2007 Actual

	Customers (Year-End)	Consumption (kWh / KW)	Distribution Revenues (\$)	Unit Revenues \$/kWh
Residential	3,290	26,672,783	\$765,738	\$0.0287
GS<50	512	15,487,130	\$268,268	\$0.0173
GS>50 to 499 kW	46	75,147	\$268,181	\$3.5688
GS>500 kW to 4999 kW	4	38,208	\$207,492	\$5.4305
Large Use	1	137,861	\$209,117	\$1.5169
Unmetered Scattered Load	9	153,351	\$3,987	\$0.0260
Sentinel Lighting	13	65	\$1,190	\$18.3077
Street Lighting	1,333	2,842	\$23,121	\$8.1355
TOTAL	5,208		\$1,747,094	

2007 Actual - Normalized

	Customers (Year-End)	Consumption (kWh / KW)	Distribution Revenues (\$)	Normalized Consumption (kWh / KW)	Normalized Distribution Revenues (\$)	Unit Revenues \$/kWh
Residential	3,290	26,672,783	\$765,738.00	26,672,783	\$780,324.58	\$0.0293
GS<50	512	15,487,130	\$268,268.00	15,487,130	\$286,111.32	\$0.0185
GS>50 to 499 kW	46	75,147	\$268,181.25	71,037	\$298,187.19	\$4.1976
GS>500 kW to 4999 kW	4	38,208	\$207,491.75	42,318	\$229,181.42	\$5.4157
Large Use	1	137,861	\$209,117.00	137,861	\$208,496.71	\$1.5124
Unmetered Scattered Load	9	153,351	\$3,987.43	177,482	\$4,537.67	\$0.0256
Sentinel Lighting	13	65	\$1,190.00	64	\$1,149.96	\$17.9681
Street Lighting	1,333	2,842	\$23,121.00	2,842	\$18,906.36	\$6.6525
TOTAL	5,208		\$1,747,094.43		\$1,826,895.20	

2008 Bridge - Normalized

	Customers (Year-End)	Consumption (kWh / KW)	Distribution Revenues (\$)	Normalized Consumption (kWh / KW)	Normalized Distribution Revenues (\$)	
Residential	3,323	27,439,005	\$751,566.02	27,992,952	\$796,993.64	\$0.0285
GS<50	517	15,294,877	\$269,668.18	16,289,119	\$292,289.26	\$0.0179
GS>50 to 499 kW	48	73,456	\$305,216.74	78,096	\$315,398.23	\$4.0386
GS>500 kW to 4999 kW	4	39,379	\$181,953.36	43,192	\$230,468.38	\$5.3359
Large Use	1	147,467	\$211,832.54	131,036	\$203,315.17	\$1.5516
Unmetered Scattered Load	9	151,864	\$3,948.75	166,491	\$4,480.51	\$0.0269
Sentinel Lighting	13	64	\$1,140.00	65	\$1,154.18	\$17.7566
Street Lighting	1,333	2,867	\$18,862.84	2,666	\$18,438.86	\$6.9163
TOTAL	5,248		\$1,744,188.43		\$1,862,538.23	

2009 Test - Normalized

	Customers (Year-End)	Consumption (kWh / KW)	Distribution Revenues (\$)	Unit Revenues \$/kWh
Residential	3,356	28,270,944	\$804,908.41	\$0.028471
GS<50	522	16,446,654	\$295,116.04	\$0.017944
GS>50 to 499 kW	51	82,977	\$335,110.62	\$4.038596
GS>500 kW to 4999 kW	4	43,192	\$230,468.38	\$5.335904
Large Use	1	131,036	\$203,315.17	\$1.551598
Unmetered Scattered Load	9	166,491	\$4,480.51	\$0.026911
Sentinel Lighting	13	65	\$1,154.18	\$17.756600
Street Lighting	1,333	2,666	\$18,438.86	\$6.916300
TOTAL	5,289		\$1,892,992.17	

DESCRIPTION OF REVENUE SHARING

West Coast Huron Energy does not participate in revenue sharing.

4 - Operating Costs

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OVERVIEW OF OPERATING COSTS

Operating Costs

The operating costs presented in this exhibit represent the annual expenditures required to sustain Distribution Operations. The information presented in this exhibit is grouped into two different categories: Operation & Maintenance and Other Costs which include items such as Administration & General, Sales Promotion & Customer Accounting, Depreciation, Amortization and Depletion, Shared Services and Loss Adjustment Factor.

The second category includes Income Tax, Large Corporation Tax and Ontario Capital Taxes. Exhibit 4, Tab 1, Schedule 2 provides a summary of The Applicant's Operating Costs for the historical, bridge and test years.

OM&A Costs

The OM&A costs in this exhibit represents WCHE's integrated set of asset maintenance and customer activity needs to meet public and employee safety objectives; to comply with the Distribution System Code, environmental requirements and Government direction; and to maintain distribution business service quality and reliability at targeted performance levels. These costs also include providing services to customers connected to the Applicant's Distribution system, and to meet the service levels stipulated in the Standard Supply Service Code and the Retailer Settlement Codes.

The proposed OM&A cost expenditures for the 2009 test year result from a rigorous business planning and work prioritization process that reflects risk-based decision making to ensure that the most appropriate, cost effective solutions are put in place.

OM&A expenditures totaled \$1,114,270 for 2006 Board Approved, \$1,445,398 for 2006 Actual results, \$1,371,617 for 2007 Actual results and are forecast to be \$1,407,524 in 2008 and \$1,821,250 in 2009.

Income Tax, Large Corporation Tax and Ontario Capital Taxes

This information consists of detailed calculations of income taxes, and indemnity payments to the Province. Details of the expenditures are filed at Exhibit 4, Tab 3 Schedule 1.

The Income Taxes, Large Corporation Taxes and Ontario Capital Taxes expenditures totaled \$41,727 in 2006 Board Approved, \$11,437 in 2006 Actual, \$40,056 for 2007 Actual and are forecast to be \$78,713 in 2008 and \$84,691 in 2008.

SUMMARY OF OPERATING COSTS TABLE

SUMMARY OF OPERATING COSTS		2006 Board Approved	2006 Actual	2007 Actual	2008 Bridge	2009 Test
OM&A expenses						
Operation (Working Capital)		\$355,584	\$352,301	\$266,504	\$237,000	\$380,750
Maintenance (Working Capital)		\$2,821	\$115,972	\$43,195	\$109,300	\$91,800
Billing and Collections		\$300,181	\$328,405	\$378,933	\$399,324	\$436,800
Community Relations		\$35,976	\$56,633	\$30,797	\$20,000	\$26,000
Administrative and General Expenses		\$419,708	\$592,087	\$652,188	\$641,900	\$885,900
Amortization Expenses		\$200,009	\$207,686	\$215,250	\$288,158	\$343,019
Cost of Power		\$6,119,304	\$6,548,585	\$6,560,539	\$6,536,615	\$6,672,242
Other Operating Costs		\$0	\$0	\$0	\$0	\$0
LCT,OCT and Income Taxes		\$33,957	\$9,308	\$32,597	\$65,332	\$70,294
Total Operating Costs		\$7,467,540	\$8,210,977	\$8,180,004	\$8,297,629	\$8,906,805

OM&A COSTS TABLE

OM&A COSTS	2006 Board Approved	2006 Actual	Variance form 2006 Board Approved		2006 Actual	2007 Actual	Variance form 2006 Actual
Operation (Working Capital)							
5005-Operation Supervision and Engineering	\$0.00	\$1,121.00	\$1,121.00		\$1,121.00	\$340.80	-\$780.20
5010-Load Dispatching	\$0.00	\$628.00	\$628.00		\$628.00	\$2,810.67	\$2,182.67
5012-Station Buildings and Fixtures Expense	\$0.00	\$0.00	\$0.00		\$0.00	\$0.00	\$0.00
5014-Transformer Station Equipment - Operation Labour	\$21,987.06	\$16,314.00	-\$5,673.06		\$16,314.00	\$19,366.34	\$3,052.34
5015-Transformer Station Equipment - Operation Supplies and Expenses	\$23.31	\$100.00	\$76.69		\$100.00	\$50.00	-\$50.00
5016-Distribution Station Equipment - Operation Labour	\$0.00	\$0.00	\$0.00		\$0.00	\$0.00	\$0.00
5017-Distribution Station Equipment - Operation Supplies and Expenses	\$0.00	\$0.00	\$0.00		\$0.00	\$0.00	\$0.00
5020-Overhead Distribution Lines and Feeders - Operation Labour	\$217,823.27	\$259,058.00	\$41,234.73		\$259,058.00	\$158,282.14	-\$100,775.86
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	\$0.00	\$0.00	\$0.00		\$0.00	\$0.00	\$0.00
5030-Overhead Subtransmission Feeders - Operation	\$0.00	\$0.00	\$0.00		\$0.00	\$0.00	\$0.00
5035-Overhead Distribution Transformers- Operation	\$0.00	\$0.00	\$0.00		\$0.00	\$0.00	\$0.00
5040-Underground Distribution Lines and Feeders - Operation Labour	\$0.00	\$0.00	\$0.00		\$0.00	\$0.00	\$0.00
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	\$22,924.32	\$5,593.00	-\$17,331.32		\$5,593.00	\$0.00	-\$5,593.00
5050-Underground Subtransmission Feeders - Operation	\$83,044.85	\$68,461.00	-\$14,583.85		\$68,461.00	\$85,654.13	\$17,193.13
5055-Underground Distribution Transformers - Operation	\$0.00	\$0.00	\$0.00		\$0.00	\$0.00	\$0.00
5060-Street Lighting and Signal System Expense	\$0.00	\$0.00	\$0.00		\$0.00	\$0.00	\$0.00
5065-Meter Expense	\$0.00	\$0.00	\$0.00		\$0.00	\$0.00	\$0.00
5070-Customer Premises - Operation Labour	\$0.00	\$0.00	\$0.00		\$0.00	\$0.00	\$0.00
5075-Customer Premises - Materials and Expenses	\$9,781.35	\$1,026.00	-\$8,755.35		\$1,026.00	\$0.00	-\$1,026.00
5085-Miscellaneous Distribution Expense	\$0.00	\$0.00	\$0.00		\$0.00	\$0.00	\$0.00
5090-Underground Distribution Lines and Feeders - Rental Paid	\$0.00	\$0.00	\$0.00		\$0.00	\$0.00	\$0.00
5095-Overhead Distribution Lines and Feeders - Rental Paid	\$0.00	\$0.00	\$0.00		\$0.00	\$0.00	\$0.00
5096-Other Rent	\$0.00	\$0.00	\$0.00		\$0.00	\$0.00	\$0.00
Sub-Total	\$355,584.16	\$352,301.00	-\$3,283.16		\$352,301.00	\$266,504.08	-\$85,796.92

Maintenance (Working Capital)						
5105-Maintenance Supervision and Engineering	\$0.00	\$15,616.00	\$15,616.00	\$15,616.00	\$2,376.32	-\$13,239.68
5110-Maintenance of Buildings and Fixtures - Distribution Stations	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
5112-Maintenance of Transformer Station Equipment	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
5114-Maintenance of Distribution Station Equipment	\$0.00	\$5,229.00	\$5,229.00	\$5,229.00	-\$15,793.14	-\$21,022.14
5120-Maintenance of Poles, Towers and Fixtures	\$0.00	\$8,957.00	\$8,957.00	\$8,957.00	\$319.92	-\$8,637.08
5125-Maintenance of Overhead Conductors and Devices	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
5130-Maintenance of Overhead Services	\$0.00	\$11,593.00	\$11,593.00	\$11,593.00	\$18,644.33	\$7,051.33
5135-Overhead Distribution Lines and Feeders - Right of Way	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
5145-Maintenance of Underground Conduit	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
5150-Maintenance of Underground Conductors and Devices	\$0.00	\$27,773.00	\$27,773.00	\$27,773.00	\$26,989.57	-\$783.43
5155-Maintenance of Underground Services	\$0.00	\$290.00	\$290.00	\$290.00	\$453.53	\$163.53
5160-Maintenance of Line Transformers	\$0.00	\$5,910.00	\$5,910.00	\$5,910.00	\$4,971.82	-\$938.18
5165-Maintenance of Street Lighting and Signal Systems	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
5170-Sentinel Lights - Labour	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
5172-Sentinel Lights - Materials and Expenses	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
5175-Maintenance of Meters	\$0.00	\$39,204.00	\$39,204.00	\$39,204.00	\$4,800.00	-\$34,404.00
5178-Customer Installations Expenses- Leased Property	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
5185-Water Heater Rentals - Labour	\$0.00	\$42.00	\$42.00	\$42.00	\$0.00	-\$42.00
5186-Water Heater Rentals - Materials and Expenses	\$2,820.62	\$1,358.00	-\$1,462.62	\$1,358.00	\$432.68	-\$925.32
5190-Water Heater Controls - Labour	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
5192-Water Heater Controls - Materials and Expenses	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
5195-Maintenance of Other Installations on Customer Premises	\$0.00	\$0.00	\$0.00	\$0.00		\$0.00
Sub-Total	\$2,820.62	\$115,972.00	\$113,151.38	\$115,972.00	\$43,195.03	-\$72,776.97

Billing and Collections						
5305-Supervision	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
5310-Meter Reading Expense	\$82,379.34	\$77,860.00	-\$4,519.34	\$77,860.00	\$90,989.73	\$13,129.73
5315-Customer Billing	\$217,801.87	\$249,860.00	\$32,058.13	\$249,860.00	\$287,903.53	\$38,043.53
5320-Collecting	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
5325-Collecting- Cash Over and Short	\$0.00	\$110.00	\$110.00	\$110.00	\$40.00	-\$70.00
5330-Collection Charges	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
5335-Bad Debt Expense	\$0.00	\$575.00	\$575.00	\$575.00	\$0.00	-\$575.00
5340-Miscellaneous Customer Accounts Expenses	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Sub-Total	\$300,181.21	\$328,405.00	\$28,223.79	\$328,405.00	\$378,933.26	\$50,528.26
Community Relations						
5405-Supervision	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
5410-Community Relations - Sundry	\$32,960.42	\$36,360.00	\$3,399.58	\$36,360.00	\$3,364.68	-\$32,995.32
5415-Energy Conservation	\$0.00	\$17,011.00	\$17,011.00	\$17,011.00	\$22,556.84	\$5,545.84
5420-Community Safety Program	\$1,145.00	\$0.00	-\$1,145.00	\$0.00	\$0.00	\$0.00
5425-Miscellaneous Customer Service and Informational Expenses	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
5505-Supervision	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
5510-Demonstrating and Selling Expense	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
5515-Advertising Expense	\$1,871.03	\$3,262.00	\$1,390.97	\$3,262.00	\$4,875.00	\$1,613.00
5520-Miscellaneous Sales Expense	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Sub-Total	\$35,976.45	\$56,633.00	\$20,656.55	\$56,633.00	\$30,796.52	-\$25,836.48

Administrative and General Expenses							
5605-Executive Salaries and Expenses	\$49,290.66	\$47,701.00	-\$1,589.66	\$47,701.00	\$47,841.08	\$140.08	
5610-Management Salaries and Expenses	\$38,085.89	\$47,615.00	\$9,529.11	\$47,615.00	\$47,555.76	-\$59.24	
5615-General Administrative Salaries and Expenses	\$121,224.15	\$138,572.00	\$17,347.85	\$138,572.00	\$150,364.50	\$11,792.50	
5620-Office Supplies and Expenses	\$4,054.07	\$5,353.00	\$1,298.93	\$5,353.00	\$3,612.99	-\$1,740.01	
5625-Administrative Expense Transferred Credit	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	
5630-Outside Services Employed	\$93,237.01	\$192,738.00	\$99,500.99	\$192,738.00	\$174,341.92	-\$18,396.08	
5635-Property Insurance	\$2,701.08	\$27,667.00	\$24,965.92	\$27,667.00	\$28,773.12	\$1,106.12	
5640-Injuries and Damages	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	
5645-Employee Pensions and Benefits	\$4.52	\$0.00	-\$4.52	\$0.00	\$0.65	\$0.65	
5650-Franchise Requirements	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	
5655-Regulatory Expenses	\$1,460.24	\$15,491.00	\$14,030.76	\$15,491.00	\$12,946.97	-\$2,544.03	
5660-General Advertising Expenses	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	
5665-Miscellaneous General Expenses	\$34,670.41	\$32,128.00	-\$2,542.41	\$32,128.00	\$44,451.12	\$12,323.12	
5670-Rent	\$26,400.00	\$26,400.00	\$0.00	\$26,400.00	\$26,400.00	\$0.00	
5675-Maintenance of General Plant	\$48,579.69	\$58,422.00	\$9,842.31	\$58,422.00	\$115,899.89	\$57,477.89	
5680-Electrical Safety Authority Fees	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	
5685-Independent Market Operator Fees and Penalties	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	
Sub-Total	\$419,707.72	\$592,087.00	\$172,379.28	\$592,087.00	\$652,188.00	\$60,101.00	

Amortization Expenses							
5705-Amortization Expense - Property, Plant, and Equipment	\$197,729.00	\$205,406.00	\$7,677.00	\$205,406.00	\$212,970.00	\$7,564.00	
5710-Amortization of Limited Term Electric Plant	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	
5715-Amortization of Intangibles and Other Electric Plant	\$2,280.00	\$2,280.00	\$0.00	\$2,280.00	\$2,280.00	\$0.00	
5720-Amortization of Electric Plant Acquisition Adjustments	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	
5725-Miscellaneous Amortization	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	
5730-Amortization of Unrecovered Plant and Regulatory Study Costs	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	
5735-Amortization of Deferred Development Costs	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	
5740-Amortization of Deferred Charges	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	
Sub-Total	\$200,009.00	\$207,686.00	\$7,677.00	\$207,686.00	\$215,250.00	\$7,564.00	
6105-Taxes other than Income Taxes	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	
Cost of Power							
4705-Power Purchased	\$4,229,620.42	\$4,679,585.00	\$449,964.58	\$4,679,585.00	\$4,780,362.46	\$100,777.46	
4708-Charges-WMS	\$450,165.21	\$352,951.00	-\$97,214.21	\$352,951.00	\$350,056.61	-\$2,894.39	
4710-Cost of Power Adjustments	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	
4712-Charges-One-Time	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	
4714-Charges-NW	\$712,070.45	\$767,821.00	\$55,750.55	\$767,821.00	\$708,898.12	-\$58,922.88	
4716-Charges-CN	\$641,531.04	\$661,464.00	\$19,932.96	\$661,464.00	\$633,021.39	-\$28,442.61	
4730-Rural Rate Assistance Expense	\$85,916.58	\$86,764.00	\$847.42	\$86,764.00	\$88,200.82	\$1,436.82	
5685-Independent Market Operator Fees and Penalties	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	
Sub-Total	\$6,119,303.70	\$6,548,585.00	\$429,281.30	\$6,548,585.00	\$6,560,539.40	\$11,954.40	

OM&A COSTS	2007 Actual	2008 Bridge	Variance form 2007 Actual
Operation (Working Capital)			
5005-Operation Supervision and Engineering	\$340.80	\$2,000.00	\$1,659.20
5010-Load Dispatching	\$2,810.67	\$0.00	-\$2,810.67
5012-Station Buildings and Fixtures Expense	\$0.00	\$0.00	\$0.00
5014-Transformer Station Equipment - Operation Labour	\$19,366.34	\$0.00	-\$19,366.34
5015-Transformer Station Equipment - Operation Supplies and Expenses	\$50.00	\$0.00	-\$50.00
5016-Distribution Station Equipment - Operation Labour	\$0.00	\$0.00	\$0.00
5017-Distribution Station Equipment - Operation Supplies and Expenses	\$0.00	\$0.00	\$0.00
5020-Overhead Distribution Lines and Feeders - Operation Labour	\$158,282.14	\$135,000.00	-\$23,282.14
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	\$0.00	\$0.00	\$0.00
5030-Overhead Subtransmission Feeders - Operation	\$0.00	\$0.00	\$0.00
5035-Overhead Distribution Transformers- Operation	\$0.00	\$0.00	\$0.00
5040-Underground Distribution Lines and Feeders - Operation Labour	\$0.00	\$0.00	\$0.00
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	\$0.00	\$0.00	\$0.00
5050-Underground Subtransmission Feeders - Operation	\$85,654.13	\$100,000.00	\$14,345.87
5055-Underground Distribution Transformers - Operation	\$0.00	\$0.00	\$0.00
5060-Street Lighting and Signal System Expense	\$0.00	\$0.00	\$0.00
5065-Meter Expense	\$0.00	\$0.00	\$0.00
5070-Customer Premises - Operation Labour	\$0.00	\$0.00	\$0.00
5075-Customer Premises - Materials and Expenses	\$0.00	\$0.00	\$0.00
5085-Miscellaneous Distribution Expense	\$0.00	\$0.00	\$0.00
5090-Underground Distribution Lines and Feeders - Rental Paid	\$0.00	\$0.00	\$0.00
5095-Overhead Distribution Lines and Feeders - Rental Paid	\$0.00	\$0.00	\$0.00
5096-Other Rent	\$0.00	\$0.00	\$0.00
Sub-Total	\$266,504.08	\$237,000.00	-\$29,504.08

2008 Bridge	2009 Test	Variance form 2008 Bridge
\$2,000.00	\$2,000.00	\$0.00
\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00
\$0.00	\$5,000.00	\$5,000.00
\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00
\$135,000.00	\$221,725.00	\$86,725.00
\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00
\$0.00	\$22,425.00	\$22,425.00
\$100,000.00	\$124,600.00	\$24,600.00
\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00
\$0.00	\$5,000.00	\$5,000.00
\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00
\$237,000.00	\$380,750.00	\$143,750.00

Maintenance (Working Capital)			
5105-Maintenance Supervision and Engineering	\$2,376.32	\$4,000.00	\$1,623.68
5110-Maintenance of Buildings and Fixtures - Distribution Stations	\$0.00	\$0.00	\$0.00
5112-Maintenance of Transformer Station Equipment	\$0.00	\$0.00	\$0.00
5114-Maintenance of Distribution Station Equipment	-\$15,793.14	\$35,500.00	\$51,293.14
5120-Maintenance of Poles, Towers and Fixtures	\$319.92	\$15,000.00	\$14,680.08
5125-Maintenance of Overhead Conductors and Devices	\$0.00	\$0.00	\$0.00
5130-Maintenance of Overhead Services	\$18,644.33	\$18,000.00	-\$644.33
5135-Overhead Distribution Lines and Feeders - Right of Way	\$0.00	\$0.00	\$0.00
5145-Maintenance of Underground Conduit	\$0.00	\$0.00	\$0.00
5150-Maintenance of Underground Conductors and Devices	\$26,989.57	\$20,000.00	-\$6,989.57
5155-Maintenance of Underground Services	\$453.53	\$7,000.00	\$6,546.47
5160-Maintenance of Line Transformers	\$4,971.82	\$0.00	-\$4,971.82
5165-Maintenance of Street Lighting and Signal Systems	\$0.00	\$0.00	\$0.00
5170-Sentinel Lights - Labour	\$0.00	\$0.00	\$0.00
5172-Sentinel Lights - Materials and Expenses	\$0.00	\$0.00	\$0.00
5175-Maintenance of Meters	\$4,800.00	\$6,000.00	\$1,200.00
5178-Customer Installations Expenses- Leased Property	\$0.00	\$0.00	\$0.00
5185-Water Heater Rentals - Labour	\$0.00	\$0.00	\$0.00
5186-Water Heater Rentals - Materials and Expenses	\$432.68	\$3,800.00	\$3,367.32
5190-Water Heater Controls - Labour	\$0.00	\$0.00	\$0.00
5192-Water Heater Controls - Materials and Expenses	\$0.00	\$0.00	\$0.00
5195-Maintenance of Other Installations on Customer Premises	\$0.00	\$0.00	\$0.00
Sub-Total	\$43,195.03	\$109,300.00	\$66,104.97

\$4,000.00	\$4,000.00	\$0.00
\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00
\$35,500.00	\$10,000.00	-\$25,500.00
\$15,000.00	\$27,000.00	\$12,000.00
\$0.00	\$0.00	\$0.00
\$18,000.00	\$15,000.00	-\$3,000.00
\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00
\$20,000.00	\$15,000.00	-\$5,000.00
\$7,000.00	\$5,000.00	-\$2,000.00
\$0.00	\$6,000.00	\$6,000.00
\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00
\$6,000.00	\$6,000.00	\$0.00
\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00
\$3,800.00	\$3,800.00	\$0.00
\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00
\$109,300.00	\$91,800.00	-\$17,500.00

Billing and Collections			
5305-Supervision	\$0.00	\$0.00	\$0.00
5310-Meter Reading Expense	\$90,989.73	\$88,000.00	-\$2,989.73
5315-Customer Billing	\$287,903.53	\$301,324.00	\$13,420.47
5320-Collecting	\$0.00	\$0.00	\$0.00
5325-Collecting- Cash Over and Short	\$40.00	\$10,000.00	\$9,960.00
5330-Collection Charges	\$0.00	\$0.00	\$0.00
5335-Bad Debt Expense	\$0.00	\$0.00	\$0.00
5340-Miscellaneous Customer Accounts Expenses	\$0.00	\$0.00	\$0.00
Sub-Total	\$378,933.26	\$399,324.00	\$20,390.74
Community Relations			
5405-Supervision	\$0.00	\$0.00	\$0.00
5410-Community Relations - Sundry	\$3,364.68	\$10,000.00	\$6,635.32
5415-Energy Conservation	\$22,556.84	\$0.00	-\$22,556.84
5420-Community Safety Program	\$0.00	\$0.00	\$0.00
5425-Miscellaneous Customer Service and Informational Expenses	\$0.00	\$0.00	\$0.00
5505-Supervision	\$0.00	\$0.00	\$0.00
5510-Demonstrating and Selling Expense	\$0.00	\$0.00	\$0.00
5515-Advertising Expense	\$4,875.00	\$10,000.00	\$5,125.00
5520-Miscellaneous Sales Expense	\$0.00	\$0.00	\$0.00
Sub-Total	\$30,796.52	\$20,000.00	-\$10,796.52

\$0.00	\$0.00	\$0.00
\$88,000.00	\$100,750.00	\$12,750.00
\$301,324.00	\$326,050.00	\$24,726.00
\$0.00	\$0.00	\$0.00
\$10,000.00	\$10,000.00	\$0.00
\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00
\$399,324.00	\$436,800.00	\$37,476.00
\$0.00	\$0.00	\$0.00
\$10,000.00	\$13,000.00	\$3,000.00
\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00
\$10,000.00	\$13,000.00	\$3,000.00
\$0.00	\$0.00	\$0.00
\$20,000.00	\$26,000.00	\$6,000.00

Administrative and General Expenses			
5605-Executive Salaries and Expenses	\$47,841.08	\$56,100.00	\$8,258.92
5610-Management Salaries and Expenses	\$47,555.76	\$47,200.00	-\$355.76
5615-General Administrative Salaries and Expenses	\$150,364.50	\$150,500.00	\$135.50
5620-Office Supplies and Expenses	\$3,612.99	\$6,500.00	\$2,887.01
5625-Administrative Expense Transferred Credit	\$0.00	\$0.00	\$0.00
5630-Outside Services Employed	\$174,341.92	\$230,000.00	\$55,658.08
5635-Property Insurance	\$28,773.12	\$32,000.00	\$3,226.88
5640-Injuries and Damages	\$0.00	\$0.00	\$0.00
5645-Employee Pensions and Benefits	\$0.65	\$0.00	-\$0.65
5650-Franchise Requirements	\$0.00	\$0.00	\$0.00
5655-Regulatory Expenses	\$12,946.97	\$15,300.00	\$2,353.03
5660-General Advertising Expenses	\$0.00	\$0.00	\$0.00
5665-Miscellaneous General Expenses	\$44,451.12	\$42,100.00	-\$2,351.12
5670-Rent	\$26,400.00	\$27,200.00	\$800.00
5675-Maintenance of General Plant	\$115,899.89	\$35,000.00	-\$80,899.89
5680-Electrical Safety Authority Fees	\$0.00	\$0.00	\$0.00
5685-Independent Market Operator Fees and Penalties	\$0.00	\$0.00	\$0.00
Sub-Total	\$652,188.00	\$641,900.00	-\$10,288.00

\$56,100.00	\$59,300.00	\$3,200.00
\$47,200.00	\$49,900.00	\$2,700.00
\$150,500.00	\$244,750.00	\$94,250.00
\$6,500.00	\$6,700.00	\$200.00
\$0.00	\$0.00	\$0.00
\$230,000.00	\$361,400.00	\$131,400.00
\$32,000.00	\$33,900.00	\$1,900.00
\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00
\$15,300.00	\$16,250.00	\$950.00
\$0.00	\$0.00	\$0.00
\$42,100.00	\$42,100.00	\$0.00
\$27,200.00	\$31,600.00	\$4,400.00
\$35,000.00	\$40,000.00	\$5,000.00
\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00
\$641,900.00	\$885,900.00	\$244,000.00

Amortization Expenses			
5705-Amortization Expense - Property, Plant, and Equipment	\$212,970.00	\$288,158.00	\$75,188.00
5710-Amortization of Limited Term Electric Plant	\$0.00	\$0.00	\$0.00
5715-Amortization of Intangibles and Other Electric Plant	\$2,280.00	\$0.00	-\$2,280.00
5720-Amortization of Electric Plant Acquisition Adjustments	\$0.00	\$0.00	\$0.00
5725-Miscellaneous Amortization	\$0.00	\$0.00	\$0.00
5730-Amortization of Unrecovered Plant and Regulatory Study Costs	\$0.00	\$0.00	\$0.00
5735-Amortization of Deferred Development Costs	\$0.00	\$0.00	\$0.00
5740-Amortization of Deferred Charges	\$0.00	\$0.00	\$0.00
Sub-Total	\$215,250.00	\$288,158.00	\$72,908.00
6105-Taxes other than Income Taxes	\$0.00	\$0.00	\$0.00
Cost of Power			
4705-Power Purchased	\$4,780,362.46	\$4,807,363.52	\$27,001.06
4708-Charges-WMS	\$350,056.61	\$458,684.23	\$108,627.62
4710-Cost of Power Adjustments	\$0.00	\$0.00	\$0.00
4712-Charges-One-Time	\$0.00	\$0.00	\$0.00
4714-Charges-NW	\$708,898.12	\$576,994.97	-\$131,903.15
4716-Charges-CN	\$633,021.39	\$605,363.61	-\$27,657.78
4730-Rural Rate Assistance Expense	\$88,200.82	\$88,208.51	\$7.68
5685-Independent Market Operator Fees and Penalties	\$0.00	\$0.00	\$0.00
Sub-Total	\$6,560,539.40	\$6,536,614.83	-\$23,924.57

\$288,158.00	\$343,019.50	\$54,861.49
\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00
\$288,158.00	\$343,019.50	\$54,861.49
\$0.00	\$0.00	\$0.00
\$4,807,363.52	\$4,913,262.91	\$105,899.39
\$458,684.23	\$468,788.39	\$10,104.16
\$0.00	\$0.00	\$0.00
\$0.00	\$0.00	\$0.00
\$576,994.97	\$585,765.20	\$8,770.23
\$605,363.61	\$614,273.53	\$8,909.92
\$88,208.51	\$90,151.61	\$1,943.11
\$0.00	\$0.00	\$0.00
\$6,536,614.83	\$6,672,241.64	\$135,626.81

VARIANCE ANALYSIS ON OM&A COSTS

A summary of operating and maintenance costs is presented in Exhibit 4, Tab 1, Schedule 2.

2009 Test year

The 2009 test year Operating & Maintenance forecast is shown in Exhibit 4, Tab 2, Schedule 1.

The total net cost is expected to be \$8,906,805. Operations and Maintenance represents 5.30% of the total cost. Administration and General costs represent 9.95% of the total cost. Billing and Collection costs accounts for 4.90% of the total Operating Costs. Finally Cost of Power accounts for 74.91% of the total Operating Costs.

Comparison to Fiscal 2008 Bridge Year

Exhibit 4, Tab 2, Schedule 1, provides a comparison of the 2009 test year forecast of Operation & Maintenance expenses to that forecast for the 2008 bridge year. Total net Operation & Maintenance costs are forecast to increase \$609,176 or 7.34%. The resulting cost per customer increases \$102.92 or 6.50%.

2008 Bridge Year

The 2008 bridge year Operating & Maintenance forecast is shown in Exhibit 4, Tab 2, Schedule 1.

The total net cost is expected to be \$8,297,629. Operations and Maintenance costs represent 4.18% of the total operating cost. Administration and General costs represent 7.74% of the total cost. Billing and Collection costs accounts for 4.81% of the total Operating Costs. Finally Cost of Power accounts for 78.78% of the total Operating Costs.

Comparison to Fiscal 2007 Actual

Exhibit 4, Tab 2, Schedule 1, provides a comparison of the 2009 test year forecast of Operation & Maintenance expenses to that forecast for the 2007 Actual. Total net Operation & Maintenance costs are forecast to increase \$711,774 or 8.58%. The resulting cost per customer increases \$110.52 or 6.99%.

2007 Actual

The 2007 fiscal year Operating & Maintenance forecast is shown in Exhibit 4, Tab 2, Schedule 1.

The total net cost was \$8,180,004. Operations and Maintenance costs represent 3.79% of the total cost. Administration and General costs represent 7.97% of the total cost. Billing and Collection costs accounts for 4.63% of the total Operating Costs. Finally Cost of Power accounts for 80.20% of the total Operating Costs.

Comparison to Fiscal 2006 Actual

Exhibit 4, Tab 2, Schedule 1, provides a comparison of the 2009 test year forecast of Operation & Maintenance expenses to that forecast for the 2007 fiscal year. Total net Operation & Maintenance costs are forecast to increase \$680,800 or 8.20%. The resulting cost per customer increases \$91.76 or 5.80%.

MATERIALITY ANALYSIS ON OM&A COSTS

Materiality of 1% of 2006 board approved distribution expenses of \$1,314,279 is \$13,143.

2006 Board Approved to 2006 Actual

Asset Account	Year 1	Year 2	Variance
5020-Overhead Distribution Lines & Feeder- Operation Supplies & Expenses	\$217,823	\$259,058	\$41,235

Explanation: Increased due to planned maintenance schedule cycle changes and cost of materials increase.

Asset Account	Year 1	Year 2	Variance
5105-Maintenance Supervision and Engineering	\$0	\$15,616	\$15,616

Explanation: Supervision was not accounted separately in the past.

Asset Account	Year 1	Year 2	Variance
5150-Maintenance of Underground Conductors and Devices	\$0	\$27,773	\$27,773

Explanation: Maintenance activities were minimal in the 2006 EDR due to increased capital spend in those years.

Asset Account	Year 1	Year 2	Variance
5175-Maintenance of Meters	\$0	\$39,204	\$39,204

Explanation: Maintenance of meters was necessary in these years to meet measurements canada requirements.

Asset Account	Year 1	Year 2	Variance
5315-Customer Billing	\$217,802	\$249,860	\$32,058

Explanation: Increase in wages and system upgrades.

Asset Account	Year 1	Year 2	Variance
5415-Energy Conservation	\$0	\$17,011	\$17,011

Explanation: New cost to the utility not experienced in the past.

Asset Account	Year 1	Year 2	Variance
5615-General Administrative Salaries and Expenses	\$121,224	\$138,572	\$17,348

Explanation: This change represents wage increases and overtime.

Asset Account	Year 1	Year 2	Variance
5630-Outside Services Employed	\$93,237	\$192,738	\$99,501

Explanation: This increase in cost is due to the Sifto salt OEB hearing.

Asset Account	Year 1	Year 2	Variance
5635-Property Insurance	\$2,701	\$27,667	\$24,966

Explanation: Represents actual marine insurance and building insurance costs.

Asset Account	Year 1	Year 2	Variance
5655-Regulatory Expenses	\$1,460	\$15,491	\$14,031

Explanation: This is the accounting of actual regulatory fees paid in 2006.

Asset Account	Year 1	Year 2	Variance
4705-Power Purchased	\$4,229,620	\$4,679,585	\$449,965

Explanation: 2006 was a higher consumption year than 2004 and is beyond WCHE's control.

Asset Account	Year 1	Year 2	Variance
4714-Charges NW	\$712,070	\$767,821	\$55,751

Explanation: 2006 was a higher consumption year than 2004 and is beyond WCHE's control.

Asset Account	Year 1	Year 2	Variance
4716-Charges CN	\$641,531	\$661,464	\$19,933

Explanation: 2006 was a higher consumption year than 2004 and is beyond WCHE's control.

2006 Actual to 2007 Actual

Asset Account	Year 1	Year 2	Variance
5050-Underground Subtransmission Feeders- Operation	\$68,461	\$85,654	\$17,193

Explanation: Increased due to planned maintenance schedule cycle changes and cost of materials increase.

Asset Account	Year 1	Year 2	Variance
5315-Customer Billing	\$249,860	\$287,904	\$38,044

Explanation: Increase in wages and system upgrades.

Asset Account	Year 1	Year 2	Variance
5675-Maintenance of General Plant	\$58,422	\$115,900	\$57,478

Explanation: Increased due to planned maintenance schedule cycle changes and cost of materials increase.

Asset Account	Year 1	Year 2	Variance
4705-Power Purchased	\$4,679,585	\$4,780,362	\$100,777

Explanation: 2007 Bridge year amount calculated using normalized consumption which are higher than 2006

2007 Actual to 2008 Bridge

Asset Account	Year 1	Year 2	Variance
5050-Underground Distribution Lines & Feeders- Operation Supplies & Expenses	\$85,654	\$100,000	\$14,346

Explanation: Increased due to planned maintenance schedule cycle changes and cost of materials increase.

Asset Account	Year 1	Year 2	Variance
5114-Maintenance of Distribution Station Equipment	-\$15,793	\$35,500	\$51,293

Explanation: Increased due to planned maintenance schedule cycle changes and cost of materials increase.

Asset Account	Year 1	Year 2	Variance
5120-Maintenance of Poles, Towers and Fixtures	\$320	\$15,000	\$14,680

Explanation: Increased due to planned maintenance schedule cycle changes and cost of materials increase.

Asset Account	Year 1	Year 2	Variance
5315-Customer Billing	\$287,904	\$301,324	\$13,420

Explanation: Expense to upgrade billing software, Increase in wages and salaries for billing staff, and additional data mining and settlement costs

Asset Account	Year 1	Year 2	Variance
5630-Outside Services Employed	\$174,342	\$230,000	\$55,658

Explanation: Addition of cost of Environmental resource shared with the Town of Goderich. Increase in Audit and legal fees.

Asset Account	Year 1	Year 2	Variance
5705-Amortization Expense-Property, Plant and Equipment	\$212,970	\$288,158	\$75,188

Explanation: Direct result of increase in capital budget in 2008 from 172,000 to \$453,000

Asset Account	Year 1	Year 2	Variance
4708-Charges-WMS	\$350,057	\$458,684	\$108,628

Explanation: 2008 bridge year amount calculated using normalized consumption which are higher than 2007

2008 Bridge to 2009 Test

Asset Account	Year 1	Year 2	Variance
5020-Overhead Distribution Lines and Feeders- Operation Supplies & Expenses	\$135,000	\$221,725	\$86,725

Explanation: Increased due to planned maintenance schedule cycle changes and cost of materials increase.

Asset Account	Year 1	Year 2	Variance
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expense	\$0	\$22,425	\$22,425

Explanation: Increased due to planned maintenance schedule cycle changes and cost of materials increase.

Asset Account	Year 1	Year 2	Variance
5050-Underground Subtransmission Feeders- Operation	\$100,000	\$124,600	\$24,600

Explanation: Increased due to planned maintenance schedule cycle changes and cost of materials increase.

Asset Account	Year 1	Year 2	Variance
5315-Customer Billing	\$301,324	\$326,050	\$24,726

Explanation: Increase in Salaries and supply costs

Asset Account	Year 1	Year 2	Variance
5615-General Administrative Salaries and Expenses	\$150,500	\$244,750	\$94,250

Explanation: Addition of new staff and wage increases.

Asset Account	Year 1	Year 2	Variance
5630 Outside Services Employed	\$230,000	\$361,400	\$131,400

Explanation: Addition of costs for 2009 COS rate application and interrogatory response and increased Legal costs.

Asset Account	Year 1	Year 2	Variance
5705 Amortization Expense Property Plant and Equipment	\$288,158	\$343,020	\$54,862

Explanation: Increase in capital budget amount in 2008 and 2009 has in turn increased the amortization expense.

Asset Account	Year 1	Year 2	Variance
4705 Power Purchased	\$4,807,364	\$4,913,263	\$105,899

Explanation: 2009 Test Year amount is calculated utilizing normalized consumption levels which are higher than 2008 levels.

SHARED SERVICES

A summary of shared services for actual fiscal 2006, along with the projections for the 2007 actual fiscal year, 2008 bridge year and 2009 test year are shown in the following table.

Town of Goderich

	2006 Actual	2007 Actual	2008 Bridge	2009 Test
Executive Services				
Cost allocator	Actual Costs	Actual Costs	Actual Costs	Actual Costs
Explanation	WCHE is billed for use of its parent company's executive team based on their utilization			
Total Costs	\$46,129	\$47,556	\$47,200	\$49,900

CORPORATE COST ALLOCATION

West Coast Huron Energy does not utilize corporate cost allocation.

PURCHASE OF SERVICES

(i) the identity of each company transacting with the applicant	(ii) a summary of the nature of the activity transacted	(iii) the annual dollar value in aggregate of transactions	(iv) a description of the specific methodology used in determining the price
Erie Thames Services	IT support,billing,data processing	\$ 131,000.00	contract negotiation
Erie Thames Services	rate rebasing application	\$ 100,000.00	Request for Quotes
Erie Thames Services	Operational and Asset Management	\$ 72,000.00	Request for Quotes
Town of Goderich	administration and environmental services	\$ 69,500.00	service provider/negotiation
Alexandra Marine Hospital	after hours call service	\$ 7,200.00	service provider
Takalo & Burt	audit, rate filing, consultation	\$ 40,000.00	negotiation,fee for service
Donnelly & Murphy,Borden Ladner	legal	\$ 15,000.00	fee for service
EDA,CHEC,USF,ESA,OEB	various memberships	\$ 36,650.00	fees-as required
Banter MacEwan,Mearie	insurance premiums	\$ 33,900.00	request for quotes
Goderich Signal Star	customer notifications	\$ 13,000.00	local vendor
	telephone, fax, photocopy rentals	\$ 7,200.00	local vendors

EMPLOYEE DESCRIPTION

EMPLOYEE DESCRIPTION

Number of employees (Full-time equivalents (FTE's):

	<u>2006</u>				
	<u>Board</u>	<u>2006</u>	<u>2007</u>	<u>2008</u>	<u>2009 Test</u>
	<u>Approved</u>	<u>Actual</u>	<u>Actual</u>	<u>Bridge</u>	
Executive	3	3	3	3	3
Management	3	3	2	1	1
Non-Unionized					
Unionized	7	7	7	8	8

Number of employees (Part-time equivalents (PTE's):

	<u>2006</u>				
	<u>Board</u>	<u>2006</u>	<u>2007</u>	<u>2008</u>	<u>2009 Test</u>
	<u>Approved</u>	<u>Actual</u>	<u>Actual</u>	<u>Bridge</u>	
Executive					
Management	2	2	2	2	2
Non-Unionized	2	2	1	3	3
Unionized					

Compensation (Total Salary and Wages (\$)):

	<u>2006</u>								
	<u>Board</u>		<u>2006</u>		<u>2007</u>		<u>2008</u>		<u>2009 Test</u>
	<u>Approved</u>	<u>Average</u>	<u>Actual</u>	<u>Average</u>	<u>Actual</u>	<u>Average</u>	<u>Bridge</u>	<u>Average</u>	<u>Average</u>
Executive	\$29,663	\$9,888	\$29,500	\$9,833	\$29,500	\$9,833	\$29,500	\$9,833	\$30,385
Management	\$167,396	\$55,799	\$162,119	\$32,424	\$161,780	\$40,445	\$131,615	\$43,872	\$135,564
Non-Unionized	\$0	\$0	\$13,264	\$6,632	\$7,417	\$7,417	\$21,553	\$7,184	\$22,200
Unionized	\$368,826	\$52,689	\$402,885	\$57,555	\$536,486	\$76,641	\$567,980	\$70,997	\$585,019

Compensation (Total Benefits (\$)):

	<u>2006</u>		<u>2006</u>		<u>2007</u>		<u>2008</u>		<u>2009 Test</u>	
	<u>Board</u>		<u>Actual</u>	<u>Average</u>	<u>Actual</u>	<u>Average</u>	<u>Bridge</u>	<u>Average</u>		<u>Average</u>
Executive	<u>Approved</u>	<u>Average</u>								
Management	\$0	\$0	\$599	\$200	\$649	\$219	\$694	\$231	\$715	\$238
Non-Unionized	\$16,075	\$5,358	\$42,556	\$8,511	\$51,114	\$12,779	\$38,485	\$12,828	\$39,639	\$13,213
Unionized	\$34,484	\$4,926	\$1,551	\$775	\$975	\$975	\$2,924	\$975	\$3,011	\$1,004
			\$119,294	\$17,042	\$195,914	\$24,489	\$201,791	\$25,224	\$207,845	\$25,981

Compensation (Total Incentives (\$)):

	<u>2006 Board</u>		<u>2006 Actual</u>		<u>2007</u>		<u>2008</u>		<u>2009 Test</u>	
	<u>Approved</u>	<u>Average</u>	<u>Actual</u>	<u>Average</u>	<u>Actual</u>	<u>Average</u>	<u>Bridge</u>	<u>Average</u>		<u>Average</u>
Executive										
Management	\$6,750	\$2,250	\$4,500	\$1,500	\$4,500	\$1,500	\$4,500	\$1,500	\$4,635	\$1,545
Non-Unionized	\$4,050	\$1,350	\$7,000	\$1,400	\$6,000	\$1,500	\$6,000	\$2,000	\$6,180	\$2,060
Unionized										

Total of Costs charged to O&M (\$):

	<u>2006 Board</u>		<u>2006 Actual</u>		<u>2007</u>		<u>2008</u>		<u>2009 Test</u>	
	<u>Approved</u>	<u>Average</u>	<u>Actual</u>	<u>Average</u>	<u>Actual</u>	<u>Average</u>	<u>Bridge</u>	<u>Average</u>		<u>Average</u>
TOTAL	\$267,687	\$15,746	\$334,273	\$19,663	\$404,351	\$26,957	\$405,350	\$23,844	\$417,510	\$24,559

DEPRECIATION, AMORTIZATION AND DEPLETION

DEPRECIATION, AMORTIZATION AND DEPLETION	2006 Board Approved (\$'s)	Depreciation Rate	Depreciation	2006 Actual (\$'s)	Rate %	Depreciation (\$'s)	2007 Actual (\$'s)	Rate %	Depreciation (\$'s)	2008 Bridge (\$'s)	Rate %	Depreciation (\$'s)	2009 Test (\$'s)	Rate %	Depreciation (\$'s)
Land and Buildings	\$89,638.12	2.00%	\$2,306.32	\$92,460.45	2.00%	\$2,716.00	\$92,685.45	2.00%	\$2,833.04	\$92,685.45	2.00%	\$2,837.54	\$92,685.45	2.00%	\$2,837.54
TS Primary Above 50	\$0.00		\$0.00	\$0.00		\$0.00	\$0.00		\$0.00	\$0.00		\$0.00	\$0.00		\$0.00
DS	\$151,906.63	3.30%	\$5,171.40	\$152,252.22	3.30%	\$6,090.00	\$152,252.22	3.30%	\$6,090.09	\$152,252.22	3.30%	\$6,090.09	\$182,252.22	3.30%	\$6,690.09
Poles and Wires	\$2,928,727.52	4.00%	\$105,005.71	\$3,185,514.67	4.00%	\$123,658.00	\$3,323,950.96	4.00%	\$130,189.31	\$3,608,950.96	4.00%	\$136,738.13	\$3,898,950.96	4.00%	\$144,499.62
Line Transformers	\$681,332.11	4.00%	\$24,241.04	\$656,834.55	4.00%	\$28,547.00	\$773,801.48	4.00%	\$28,612.72	\$898,801.48	4.00%	\$33,452.06	\$1,033,801.48	4.00%	\$38,652.06
Services and Meters	\$301,299.96	4.00%	\$14,702.40	\$412,830.72	4.00%	\$17,314.00	\$397,438.95	4.00%	\$16,205.39	\$402,438.95	4.00%	\$15,997.56	\$412,438.95	4.00%	\$16,297.56
General Plant	\$0.00	4.00%	\$0.00	\$0.00	4.00%	\$0.00	\$0.00	4.00%	\$0.00	\$0.00	4.00%	\$0.00	\$0.00	4.00%	\$0.00
IT Assets	\$71,797.13	20.00%	\$11,846.66	\$90,921.12	20.00%	\$13,951.00	\$92,571.36	20.00%	\$9,174.62	\$92,571.36	20.00%	\$9,257.14	\$92,571.36	20.00%	\$9,257.14
Equipment	\$349,953.42	10.00%	\$36,735.47	\$368,248.94	10.00%	\$43,260.84	\$389,838.21	10.00%	\$87,485.46	\$427,838.21	10.00%	\$94,088.90	\$717,838.21	10.00%	\$135,088.90
Other Distribution Assets	\$0.00	4.00%	\$0.00	-\$166,135.45	4.00%	\$0.00	-\$257,585.18	4.00%	-\$8,474.41	-\$257,585.18	4.00%	-\$10,303.41	-\$257,585.18	4.00%	-\$10,303.41
GROSS ASSET TOTAL	\$4,574,654.89		\$200,009.00	\$4,792,927.22		\$235,536.84	\$4,964,953.45		\$272,116.23	\$5,417,953.45		\$288,158.00	\$6,172,953.45		\$343,019.50

LOSS ADJUSTMENT FACTOR CALCULATION

LOSS ADJUSTMENT FACTOR CALCULATION

	2002	2003	2004	2005	2006	2007	Total
A "Wholesale" kWh (IESO)	146,272,733	84,327,123	85,916,192	87,417,942	87,069,383	87,554,002	578,557,375
B Wholesale kWh for Large Use customer(s) (IESO)	54,875,943	8,888,048					63,763,991
C Net "Wholesale" kWh (A)-(B)	201,148,676	93,215,171	85,916,192	87,417,942	87,069,383	87,554,002	642,321,366
D Retail kWh (Distributor)	138,008,817	81,017,931	82,368,202	83,184,361	84,870,508	83,714,097	553,163,917
E Retail kWh for Large Use Customer(s) (1% loss)	54,488,795	8,799,168					63,287,963
F Net "Retail" kWh (D)-(E)	192,497,612	89,817,099	82,368,202	83,184,361	84,870,508	83,714,097	616,451,880
G Loss Factor [(C)/(F)]	1.0449	1.0378	1.0431	1.0509	1.0259	1.0459	1.0420
H Distribution Loss Adjustment Factor							0.0045

Total Utility Loss Adjustment Factor

LAF

Supply Facility Loss Factor 1.0045

Distribution Loss Factors

Secondary Metered Customer

Total Loss Factor - Secondary Metered Customer < 5,000kW 1.0420
Total Loss Factor - Secondary Metered Customer > 5,000kW 1.0100

Primary Metered Customer

Total Loss Factor - Primary Metered Customer < 5,000kW 1.0315
Total Loss Factor - Primary Metered Customer > 5,000kW 1.0000

Total Loss Factor

Secondary Metered Customer

Total Loss Factor - Secondary Metered Customer < 5,000kW 1.0467
Total Loss Factor - Secondary Metered Customer > 5,000kW 1.0145

Primary Metered Customer

Total Loss Factor - Primary Metered Customer < 5,000kW 1.0362
Total Loss Factor - Primary Metered Customer > 5,000kW 1.0045

MATERIALITY ANALYSIS ON DISTRIBUTION LOSSES

The resulting Loss Factor adjustment is less than 5%.

TAX CALCULATIONS

Summary of Income Tax Calculation

	2006 Board Approved	2006 Actual	2007 Actual	2008 Bridge	2009 Test
<u>Determination of Taxable Income</u>					
Regulatory Net Income (before tax)	\$214,459	\$51,069	\$143,936	\$357,768	\$384,776
Book to Tax Adjustments					
Additions to Accounting Income:					
Depreciation and amortization	\$208,110	\$235,537	\$272,116	\$288,158	\$343,019
Meals & entertainment / Mileage					
Other Additions		\$0	\$0	\$158,783	\$164,390
Total Additions	\$208,110	\$235,537	\$272,116	\$446,941	\$507,410
Deductions from Accounting Income:					
Capital Cost Allowance	\$239,253	\$236,618	\$240,987	\$249,707	\$307,997
Cumulative eligible capital deductions	\$946				
Gain on Disposal					
Other Deductions		\$0	\$0	\$170,696	\$170,696
Total Deductions	\$240,199	\$236,618	\$240,987	\$420,403	\$478,693
Regulatory Taxable Income	\$182,370	\$49,987	\$175,066	\$384,306	\$413,493
Corporate Income Tax Rate	18.62%	18.62%	18.62%	17.00%	17.00%
Ontario Capital Tax Rate					
Subtotal					
Less: R&D ITC (0.3)					
Regulatory Income Tax	\$33,957	\$9,308	\$32,597	\$65,332	\$70,294
<u>Calculation of Utility Income Taxes</u>					
Income Taxes (Line 23)	\$33,957	\$9,308	\$32,597	\$65,332	\$70,294
Ontario Capital Tax	\$0	\$0	\$0	\$0	\$0
Large Corporation Tax (Line 14, page 2)					
Total Taxes	\$33,957	\$9,308	\$32,597	\$65,332	\$70,294
Taxes Grossed up for Rate Purposes	\$41,727	\$11,437	\$40,056	\$78,713	\$84,691
<u>Tax Rates</u>					
Federal Tax	12.00%	12.00%	12.00%	11.50%	11.50%
Federal Surtax	1.12%	1.12%	1.12%	0.00%	0.00%
Provincial Tax	5.50%	5.50%	5.50%	5.50%	5.50%
Total Tax Rate	18.62%	18.62%	18.62%	17.00%	17.00%

INTEREST EXPENSE

Interest Expense

	2006 Board Approved	2006 Actual	2007 Bridge	2008 Bridge	2009 Test
Actual Interest Expense	\$70,647.92	\$70,647.92	\$70,647.92	\$70,647.92	\$164,390.12
Capitalized Interest	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Actual Interest	\$70,647.92	\$70,647.92	\$70,647.92	\$70,647.92	\$164,390.12
Interest forecast Adjustments	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Total Interest	\$70,647.92	\$70,647.92	\$70,647.92	\$70,647.92	\$164,390.12
Deemed Interest	\$172,737.64	\$172,737.64	\$172,737.64	\$172,737.64	\$170,696.39
Excess Interest	-\$102,089.73	-\$102,089.73	-\$102,089.73	-\$102,089.73	-\$6,306.27

CAPITAL COST ALLOWANCE

CAPITAL COST ALLOWANCE

2006 Board Approved

Class	Class Description	UCC 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	\$3,432,301	\$204,024		\$3,636,325	\$102,012		\$3,534,313	4%	\$141,373	\$3,494,952
2	Distribution System - pre 1988				\$0	\$0		\$0	6%	\$0	\$0
8	General Office/Stores Equip	\$219,472			\$219,472	\$0		\$219,472	20%	\$43,894	\$175,578
10	Computer Hardware/ Vehicles	\$183,347	\$14,990		\$198,337	\$7,495		\$190,842	30%	\$57,253	\$141,084
10.1	Certain Automobiles				\$0	\$0		\$0	30%	\$0	\$0
12	Computer Software	\$43,111			\$43,111	\$0		\$43,111	100%	\$43,111	\$0
13 1	Lease # 1				\$0	\$0		\$0		\$0	\$0
13 2	Lease #2				\$0	\$0		\$0		\$0	\$0
13 3	Lease # 3				\$0	\$0		\$0		\$0	\$0
13 4	Lease # 4				\$0	\$0		\$0		\$0	\$0
14	Franchise				\$0	\$0		\$0		\$0	\$0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs				\$0	\$0		\$0		\$0	\$0
43.1	Certain Energy-Efficient Electrical Generating Equipment				\$0	\$0		\$0		\$0	\$0
45	Computers & Systems Software acq'd post Mar 22/04				\$0	\$0		\$0		\$0	\$0
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)				\$0	\$0		\$0		\$0	\$0
47	Distribution System - post 22-Feb-2005				\$0	\$0		\$0	8%	\$0	\$0
98	No CCA				\$0	\$0		\$0		\$0	\$0
TOTAL		\$3,878,230	\$219,014	\$0	\$4,097,244	\$109,507		\$3,987,737		\$285,630	\$3,811,614

2006 Actual

Class	Class Description	UCC 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	\$3,494,952			\$3,494,952	\$0	\$3,494,952	4%	\$139,798	\$3,355,154
2	Distribution System - pre 1988	\$0			\$0	\$0	\$0	6%	\$0	\$0
8	General Office/Stores Equip	\$175,578			\$175,578	\$0	\$175,578	20%	\$35,116	\$140,462
10	Computer Hardware/ Vehicles	\$141,084	\$37,420		\$178,504	\$18,710	\$159,794	30%	\$47,938	\$130,566
10.1	Certain Automobiles	\$0			\$0	\$0	\$0	30%	\$0	\$0
12	Computer Software	\$0			\$0	\$0	\$0	100%	\$0	\$0
13 1	Lease # 1	\$0			\$0	\$0	\$0		\$0	\$0
13 2	Lease #2	\$0			\$0	\$0	\$0		\$0	\$0
13 3	Lease # 3	\$0			\$0	\$0	\$0		\$0	\$0
13 4	Lease # 4	\$0			\$0	\$0	\$0		\$0	\$0
14	Franchise	\$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
43.1	Certain Energy-Efficient Electrical Generating Equipment	\$0			\$0	\$0	\$0		\$0	\$0
45	Computers & Systems Software acq'd post Mar 22/04	\$0			\$0	\$0	\$0		\$0	\$0
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	\$0			\$0	\$0	\$0		\$0	\$0
47	Distribution System - post 22-Feb-2005	\$0	\$344,166		\$344,166	\$172,083	\$172,083	8%	\$13,767	\$330,399
98	No CCA	\$0			\$0	\$0	\$0		\$0	\$0
	TOTAL	\$3,811,614	\$381,585	\$0	\$4,193,200	\$190,793	\$4,002,407		\$236,618	\$3,956,581

2007 Actual

Class	Class Description	UCC 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	\$3,355,154			\$3,355,154	\$0	\$3,355,154	4%	\$134,206	\$3,220,948
2	Distribution System - pre 1988	\$0			\$0	\$0	\$0	6%	\$0	\$0
8	General Office/Stores Equip	\$140,462			\$140,462	\$0	\$140,462	20%	\$28,092	\$112,370
10	Computer Hardware/ Vehicles	\$130,566	\$23,240		\$153,805	\$11,620	\$142,185	30%	\$42,656	\$111,150
10.1	Certain Automobiles	\$0			\$0	\$0	\$0	30%	\$0	\$0
12	Computer Software	\$0			\$0	\$0	\$0	100%	\$0	\$0
13 1	Lease # 1	\$0			\$0	\$0	\$0		\$0	\$0
13 2	Lease #2	\$0			\$0	\$0	\$0		\$0	\$0
13 3	Lease # 3	\$0			\$0	\$0	\$0		\$0	\$0
13 4	Lease # 4	\$0			\$0	\$0	\$0		\$0	\$0
14	Franchise	\$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
43.1	Certain Energy-Efficient Electrical Generating Equipment	\$0			\$0	\$0	\$0		\$0	\$0
45	Computers & Systems Software acq'd post Mar 22/04	\$0			\$0	\$0	\$0		\$0	\$0
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	\$0			\$0	\$0	\$0		\$0	\$0
47	Distribution System - post 22-Feb-2005	\$330,399	\$240,011		\$570,411	\$120,006	\$450,405	8%	\$36,032	\$534,378
98	No CCA	\$0			\$0	\$0	\$0		\$0	\$0
	TOTAL	\$3,956,581	\$263,251	\$0	\$4,219,832	\$131,625	\$4,088,206		\$240,987	\$3,978,845

2008 Bridge

Class	Class Description	UCC 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	\$3,220,948			\$3,220,948	\$0	\$3,220,948	4%	\$128,838	\$3,092,110
2	Distribution System - pre 1988	\$0			\$0	\$0	\$0	6%	\$0	\$0
8	General Office/Stores Equip	\$112,370			\$112,370	\$0	\$112,370	20%	\$22,474	\$89,896
	Computer Hardware/									
10	Vehicles	\$111,150	\$38,000		\$149,150	\$19,000	\$130,150	30%	\$39,045	\$110,105
10.1	Certain Automobiles	\$0			\$0	\$0	\$0	30%	\$0	\$0
12	Computer Software	\$0			\$0	\$0	\$0	100%	\$0	\$0
13.1	Lease # 1	\$0			\$0	\$0	\$0		\$0	\$0
13.2	Lease #2	\$0			\$0	\$0	\$0		\$0	\$0
13.3	Lease # 3	\$0			\$0	\$0	\$0		\$0	\$0
13.4	Lease # 4	\$0			\$0	\$0	\$0		\$0	\$0
14	Franchise	\$0			\$0	\$0	\$0		\$0	\$0
	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	\$0			\$0	\$0	\$0		\$0	\$0
	Certain Energy-Efficient Electrical Generating Equipment	\$0			\$0	\$0	\$0		\$0	\$0
43.1	Computers & Systems Software acq'd post Mar 22/04	\$0			\$0	\$0	\$0		\$0	\$0
45	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	\$0			\$0	\$0	\$0		\$0	\$0
46	Distribution System - post 22-Feb-2005	\$534,378	\$415,000		\$949,378	\$207,500	\$741,878	8%	\$59,350	\$890,028
98	No CCA	\$0			\$0	\$0	\$0		\$0	\$0
	TOTAL	\$3,978,845	\$453,000	\$0	\$4,431,845	\$226,500	\$4,205,345		\$249,707	\$4,182,138

2009 Test

Class	Class Description	UCC 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	\$3,092,110			\$3,092,110	\$0		\$3,092,110	4%	\$123,684	\$2,968,425
2	Distribution System - pre 1988	\$0			\$0	\$0		\$0	6%	\$0	\$0
8	General Office/Stores Equip	\$89,896			\$89,896	\$0		\$89,896	20%	\$17,979	\$71,917
10	Computer Hardware/ Vehicles	\$110,105	\$290,000		\$400,105	\$145,000		\$255,105	30%	\$76,531	\$323,573
10.1	Certain Automobiles	\$0			\$0	\$0		\$0	30%	\$0	\$0
12	Computer Software	\$0			\$0	\$0		\$0	100%	\$0	\$0
13 1	Lease # 1	\$0			\$0	\$0		\$0		\$0	\$0
13 2	Lease #2	\$0			\$0	\$0		\$0		\$0	\$0
13 3	Lease # 3	\$0			\$0	\$0		\$0		\$0	\$0
13 4	Lease # 4	\$0			\$0	\$0		\$0		\$0	\$0
14	Franchise	\$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
43.1	Certain Energy-Efficient Electrical Generating Equipment	\$0			\$0	\$0		\$0		\$0	\$0
45	Computers & Systems Software acq'd post Mar 22/04	\$0			\$0	\$0		\$0		\$0	\$0
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	\$0			\$0	\$0		\$0		\$0	\$0
47	Distribution System - post 22-Feb-2005	\$890,028	\$465,000		\$1,355,028	\$232,500		\$1,122,528	8%	\$89,802	\$1,265,226
98	No CCA	\$0			\$0	\$0		\$0		\$0	\$0
TOTAL		\$4,182,138	\$755,000	\$0	\$4,937,138	\$377,500		\$4,559,638		\$307,997	\$4,629,141

5 – Deferral and Variance Accounts

1	1	Description of Deferral and variance accounts
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DESCRIPTION OF DEFERRAL AND VARIANCE ACCOUNTS

In 2008 rebasing decisions the OEB has rejected the request to disposition variance / deferral accounts for the majority if not all LDC applications.

Considering that the RSVAs are monitored quarterly by the OEB for disposition requirements and the generic proceeding to be scheduled in the future, WCHE is not applying to recover or give back any variance account balances in this application.

As we are not proposing to disposition any variance or deferral accounts, balances have not been filed with this application.

<u>Ex.</u>	<u>Tab</u>	<u>Schedule</u>	<u>Contents of Schedule</u>
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6 – Cost of Capital and Rate of Return

1	1	Overview
	2	Capital Structure
	3	Cost of Debt
	4	Return on Equity

OVERVIEW

The purpose of this evidence is to summarize the method and cost of financing the Applicant's capital requirements for the 2009 test years.

Capital Structure

West Coast Huron Energy has a deemed current capital structure of 50% debt, 50% equity, as approved by the Ontario Energy Board in RP-2005-0020, and a return on equity of 9.00%, consistent with the return specified in the Board's Decision in EB-2007-0892 dated April 17th, 2008. West Coast Huron Energy is requesting Board approval of a deemed capital structure of 53.33% debt, 46.67% equity including an equity return of 8.68%.

This change in deemed capital structure complies with Ontario Energy Board's report on cost of Capital and 2nd Generation IRM for Ontario's Electricity Distributors dated December 20th, 2006. The OEB report indicates that Distributors will be required to phase in a 60/40 Debt to Equity capital structure that must be completed by 2010.

Return on Equity

West Coast Huron Energy is requesting an equity return of 8.68% for its 2009 Rates.

Cost of Debt

Exhibit 6, Tab 1, Schedule 3 provides the detailed calculation of West Coast Huron Energy forecast long-term debt cost of 7.25% for 2008 and 7.25% for 2009.

CAPITAL STRUCTURE

CAPITAL STRUCTURE

2006 Board Approved

Elements	\$ Million	Ratio (%)	Cost Rate (%)	Return (%)
Long-term debt	\$1,505,068.00	28.57%	7.25%	7.25%
Unfunded short-term debt	\$353,532.00	6.71%		
Preference shares		0.00%		9.00%
Common equity	\$3,410,092.00	64.72%		9.00%
Total	\$5,268,692.00			

2007 Actual

Elements	\$ Million	Ratio (%)	Cost Rate (%)	Return (%)
Long-term debt	\$1,505,068.00	28.57%	7.25%	7.25%
Unfunded short-term debt	\$353,532.00	6.71%		
Preference shares		0.00%		9.00%
Common equity	\$3,410,092.00	64.72%		9.00%
Total	\$5,268,692.00			

2008 Bridge

Elements	\$ Million	Ratio (%)	Cost Rate (%)	Return (%)
Long-term debt	\$1,505,068.00	31.09%	7.25%	7.25%
Unfunded short-term debt	\$353,532.00	7.30%	4.77%	
Preference shares		0.00%		8.68%
Common equity	\$2,981,938.63	61.60%		8.68%
Total	\$4,840,538.63			

2009 Test

Elements	\$ Million	Ratio (%)	Cost Rate (%)	Return (%)
Long-term debt	\$1,505,068.00	31.09%	7.25%	7.25%
Unfunded short-term debt	\$353,532.00	7.30%	4.77%	
Preference shares		0.00%		8.68%
Common equity	\$3,202,160.91	66.15%		8.68%
Total	\$5,060,760.91			

West Coast Huron Energy Corporation's Debt Equity split shown here for 2009 does not match its deemed amounts for the rate making process. WCHE plans to adjust its actual debt equity split to match the deemed proportion in early 2009 prior to the implementation of its new rates. WCHE is in the process of investigating options for adjusting its Debt Equity split.

COST OF DEBT

COST OF DEBT

	2006 Board Approved			2006 Actual			2007 Actual			2008 Bridge			2009 Test		
	Principle	Carrying Costs	Calculated Cost Rate	Principle	Carrying Costs	Calculated Cost Rate	Principle	Carrying Costs	Calculated Cost Rate	Principle	Carrying Costs	Calculated Cost Rate	Principle	Carrying Costs	Calculated Cost Rate
Long-Term Debt															
Town of Goderich	\$974,454	\$70,648	7.25%	\$974,454	\$70,648	7.25%	\$974,454	\$70,648	7.25%	\$974,454	\$70,648	7.25%	\$974,454	\$70,648	7.25%
Total	\$974,454	\$70,648	7.25%	\$974,454	\$70,648	7.25%	\$974,454	\$70,648	7.25%	\$974,454	\$70,648	7.25%	\$974,454	\$70,648	7.25%

Return on Equity Calculation

<u>Government of Canada Bond Yields</u>	<u>Rate</u>
3-month forecast of the 10 year bond yield	4.60%
12-month forecast of the 10-year bond yield	4.80%
Average actual prior month 30-year bond yield	4.03%
Average actual prior month 10-year bond yield	4.12%
Long Term Canada Bond Forecast	4.61%
Return on Equity	8.68%

Weighted Average Cost of Capital

	Deemed Portion	Effective Rate	Average Cost of Capital
Cost of Debt	53.33%	7.06%	3.77%
Return on Equity	46.67%	8.68%	4.05%
Weighted Average Cost of Capital			7.82%

West Coast Huron Energy is proposing its rates in this application based upon the above noted rates. WCHE will amend these rates closer to the approval of its application based on the rates determined by the Ontario Energy Board in early 2009.

<u>Ex.</u>	<u>Tab</u>	<u>Schedule</u>	<u>Contents of Schedule</u>
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7 - Calculation of Revenue Deficiency or Surplus

1	1	Determination of Net Utility Income and Calculation of Revenue Deficiency or Surplus
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OVERVIEW OF CALCULATION OF REVENUE DEFICIENCY OR SURPLUS

The information in this Exhibit supports West Coast Huron Energy Corporation's request in this Application for an increase in its 2009 Revenue Requirement. WCHE requires a distribution revenue requirement of \$2,541,041 to continue to provide its customers safe reliable supply of electricity, service its debt and pay its deemed PILS.

West Coast Huron Energy Target return on Rate Base is calculated using 46.67% of Rate Base with a target return on Rate base of \$214,007. Utilizing current rates and 2008 forecasted customer data WCHE would expect \$1,892,992 in distribution revenue which creates a revenue deficiency of \$562,312, which grossed up for tax purposes is \$677,484.

This revenue deficiency is in large part attributable to the increase in rate base due to the capital expenditure program in place at WCHE. The rate base has increased by \$517,704 since 2006 rebasing, coupled with this impact is a \$706,980 increase in operating costs since 2006 rebasing.

WCHE's 2008 revenue sufficiency is outlined in detail below in the Determination of Net Utility Income Table.

DETERMINATION OF NET UTILITY INCOME

Determination of Net Utility Income

	Existing Rates	Proposed Rates
Revenue Deficiency		\$677,484
Distribution Revenue	\$1,892,992	\$1,892,992
Other Operating Revenue (Net)	\$92,696	\$92,696
Total Revenue	<u>\$1,985,688</u>	<u>\$2,663,172</u>
Costs and Expenses		
Distribution Costs	\$1,348,700	\$1,348,700
Operation & Maintenance	\$472,550	\$472,550
Depreciation & Amortization	\$343,019	\$343,019
Property & Capital Taxes	\$70,294	\$70,294
Interest	\$170,769	\$170,769
Total Costs and Expenses	<u>\$2,405,332</u>	<u>\$2,405,332</u>
Utility Income Before Income Taxes	-\$419,644	\$257,840
Income Taxes	-\$71,339	\$43,833
Utility Income	<u><u>-\$348,304</u></u>	<u><u>\$214,007</u></u>
Rate Base	\$5,282,880	\$5,282,880
Equity Portion	46.6700%	46.6700%
Equity Component of Rate Base	\$2,465,520	\$2,465,520
Target Return on Equity	8.68%	8.68%
Return on Rate Base	\$214,007.16	\$214,007.16
Revenue Sufficiency	-\$562,311.61	\$0.00

8 – Cost Allocation

TAB 1	Schedule 1	Cost Allocation – 2009 Rebasing Application
	Schedule 2	Summary of Results and Proposed Changes

COST ALLOCATION OVERVIEW

Introduction:

In a staff discussion paper released on June 28, 2007, Board Staff provided some guidelines on both the allocation of costs and on general fixed-variable rate design. The starting point for the 2008 allocated costs is the 2006 Cost Allocation Information Filings filed in late 2006 to early 2007.

Board staff suggested the following generic guidelines on page 25 of the June 28 document, note any value below 100% is a subsidization received and anything above 100% is subsidization towards other classes:

- o Residential Class
 - o Revenue to cost ratios between 80% and 120%
- o General Service < 50 kW
 - o Revenue to cost ratios between 80% and 120%
- o Unmetered Scattered Load
 - o Revenue to cost ratios between 80% and 120%
- o General Service > 50 to 4,999 kW
 - o Revenue to cost ratios between 80% and 180%
- o Large Use customers (above 5,000 kW)
 - o Revenue to cost ratios between 80% and 180%
- o Sentinel Light
 - o Revenue to cost ratios between 70% to 120%
- o Street Light
 - o Revenue to cost ratios between 70% to 120%

Background:

The West Coast Huron Energy 2006 Cost Allocation Information Filing produced the following results:

- o Residential Class = 82.39%
- o General Service < 50 kW = 81.66%
- o General Service 50 to 499 kW = 169.08%
- o General Service 500 to 4,999 kW = 371.28%
- o Large Use > 5,000 kW = 108.03%
- o Street Light = 27.82%
- o Sentinel Light = 81.15%
- o Unmetered Scattered Load = 63.57%

The cost allocation portion of this 2009 rebasing application was handled using a four step approach.

SUMMARY OF RESULTS AND PROPOSED CHANGES

Step 1

The first step was to determine the minimum required changes in revenue to cost ratios, by customer class, between the 2006 CA informational filing values compared to the June 28 Board Staff guidelines.

<u>Customer Class</u>	<u>2006 CA RC Ratio</u>	<u>Board Staff RC Target</u>	<u>Minimum Recommended Movement</u>
Residential	82.39%	85% - 115%	2.61%
GS < 50 kW	81.66%	80% - 120%	0.00%
GS 50 to 499 kW	169.08%	80% - 180%	0.00%
GS 3,000 to 4,999 kW	371.28%	80% - 180%	-191.28%
Large Use (above 5,000 kW)	108.03%	80% - 180%	0.00%
Street Light	27.82%	70% - 120%	42.18%
Sentinel Light	81.15%	70% - 120%	0.00%
Unmetered Load	63.57%	80% - 120%	16.43%

Note: West Coast Huron Energy has used the same recommended RC band as with the large use class as demand levels are similar

The process utilized for adjusting revenue to cost ratios was as follows:

1. Adjust the 2006 cost allocation total revenue requirement (distribution revenue plus miscellaneous service charge revenue) calculated by customer class to incorporate the minimum recommended movement as outlined above (e.g. GS < 50 kW class total revenue divided by 144.26 multiplied by 120 = 120% RC%)
2. Calculate class specific adjusted 2006 total revenue requirement and adjust to ensure revenue neutrality (minimum movement's results in a \$114,113 under recovery of distribution revenue which needs to be spread over a selected group of customer classes to ensure revenue neutrality).
3. Upon generating revenue neutral adjusted class specific total revenue requirement, calculate 2006 adjusted % share to LDC 2006 total revenue requirement (see chart below) and use values to allocate 2008 total revenue requirement.
4. Isolate 2008 distribution revenue requirement by class (total revenue requirement less class allocation of miscellaneous revenue) to be used in rate design process.

After implementation, of the above minimum adjustments, the 2006 total revenue requirement was \$114,113 under the 2006 cost allocation distribution revenue

requirement. This \$114,113 is due to the fact that the minimum adjustments are not equal and offsetting. West Coast Huron Energy spread the \$114,113 under recovery to (GS < 50 kW, GS 50 to 999 kW, GS 1,000 to 2,999 kW, GS 3,000 to 4,999 kW and unmetered customer classes) using distribution revenue as an allocation base. After the minimum recommended adjustments and the \$114,113 under recovery adjustment, the specific customer class revenue to cost ratios are as follows:

<u>Customer Class</u>	<u>2006 Adjusted Cost Allocation RC %</u>	<u>2009 Total Revenue Allocation</u>	<u>2009 Total Revenue Requirement</u>
Residential	87.70%	46.54%	\$ 1,218,742
GS < 50 kW	84.26%	16.56%	\$ 433,588
GS 50 to 499 kW	174.79%	16.42%	\$ 429,984
GS 500 to 4,999	180.00%	5.85%	\$ 153,269
Large Use (above 5,000 kW)	111.46%	11.14%	\$ 291,743
Street Light	70.00%	2.89%	\$ 75,706
Sentinel Light	81.27%	0.06%	\$ 1,667
Unmetered Load	120.17%	0.53%	\$ 13,841
Total		100.00%	\$ 2,618,540

The resulting bill impacts from the above revenue to cost ratios did not produce customer impacts outside of the standard 10% threshold that has been previously used by the OEB for evaluating appropriate rate design changes, with the exception of the Street Light and Sentinel Light classes. As these classes were expected to create such a problem due to significant underpayment related to cost causality, no immediate mitigation techniques were utilized.

Step 2

As the minimum adjustments (Board Staff guidelines) did not create any “unacceptable” customer impacts, a second approach to cost allocation was utilized, namely moving everyone to a 100% revenue to cost ratio.

A similar approach was utilized to move all classes to 100% revenue to cost ratios as described in Step 1 above. On a class by class basis, the 2006 cost allocation total revenue value was forced to ensure all classes had a 100% revenue to cost ratio. This determined the % of total revenue requirement that each class should pay for as seen on the following chart. As this process is revenue neutral there was no need for a secondary adjustment as was utilized in step 1 above. A class specific allocation of 2006 total revenue was calculated and utilized to distribute 2008 total revenue requirement.

<u>Customer Class</u>	<u>2006 Adjusted Cost Allocation RC %</u>	<u>2009 Total Revenue Allocation</u>	<u>2009 Total Revenue Requirement</u>
Residential	100%	53.07%	\$ 1,389,634
GS < 50 kW	100%	19.65%	\$ 514,582
GS 50 to 499 kW	100%	9.39%	\$ 245,994
GS 500 to 4,999	100%	3.25%	\$ 85,026
Large Use (above 5,000 kW)	100%	10.00%	\$ 261,741
Street Light	100%	4.12%	\$ 107,995
Sentinel Light	100%	0.08%	\$ 2,051
Unmetered Load	100%	0.44%	\$ 11,517
Total		100.00%	\$ 2,618,540

Upon moving all rate classes to 100% cost allocation West Coast Huron Energy determined that there were too many rate classes that experienced extremely significant rate impacts and determined to move one half of the way to 100% cost allocation and then subsidized the GS>500 to 4,999 kW rate class down to the maximum and Street Lighting class up to the minimum.

Step 3

The third phase of cost allocation utilized by West Coast Huron was to move to one half of the way to 100% cost allocation.

<u>Customer Class</u>	<u>2006 Adjusted Cost Allocation RC %</u>	<u>2009 Total Revenue Allocation</u>	<u>2009 Total Revenue Requirement</u>
Residential	90.91%	48.40%	\$ 1,267,276
GS < 50 kW	90.55%	17.85%	\$ 476,405
GS 50 to 499 kW	136.82%	12.64%	\$ 330,957
GS 500 to 4,999	244.89%	7.65%	\$ 200,356
Large Use (above 5,000 kW)	104.18%	10.40%	\$ 272,247
Street Light	62.99%	2.64%	\$ 69,022
Sentinel Light	90.29%	0.07%	\$ 1,858
Unmetered Load	80.97%	0.36%	\$ 9,419
Total		100.00%	\$ 2,618,540

The resulting revenue to cost ratios did not move the GS>500 to 4,999 kW class down to the maximum and the Street Lighting class up to the minimum. As a result the final step in WCHE's cost allocation was to move both of these classes to within the board approved guidelines.

Step 4

Adjust for GS>500 to 4,999 kW and Street Lighting classes

Adjust for Street Lighting

<u>Customer Class</u>	<u>2006 Adjusted Cost Allocation RC %</u>	<u>2009 Total Revenue Allocation</u>	<u>2009 Total Revenue Requirement</u>
Residential	90.64%	48.32%	\$ 1,263,619
GS < 50 kW	90.28%	17.84%	\$ 466,056
GS 50 to 499 kW	136.40%	12.46%	\$ 330,003
GS 500 to 4,999	244.16%	7.69%	\$ 199,778
Large Use (above 5,000 kW)	103.87%	10.34%	\$ 271,462
Street Light	70.00%	2.92%	\$ 76,378
Sentinel Light	90.03%	0.07%	\$ 1,852
Unmetered Load	80.73%	0.35%	\$ 9,392
Total		100.00%	\$ 2,618,540

Adjust for GS>500 to 4,999 kW Applied for Rate Design

<u>Customer Class</u>	<u>2006 Adjusted Cost Allocation RC %</u>	<u>2009 Total Revenue Allocation</u>	<u>2009 Total Revenue Requirement</u>
Residential	92.69%	49.19%	\$ 1,288,034
GS < 50 kW	92.32%	18.14%	\$ 475,061
GS 50 to 499 kW	136.74%	12.85%	\$ 336,379
GS 500 to 4,999	180.00%	5.84%	\$ 153,044
Large Use (above 5,000 kW)	105.72%	10.57%	\$ 276,707
Street Light	72.09%	2.97%	\$ 77,853
Sentinel Light	92.06%	0.07%	\$ 1,888
Unmetered Load	83.12%	0.37%	\$ 9,573
Total		100.00%	\$ 2,618,540

<u>Customer Class</u>	<u>Board Staff RC Targets</u>	<u>Applied for RC%</u>	<u>Subsidization Value</u>	<u>Total Revenue Allocation</u>	<u>2009 Total Revenue Requirement</u>
Residential	85% - 115%	92.69%	\$ 16,340	49.19%	\$ 1,288,034
GS < 50 kW	80% - 120%	92.32%	\$ 6,027	18.14%	\$ 475,061
GS 50 to 499 kW	80% - 180%	136.74%	\$ 4,267	12.85%	\$ 336,379
GS 500 to 4,999	80% - 180%	180.00%	(\$33,706)	5.84%	\$ 153,044
Large Use (above 5,000 kW)	80% - 180%	105.72%	\$ 3,510	10.57%	\$ 276,707
Street Light	70% - 120%	72.09%	\$ 6,414	2.97%	\$ 77,853
Sentinel Light	70% - 120%	92.06%	\$ 24	0.07%	\$ 1,888
Unmetered Load	80% - 120%	83.12%	\$ 121	0.37%	\$ 9,573
Total				100%	\$ 2,618,540

West Coast Huron Energy proposes moving all rate classes to parity (revenue to cost ratio of 100%), upon the next rebasing window using the appropriate cost allocation guidelines in place at that time.

West Coast Huron Energy is including a sample of customer impacts for reference, full impact analysis can be found in Exhibit 9.

Residential

500

kWh Consumption

	Metric	2008 Bill			2009 Bill			IMPACT		
		Volume	Rate \$	Charge \$	Volume	Rate \$	Charge \$	Change \$	Change %	% of Total Bill
Monthly Service Charge				14.09			14.09	0.00	0.0%	0.0%
Distribution	kWh	500	0.00840	4.20	500	0.02414	12.07	7.87	187.4%	12.0%
Sub-Total				18.29			26.16	7.87	43.0%	12.0%
Regulatory Asset Recovery	kWh	500		0.00	500		0.00	0.00		0.0%
Retail Transmission - Network	kWh	536	0.00390	2.09	523	0.00390	2.04	(0.05)	-2.4%	-0.1%
Retail Transmission - Line and Transformation	kWh	536	0.00410	2.20	523	0.00410	2.15	(0.05)	-2.4%	-0.1%
Wholesale Market Service	kWh	536	0.00520	2.79	523	0.00520	2.72	(0.07)	-2.4%	-0.1%
Rural Rate Protection Charge	kWh	536	0.00100	0.54	523	0.00100	0.52	(0.01)	-2.4%	0.0%
Debt Retirement Charge	kWh	500	0.00700	3.50	500	0.00700	3.50	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	536	0.05450	29.23	523	0.05450	28.52	(0.71)	-2.4%	-1.1%
Total Bill				58.63			65.61	6.98	11.9%	10.6%

Residential

750

kWh Consumption

	Metric	2008 Bill			2009 Bill			IMPACT		
		Volume	Rate \$	Charge \$	Volume	Rate \$	Charge \$	Change \$	Change %	% of Total Bill
Monthly Service Charge				14.09			14.09	0.00	0.0%	0.0%
Distribution	kWh	750	0.00840	6.30	750	0.02414	18.11	11.81	187.4%	12.9%
Sub-Total				20.39			32.20	11.81	57.9%	12.9%
Regulatory Asset Recovery	kWh	750		0.00	750		0.00	0.00		0.0%
Retail Transmission - Network	kWh	804	0.00390	3.14	785	0.00390	3.06	(0.08)	-2.4%	-0.1%
Retail Transmission - Line and Transformation	kWh	804	0.00410	3.30	785	0.00410	3.22	(0.08)	-2.4%	-0.1%
Wholesale Market Service	kWh	804	0.00520	4.18	785	0.00520	4.08	(0.10)	-2.4%	-0.1%
Rural Rate Protection Charge	kWh	804	0.00100	0.80	785	0.00100	0.78	(0.02)	-2.4%	0.0%
Debt Retirement Charge	kWh	750	0.00700	5.25	750	0.00700	5.25	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	804	0.05450	43.84	785	0.05450	42.78	(1.06)	-2.4%	-1.2%
Total Bill				80.91			91.37	10.47	12.9%	11.5%

Residential

1,000

kWh Consumption

	Metric	2008 Bill			2009 Bill			IMPACT		
		Volume	Rate \$	Charge \$	Volume	Rate \$	Charge \$	Change \$	Change %	% of Total Bill
Monthly Service Charge				14.09			14.09	0.00	0.0%	0.0%
Distribution	kWh	1,000	0.00840	8.40	1,000	0.02414	24.14	15.74	187.4%	13.4%
Sub-Total				22.49			38.23	15.74	70.0%	13.4%
Regulatory Asset Recovery	kWh	1,000		0.00	1,000		0.00	0.00		0.0%
Retail Transmission - Network	kWh	1,073	0.00390	4.18	1,047	0.00390	4.08	(0.10)	-2.4%	-0.1%
Retail Transmission - Line and Transformation	kWh	1,073	0.00410	4.40	1,047	0.00410	4.29	(0.11)	-2.4%	-0.1%
Wholesale Market Service	kWh	1,073	0.00520	5.58	1,047	0.00520	5.44	(0.13)	-2.4%	-0.1%
Rural Rate Protection Charge	kWh	1,073	0.00100	1.07	1,047	0.00100	1.05	(0.03)	-2.4%	0.0%
Debt Retirement Charge	kWh	1,000	0.00700	7.00	1,000	0.00700	7.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	1,073	0.05450	58.46	1,047	0.05450	57.04	(1.41)	-2.4%	-1.2%
Total Bill				103.18			117.14	13.96	13.5%	11.9%

GS <50
1,000

kWh Consumption

	Metric	2008 Bill			2009 Bill			IMPACT		
		Volume	Rate \$	Charge \$	Volume	Rate \$	Charge \$	Change \$	Change %	% of Total Bill
Monthly Service Charge				33.46			33.46	0.00	0.0%	0.0%
Distribution	kWh	1,000	0.00520	5.20	1,000	0.01529	15.29	10.09	194.0%	8.0%
Sub-Total				38.66			48.75	10.09	26.1%	8.0%
Regulatory Asset Recovery	kWh	1,000		0.00	1,000		0.00	0.00		0.0%
Retail Transmission - Network	kWh	1,043	0.00360	3.75	1,044	0.00360	3.76	0.00	0.1%	0.0%
Retail Transmission - Line and Transformation	kWh	1,043	0.00370	3.86	1,044	0.00370	3.86	0.00	0.1%	0.0%
Wholesale Market Service	kWh	1,043	0.00520	5.42	1,044	0.00520	5.43	0.00	0.1%	0.0%
Rural Rate Protection Charge	kWh	1,043	0.00100	1.04	1,044	0.00100	1.04	0.00	0.1%	0.0%
Debt Retirement Charge	kWh	1,000	0.00700	7.00	1,000	0.00700	7.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	1,043	0.05450	56.83	1,044	0.05450	56.87	0.05	0.1%	0.0%
Total Bill				116.56			126.71	10.14	8.7%	8.0%

GS <50
2,000

kWh Consumption

	Metric	2008 Bill			2009 Bill			IMPACT		
		Volume	Rate \$	Charge \$	Volume	Rate \$	Charge \$	Change \$	Change %	% of Total Bill
Monthly Service Charge				33.46			33.46	0.00	0.0%	0.0%
Distribution	kWh	2,000	0.00520	10.40	2,000	0.01529	30.57	20.17	194.0%	9.2%
Sub-Total				43.86			64.03	20.17	46.0%	9.2%
Regulatory Asset Recovery	kWh	2,000		0.00	2,000		0.00	0.00		0.0%
Retail Transmission - Network	kWh	2,085	0.00360	7.51	2,087	0.00360	7.51	0.01	0.1%	0.0%
Retail Transmission - Line and Transformation	kWh	2,085	0.00370	7.72	2,087	0.00370	7.72	0.01	0.1%	0.0%
Wholesale Market Service	kWh	2,085	0.00520	10.84	2,087	0.00520	10.85	0.01	0.1%	0.0%
Rural Rate Protection Charge	kWh	2,085	0.00100	2.09	2,087	0.00100	2.09	0.00	0.1%	0.0%
Debt Retirement Charge	kWh	2,000	0.00700	14.00	2,000	0.00700	14.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	2,085	0.05450	113.65	2,087	0.05450	113.75	0.09	0.1%	0.0%
Total Bill				199.67			219.96	20.29	10.2%	9.2%

GS <50
5,000

kWh Consumption

	Metric	2008 Bill			2009 Bill			IMPACT		
		Volume	Rate \$	Charge \$	Volume	Rate \$	Charge \$	Change \$	Change %	% of Total Bill
Monthly Service Charge				33.46			33.46	0.00	0.0%	0.0%
Distribution	kWh	5,000	0.00520	26.00	5,000	0.01529	76.43	50.43	194.0%	10.1%
Sub-Total				59.46			109.89	50.43	84.8%	10.1%
Regulatory Asset Recovery	kWh	5,000		0.00	5,000		0.00	0.00		0.0%
Retail Transmission - Network	kWh	5,214	0.00360	18.77	5,218	0.00360	18.78	0.02	0.1%	0.0%
Retail Transmission - Line and Transformation	kWh	5,214	0.00370	19.29	5,218	0.00370	19.31	0.02	0.1%	0.0%
Wholesale Market Service	kWh	5,214	0.00520	27.11	5,218	0.00520	27.13	0.02	0.1%	0.0%
Rural Rate Protection Charge	kWh	5,214	0.00100	5.21	5,218	0.00100	5.22	0.00	0.1%	0.0%
Debt Retirement Charge	kWh	5,000	0.00700	35.00	5,000	0.00700	35.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	5,214	0.05450	284.14	5,218	0.05450	284.37	0.23	0.1%	0.0%
Total Bill				448.98			499.70	50.72	11.3%	10.2%

GS>50 to 499 kW

55 kW Consumption
15,000 kWh Consumption

	Metric	2008 Bill			2009 Bill			IMPACT		
		Volume	Rate \$	Charge \$	Volume	Rate \$	Charge \$	Change \$	Change %	% of Total Bill
Monthly Service Charge				402.56			402.56	0.00	0.0%	0.0%
Distribution	kW	55	1.06950	58.82	55	1.28803	70.84	12.02	20.4%	0.7%
Sub-Total				461.38			473.40	12.02	2.6%	0.7%
Regulatory Asset Recovery	kW	55		0.00	55		0.00	0.00		0.0%
Retail Transmission - Network	kW	59	1.45850	86.04	58	1.45840	83.95	(2.09)	-2.4%	-0.1%
Retail Transmission - Line and Transformation	kW	59	1.47250	86.87	58	1.47250	84.77	(2.10)	-2.4%	-0.1%
Wholesale Market Service	kWh	16,089	0.00520	83.66	15,700	0.00520	81.64	(2.02)	-2.4%	-0.1%
Rural Rate Protection Charge	kWh	16,089	0.00100	16.09	15,700	0.00100	15.70	(0.39)	-2.4%	0.0%
Debt Retirement Charge	kWh	15,000	0.00700	105.00	15,000	0.00700	105.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	16,089	0.05450	876.85	15,700	0.05450	855.64	(21.21)	-2.4%	-1.2%
Total Bill				1,715.89			1,700.10	(15.79)	-0.9%	-0.9%

GS>50 to 499 kW

125 kW Consumption
20,000 kWh Consumption

	Metric	2008 Bill			2009 Bill			IMPACT		
		Volume	Rate \$	Charge \$	Volume	Rate \$	Charge \$	Change \$	Change %	% of Total Bill
Monthly Service Charge				402.56			402.56	0.00	0.0%	0.0%
Distribution	kW	125	1.06950	133.69	125	1.28803	161.00	27.32	20.4%	1.2%
Sub-Total				536.25			563.56	27.32	5.1%	1.2%
Regulatory Asset Recovery	kW	125		0.00	125		0.00	0.00		0.0%
Retail Transmission - Network	kW	134	1.45850	195.55	131	1.45840	190.81	(4.74)	-2.4%	-0.2%
Retail Transmission - Line and Transformation	kW	134	1.47250	197.43	131	1.47250	192.65	(4.78)	-2.4%	-0.2%
Wholesale Market Service	kWh	21,452	0.00520	111.55	20,933	0.00520	108.85	(2.70)	-2.4%	-0.1%
Rural Rate Protection Charge	kWh	21,452	0.00100	21.45	20,933	0.00100	20.93	(0.52)	-2.4%	0.0%
Debt Retirement Charge	kWh	20,000	0.00700	140.00	20,000	0.00700	140.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	21,452	0.05450	1,169.13	20,933	0.05450	1,140.85	(28.28)	-2.4%	-1.2%
Total Bill				2,371.36			2,357.66	(13.70)	-0.6%	-0.6%

GS>50 to 499 kW

250 kW Consumption
50,000 kWh Consumption

	Metric	2008 Bill			2009 Bill			IMPACT		
		Volume	Rate \$	Charge \$	Volume	Rate \$	Charge \$	Change \$	Change %	% of Total Bill
Monthly Service Charge				402.56			402.56	0.00	0.0%	0.0%
Distribution	kW	250	1.06950	267.38	250	1.28803	322.01	54.63	20.4%	1.1%
Sub-Total				669.94			724.57	54.63	8.2%	1.1%
Regulatory Asset Recovery	kW	250		0.00	250		0.00	0.00		0.0%
Retail Transmission - Network	kW	268	1.45850	391.10	262	1.45840	381.61	(9.49)	-2.4%	-0.2%
Retail Transmission - Line and Transformation	kW	268	1.47250	394.85	262	1.47250	385.30	(9.55)	-2.4%	-0.2%
Wholesale Market Service	kWh	53,630	0.00520	278.88	52,333	0.00520	272.13	(6.75)	-2.4%	-0.1%
Rural Rate Protection Charge	kWh	53,630	0.00100	53.63	52,333	0.00100	52.33	(1.30)	-2.4%	0.0%
Debt Retirement Charge	kWh	50,000	0.00700	350.00	50,000	0.00700	350.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	53,630	0.05450	2,922.84	52,333	0.05450	2,852.13	(70.70)	-2.4%	-1.4%
Total Bill				5,061.22			5,018.07	(43.15)	-0.9%	-0.9%

9 - Rate Design

TAB	1	Schedule 1	Rate Design Overview
		Schedule 2	Existing Rate Classes
		Schedule 3	Existing Rate Schedule
		Schedule 4	Proposed Rate Classes if different than existing
		Schedule 5	Proposed Rate Schedule
		Schedule 6	Summary of Proposed Rate Schedule
		Schedule 7	Reconciliation of Rate Class Revenue to total Revenue Requirement
		Schedule 8	Rate Impacts
		Schedule 9	Proposed Changes to Terms and Conditions of Service

RATE DESIGN OVERVIEW - 2008 Rebasing Application

In the June 28, 2007 Staff discussion paper section 4.4 recommends a range of the floor value equal to the class specific avoided costs and a ceiling value equal to 120% of the minimum system with PLCC adjustment outlined in the 2006 CA informational filing, or current approved rate. Below is a summary of the floor, ceiling and applied for values contained in the West Coast Huron Energy application.

Customer Class	Floor Value	Ceiling Value	120% Ceiling Value	Current Rate	Applied for Value
Residential	\$4.83	\$13.80	\$16.56	\$14.09	\$14.09
GS < 50 kW	\$17.45	\$31.48	\$37.78	\$33.46	\$33.46
GS 50 to 499 kW	\$54.44	\$80.36	\$96.43	\$402.56	\$402.56
GS 500 to 4,999 kW	\$119.05	\$204.53	\$245.44	\$3,476.42	\$2,322.41
Large Use	\$166.30	\$262.82	\$315.39	\$8,652.72	\$8,652.72
Street Light	\$0.57	\$9.41	\$11.29	\$0.71	\$1.95
Sentinel Light	\$0.41	\$3.55	\$4.26	\$5.64	\$5.64
Unmetered Load	\$9.17	\$19.80	\$23.76	\$33.47	\$33.47

In general, West Coast Huron Energy has followed the guidelines outlined by Board Staff in the June 28 communication. The exception to these guidelines is the GS 500 to 4,999 kW class.

Historically the issue of fixed / variable rates has been widely debated since the commencement of the Ontario Government White Paper with arguments made for entirely fixed distribution rates to the fixed / variable structure currently employed and in the near future with a further reduction to values between the floor / ceiling as guided by Board Staff.

Currently West Coast Huron Energy collects the following fixed charge from the identified customer classes:

- o General Service 500 to 4,999 kW = \$3,476.42 representing 4 customers

In an effort to stabilize revenues, West Coast Huron Energy has elected to move the General Service 50 to 999 kW class Regular fixed charge to the same fixed variable split for this rate class as was applied in the 2006 EDR application. This rate class as noted in Exhibit 8 is benefiting from the change in cost allocation as its revenue to cost ratio is moving significantly closer to 100%.

EXISTING RATE CLASSES

Residential

This classification refers to the supply of electrical energy to customers residing in residential dwelling units.

General Service Less than 50 kW

This classification 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 of the distributor's Conditions of Service that require centralized bulk metering. General Service buildings are defined as buildings that are used for purposes

General Service 50 to 499 kW

This classification refers to the supply of electrical energy to General Service Customers requiring a connection with a connected load or whose average monthly maximum demand used for billing purposes is equal to or greater than 50 kW but less than 500 kW.

General Service 500 to 4,999 kW

This classification refers to the supply of electrical energy to General Service Customers requiring a connection with a connected load or whose average monthly maximum demand used for billing purposes is equal to or greater than 500 kW but less than 5,000 kW.

Large Use

This classification refers to the supply of electrical energy to General Service Customers requiring a connection with a connected load or 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, 5,000 kW.

Unmetered Scattered Load

This classification refers 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

Sentinel Lighting

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

Street Lighting

This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of transportation and private roadway lighting, 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

Residential

	UOM	Rate
Service Charge	\$	\$14.0900
Distribution Volumetric Rate	\$/kWh	\$0.0084
Retail Transmission Rate – Network Service Rate	\$/kWh	\$0.0039
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	\$0.0041
Wholesale Market Service Rate	\$/kWh	\$0.0052
Rural Rate Protection Charge	\$/kWh	\$0.0010
Regulated Price Plan – Administration Charge	\$	\$0.2500

GS<50 kW

Service Charge	\$	\$33.4600
Distribution Volumetric Rate	\$/kWh	\$0.0052
Retail Transmission Rate – Network Service Rate	\$/kWh	\$0.0036
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	\$0.0037
Wholesale Market Service Rate	\$/kWh	\$0.0052
Rural Rate Protection Charge	\$/kWh	\$0.0010
Regulated Price Plan – Administration Charge	\$	\$0.2500

GS>50 to 499 kW

Service Charge	\$	\$402.5600
Distribution Volumetric Rate	\$/kW	\$1.0695
Retail Transmission Rate – Network Service Rate	\$/kW	\$1.4585
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	\$1.4725
Wholesale Market Service Rate	\$/kWh	\$0.0052
Rural Rate Protection Charge	\$/kWh	\$0.0010
Regulated Price Plan – Administration Charge	\$	\$0.2500

GS>500 to 4999 kW

Service Charge	\$	\$3,476.4200
Distribution Volumetric Rate	\$/kW	\$1.4725
Retail Transmission Rate – Network Service Rate	\$/kW	\$1.5491
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	\$1.6142
Wholesale Market Service Rate	\$/kWh	\$0.0052
Rural Rate Protection Charge	\$/kWh	\$0.0010
Regulated Price Plan – Administration Charge	\$	\$0.2500

Large Use

Service Charge	\$	\$8,652.7200
Distribution Volumetric Rate	\$/kW	\$0.7592
Retail Transmission Rate – Network Service Rate	\$/kW	\$1.7153
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	\$1.8459
Wholesale Market Service Rate	\$/kWh	\$0.0052
Rural Rate Protection Charge	\$/kWh	\$0.0010
Regulated Price Plan – Administration Charge	\$	\$0.2500

Street Lighting

Service Charge	\$	\$0.7100
Distribution Volumetric Rate	\$/kW	\$2.6563
Retail Transmission Rate – Network Service Rate	\$/kW	\$1.1000
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	\$1.1384
Wholesale Market Service Rate	\$/kWh	\$0.0052
Rural Rate Protection Charge	\$/kWh	\$0.0010
Regulated Price Plan – Administration Charge	\$	\$0.2500

Sentinel Lighting

Service Charge	\$	\$5.6400
Distribution Volumetric Rate	\$/kW	\$4.2206
Retail Transmission Rate – Network Service Rate	\$/kW	\$1.1056
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	\$1.1621
Wholesale Market Service Rate	\$/kWh	\$0.0052
Rural Rate Protection Charge	\$/kWh	\$0.0010
Regulated Price Plan – Administration Charge	\$	\$0.2500

Unmetered Scattered Load

	\$	\$33.4700
Distribution Volumetric Rate	\$/kWh	\$0.0052
Retail Transmission Rate – Network Service Rate	\$/kWh	\$0.0036
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	\$0.0037
Wholesale Market Service Rate	\$/kWh	\$0.0052
Rural Rate Protection Charge	\$/kWh	\$0.0010
Regulated Price Plan – Administration Charge	\$	\$0.2500

PROPOSED RATE CLASSES IF DIFFERENT THAN EXISTING

West Coast Huron Energy Powerlines proposes no change to its rate classes as approved in its current rates.

PROPOSED RATE SCHEDULE

Residential	UOM	2009
Service Charge	\$	\$14.0900
Distribution Volumetric Rate	\$/kWh	\$0.0241
Retail Transmission Rate – Network Service Rate	\$/kWh	\$0.0039
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	\$0.0041
Wholesale Market Service Rate	\$/kWh	\$0.0052
Rural Rate Protection Charge	\$/kWh	\$0.0010
Regulated Price Plan – Administration Charge	\$	\$0.2500
GS<50 kW		2009
Service Charge	\$	\$33.4600
Distribution Volumetric Rate	\$/kWh	\$0.0153
Retail Transmission Rate – Network Service Rate	\$/kWh	\$0.0036
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	\$0.0037
Wholesale Market Service Rate	\$/kWh	\$0.0052
Rural Rate Protection Charge	\$/kWh	\$0.0010
Regulated Price Plan – Administration Charge	\$	\$0.2500
GS>50 to 499 kW		2009
Service Charge	\$	\$402.5600
Distribution Volumetric Rate	\$/kW	\$1.2880
Retail Transmission Rate – Network Service Rate	\$/kW	\$1.4585
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	\$1.4725
Wholesale Market Service Rate	\$/kWh	\$0.0052
Rural Rate Protection Charge	\$/kWh	\$0.0010
Regulated Price Plan – Administration Charge	\$	\$0.2500
GS>500 to 4999 kW		2009
Service Charge	\$	\$2,322.4059
Distribution Volumetric Rate	\$/kW	\$1.4575
Retail Transmission Rate – Network Service Rate	\$/kW	\$1.5491
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	\$1.6142
Wholesale Market Service Rate	\$/kWh	\$0.0052
Rural Rate Protection Charge	\$/kWh	\$0.0010
Regulated Price Plan – Administration Charge	\$	\$0.2500

Large Use		2009
Service Charge	\$	\$8,652.7200
Distribution Volumetric Rate	\$/kW	\$1.8568
Retail Transmission Rate – Network Service Rate	\$/kW	\$1.7153
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	\$1.8459
Wholesale Market Service Rate	\$/kWh	\$0.0052
Rural Rate Protection Charge	\$/kWh	\$0.0010
Regulated Price Plan – Administration Charge	\$	\$0.2500
Street Lighting		2009
Service Charge	\$	\$1.9458
Distribution Volumetric Rate	\$/kW	\$16.6634
Retail Transmission Rate – Network Service Rate	\$/kW	\$1.1000
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	\$1.1384
Wholesale Market Service Rate	\$/kWh	\$0.0052
Rural Rate Protection Charge	\$/kWh	\$0.0010
Regulated Price Plan – Administration Charge	\$	\$0.2500
Sentinel Lighting		2009
Service Charge	\$	\$5.6400
Distribution Volumetric Rate	\$/kW	\$14.6506
Retail Transmission Rate – Network Service Rate	\$/kW	\$1.1056
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	\$1.1621
Wholesale Market Service Rate	\$/kWh	\$0.0052
Rural Rate Protection Charge	\$/kWh	\$0.0010
Regulated Price Plan – Administration Charge	\$	\$0.2500
Unmetered Scattered Load		2009
Service Charge	\$	\$33.4700
Distribution Volumetric Rate	\$/kWh	\$0.0341
Retail Transmission Rate – Network Service Rate	\$/kWh	\$0.0036
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	\$0.0037
Wholesale Market Service Rate	\$/kWh	\$0.0052
Rural Rate Protection Charge	\$/kWh	\$0.0010
Regulated Price Plan – Administration Charge	\$	\$0.2500

SUMMARY OF PROPOSED RATE SCHEDULE

The following is a summary of the proposed changes to West Coast Huron Energy rates for the 2009 test year. The Applicant is forecasting a distribution related delivery deficiency for the 2008 test year of \$549,686.98.

The impact on each rate class is described below.

Residential:

The proposed changes to Residential are summarized below.

	2006 Board Approved	2008 Proposed	% change
Service Charge	\$14.09	\$14.09	0.00%
Distribution Volumetric Rate	\$0.0084	\$0.0241	187.39%

Due to the change in cost allocation WCHE has experienced a significant increase to the costs allocated to the residential class. WCHE attempted to adjust the fixed cost recovery through the monthly fixed charge in order to mitigate the impact of cost allocation. However, after multiple iterations WCHE determined that not changing the current approved fixed charge and recovering the increase in distribution revenue through variable rates allows the customer to control their costs through reduced consumption. If WCHE were to adjust its fixed variable split to the percentages approved in the 2006 EDR the low consumption customers would experience rate impacts that are well outside the tolerance levels suggested by the OEB. The net impact of the changes to cost allocation is an increase in the revenue-to-cost ratios for Residential customers (from 82.39% to 92.69%).

The impact on a typical residential customer is an increase of 57.9% on the delivery component of the bill or \$10.47. The overall bill impact on a typical Residential customer is shown in detail in Exhibit 9, Tab 1, Schedule 9.

GS<50 kW:

The proposed changes to GS<50 kW are summarized below.

	2006 Board Approved	2008 Proposed	% change
Service Charge	\$33.46	\$33.46	0.00%
Distribution Volumetric Rate	\$0.0052	\$0.0153	193.97%

Due to the change in cost allocation WCHE has experienced a significant increase to the costs allocated to the residential class. WCHE attempted to adjust the fixed cost recovery through the monthly fixed charge in order to mitigate the impact of cost allocation. However, after multiple iterations WCHE determined that not changing the current approved fixed charge and recovering the increase in distribution revenue through variable rates allows the customer to control their costs through reduced consumption. If WCHE were to adjust its fixed variable split to the percentages approved in the 2006 EDR the low consumption customers would experience rate impacts that are well outside the tolerance levels suggested by the OEB. The net impact

of the changes to cost allocation is an increase in the revenue-to-cost ratios for Residential customers (from 81.66% to 92.20%).

The impact on a typical GS<50 kW customer is an increase of 46.0% on the delivery component of the bill. The overall bill impact on a typical GS<50 kW customer is shown in detail in Exhibit 9, Tab 1, Schedule 9.

GS>50 to 499 kW:

The proposed changes to GS>50 to 999 kW are summarized below.

	2006 Board Approved	2008 Proposed	% change
Service Charge	\$402.56	\$402.56	0.00%
Distribution Volumetric Rate	\$1.0695	\$1.2880	10.43%

Since the GS>50 to 499 kW class already had rates greater than 120% of the ceiling fixed price and the fixed variable split resulting from the 2006 EDR fixed charge is similar to the fixed variable split of the EDR process. WCHE determined that it would retain its current fixed charge in the 2009 rate process since when factoring in the change in loss factor this rate class will experience a reduction in its rates. The net impact of the change in cost allocation is a decrease in the revenue-to-cost ratios for GS.50 to 499 kW customers (from 169.08% to 136.74%).

The impact on a typical GS>50 to 499 kW customer is an increase of 5.1% on the delivery component of the bill. The overall bill impact on a typical GS>50 to 499 kW customer is shown in detail in Exhibit 9, Tab 1, Schedule 9.

GS>500 to 4999 kW:

The proposed changes to GS>500 to 4999 kW are summarized below.

	2006 Board Approved	2008 Proposed	% change
Service Charge	\$3,476.42	\$2,322.41	-33.20%
Distribution Volumetric Rate	\$1.4725	\$1.4575	-1.02%

In order to adjust the fixed cost recovery through the monthly fixed charge, WCHE is proposing to decrease the monthly customer charge by \$1,154.01 in the 2009 test year, in order to maintain the same fixed variable split that was approved in the 2006 EDR. The net impact of these changes is a decrease in the revenue-to-cost ratios for GS>500 to 4999 kW customers (from 371.28% to 180.00%).

The impact on a typical GS>500 to 4999 kW customer is a decrease of 20.0% on the delivery component of the bill. The overall bill impact on a typical GS>1000 to 2999 kW customer is shown in detail in Exhibit 9, Tab 1, Schedule 9.

Large Use:

The proposed changes to Large Use are summarized below.

	2006 Board Approved	2008 Proposed	% change
Service Charge	\$8,652.72	\$8,652.72	0.00%
Distribution Volumetric Rate	\$0.7592	\$1.8568	144.57%

Since the GS>50 to 499 kW class already had rates greater than 120% of the ceiling fixed price and the fixed variable split is significantly lower than that used in the 2006 EDR process, WCHE determined that it would retain its current fixed charge in the 2009 rate process as opposed to increasing the fixed charge for this customer class. The net impact of the change in cost allocation is an increase in the revenue-to-cost ratios for Large Use customers (from 108.03% to 105.72%).

The impact on a typical Large Use customer is an increase of 50.0% on the delivery component of the bill. The overall bill impact on a typical Large Use customer is shown in detail in Exhibit 9, Tab 1, Schedule 9.

Street Lighting:

The proposed changes to Street Lighting are summarized below.

	2006 Board Approved	2008 Proposed	% change
Service Charge	\$0.71	\$1.95	174.05%
Distribution Volumetric Rate	\$2.6563	\$16.6634	527.32%

Explanation; In order to adjust the fixed cost recovery through the monthly fixed charge; WCHE is proposing to increase the monthly customer charge by \$1.24 in the 2009 test year. The net impact of these changes is an increase in the revenue-to-cost ratios for Street Lighting connections (from 27.82% to 72.09%).

The impact on a typical Street Lighting connection is an increase of 434.5% on the delivery component of the bill. The overall bill impact on a typical Street Lighting connection is shown in detail in Exhibit 9, Tab 1, Schedule 9.

Sentinel Lighting:

The proposed changes to Sentinel Lighting are summarized below.

	2006 Board Approved	2008 Proposed	% change
Service Charge	\$5.64	\$5.64	0.00%
Distribution Volumetric Rate	\$4.2206	\$14.6506	247.12%

Since the GS>50 to 499 kW class already had rates greater than 120% of the ceiling fixed price and the fixed variable split resulting from the 2006 EDR fixed charge is similar to the fixed variable split of the EDR process. WCHE determined that it would retain its current fixed charge in the 2009 rate process as opposed to increasing the fixed charge for this customer class. The net impact of the change in cost allocation is a decrease in the revenue-to-cost ratios for GS.50 to 499 kW customers (from 81.15% to 92.06%).

The impact on a typical Sentinel Lighting customer is an increase of 88.8% on the delivery component of the bill. The overall bill impact on a typical Sentinel Lighting customer is shown in detail in Exhibit 9, Tab 1, Schedule 9.

Unmetered Scattered Load:

The proposed changes to Unmetered Scattered Load are summarized below.

	2006 Board Approved	2008 Proposed	% change
Service Charge	\$33.47	\$33.47	0.00%
Distribution Volumetric Rate	\$0.0052	\$0.0341	555.54%

Since the GS>50 to 499 kW class already had rates greater than 120% of the ceiling fixed price and the fixed variable split resulting from the 2006 EDR fixed charge is similar to the fixed variable split of the EDR process. WCHE determined that it would retain its current fixed charge in the 2009 rate process as opposed to increasing the fixed charge for this customer class. The net impact of these changes is an increase in the revenue-to-cost ratios for Unmetered Scattered Load customers (from 63.57% to 83.12%).

The impact on a typical Unmetered Scattered Load customer is a decrease of 47.0% on the delivery component of the bill. The overall bill impact on a typical Unmetered Scattered Load customer is shown in detail in Exhibit 9, Tab 1, Schedule 9.

**RECONCILIATION OF RATE CLASS REVENUE TO TOTAL REVENUE
REQUIREMENT**

		A	B	A+B
Distribution Revenue Requirement		\$ 2,541,040.77	Transformer Allowance Recovery	
Cost allocation results				
Residential	49.19%	\$ 1,249,913.04		\$ 1,249,913.04
GS < 50 kW	18.14%	\$ 461,000.93		\$ 461,000.93
GS>50 to 499 kW	12.85%	\$ 326,423.12	\$ 26,820.40	\$ 353,243.52
GS>500 kW to 4999 kW	5.84%	\$ 148,514.77	\$ 25,915.20	\$ 174,429.97
Large Use	10.57%	\$ 268,517.45	\$ 78,621.60	\$ 347,139.05
Sentinel Lighting	0.07%	\$ 1,832.13		\$ 1,832.13
Street Lights	2.97%	\$ 75,549.25		\$ 75,549.25
Unmetered	0.37%	\$ 9,290.07		\$ 9,290.07
Total	100.00%	\$ 2,541,040.77	\$ 131,357.20	\$ 2,672,397.97

	Customers	Consumption	Proposed	Proposed	Distribution
	(Year-End)	(kWh / KW)	Fixed	Variable	Revenues (\$)
			Charge	Charge	
Residential	3,356	28,270,944	\$14.09	\$0.0241	\$1,249,913.04
GS<50	522	16,446,654	\$33.46	\$0.0153	\$461,000.93
GS>50 to 499 kW	51	82,977	\$402.56	\$1.2880	\$353,243.52
GS>500 kW to 4999 kW	4	43,192	\$2,322.41	\$1.4575	\$174,429.97
Large Use	1	131,036	\$8,652.46	\$1.8568	\$347,139.05
Unmetered Scattered Load	9	166,491	\$33.47	\$0.0341	\$9,290.07
Sentinel Lighting	13	65	\$5.64	\$14.6506	\$1,832.13
Street Lighting	1,333	2,666	\$1.95	\$16.6634	\$75,549.25
TOTAL	5,289				\$2,672,397.97

RATE IMPACTS

This exhibit 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.

The total bill impacts are calculated for the average customer per residential rate class and for General Service Classes at certain levels of consumption. The rates are assessed on the basis of moving to the proposed distribution rates derived in Exhibit 9, Tab 1, Schedule 5. The total bill impacts are premised on the distribution rates arising from the new revenue requirements.

RATE IMPACTS

Residential

100

kWh Consumption

	Metric	2008 Bill			2009 Bill			IMPACT		
		Volume	Rate \$	Charge \$	Volume	Rate \$	Charge \$	Change \$	Change %	% of Total Bill
Monthly Service Charge				13.83			14.09	0.26	1.9%	1.1%
Distribution	kWh	100	0.00840	0.84	100	0.02414	2.41	1.57	187.4%	6.5%
Sub-Total				14.67			16.50	1.83	12.5%	7.5%
Regulatory Asset Recovery	kWh	100		0.00	100		0.00	0.00		0.0%
Retail Transmission - Network	kWh	107	0.00390	0.42	105	0.00390	0.41	(0.01)	-2.4%	0.0%
Retail Transmission - Line and Transformation	kWh	107	0.00410	0.44	105	0.00410	0.43	(0.01)	-2.4%	0.0%
Wholesale Market Service	kWh	107	0.00520	0.56	105	0.00520	0.54	(0.01)	-2.4%	-0.1%
Rural Rate Protection Charge	kWh	107	0.00100	0.11	105	0.00100	0.10	(0.00)	-2.4%	0.0%
Debt Retirement Charge	kWh	100	0.00700	0.70	100	0.00700	0.70	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	107	0.05450	5.85	105	0.05450	5.70	(0.14)	-2.4%	-0.6%
Total Bill				22.74			24.39	1.66	7.3%	6.8%

Residential

250

kWh Consumption

	Metric	2008 Bill			2009 Bill			IMPACT		
		Volume	Rate \$	Charge \$	Volume	Rate \$	Charge \$	Change \$	Change %	% of Total Bill
Monthly Service Charge				13.83			14.09	0.26	1.9%	0.7%
Distribution	kWh	250	0.00840	2.10	250	0.02414	6.04	3.94	187.4%	9.9%
Sub-Total				15.93			20.13	4.20	26.3%	10.5%
Regulatory Asset Recovery	kWh	250		0.00	100		0.00	0.00		0.0%
Retail Transmission - Network	kWh	268	0.00390	1.05	262	0.00390	1.02	(0.03)	-2.4%	-0.1%
Retail Transmission - Line and Transformation	kWh	268	0.00410	1.10	262	0.00410	1.07	(0.03)	-2.4%	-0.1%
Wholesale Market Service	kWh	268	0.00520	1.39	262	0.00520	1.36	(0.03)	-2.4%	-0.1%
Rural Rate Protection Charge	kWh	268	0.00100	0.27	262	0.00100	0.26	(0.01)	-2.4%	0.0%
Debt Retirement Charge	kWh	250	0.00700	1.75	250	0.00700	1.75	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	268	0.05450	14.61	262	0.05450	14.26	(0.35)	-2.4%	-0.9%
Total Bill				36.10			39.85	3.75	10.4%	9.4%

Residential

500

kWh Consumption

	Metric	2008 Bill			2009 Bill			IMPACT		
		Volume	Rate \$	Charge \$	Volume	Rate \$	Charge \$	Change \$	Change %	% of Total Bill
Monthly Service Charge				13.83			14.09	0.26	1.9%	0.4%
Distribution	kWh	500	0.00840	4.20	500	0.02414	12.07	7.87	187.4%	12.0%
Sub-Total				18.03			26.16	8.13	45.1%	12.4%
Regulatory Asset Recovery	kWh	500		0.00	500		0.00	0.00		0.0%
Retail Transmission - Network	kWh	536	0.00390	2.09	523	0.00390	2.04	(0.05)	-2.4%	-0.1%
Retail Transmission - Line and Transformation	kWh	536	0.00410	2.20	523	0.00410	2.15	(0.05)	-2.4%	-0.1%
Wholesale Market Service	kWh	536	0.00520	2.79	523	0.00520	2.72	(0.07)	-2.4%	-0.1%
Rural Rate Protection Charge	kWh	536	0.00100	0.54	523	0.00100	0.52	(0.01)	-2.4%	0.0%
Debt Retirement Charge	kWh	500	0.00700	3.50	500	0.00700	3.50	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	536	0.05450	29.23	523	0.05450	28.52	(0.71)	-2.4%	-1.1%
Total Bill				58.37			65.61	7.24	12.4%	11.0%

Residential

750

kWh Consumption

	Metric	2008 Bill			2009 Bill			IMPACT		
		Volume	Rate \$	Charge \$	Volume	Rate \$	Charge \$	Change \$	Change %	% of Total Bill
Monthly Service Charge				13.83			14.09	0.26	1.9%	0.3%
Distribution	kWh	750	0.00840	6.30	750	0.02414	18.11	11.81	187.4%	12.9%
Sub-Total				20.13			32.20	12.07	59.9%	13.2%
Regulatory Asset Recovery	kWh	750		0.00	750		0.00	0.00		0.0%
Retail Transmission - Network	kWh	804	0.00390	3.14	785	0.00390	3.06	(0.08)	-2.4%	-0.1%
Retail Transmission - Line and Transformation	kWh	804	0.00410	3.30	785	0.00410	3.22	(0.08)	-2.4%	-0.1%
Wholesale Market Service	kWh	804	0.00520	4.18	785	0.00520	4.08	(0.10)	-2.4%	-0.1%
Rural Rate Protection Charge	kWh	804	0.00100	0.80	785	0.00100	0.78	(0.02)	-2.4%	0.0%
Debt Retirement Charge	kWh	750	0.00700	5.25	750	0.00700	5.25	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	804	0.05450	43.84	785	0.05450	42.78	(1.06)	-2.4%	-1.2%
Total Bill				80.65			91.37	10.73	13.3%	11.7%

Residential

1,000

kWh Consumption

	Metric	2008 Bill			2009 Bill			IMPACT		
		Volume	Rate \$	Charge \$	Volume	Rate \$	Charge \$	Change \$	Change %	% of Total Bill
Monthly Service Charge				13.83			14.09	0.26	1.9%	0.2%
Distribution	kWh	1,000	0.00840	8.40	1,000	0.02414	24.14	15.74	187.4%	13.4%
Sub-Total				22.23			38.23	16.00	72.0%	13.7%
Regulatory Asset Recovery	kWh	1,000		0.00	1,000		0.00	0.00		0.0%
Retail Transmission - Network	kWh	1,073	0.00390	4.18	1,047	0.00390	4.08	(0.10)	-2.4%	-0.1%
Retail Transmission - Line and Transformation	kWh	1,073	0.00410	4.40	1,047	0.00410	4.29	(0.11)	-2.4%	-0.1%
Wholesale Market Service	kWh	1,073	0.00520	5.58	1,047	0.00520	5.44	(0.13)	-2.4%	-0.1%
Rural Rate Protection Charge	kWh	1,073	0.00100	1.07	1,047	0.00100	1.05	(0.03)	-2.4%	0.0%
Debt Retirement Charge	kWh	1,000	0.00700	7.00	1,000	0.00700	7.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	1,073	0.05450	58.46	1,047	0.05450	57.04	(1.41)	-2.4%	-1.2%
Total Bill				102.92			117.14	14.22	13.8%	12.1%

Residential

1,500

kWh Consumption

	Metric	2008 Bill			2009 Bill			IMPACT		
		Volume	Rate \$	Charge \$	Volume	Rate \$	Charge \$	Change \$	Change %	% of Total Bill
Monthly Service Charge				13.83			14.09	0.26	1.9%	0.2%
Distribution	kWh	1,500	0.00840	12.60	1,500	0.02414	36.21	23.61	187.4%	14.0%
Sub-Total				26.43			50.30	23.87	90.3%	14.2%
Regulatory Asset Recovery	kWh	1,500		0.00	1,500		0.00	0.00		0.0%
Retail Transmission - Network	kWh	1,609	0.00390	6.27	1,570	0.00390	6.12	(0.15)	-2.4%	-0.1%
Retail Transmission - Line and Transformation	kWh	1,609	0.00410	6.60	1,570	0.00410	6.44	(0.16)	-2.4%	-0.1%
Wholesale Market Service	kWh	1,609	0.00520	8.37	1,570	0.00520	8.16	(0.20)	-2.4%	-0.1%
Rural Rate Protection Charge	kWh	1,609	0.00100	1.61	1,570	0.00100	1.57	(0.04)	-2.4%	0.0%
Debt Retirement Charge	kWh	1,500	0.00700	10.50	1,500	0.00700	10.50	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	1,609	0.05450	87.69	1,570	0.05450	85.56	(2.12)	-2.4%	-1.3%
Total Bill				147.46			168.66	21.20	14.4%	12.6%

Residential
2,000

kWh Consumption

	Metric	2008 Bill			2009 Bill			IMPACT		
		Volume	Rate \$	Charge \$	Volume	Rate \$	Charge \$	Change \$	Change %	% of Total Bill
Monthly Service Charge				13.83			14.09	0.26	1.9%	0.1%
Distribution	kWh	2,000	0.00840	16.80	2,000	0.02414	48.28	31.48	187.4%	14.3%
Sub-Total				30.63			62.37	31.74	103.6%	14.4%
Regulatory Asset Recovery	kWh	2,000		0.00	2,000		0.00	0.00		0.0%
Retail Transmission - Network	kWh	2,145	0.00390	8.37	2,093	0.00390	8.16	(0.20)	-2.4%	-0.1%
Retail Transmission - Line and Transformation	kWh	2,145	0.00410	8.80	2,093	0.00410	8.58	(0.21)	-2.4%	-0.1%
Wholesale Market Service	kWh	2,145	0.00520	11.16	2,093	0.00520	10.89	(0.27)	-2.4%	-0.1%
Rural Rate Protection Charge	kWh	2,145	0.00100	2.15	2,093	0.00100	2.09	(0.05)	-2.4%	0.0%
Debt Retirement Charge	kWh	2,000	0.00700	14.00	2,000	0.00700	14.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	2,145	0.05450	116.91	2,093	0.05450	114.09	(2.83)	-2.4%	-1.3%
Total Bill				192.01			220.18	28.18	14.7%	12.8%

GS <50
1,000

kWh Consumption

	Metric	2008 Bill			2009 Bill			IMPACT		
		Volume	Rate \$	Charge \$	Volume	Rate \$	Charge \$	Change \$	Change %	% of Total Bill
Monthly Service Charge				33.20			33.46	0.26	0.8%	0.2%
Distribution	kWh	1,000	0.00520	5.20	1,000	0.01529	15.29	10.09	194.0%	7.9%
Sub-Total				38.40			48.75	10.35	26.9%	8.2%
Regulatory Asset Recovery	kWh	1,000		0.00	1,000		0.00	0.00		0.0%
Retail Transmission - Network	kWh	1,073	0.00360	3.86	1,047	0.00360	3.77	(0.09)	-2.4%	-0.1%
Retail Transmission - Line and Transformation	kWh	1,073	0.00370	3.97	1,047	0.00370	3.87	(0.10)	-2.4%	-0.1%
Wholesale Market Service	kWh	1,073	0.00520	5.58	1,047	0.00520	5.44	(0.13)	-2.4%	-0.1%
Rural Rate Protection Charge	kWh	1,073	0.00100	1.07	1,047	0.00100	1.05	(0.03)	-2.4%	0.0%
Debt Retirement Charge	kWh	1,000	0.00700	7.00	1,000	0.00700	7.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	1,073	0.05450	58.46	1,047	0.05450	57.04	(1.41)	-2.4%	-1.1%
Total Bill				118.34			126.92	8.58	7.3%	6.8%

GS <50
2,000

kWh Consumption

	Metric	2008 Bill			2009 Bill			IMPACT		
		Volume	Rate \$	Charge \$	Volume	Rate \$	Charge \$	Change \$	Change %	% of Total Bill
Monthly Service Charge				33.20			33.46	0.26	0.8%	0.1%
Distribution	kWh	2,000	0.00520	10.40	2,000	0.01529	30.57	20.17	194.0%	9.2%
Sub-Total				43.60			64.03	20.43	46.9%	9.3%
Regulatory Asset Recovery	kWh	2,000		0.00	2,000		0.00	0.00		0.0%
Retail Transmission - Network	kWh	2,145	0.00360	7.72	2,093	0.00360	7.54	(0.19)	-2.4%	-0.1%
Retail Transmission - Line and Transformation	kWh	2,145	0.00370	7.94	2,093	0.00370	7.75	(0.19)	-2.4%	-0.1%
Wholesale Market Service	kWh	2,145	0.00520	11.16	2,093	0.00520	10.89	(0.27)	-2.4%	-0.1%
Rural Rate Protection Charge	kWh	2,145	0.00100	2.15	2,093	0.00100	2.09	(0.05)	-2.4%	0.0%
Debt Retirement Charge	kWh	2,000	0.00700	14.00	2,000	0.00700	14.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	2,145	0.05450	116.91	2,093	0.05450	114.09	(2.83)	-2.4%	-1.3%
Total Bill				203.47			220.38	16.90	8.3%	7.7%

GS <50
5,000

kWh Consumption

	Metric	2008 Bill			2009 Bill			IMPACT		
		Volume	Rate \$	Charge \$	Volume	Rate \$	Charge \$	Change \$	Change %	% of Total Bill
Monthly Service Charge				33.20			33.46	0.26	0.8%	0.1%
Distribution	kWh	5,000	0.00520	26.00	5,000	0.01529	76.43	50.43	194.0%	10.1%
Sub-Total				59.20			109.89	50.69	85.6%	10.1%
Regulatory Asset Recovery	kWh	5,000		0.00	5,000		0.00	0.00		0.0%
Retail Transmission - Network	kWh	5,363	0.00360	19.31	5,233	0.00360	18.84	(0.47)	-2.4%	-0.1%
Retail Transmission - Line and Transformation	kWh	5,363	0.00370	19.84	5,233	0.00370	19.36	(0.48)	-2.4%	-0.1%
Wholesale Market Service	kWh	5,363	0.00520	27.89	5,233	0.00520	27.21	(0.67)	-2.4%	-0.1%
Rural Rate Protection Charge	kWh	5,363	0.00100	5.36	5,233	0.00100	5.23	(0.13)	-2.4%	0.0%
Debt Retirement Charge	kWh	5,000	0.00700	35.00	5,000	0.00700	35.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	5,363	0.05450	292.28	5,233	0.05450	285.21	(7.07)	-2.4%	-1.4%
Total Bill				458.88			500.75	41.87	9.1%	8.4%

GS <50
10,000

kWh Consumption

	Metric	2008 Bill			2009 Bill			IMPACT		
		Volume	Rate \$	Charge \$	Volume	Rate \$	Charge \$	Change \$	Change %	% of Total Bill
Monthly Service Charge				33.20			33.46	0.26	0.8%	0.0%
Distribution	kWh	10,000	0.00520	52.00	10,000	0.01529	152.86	100.86	194.0%	10.4%
Sub-Total				85.20			186.32	101.12	118.7%	10.4%
Regulatory Asset Recovery	kWh	10,000		0.00	10,000		0.00	0.00		0.0%
Retail Transmission - Network	kWh	10,726	0.00360	38.61	10,467	0.00360	37.68	(0.93)	-2.4%	-0.1%
Retail Transmission - Line and Transformation	kWh	10,726	0.00370	39.69	10,467	0.00370	38.73	(0.96)	-2.4%	-0.1%
Wholesale Market Service	kWh	10,726	0.00520	55.78	10,467	0.00520	54.43	(1.35)	-2.4%	-0.1%
Rural Rate Protection Charge	kWh	10,726	0.00100	10.73	10,467	0.00100	10.47	(0.26)	-2.4%	0.0%
Debt Retirement Charge	kWh	10,000	0.00700	70.00	10,000	0.00700	70.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	10,726	0.05450	584.57	10,467	0.05450	570.43	(14.14)	-2.4%	-1.5%
Total Bill				884.57			968.05	83.48	9.4%	8.6%

GS <50
15,000

kWh Consumption

	Metric	2008 Bill			2009 Bill			IMPACT		
		Volume	Rate \$	Charge \$	Volume	Rate \$	Charge \$	Change \$	Change %	% of Total Bill
Monthly Service Charge				33.20			33.46	0.26	0.8%	0.0%
Distribution	kWh	15,000	0.00520	78.00	15,000	0.01529	229.29	151.29	194.0%	10.5%
Sub-Total				111.20			262.75	151.55	136.3%	10.6%
Regulatory Asset Recovery	kWh	15,000		0.00	15,000		0.00	0.00		0.0%
Retail Transmission - Network	kWh	16,089	0.00360	57.92	15,700	0.00360	56.52	(1.40)	-2.4%	-0.1%
Retail Transmission - Line and Transformation	kWh	16,089	0.00370	59.53	15,700	0.00370	58.09	(1.44)	-2.4%	-0.1%
Wholesale Market Service	kWh	16,089	0.00520	83.66	15,700	0.00520	81.64	(2.02)	-2.4%	-0.1%
Rural Rate Protection Charge	kWh	16,089	0.00100	16.09	15,700	0.00100	15.70	(0.39)	-2.4%	0.0%
Debt Retirement Charge	kWh	15,000	0.00700	105.00	15,000	0.00700	105.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	16,089	0.05450	876.85	15,700	0.05450	855.64	(21.21)	-2.4%	-1.5%
Total Bill				1,310.25			1,435.34	125.09	9.5%	8.7%

GS>50 to 499 kW

55 kW Consumption
15,000 kWh Consumption

	Metric	2008 Bill			2009 Bill			IMPACT		
		Volume	Rate \$	Charge \$	Volume	Rate \$	Charge \$	Change \$	Change %	% of Total Bill
Monthly Service Charge				402.30			402.56	0.26	0.1%	0.0%
Distribution	kW	55	1.06950	58.82	55	1.28803	70.84	12.02	20.4%	0.7%
Sub-Total				461.12			473.40	12.28	2.7%	0.7%
Regulatory Asset Recovery	kW	55		0.00	55		0.00	0.00		0.0%
Retail Transmission - Network	kW	59	1.45850	86.04	58	1.45840	83.95	(2.09)	-2.4%	-0.1%
Retail Transmission - Line and Transformation	kW	59	1.47250	86.87	58	1.47250	84.77	(2.10)	-2.4%	-0.1%
Wholesale Market Service	kWh	16,089	0.00520	83.66	15,700	0.00520	81.64	(2.02)	-2.4%	-0.1%
Rural Rate Protection Charge	kWh	16,089	0.00100	16.09	15,700	0.00100	15.70	(0.39)	-2.4%	0.0%
Debt Retirement Charge	kWh	15,000	0.00700	105.00	15,000	0.00700	105.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	16,089	0.05450	876.85	15,700	0.05450	855.64	(21.21)	-2.4%	-1.2%
Total Bill				1,715.63			1,700.10	(15.53)	-0.9%	-0.9%

GS>50 to 499 kW

125 kW Consumption
20,000 kWh Consumption

	Metric	2008 Bill			2009 Bill			IMPACT		
		Volume	Rate \$	Charge \$	Volume	Rate \$	Charge \$	Change \$	Change %	% of Total Bill
Monthly Service Charge				402.30			402.56	0.26	0.1%	0.0%
Distribution	kW	125	1.06950	133.69	125	1.28803	161.00	27.32	20.4%	1.2%
Sub-Total				535.99			563.56	27.58	5.1%	1.2%
Regulatory Asset Recovery	kW	125		0.00	125		0.00	0.00		0.0%
Retail Transmission - Network	kW	134	1.45850	195.55	131	1.45840	190.81	(4.74)	-2.4%	-0.2%
Retail Transmission - Line and Transformation	kW	134	1.47250	197.43	131	1.47250	192.65	(4.78)	-2.4%	-0.2%
Wholesale Market Service	kWh	21,452	0.00520	111.55	20,933	0.00520	108.85	(2.70)	-2.4%	-0.1%
Rural Rate Protection Charge	kWh	21,452	0.00100	21.45	20,933	0.00100	20.93	(0.52)	-2.4%	0.0%
Debt Retirement Charge	kWh	20,000	0.00700	140.00	20,000	0.00700	140.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	21,452	0.05450	1,169.13	20,933	0.05450	1,140.85	(28.28)	-2.4%	-1.2%
Total Bill				2,371.10			2,357.66	(13.44)	-0.6%	-0.6%

GS>50 to 499 kW

250 kW Consumption
50,000 kWh Consumption

	Metric	2008 Bill			2009 Bill			IMPACT		
		Volume	Rate \$	Charge \$	Volume	Rate \$	Charge \$	Change \$	Change %	% of Total Bill
Monthly Service Charge				402.30			402.56	0.26	0.1%	0.0%
Distribution	kW	250	1.06950	267.38	250	1.28803	322.01	54.63	20.4%	1.1%
Sub-Total				669.68			724.57	54.89	8.2%	1.1%
Regulatory Asset Recovery	kW	250		0.00	250		0.00	0.00		0.0%
Retail Transmission - Network	kW	268	1.45850	391.10	262	1.45840	381.61	(9.49)	-2.4%	-0.2%
Retail Transmission - Line and Transformation	kW	268	1.47250	394.85	262	1.47250	385.30	(9.55)	-2.4%	-0.2%
Wholesale Market Service	kWh	53,630	0.00520	278.88	52,333	0.00520	272.13	(6.75)	-2.4%	-0.1%
Rural Rate Protection Charge	kWh	53,630	0.00100	53.63	52,333	0.00100	52.33	(1.30)	-2.4%	0.0%
Debt Retirement Charge	kWh	50,000	0.00700	350.00	50,000	0.00700	350.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	53,630	0.05450	2,922.84	52,333	0.05450	2,852.13	(70.70)	-2.4%	-1.4%
Total Bill				5,060.96			5,018.07	(42.89)	-0.8%	-0.9%

GS>50 to 499 kW

350 kW Consumption
125,000 kWh Consumption

	Metric	2008 Bill			2009 Bill			IMPACT		
		Volume	Rate \$	Charge \$	Volume	Rate \$	Charge \$	Change \$	Change %	% of Total Bill
Monthly Service Charge				402.30			402.56	0.26	0.1%	0.0%
Distribution	kW	350	1.06950	374.33	350	1.28803	450.81	76.49	20.4%	0.7%
Sub-Total				776.63			853.37	76.75	9.9%	0.7%
Regulatory Asset Recovery	kW	350		0.00	350		0.00	0.00		0.0%
Retail Transmission - Network	kW	375	1.45850	547.54	366	1.45840	534.25	(13.28)	-2.4%	-0.1%
Retail Transmission - Line and Transformation	kW	375	1.47250	552.79	366	1.47250	539.42	(13.37)	-2.4%	-0.1%
Wholesale Market Service	kWh	134,075	0.00520	697.19	130,832	0.00520	680.33	(16.86)	-2.4%	-0.2%
Rural Rate Protection Charge	kWh	134,075	0.00100	134.08	130,832	0.00100	130.83	(3.24)	-2.4%	0.0%
Debt Retirement Charge	kWh	125,000	0.00700	875.00	125,000	0.00700	875.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	134,075	0.05450	7,307.09	130,832	0.05450	7,130.33	(176.76)	-2.4%	-1.6%
Total Bill				10,890.30			10,743.53	(146.77)	-1.3%	-1.4%

GS>50 to 499 kW

450 kW Consumption
250,000 kWh Consumption

	Metric	2008 Bill			2009 Bill			IMPACT		
		Volume	Rate \$	Charge \$	Volume	Rate \$	Charge \$	Change \$	Change %	% of Total Bill
Monthly Service Charge				402.30			402.56	0.26	0.1%	0.0%
Distribution	kW	450	1.06950	481.28	450	1.28803	579.61	98.34	20.4%	0.5%
Sub-Total				883.58			982.17	98.60	11.2%	0.5%
Regulatory Asset Recovery	kW	450		0.00	450		0.00	0.00		0.0%
Retail Transmission - Network	kW	483	1.45850	703.97	471	1.45840	686.90	(17.08)	-2.4%	-0.1%
Retail Transmission - Line and Transformation	kW	483	1.47250	710.73	471	1.47250	693.54	(17.19)	-2.4%	-0.1%
Wholesale Market Service	kWh	268,150	0.00520	1,394.38	261,663	0.00520	1,360.65	(33.73)	-2.4%	-0.2%
Rural Rate Protection Charge	kWh	268,150	0.00100	268.15	261,663	0.00100	261.66	(6.49)	-2.4%	0.0%
Debt Retirement Charge	kWh	250,000	0.00700	1,750.00	250,000	0.00700	1,750.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	268,150	0.05450	14,614.18	261,663	0.05450	14,260.66	(353.51)	-2.4%	-1.8%
Total Bill				20,324.99			19,995.58	(329.40)	-1.6%	-1.6%

Large Use

6,000 kW Consumption
2,800,000 kWh Consumption

	Metric	2008 Bill			2009 Bill			IMPACT		
		Volume	Rate \$	Charge \$	Volume	Rate \$	Charge \$	Change \$	Change %	% of Total Bill
Monthly Service Charge				8,652.46			8,652.46	0.00	0.0%	0.0%
Distribution	kW	6,000	0.75920	4,555.20	6,000	1.85681	11,140.89	6,585.69	144.6%	2.9%
Sub-Total				13,207.66			19,793.35	6,585.69	49.9%	2.9%
Regulatory Asset Recovery	kW	6,000		0.00	6,000		0.00	0.00		0.0%
Retail Transmission - Network	kW	6,000	1.71530	10,291.80	6,000	1.71530	10,291.80	0.00	0.0%	0.0%
Retail Transmission - Line and Transformation	kW	6,000	1.84590	11,075.40	6,000	1.84590	11,075.40	0.00	0.0%	0.0%
Wholesale Market Service	kWh	2,800,000	0.00520	14,560.00	2,800,000	0.00520	14,560.00	0.00	0.0%	0.0%
Rural Rate Protection Charge	kWh	2,800,000	0.00100	2,800.00	2,800,000	0.00100	2,800.00	0.00	0.0%	0.0%
Debt Retirement Charge	kWh	2,800,000	0.00700	19,600.00	2,800,000	0.00700	19,600.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	2,800,000	0.05450	152,600.00	2,800,000	0.05450	152,600.00	0.00	0.0%	0.0%
Total Bill				224,134.86			230,720.55	6,585.69	2.9%	2.9%

Large Use

15,000 kW Consumption
7,000,000 kWh Consumption

	Metric	2008 Bill			2009 Bill			IMPACT		
		Volume	Rate \$	Charge \$	Volume	Rate \$	Charge \$	Change \$	Change %	% of Total Bill
Monthly Service Charge				8,652.46			8,652.46	0.00	0.0%	0.0%
Distribution	kW	15,000	0.75920	11,388.00	15,000	1.85681	27,852.22	16,464.22	144.6%	2.9%
Sub-Total				20,040.46			36,504.68	16,464.22	82.2%	2.9%
Regulatory Asset Recovery	kW	15,000		0.00	15,000		0.00	0.00	0.0%	0.0%
Retail Transmission - Network	kW	15,000	1.71530	25,729.50	15,000	1.71530	25,729.50	0.00	0.0%	0.0%
Retail Transmission - Line and Transformation	kW	15,000	1.84590	27,688.50	15,000	1.84590	27,688.50	0.00	0.0%	0.0%
Wholesale Market Service	kWh	7,000,000	0.00520	36,400.00	7,000,000	0.00520	36,400.00	0.00	0.0%	0.0%
Rural Rate Protection Charge	kWh	7,000,000	0.00100	7,000.00	7,000,000	0.00100	7,000.00	0.00	0.0%	0.0%
Debt Retirement Charge	kWh	7,000,000	0.00700	49,000.00	7,000,000	0.00700	49,000.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	7,000,000	0.05450	381,500.00	7,000,000	0.05450	381,500.00	0.00	0.0%	0.0%
Total Bill				547,358.46			563,822.68	16,464.22	3.0%	2.9%

Large Use

30,000 kW Consumption
20,000,000 kWh Consumption

	Metric	2008 Bill			2009 Bill			IMPACT		
		Volume	Rate \$	Charge \$	Volume	Rate \$	Charge \$	Change \$	Change %	% of Total Bill
Monthly Service Charge				8,652.46			8,652.46	0.00	0.0%	0.0%
Distribution	kW	30,000	0.75920	22,776.00	30,000	1.85681	55,704.43	32,928.43	144.6%	2.2%
Sub-Total				31,428.46			64,356.89	32,928.43	104.8%	2.2%
Regulatory Asset Recovery	kW	30,000		0.00	30,000		0.00	0.00	0.0%	0.0%
Retail Transmission - Network	kW	30,000	1.71530	51,459.00	30,000	1.71530	51,459.00	0.00	0.0%	0.0%
Retail Transmission - Line and Transformation	kW	30,000	1.84590	55,377.00	30,000	1.84590	55,377.00	0.00	0.0%	0.0%
Wholesale Market Service	kWh	20,000,000	0.00520	104,000.00	20,000,000	0.00520	104,000.00	0.00	0.0%	0.0%
Rural Rate Protection Charge	kWh	20,000,000	0.00100	20,000.00	20,000,000	0.00100	20,000.00	0.00	0.0%	0.0%
Debt Retirement Charge	kWh	20,000,000	0.00700	140,000.00	20,000,000	0.00700	140,000.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	20,000,000	0.05450	1,090,000.00	20,000,000	0.05450	1,090,000.00	0.00	0.0%	0.0%
Total Bill				1,492,264.46			1,525,192.89	32,928.43	2.2%	2.2%

Large Use

100,000 kW Consumption
53,000,000 kWh Consumption

	Metric	2008 Bill			2009 Bill			IMPACT		
		Volume	Rate \$	Charge \$	Volume	Rate \$	Charge \$	Change \$	Change %	% of Total Bill
Monthly Service Charge				8,652.46			8,652.46	0.00	0.0%	0.0%
Distribution	kW	100,000	0.75920	75,920.00	100,000	1.85681	185,681.44	109,761.44	144.6%	2.7%
Sub-Total				84,572.46			194,333.90	109,761.44	129.8%	2.7%
Regulatory Asset Recovery	kW	100,000		0.00	100,000		0.00	0.00	0.0%	0.0%
Retail Transmission - Network	kW	100,000	1.71530	171,530.00	100,000	1.71530	171,530.00	0.00	0.0%	0.0%
Retail Transmission - Line and Transformation	kW	100,000	1.84590	184,590.00	100,000	1.84590	184,590.00	0.00	0.0%	0.0%
Wholesale Market Service	kWh	53,000,000	0.00520	275,600.00	53,000,000	0.00520	275,600.00	0.00	0.0%	0.0%
Rural Rate Protection Charge	kWh	53,000,000	0.00100	53,000.00	53,000,000	0.00100	53,000.00	0.00	0.0%	0.0%
Debt Retirement Charge	kWh	53,000,000	0.00700	371,000.00	53,000,000	0.00700	371,000.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	53,000,000	0.05450	2,888,500.00	53,000,000	0.05450	2,888,500.00	0.00	0.0%	0.0%
Total Bill				4,028,792.46			4,138,553.90	109,761.44	2.7%	2.7%

Street Light

1 kW Consumption
25 kWh Consumption

	Metric	2008 Bill			2009 Bill			IMPACT		
		Volume	Rate \$	Charge \$	Volume	Rate \$	Charge \$	Change \$	Change %	% of Total Bill
Monthly Service Charge				0.71			1.95	1.24	174.1%	6.9%
Distribution	kW	1	2.65630	1.99	1	16.66339	12.50	10.51	527.3%	58.6%
Sub-Total				2.70			14.44	11.74	434.5%	65.5%
Regulatory Asset Recovery	kW	1		0.00	1		0.00	0.00		0.0%
Retail Transmission - Network	kW	1	1.10000	0.85	1	1.10000	0.85	0.00	0.1%	0.0%
Retail Transmission - Line and Transformation	kW	1	1.13840	0.88	1	1.13840	0.88	0.00	0.1%	0.0%
Wholesale Market Service	kWh	26	0.00520	0.13	26	0.00520	0.13	0.00	0.1%	0.0%
Rural Rate Protection Charge	kWh	26	0.00100	0.03	26	0.00100	0.03	0.00	0.1%	0.0%
Debt Retirement Charge	kWh	25	0.00700	0.18	25	0.00700	0.18	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	26	0.05450	1.41	26	0.05450	1.41	0.00	0.1%	0.0%
Total Bill				6.18			17.92	11.74	190.1%	65.5%

Sentinel

0.75 kW Consumption
25 kWh Consumption

	Metric	2008 Bill			2009 Bill			IMPACT		
		Volume	Rate \$	Charge \$	Volume	Rate \$	Charge \$	Change \$	Change %	% of Total Bill
Monthly Service Charge				5.64			5.64	0.00	0.0%	0.0%
Distribution	kW	1	4.22060	3.17	1	14.65061	10.99	7.82	247.1%	38.8%
Sub-Total				8.81			16.63	7.82	88.8%	38.8%
Regulatory Asset Recovery	kW	1		0.00	1		0.00	0.00		0.0%
Retail Transmission - Network	kW	1	1.10560	0.86	1	1.10560	0.87	0.00	0.1%	0.0%
Retail Transmission - Line and Transformation	kW	1	1.16210	0.91	1	1.16210	0.91	0.00	0.1%	0.0%
Wholesale Market Service	kWh	26	0.00520	0.14	26	0.00520	0.14	0.00	0.1%	0.0%
Rural Rate Protection Charge	kWh	26	0.00100	0.03	26	0.00100	0.03	0.00	0.1%	0.0%
Debt Retirement Charge	kWh	25	0.00700	0.18	25	0.00700	0.18	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	26	0.05450	1.42	26	0.05450	1.42	0.00	0.1%	0.0%
Total Bill				12.34			20.16	7.83	63.4%	38.8%

Sentinel

0.75 kW Consumption
50 kWh Consumption

	Metric	2008 Bill			2009 Bill			IMPACT		
		Volume	Rate \$	Charge \$	Volume	Rate \$	Charge \$	Change \$	Change %	% of Total Bill
Monthly Service Charge				5.64			5.64	0.00	0.0%	0.0%
Distribution	kW	1	4.22060	3.17	1	14.65061	10.99	7.82	247.1%	35.7%
Sub-Total				8.81			16.63	7.82	88.8%	35.7%
Regulatory Asset Recovery	kW	1		0.00	1		0.00	0.00		0.0%
Retail Transmission - Network	kW	1	1.10560	0.86	1	1.10560	0.87	0.00	0.1%	0.0%
Retail Transmission - Line and Transformation	kW	1	1.16210	0.91	1	1.16210	0.91	0.00	0.1%	0.0%
Wholesale Market Service	kWh	52	0.00520	0.27	52	0.00520	0.27	0.00	0.1%	0.0%
Rural Rate Protection Charge	kWh	52	0.00100	0.05	52	0.00100	0.05	0.00	0.1%	0.0%
Debt Retirement Charge	kWh	50	0.00700	0.35	50	0.00700	0.35	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	52	0.05450	2.84	52	0.05450	2.84	0.00	0.1%	0.0%
Total Bill				14.09			21.92	7.83	55.5%	35.7%

Unmetered Scattered Load

1 kW Consumption
600 kWh Consumption

	Metric	2008 Bill			2009 Bill			IMPACT		
		Volume	Rate \$	Charge \$	Volume	Rate \$	Charge \$	Change \$	Change %	% of Total Bill
Monthly Service Charge				33.47			33.47	0.00	0.0%	0.0%
Distribution	kWh	1	0.00520	3.12	1	0.03409	20.45	17.33	555.5%	18.0%
Sub-Total				36.59			53.92	17.33	47.4%	18.0%
Regulatory Asset Recovery	kW	1		0.00	1		0.00	0.00	0.0%	0.0%
Retail Transmission - Network	kW	1	0.00360	0.00	1	0.00360	0.00	0.00	0.1%	0.0%
Retail Transmission - Line and Transformation	kW	1	0.00370	0.00	1	0.00370	0.00	0.00	0.1%	0.0%
Wholesale Market Service	kWh	626	0.00520	3.25	626	0.00520	3.26	0.00	0.1%	0.0%
Rural Rate Protection Charge	kWh	626	0.00100	0.63	626	0.00100	0.63	0.00	0.1%	0.0%
Debt Retirement Charge	kWh	600	0.00700	4.20	600	0.00700	4.20	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	626	0.05450	34.10	626	0.05450	34.12	0.03	0.1%	0.0%
Total Bill				78.77			96.14	17.36	22.0%	18.1%

GS>500 kW to 4999 kW

1700 kW Consumption
700000 kWh Consumption

	Metric	2008 Bill			2009 Bill			IMPACT		
		Volume	Rate \$	Charge \$	Volume	Rate \$	Charge \$	Change \$	Change %	% of Total Bill
Monthly Service Charge				3,476.16			2,322.41	(1,153.75)	-33.2%	-2.0%
Distribution	kW	1,700	1.47250	2,503.25	1,700	1.45755	2,477.83	(25.42)	-1.0%	0.0%
Sub-Total				5,979.41			4,800.24	(1,179.17)	-19.7%	-2.0%
Regulatory Asset Recovery	kW	1,700		0.00	1,700		0.00	0.00	0.0%	0.0%
Retail Transmission - Network	kW	1,700	1.54910	2,633.47	1,700	1.54910	2,633.47	0.00	0.0%	0.0%
Retail Transmission - Line and Transformation	kW	1,700	1.61420	2,744.14	1,700	1.61420	2,744.14	0.00	0.0%	0.0%
Wholesale Market Service	kWh	700,000	0.00520	3,640.00	700,000	0.00520	3,640.00	0.00	0.0%	0.0%
Rural Rate Protection Charge	kWh	700,000	0.00100	700.00	700,000	0.00100	700.00	0.00	0.0%	0.0%
Debt Retirement Charge	kWh	700,000	0.00700	4,900.00	700,000	0.00700	4,900.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	700,000	0.05450	38,150.00	700,000	0.05450	38,150.00	0.00	0.0%	0.0%
Total Bill				58,747.02			57,567.85	(1,179.17)	-2.0%	-2.0%

GS>500 kW to 4999 kW

1500 kW Consumption
750000 kWh Consumption

	Metric	2008 Bill			2009 Bill			IMPACT		
		Volume	Rate \$	Charge \$	Volume	Rate \$	Charge \$	Change \$	Change %	% of Total Bill
Monthly Service Charge				3,476.16			2,322.41	(1,153.75)	-33.2%	-2.0%
Distribution	kW	1,500	1.47250	2,208.75	1,500	1.45755	2,186.32	(22.43)	-1.0%	0.0%
Sub-Total				5,684.91			4,508.73	(1,176.18)	-20.7%	-2.0%
Regulatory Asset Recovery	kW	1,500		0.00	1,500		0.00	0.00	0.0%	0.0%
Retail Transmission - Network	kW	1,500	1.54910	2,323.65	1,500	1.54910	2,323.65	0.00	0.0%	0.0%
Retail Transmission - Line and Transformation	kW	1,500	1.61420	2,421.30	1,500	1.61420	2,421.30	0.00	0.0%	0.0%
Wholesale Market Service	kWh	750,000	0.00520	3,900.00	750,000	0.00520	3,900.00	0.00	0.0%	0.0%
Rural Rate Protection Charge	kWh	750,000	0.00100	750.00	750,000	0.00100	750.00	0.00	0.0%	0.0%
Debt Retirement Charge	kWh	750,000	0.00700	5,250.00	750,000	0.00700	5,250.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	750,000	0.05450	40,875.00	750,000	0.05450	40,875.00	0.00	0.0%	0.0%
Total Bill				61,204.86			60,028.68	(1,176.18)	-1.9%	-2.0%

GS>500 kW to 4999 kW

1000
450000

kW Consumption
kWh Consumption

	Metric	2008 Bill			2009 Bill			IMPACT		
		Volume	Rate \$	Charge \$	Volume	Rate \$	Charge \$	Change \$	Change %	% of Total Bill
Monthly Service Charge				3,476.16			2,322.41	(1,153.75)	-33.2%	-2.0%
Distribution	kW	1,000	1.47250	1,472.50	1,000	1.45755	1,457.55	(14.95)	-1.0%	0.0%
Sub-Total				4,948.66			3,779.96	(1,168.70)	-23.6%	-2.0%
Regulatory Asset Recovery	kW	1,000		0.00	1,000		0.00	0.00	0.0%	0.0%
Retail Transmission - Network	kW	1,000	1.54910	1,549.10	1,000	1.54910	1,549.10	0.00	0.0%	0.0%
Retail Transmission - Line and Transformation	kW	1,000	1.61420	1,614.20	1,000	1.61420	1,614.20	0.00	0.0%	0.0%
Wholesale Market Service	kWh	450,000	0.00520	2,340.00	450,000	0.00520	2,340.00	0.00	0.0%	0.0%
Rural Rate Protection Charge	kWh	450,000	0.00100	450.00	450,000	0.00100	450.00	0.00	0.0%	0.0%
Debt Retirement Charge	kWh	450,000	0.00700	3,150.00	450,000	0.00700	3,150.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	450,000	0.05450	24,525.00	450,000	0.05450	24,525.00	0.00	0.0%	0.0%
Total Bill				38,576.96			37,408.26	(1,168.70)	-3.0%	-2.0%

GS>500 kW to 4999 kW

1800
1000000

kW Consumption
kWh Consumption

	Metric	2008 Bill			2009 Bill			IMPACT		
		Volume	Rate \$	Charge \$	Volume	Rate \$	Charge \$	Change \$	Change %	% of Total Bill
Monthly Service Charge				3,476.16			2,322.41	(1,153.75)	-33.2%	-2.0%
Distribution	kW	1,800	1.47250	2,650.50	1,800	1.45755	2,623.59	(26.91)	-1.0%	0.0%
Sub-Total				6,126.66			4,946.00	(1,180.66)	-19.3%	-2.1%
Regulatory Asset Recovery	kW	1,800		0.00	1,800		0.00	0.00	0.0%	0.0%
Retail Transmission - Network	kW	1,800	1.54910	2,788.38	1,800	1.54910	2,788.38	0.00	0.0%	0.0%
Retail Transmission - Line and Transformation	kW	1,800	1.61420	2,905.56	1,800	1.61420	2,905.56	0.00	0.0%	0.0%
Wholesale Market Service	kWh	1,000,000	0.00520	5,200.00	1,000,000	0.00520	5,200.00	0.00	0.0%	0.0%
Rural Rate Protection Charge	kWh	1,000,000	0.00100	1,000.00	1,000,000	0.00100	1,000.00	0.00	0.0%	0.0%
Debt Retirement Charge	kWh	1,000,000	0.00700	7,000.00	1,000,000	0.00700	7,000.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	1,000,000	0.05450	54,500.00	1,000,000	0.05450	54,500.00	0.00	0.0%	0.0%
Total Bill				79,520.60			78,339.94	(1,180.66)	-1.5%	-2.1%

GS>500 kW to 4999 kW

2000
800000

kW Consumption
kWh Consumption

	Metric	2008 Bill			2009 Bill			IMPACT		
		Volume	Rate \$	Charge \$	Volume	Rate \$	Charge \$	Change \$	Change %	% of Total Bill
Monthly Service Charge				3,476.16			2,322.41	(1,153.75)	-33.2%	-2.0%
Distribution	kW	2,000	1.47250	2,945.00	2,000	1.45755	2,915.10	(29.90)	-1.0%	-0.1%
Sub-Total				6,421.16			5,237.51	(1,183.65)	-18.4%	-2.1%
Regulatory Asset Recovery	kW	2,000		0.00	2,000		0.00	0.00	0.0%	0.0%
Retail Transmission - Network	kW	2,000	1.54910	3,098.20	2,000	1.54910	3,098.20	0.00	0.0%	0.0%
Retail Transmission - Line and Transformation	kW	2,000	1.61420	3,228.40	2,000	1.61420	3,228.40	0.00	0.0%	0.0%
Wholesale Market Service	kWh	800,000	0.00520	4,160.00	800,000	0.00520	4,160.00	0.00	0.0%	0.0%
Rural Rate Protection Charge	kWh	800,000	0.00100	800.00	800,000	0.00100	800.00	0.00	0.0%	0.0%
Debt Retirement Charge	kWh	800,000	0.00700	5,600.00	800,000	0.00700	5,600.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	800,000	0.05450	43,600.00	800,000	0.05450	43,600.00	0.00	0.0%	0.0%
Total Bill				66,907.76			65,724.11	(1,183.65)	-1.8%	-2.1%

GS>500 kW to 4999 kW

3,000 kW Consumption
800,000 kWh Consumption

	Metric	2008 Bill			2009 Bill			IMPACT		
		Volume	Rate \$	Charge \$	Volume	Rate \$	Charge \$	Change \$	Change %	% of Total Bill
Monthly Service Charge				3,476.16			2,322.41	(1,153.75)	-33.2%	-1.6%
Distribution	kW	3,000	1.47250	4,417.50	3,000	1.45755	4,372.65	(44.85)	-1.0%	-0.1%
Sub-Total				7,893.66			6,695.06	(1,198.60)	-15.2%	-1.6%
Regulatory Asset Recovery	kW	3,000		0.00	3,000		0.00	0.00		0.0%
Retail Transmission - Network	kW	3,128	1.54910	4,845.74	3,131	1.54910	4,849.71	3.97	0.1%	0.0%
Retail Transmission - Line and Transformation	kW	3,128	1.61420	5,049.38	3,131	1.61420	5,053.52	4.14	0.1%	0.0%
Wholesale Market Service	kWh	834,160	0.00520	4,337.63	834,844	0.00520	4,341.19	3.56	0.1%	0.0%
Rural Rate Protection Charge	kWh	834,160	0.00100	834.16	834,844	0.00100	834.84	0.68	0.1%	0.0%
Debt Retirement Charge	kWh	800,000	0.00700	5,600.00	800,000	0.00700	5,600.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	834,160	0.05450	45,461.72	834,844	0.05450	45,499.00	37.28	0.1%	0.1%
Total Bill				74,022.29			72,873.32	(1,148.97)	-1.6%	-1.6%

GS>500 kW to 4999 kW

3,000 kW Consumption
1,000,000 kWh Consumption

	Metric	2008 Bill			2009 Bill			IMPACT		
		Volume	Rate \$	Charge \$	Volume	Rate \$	Charge \$	Change \$	Change %	% of Total Bill
Monthly Service Charge				3,476.16			2,322.41	(1,153.75)	-33.2%	-1.6%
Distribution	kW	3,000	1.47250	4,417.50	3,000	1.45755	4,372.65	(44.85)	-1.0%	-0.1%
Sub-Total				7,893.66			6,695.06	(1,198.60)	-15.2%	-1.6%
Regulatory Asset Recovery	kW	3,000		0.00	3,000		0.00	0.00		0.0%
Retail Transmission - Network	kW	3,128	1.54910	4,845.74	3,131	1.54910	4,849.71	3.97	0.1%	0.0%
Retail Transmission - Line and Transformation	kW	3,128	1.61420	5,049.38	3,131	1.61420	5,053.52	4.14	0.1%	0.0%
Wholesale Market Service	kWh	1,042,700	0.00520	5,422.04	1,043,555	0.00520	5,426.49	4.45	0.1%	0.0%
Rural Rate Protection Charge	kWh	1,042,700	0.00100	1,042.70	1,043,555	0.00100	1,043.55	0.85	0.1%	0.0%
Debt Retirement Charge	kWh	1,000,000	0.00700	7,000.00	1,000,000	0.00700	7,000.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	1,042,700	0.05450	56,827.15	1,043,555	0.05450	56,873.75	46.60	0.1%	0.1%
Total Bill				88,080.67			86,942.07	(1,138.60)	-1.3%	-1.6%

GS>500 kW to 4999 kW

4,000 kW Consumption
1,200,000 kWh Consumption

	Metric	2008 Bill			2009 Bill			IMPACT		
		Volume	Rate \$	Charge \$	Volume	Rate \$	Charge \$	Change \$	Change %	% of Total Bill
Monthly Service Charge				3,476.16			2,322.41	(1,153.75)	-33.2%	-1.6%
Distribution	kW	4,000	1.47250	5,890.00	4,000	1.45755	5,830.20	(59.80)	-1.0%	-0.1%
Sub-Total				9,366.16			8,152.61	(1,213.55)	-13.0%	-1.7%
Regulatory Asset Recovery	kW	4,000		0.00	4,000		0.00	0.00		0.0%
Retail Transmission - Network	kW	4,171	1.54910	6,460.99	4,174	1.54910	6,466.28	5.30	0.1%	0.0%
Retail Transmission - Line and Transformation	kW	4,171	1.61420	6,732.51	4,174	1.61420	6,738.03	5.52	0.1%	0.0%
Wholesale Market Service	kWh	1,251,240	0.00520	6,506.45	1,252,266	0.00520	6,511.78	5.33	0.1%	0.0%
Rural Rate Protection Charge	kWh	1,251,240	0.00100	1,251.24	1,252,266	0.00100	1,252.27	1.03	0.1%	0.0%
Debt Retirement Charge	kWh	1,200,000	0.00700	8,400.00	1,200,000	0.00700	8,400.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	1,251,240	0.05450	68,192.58	1,252,266	0.05450	68,248.49	55.91	0.1%	0.1%
Total Bill				106,909.92			105,769.46	(1,140.46)	-1.1%	-1.6%

GS>500 kW to 4999 kW

4,000 kW Consumption
1,800,000 kWh Consumption

	Metric	2008 Bill			2009 Bill			IMPACT		
		Volume	Rate \$	Charge \$	Volume	Rate \$	Charge \$	Change \$	Change %	% of Total Bill
Monthly Service Charge				3,476.16			2,322.41	(1,153.75)	-33.2%	-1.6%
Distribution	kW	4,000	1.47250	5,890.00	4,000	1.45755	5,830.20	(59.80)	-1.0%	-0.1%
Sub-Total				9,366.16			8,152.61	(1,213.55)	-13.0%	-1.7%
Regulatory Asset Recovery	kW	4,000		0.00	4,000		0.00	0.00		0.0%
Retail Transmission - Network	kW	4,171	1.54910	6,460.99	4,174	1.54910	6,466.28	5.30	0.1%	0.0%
Retail Transmission - Line and Transformation	kW	4,171	1.61420	6,732.51	4,174	1.61420	6,738.03	5.52	0.1%	0.0%
Wholesale Market Service	kWh	1,876,860	0.00520	9,759.67	1,878,399	0.00520	9,767.67	8.00	0.1%	0.0%
Rural Rate Protection Charge	kWh	1,876,860	0.00100	1,876.86	1,878,399	0.00100	1,878.40	1.54	0.1%	0.0%
Debt Retirement Charge	kWh	1,800,000	0.00700	12,600.00	1,800,000	0.00700	12,600.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	1,876,860	0.05450	102,288.87	1,878,399	0.05450	102,372.74	83.87	0.1%	0.1%
Total Bill				149,085.05			147,975.73	(1,109.32)	-0.7%	-1.5%

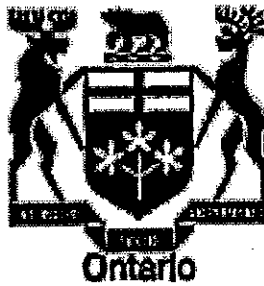
GS>500 kW to 4999 kW

3,000 kW Consumption
1,000,000 kWh Consumption

	Metric	2008 Bill			2009 Bill			IMPACT		
		Volume	Rate \$	Charge \$	Volume	Rate \$	Charge \$	Change \$	Change %	% of Total Bill
Monthly Service Charge				3,476.16			2,322.41	(1,153.75)	-33.2%	-1.6%
Distribution	kW	3,000	1.47250	4,417.50	3,000	1.45755	4,372.65	(44.85)	-1.0%	-0.1%
Sub-Total				7,893.66			6,695.06	(1,198.60)	-15.2%	-1.6%
Regulatory Asset Recovery	kW	3,000		0.00	3,000		0.00	0.00		0.0%
Retail Transmission - Network	kW	3,128	1.54910	4,845.74	3,131	1.54910	4,849.71	3.97	0.1%	0.0%
Retail Transmission - Line and Transformation	kW	3,128	1.61420	5,049.38	3,131	1.61420	5,053.52	4.14	0.1%	0.0%
Wholesale Market Service	kWh	1,042,700	0.00520	5,422.04	1,043,555	0.00520	5,426.49	4.45	0.1%	0.0%
Rural Rate Protection Charge	kWh	1,042,700	0.00100	1,042.70	1,043,555	0.00100	1,043.55	0.85	0.1%	0.0%
Debt Retirement Charge	kWh	1,000,000	0.00700	7,000.00	1,000,000	0.00700	7,000.00	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	1,042,700	0.05450	56,827.15	1,043,555	0.05450	56,873.75	46.60	0.1%	0.1%
Total Bill				88,080.67			86,942.07	(1,138.60)	-1.3%	-1.6%

PROPOSED CHANGES TO TERMS AND CONDITIONS OF SERVICES

Please refer back to Exhibit 1, Tab 1, Schedule 17 for proposed changes to terms and conditions of service



Electricity Distribution Licence

ED-2002-0510

West Coast Huron Energy Inc.

Valid Until
October 6, 2023

A handwritten signature in cursive script, reading "M.C. Garner".

Mark C. Garner
Secretary
Ontario Energy Board

Date of Issuance: October 7, 2003

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

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

1 **Definitions**

In this Licence:

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

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

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

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

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

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

“**Licensee**” means: West Coast Huron Energy Inc.;

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

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

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

“**regulation**” means a regulation made under the Act or the Electricity Act;

14
"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;

15
"service area" with respect to a distributor, means the area in which the distributor is authorized by its licence to distribute electricity;

16
"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;

17
"wholesaler" means a person that purchases electricity or ancillary services in the IMO-administered markets or directly from a generator or, a person who sells electricity or ancillary services through the IMO-administered markets or directly to another person other than a consumer.

2 Interpretation

- 18
2.1 In this Licence words and phrases shall have the meaning ascribed to them in the Act or the Electricity Act. Words or phrases importing the singular shall include the plural and vice versa. Headings are for convenience only and shall not affect the interpretation of the licence. Any reference to a document or a provision of a document includes an amendment or supplement to, or a replacement of, that document or that provision of that document. In the computation of time under this licence where there is a reference to a number of days between two events, they shall be counted by excluding the day on which the first event happens and including the day on which the second event happens and where the time for doing an act expires on a holiday, the act may be done on the next day.

3 Authorization

- 19
20
3.1 The Licensee is authorized, under Part V of the Act and subject to the terms and conditions set out in this Licence:

- 21
22
23
24
a) to own and operate a distribution system in the service area described in Schedule 1 of this Licence;
- b) to retail electricity for the purposes of fulfilling its obligation under section 29 of the Electricity Act in the manner specified in Schedule 2 of this Licence; and
- c) to act as a wholesaler for the purposes of fulfilling its obligations under the Retail Settlement Code or under section 29 of the Electricity Act.

4	Obligation to Comply with Legislation, Regulations and Market Rules	25
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.	26
4.2	The Licensee shall comply with all applicable Market Rules.	27
5	Obligation to Comply with Codes	28
5.1	The Licensee shall at all times comply with the following Codes (collectively the "Codes") approved by the Board, except where the Licensee has been specifically exempted from such compliance by the Board. Any exemptions granted to the licensee are set out in Schedule 3 of this Licence. The following Codes apply to this Licence:	29
a)	the Affiliate Relationships Code for Electricity Distributors and Transmitters;	30
b)	the Distribution System Code;	31
c)	the Retail Settlement Code; and	32
d)	the Standard Supply Service Code.	33
5.2	The Licensee shall:	34
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	35
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.	36
6	Obligation to Provide Non-discriminatory Access	37
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.	38
7	Obligation to Connect	39
7.1	The Licensee shall connect a building to its distribution system if:	40

- a) the building lies along any of the lines of the distributor's distribution system; and 41
- b) the owner, occupant or other person in charge of the building requests the connection in writing. 42
- 7.2 The Licensee shall make an offer to connect a building to its distribution system if: 43
- a) the building is within the Licensee's service area as described in Schedule 1; and 44
- b) the owner, occupant or other person in charge of the building requests the connection in writing. 45
- 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. 46
- 7.4 The Licensee shall not refuse to connect or refuse to make an offer to connect unless it is permitted to do so by the *Act* or a regulation or any Codes to which the Licensee is obligated to comply with as a condition of this Licence. 47
- 8 Obligation to Sell Electricity** 48
- 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. 49
- 9 Obligation to Maintain System Integrity** 50
- 9.1 The Licensee shall maintain its distribution system in accordance with the standards established in the Distribution System Code and Market Rules, and have regard to any other recognized industry operating or planning standards adopted by the Board. 51
- 10 Market Power Mitigation Rebates** 52
- 10.1 The Licensee shall comply with the pass through of Ontario Power Generation rebate conditions set out in Appendix A of this Licence. 53

11	Distribution Rates	54
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.	55
12	Separation of Business Activities	56
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.	57
13	Expansion of Distribution System	58
13.1	The Licensee shall not construct, expand or reinforce an electricity distribution system or make an interconnection except in accordance with the Act and Regulations, the Distribution System Code and applicable provisions of the Market Rules.	59
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.	60
14	Provision of Information to the Board	61
14.1	The Licensee shall maintain records of and provide, in the manner and form determined by the Board, such information as the Board may require from time to time.	62
14.2	Without limiting the generality of condition 14.1 the Licensee shall notify the Board of any material change in circumstances that adversely affects or is likely to adversely affect the business, operations or assets of the Licensee as soon as practicable, but in any event no more than twenty (20) days past the date upon which such change occurs.	63
15	Restrictions on Provision of Information	64
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.	65
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:	66

- a) to comply with any legislative or regulatory requirements, including the conditions of this Licence; 67
- b) for billing, settlement or market operations purposes; 68
- c) for law enforcement purposes; or 69
- d) to a debt collection agency for the processing of past due accounts of the consumer, retailer, wholesaler or generator. 70
- 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. 71
- 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. 72
- 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. 73
- 16 Customer Complaint and Dispute Resolution** 74
- 16.1 The Licensee shall: 75
- a) have a process for resolving disputes with customers that deals with disputes in a fair, reasonable and timely manner; 76
- b) publish information which will make its customers aware of and help them to use its dispute resolution process; 77
- 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; 78
- d) give or send free of charge a copy of the process to any person who reasonably requests it; and 79
- e) subscribe to and refer unresolved complaints to an independent third party complaints resolution service provider selected by the Board. This condition will become effective on a date to be determined by the Board. The Board will provide reasonable notice to the Licensee of the date this condition becomes effective. 80

17	Term of Licence	81
17.1	This Licence shall take effect on October 7, 2003 and expire on October 6, 2023. The term of this Licence may be extended by the Board.	82
18	Fees and Assessments	83
18.1	The Licensee shall pay all fees charged and amounts assessed by the Board.	84
19	Communication	85
19.1	The Licensee shall designate a person that will act as a primary contact with the Board on matters related to this Licence. The Licensee shall notify the Board promptly should the contact details change.	86
19.2	All official communication relating to this Licence shall be in writing.	87
19.3	All written communication is to be regarded as having been given by the sender and received by the addressee:	88
a)	when delivered in person to the addressee by hand, by registered mail or by courier;	89
b)	ten (10) business days after the date of posting if the communication is sent by regular mail; and	90
c)	when received by facsimile transmission by the addressee, according to the sender's transmission report.	91
20	Copies of the Licence	92
20.1	The Licensee shall:	93
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	94
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.	95

SCHEDULE 1 DEFINITION OF DISTRIBUTION SERVICE AREA

96

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

97

The Town of Goderich as at July 1, 1986.

98

SCHEDULE 2 PROVISION OF STANDARD SUPPLY SERVICE

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.

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

SCHEDULE 3 LIST OF CODE EXEMPTIONS

102

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

103

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.

104

APPENDIX A MARKET POWER MITIGATION REBATES

1 Definitions and Interpretation

In this Licence,

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

“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;

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

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

2 Information Given to IMO

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:

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

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

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

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and 117

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*. 118

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. 119

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. 120

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. 121

3 Pass Through of Rebate 122

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: 123

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; 124

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 125

c embedded distributors to whom the distributor distributes electricity. 126

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. 127

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:

128

"ONTARIO POWER GENERATION INC. rebate"

129

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.

130

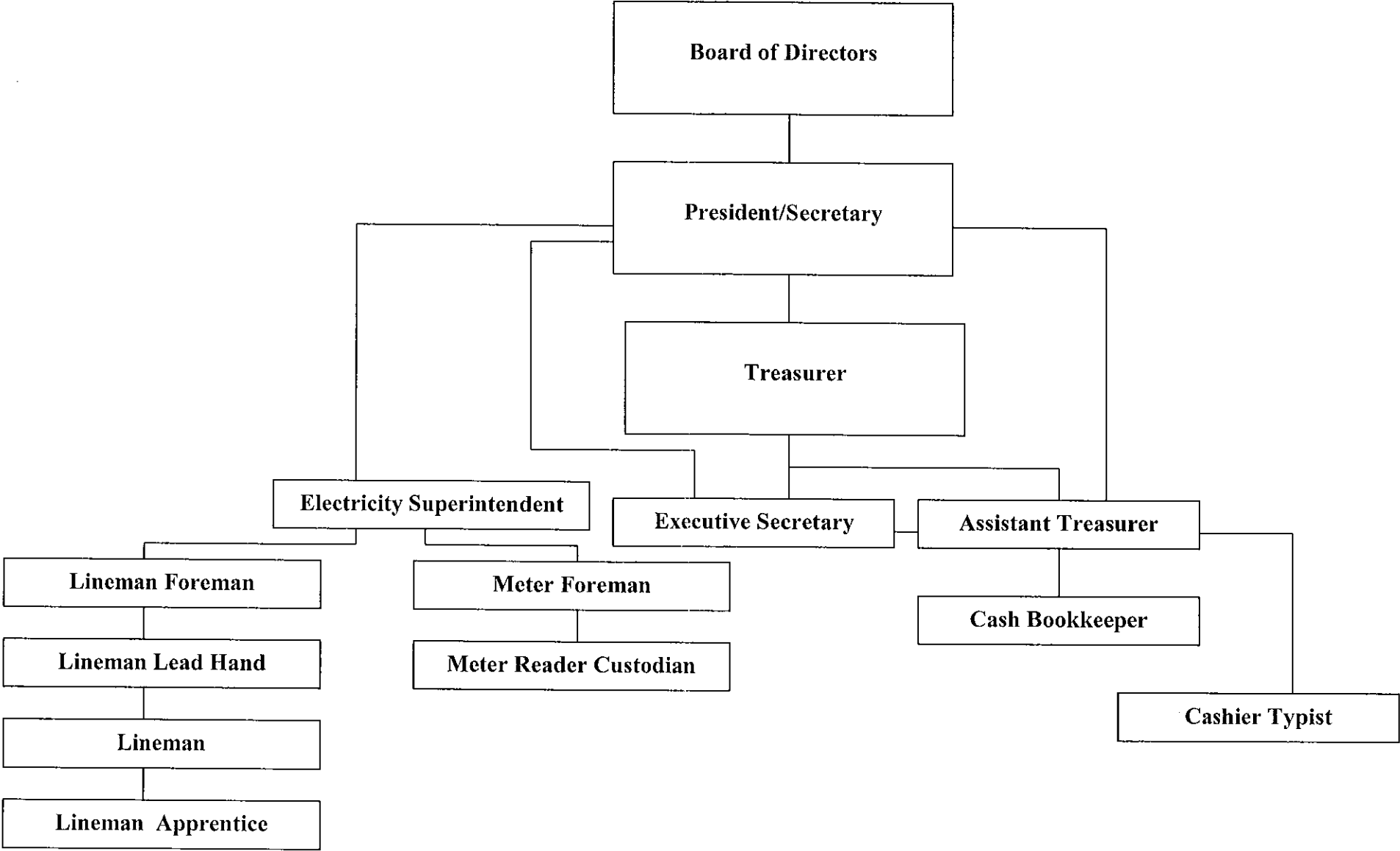
Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party.

131

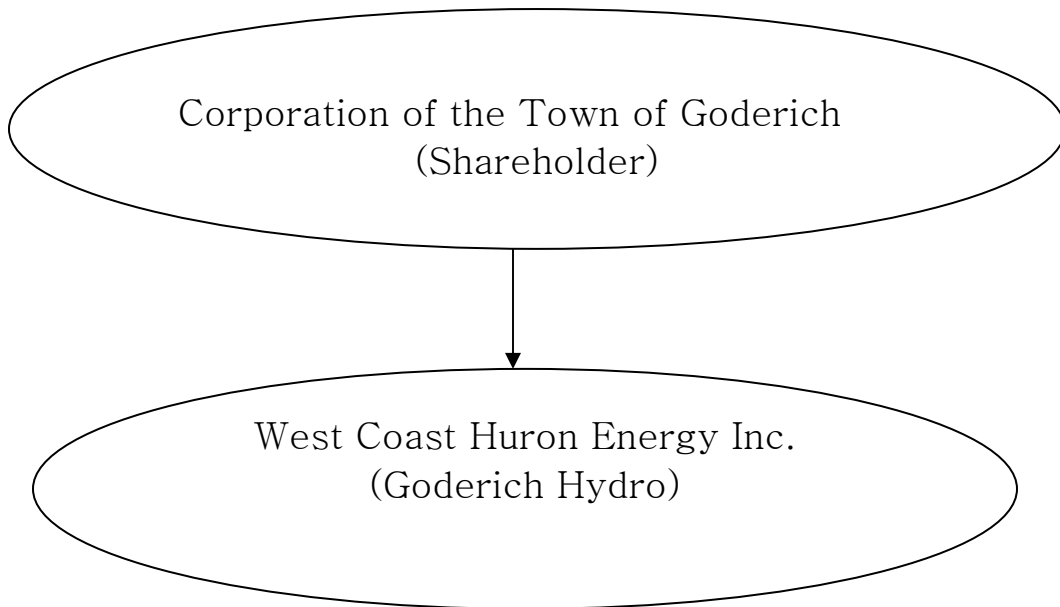
Pending pass-through or return to the IMO of any rebate received, the distributor shall hold the funds received in trust for the beneficiaries thereof in a segregated account.

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WEST COAST HURON ENERGY INC. (GODERICH HYDRO)
ORGANIZATIONAL FLOW CHART



Corporate Entity Relationship



CONDITIONS OF SERVICE

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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 out 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 through 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 unauthorized 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 $\frac{1}{2}$ hour before sunset and $\frac{1}{2}$ 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 arresters.

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:

- **New Substation**: in which case all components of the substation shall be reported upon.
- **Modified substation**: 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 be 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 subdivisions;

“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, 1998*, S.O. 1998, c.15, Schedule A;

“Energy Competition Act” means the *Energy Competition Act, 1998*, 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 Act*;

“Measurement Canada” means the Special Operating Agency established in August 1996 by the *Electricity and Gas Inspection Act*, 1980-81-82-83, c. 87., and *Electricity and Gas Inspection Regulations* (SOR/86-131);

“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, 1998*, 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

Distribution Connection Process

Request For Connection Form

Electrical Planning Requirements Document

Electric Service Meter Base/ Service Verification Form

Contact Information

Local Distribution Company	Contact Phone Number	
Centre Wellington Hydro Ltd.		730 Gartshore Street, Box 217 Fergus, Ont. N1M 2W8
Licence # ED-2002-0498	Phone: (519) 843-2900	
COLLUS Power Corp.		Box 189, 43 Stewart Road Collingwood, Ont. L9Y 3Z5
Licence # ED-2002-0518	Phone: (705) 445-1800	
Grand Valley Energy Inc.		P.O. Box 400 - 400 C Line Orangeville, Ont. L9W 2Z7
Licence # ED-2002-0512	Phone: (519) 928-3112	
Hydro 2000 Inc.		265 St. Philippe Street P.O.Box 370 Alfred, Ont. K0B 1A0
Licence # ED-2002-0542	Phone: (613) 679-4093	
Innisfil Hydro Distribution Systems Limited.		2073 Commerce Park Drive Innisfil, Ont. L9S 4A2
Licence # ED-2002-0520	Phone: (705) 431-4321	
Lakefront Utilities Inc.		207 Division St. P.O. Box 577 Cobourg, Ont. K9A 4L3
Licence # ED-2002-0545	Phone: (905) 372-2193	
Lakeland Power Distribution Ltd.		5-45 Cairns Cres. Huntsville, Ont. P1H 2M2
Licence # ED-2002-0540	Phone: (705) 789-5442	
Midland Power Utility Corporation		16984 Highway #12 Midland, Ont. L4R 4P4
Licence # ED-2002-0541	Phone: (705) 526-9361	
Orangeville Hydro Ltd.		P.O. Box 400 - 400 C Line Orangeville, Ont. L9W 2Z7
Licence # ED-2002-0500	Phone: (519) 942-8000	
Orillia Power Distribution Corporation		360 West St. South, P.O. Box 398 Orillia, Ont. L3V 6J9
Licence # ED-2002-0530	Phone: (705) 326-2495	
Parry Sound Power Corporation		125 William Street Parry Sound, Ont. P2A 1V9
Licence # ED-2003-0006	Phone: (705) 746-5866	
Rideau St. Lawrence Distribution Inc.		985 Industrial Rd. P.O. Box 699 Prescott, Ont. K0E 1T0
Licence # ED-2003-0003	Phone: (613) 925-3851	
Wasaga Distribution Inc.		950 River Road West P.O. Box 20 Wasaga Beach, Ont. L0L 2P0
Licence # ED-2002-0544	Phone: (705) 429-2517	
Wellington North Power Inc.		290 Queen Street West, P.O. Box 359 Mount Forest, Ont. N0G 2L0
Licence # ED-2002-0511	Phone: (519) 323-1710	
Westario Power Inc.		24 Eastridge Road R.R. #2 Walkerton, Ont. N0G 2V0
Licence # ED-2002-0515	Phone: (519) 507-6937 Toll Free: 1-866-978-2746	
West Coast Huron Energy Inc.		64 West Street Goderich, Ont. N7A 2K4
Licence # ED-2002-0510	Phone: (519) 524-7371	
Woodstock Hydro Services Inc.		16 Graham Street P.O. Box 1598 Woodstock, Ont. N4S 0A8
Licence # ED-2003-0011	Phone: (519) 537-3488	

Note: Licence Numbers published by OEB as of May 8, 2008



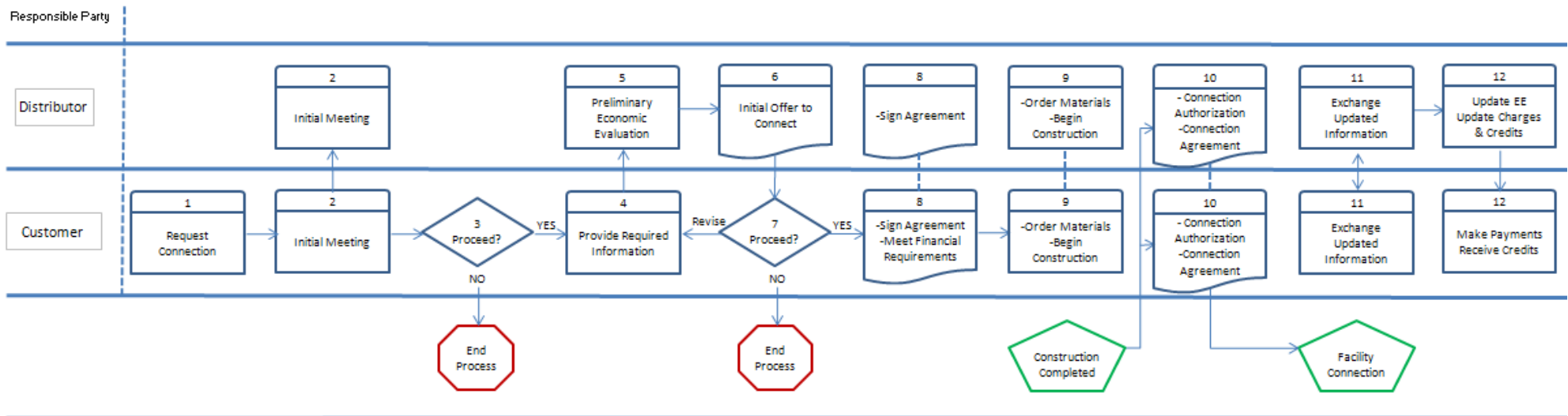
Cornerstone Hydro Electric Concepts Association Inc.



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Distribution Connection

Distribution Connection Developments & General Service Customers





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:
 - o Extension of an existing Feeder
 - o Potential requirement for a new DS
 - o 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?
If YES - Identify Phase

Y / N

Type & Number of Connections:

Residential:
Commercial:
Industrial:

Average Monthly Consumption
Per Unit -
Winter

Kwh's
Kwh's
Kwh's

Per Unit - Summer

Kwh's
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:



Cornerstone Hydro Electric Concepts Association Inc.



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

What service voltage is required (☒ one only):

- ☐ 120/240 Volt Single Phase
- ☐ 120/208 Volt Three Phase
- ☐ 347/600 Volt Three Phase
- ☐ Primary

Required In-Service Date:

Month / Day / Year ____/____/____

**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

Metering Type (☒ one only):

- ☐ Single Meter
- ☐ Multiple Meters

Quantity of Meter installations

100A or less: _____

101A to 200A: _____

more than 200A: _____

Comments: Please use the back of this form for comments

Signed: _____

(Representative of Applicant)

Name: _____

Date: _____

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 #)



Cornerstone Hydro Electric Concepts Association Inc.



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**West Coast Huron Energy Inc.
Financial Statements
December 31, 2007**

AUDITORS' REPORT

To the Shareholder of
West Coast Huron Energy Inc.

We have audited the balance sheet of West Coast Huron Energy Inc. as at December 31, 2007 and the statements of earnings and retained earnings, and cash flows for the year then ended. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

Except as explained in the following paragraph, 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.

Management has recorded an accrual for employee future benefits of \$150,000. There has been no actuarial valuation made of this liability. Due to the complexity of this estimate and its sensitivity to assumptions used we were unable to obtain sufficient appropriate evidence to provide reasonable assurance that management's estimate of the employee future benefits liability is reasonable within the context of the financial statements as a whole.

In our opinion, except for the adjustments, if any, to the liability for employee future benefits referred to in the preceding paragraph, these financial statements present fairly, in all material respects, the financial position of West Coast Huron Energy Inc. as at December 31, 2007 and the results of its operations for the year then ended in accordance with Canadian generally accepted accounting principles.

TAKALO & BURT

Goderich, Ontario
March 18, 2008

LICENCED PUBLIC ACCOUNTANTS
CHARTERED ACCOUNTANTS

West Coast Huron Energy Inc.**Statement of Earnings (Loss) and Retained Earnings**

For the year ended December 31

2007

2006

Service Revenue

Energy	\$ 8,089,144	\$ 8,039,724
Streetlighting	<u>81,785</u>	<u>95,623</u>

8,170,929 8,135,347

IMO Cost of Power Charges

6,560,539 6,548,585

Gross margin on service revenue

1,610,390 1,586,762

Other revenue

Rentals	55,490	51,807
Interest and penalties	42,262	33,118
Other	37,140	32,785
Sewage and water collection fees	27,166	26,433
OPA conservation funding	<u>25,446</u>	<u>-</u>

187,504 144,143

1,797,894 1,730,905

Expenditure

Administration	888,477	835,767
Operations and maintenance	302,607	437,878
Amortization of capital assets and deferred charges	215,250	207,686
Building and maintenance	105,313	49,163
Interest and bank charges	86,543	85,615
Conservation and demand side management	48,003	17,011
Rent	26,400	26,400
Customer relations	<u>8,240</u>	<u>39,622</u>

1,680,833 1,699,142

Net earnings (loss) before income taxes

117,061 31,763

Income taxes

Current	<u>29,788</u>	<u>-</u>
---------	---------------	----------

Net earnings

\$ 87,273 \$ 31,763

Retained earnings, beginning of year

\$ 148,005 \$ 116,242

Net earnings

87,273 31,763

Retained earnings, end of year

\$ 235,278 \$ 148,005

West Coast Huron Energy Inc.**Balance Sheet**

December 31

2007

2006

ASSETS**Current**

Cash	\$ 728,580	\$ 195,716
Receivables	263,103	337,092
Inventory	223,549	207,470
Unbilled revenue	806,436	809,905
Income taxes recoverable	76,406	133,360
Prepays	8,302	8,302

2,106,376 1,691,845**Property, plant and equipment, net (Note 4)**3,791,313 3,794,475**Other**

Regulatory asset (Note 7)	-	105,218
Goodwill	68,119	68,119
Deferred charges (Note 6)	6,843	9,123
Investment (Note 5)	1	1

74,963 182,461\$ 5,972,652 \$ 5,668,781**LIABILITIES****Current**

Payables and accruals	\$ 668,178	\$ 911,614
Current portion of customer deposits	50,000	50,000

718,178 961,614**Long-term**

Note payable (Note 9)	974,454	974,454
Regulatory liability (Note 7)	409,238	-
Customer deposits	225,412	174,616

1,609,104 1,149,0702,327,282 2,110,684**SHAREHOLDER'S EQUITY**

Capital stock (Note 13)	3,410,092	3,410,092
Retained earnings	235,278	148,005

3,645,370 3,558,097\$ 5,972,652 \$ 5,668,781**Contingencies and commitments (Notes 7 and 12)****APPROVED ON BEHALF OF THE BOARD:**_____
Director_____
Director

Takalo & Burt
CHARTERED ACCOUNTANTS

West Coast Huron Energy Inc.
Statement of Cash Flows
For the year ended December 31

	2007	2006
Operating activities		
Net earnings	\$ 87,273	\$ 31,763
Adjustments for non-cash items		
Amortization of property, plant and equipment	212,970	210,183
Amortization of goodwill and deferred charges	2,280	2,280
Change in non-cash working capital balances		
Decrease (increase) in receivables	73,989	(232,346)
Decrease in unbilled revenue	3,469	146,593
Decrease (increase) in inventory	(16,079)	27,626
Decrease in prepaids	-	948
Decrease in payables and accruals	(243,436)	(636,724)
Decrease (increase) in income taxes recoverable	<u>56,954</u>	<u>(37,572)</u>
Net cash provided by operating activities	<u>177,420</u>	<u>(487,249)</u>
Financing activities		
Increase in customer deposits - net	<u>50,796</u>	<u>11,783</u>
Net cash provided by financing activities	<u>50,796</u>	<u>11,783</u>
Investing activities		
Purchase of property, plant and equipment	(209,808)	(108,118)
Decrease in regulatory assets/liabilities	<u>514,456</u>	<u>363,444</u>
Net cash provided by investing activities	<u>304,648</u>	<u>255,326</u>
Net increase (decrease) in cash	532,864	(220,140)
Cash, beginning of year	<u>195,716</u>	<u>415,856</u>
Cash, end of year	<u>\$ 728,580</u>	<u>\$ 195,716</u>

West Coast Huron Energy Inc.
Notes to the Financial Statements
December 31, 2007

1. INCORPORATION

West Coast Huron Energy Inc. was incorporated under the Business Corporations Act of Ontario pursuant to requirements of the Electricity Act 1998. The Town of Goderich passed a Bylaw transferring certain assets and liabilities of the Public Utilities Commission of the Town of Goderich Municipal Electrical Utility to this corporation. In exchange for these assets, the Town of Goderich received a promissory note and common shares.

2. REGULATION

The Ontario Energy Board (OEB) has regulatory oversight powers over electricity matters in Ontario. The OEB issues distribution licences to all owners or operators of a distribution system in Ontario. This licence sets out requirements for regulatory accounting principles, the filing process for rate setting purposes as well as many other conditions for operation. The OEB has the authority to approve and fix rates charged for the transmission and distribution of electricity and thereby also to provide rate protection to electricity customers.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The financial statements have been prepared in accordance with the Canadian generally accepted accounting principles (GAAP), including accounting principles prescribed by the OEB and reflect the significant accounting principles summarized below.

In order to achieve a matching of revenues and expenses for the distribution of electricity, accounting policies may differ from that otherwise expected under Canadian generally accepted accounting principles for non-rate regulated enterprises. Specifically:

- a) Capital and operating costs incurred with respect to the transition to a competitive electricity market have been deferred with amortization to commence on the date that a rate increase is implemented to offset the amortization of these transitional costs.
- b) The Company provides for amounts in lieu of corporate income taxes using the taxes payable method.
- c) The Company has deferred certain cost of power variances in accordance with Article 490 of the OEB's Accounting Procedures Handbook.
- d) Spare transformers are treated as capital assets not as inventory.

Revenue recognition

Energy revenue is recorded on the basis of regular meter readings plus current estimates of customer usage between the last meter reading date and the end of the year at unbundled hydro rates approved by the Ontario Energy Board. Distribution revenue is recorded based on customer usage for the year at approved rates. Service charge and administration revenue are recorded based on approved flat rates including an estimate of amounts earned but unbilled to the end of the year.

West Coast Huron Energy Inc.
Notes to the Financial Statements
December 31, 2007

Inventory

Inventory, which consists of parts and supplies acquired for internal construction or consumption, is valued at the lower of cost and replacement cost. Cost is determined on an average cost basis.

Property, plant and equipment

Property, plant and equipment are carried at cost less accumulated amortization. Certain assets may be acquired or constructed with financial assistance from developers or customers. Such contributions are offset against the related asset cost.

Amortization of property, plant and equipment is provided for on the straight-line basis over the estimated service life of the assets. Amortization of contributions from developers or customers are amortized at the rates corresponding with the useful lives of the related capital asset. The estimated service lives of the various assets used in the calculation of amortization are summarized below:

	Estimated life (in years)
Buildings	25
Substation Equipment	25
Overhead Distribution System	25
Underground Distribution System	25
Line Transformers and Spares	25
Fibre Optics	25
Meters	25
Trucks and Equipment	4 - 8
Computer Equipment	10
Office Equipment	10

Deferred charges

Deferred charges are stated at cost. Amortization is recorded on the straight-line basis over ten years.

Goodwill

Goodwill is not amortized. The carrying value of the goodwill is tested for impairment annually. Goodwill will be adjusted for impairment losses in the year that the impairment is identified.

Impairment of long-lived assets

The Company reviews long-lived assets for impairment whenever events or circumstances indicate that the long-lived assets' carrying amount may not be recoverable. When management determines that an impairment exists, the impairment loss will be determined by comparing the carrying amount of the asset to its fair value. The impairment loss is recorded in the period in which the impairment occurs.

West Coast Huron Energy Inc.
Notes to the Financial Statements
December 31, 2007

Regulatory assets and liabilities

In accordance with Canadian Institute of Chartered Accountants Accounting Guideline 19 "Disclosures by Entities Subject to Rate Regulation", certain costs and variance account balances considered to be "regulatory assets" or "regulatory liabilities" are recorded separately on the company's balance sheet until approval for disposition is received from the Ontario Energy Board. The main categories of regulatory assets/liabilities of the company are comprised of transition costs and settlement variances

Transition costs

Costs incurred to implement the transition to the new unbundled rate structure are deferred in accordance with the criteria set out by the Ontario Energy Board. They are shown as a long term receivable on the balance sheet as they are to be recovered by future hydro rates pending approval by the Ontario Energy Board. Under regulation, certain costs are allowed to be deferred that would be expensed when incurred under Canadian GAAP for unregulated businesses.

Effective January 1, 2003, transition costs have been increased annually by capitalized interest recorded at a prescribed rate and calculated using the simple interest on the prior year's closing balance. The offsetting credit is recorded as interest income.

Settlement variances

The company has recognized settlement variances for the period May 1, 2002 to December 31, 2007. The variance represents the difference between the amount charged by the Independent Electricity System Operator for electricity and the recovery of these costs from customers. The nature of this variance is that it will fluctuate between assets and liabilities over time and are reported at period end dates in accordance with rules prescribed by the OEB. The variance will be recovered in future billing periods and through future hydro rates as approved by the Ontario Energy Board.

Interest is capitalized monthly, calculated and recorded using simple interest at a prescribed rate on the carrying value to compensate the company for the timing difference. The offsetting credit is recorded as interest income.

OMERS pension costs

The Company has recognized a regulatory asset that consists of contributions made by the Company for the period January 1, 2005 to April 30, 2006 as required by the OEB. In the absence of rate regulation these costs would have been expensed in the period in which they were incurred.

Interest is capitalized monthly, calculated and recorded using simple interest at a prescribed rate on the carrying value to compensate the company for the timing difference. The offsetting credit is recorded as interest income.

Conservation demand management

Funds have been allocated to spending on conservation and demand management initiatives over a three year period to 2007. This period has been extended to April 2008. Any amounts collected in excess of expenditures related to this project have been deferred in accordance with the Ontario Energy Board.

West Coast Huron Energy Inc.
Notes to the Financial Statements
December 31, 2007

Smart Meter Program

Revenue is being collected from each residential customer on a monthly basis in order to fund the Company's Smart Meter program in accordance with hydro rates approved on May 1, 2006. Any revenue collected in excess of the capital and operating expenditures for this project are being deferred in accordance with the Ontario Energy Board.

Regulatory asset/liability recovery account

In 2005, the OEB ordered that the approved regulatory balances be aggregated into a single regulatory account. The OEB approved the recovery of transition costs of \$225,480, settlement variances to December 31, 2004 of \$226,585, interest on the settlement variances calculated to April 30, 2006 of \$48,938 and other regulatory assets of \$17,001. In compliance with the OEB order, transition costs, settlement variance balances and other regulatory assets approved for recovery have been reallocated into the regulatory asset/liability recovery account. Specific distribution rates have been implemented that are estimated to recover these amounts over a period ending April 30, 2008. Revenues collected via these specific distribution rates are also allocated to the regulatory asset/liability account as they are intended to offset or recover the approved amounts. Total revenue collected via these permitted rates including accrued interest is \$477,530 (2006-\$487,534). Any over/under recovery of these approved amounts will be factored into future rate approvals. Interest is charged on both the amount to be recovered and the total recovered amount calculated based on the method and at interest rates prescribed by the OEB.

Payments in lieu of corporate taxes

The corporation is a "municipal electric utility" (MEU) under the Electricity Act, 1998 and as such is exempt from tax under the Income Tax Act (Canada). The corporation is required, for each taxation year, to make a payment in lieu of corporate taxes. As a rate regulated entity the company is allowed to account for taxes using the taxes payable method. Under the taxes payable method, no provisions are made for future income taxes that result from temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. When the future income taxes become payable, it is expected that they will be included in the rates approved by the Ontario Energy Board and recovered from the customers at that time.

Employee future benefits

The Company provides its retired employees with extended health benefits and life insurance. The cost of these benefits is expensed as earned through employment service.

Customer's deposits

Customer deposits represent funds collected from customers to guarantee the payment of energy bills. Deposits estimated to be refundable within the next fiscal year have been classified as a current liability. Interest is paid on customer balances annually at rates established by the Corporation.

West Coast Huron Energy Inc.
Notes to the Financial Statements
December 31, 2007

Use of estimates

The preparation of financial statements in accordance with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the year. Actual results could differ from the current estimates including changes as a result of future decisions made by the Ontario Energy Board and an actuarial valuation of employee future benefits. These estimates are reviewed periodically and, as adjustments become necessary, they are reported in earnings in the period in which they become known.

4. PROPERTY, PLANT AND EQUIPMENT

	<u>Cost</u>	<u>Net Book Accumulated Amortization</u>	<u>Net Book Value 2007</u>	<u>Value 2006</u>
Land	\$ 21,747	\$ -	\$ 21,747	21,747
Buildings	70,939	19,247	51,692	54,305
Substation Equipment	152,252	42,574	109,678	115,768
Overhead Distribution system	2,235,255	566,076	1,669,179	1,699,376
Underground Distribution system	965,494	246,264	719,230	704,102
Services	55,958	3,160	52,798	22,727
Line Transformers and Spares	785,589	187,786	597,803	558,029
Fibre Optics	157,082	44,045	113,037	119,320
Meters	391,731	94,660	297,071	310,358
Trucks and Equipment	328,037	270,097	57,940	90,358
Computer Equipment	140,343	59,460	80,883	76,998
Office Equipment	55,901	35,646	20,255	21,387
	<u>\$ 5,360,328</u>	<u>\$ 1,569,015</u>	<u>\$ 3,791,313</u>	<u>\$ 3,794,475</u>

As at December 31, 2007 spare transformers in the amount of \$124,798 (2006 - 125,896) were included in property plant and equipment. In the absence of rate regulation, inventory would have been \$124,798 higher (2006 - \$125,896)

5. INVESTMENT

The company is a limited partner in ENERconnect. ENERconnect is not openly traded on the markets. Market value has not been estimated by management.

6. DEFERRED CHARGES

	<u>Cost</u>	<u>Accumulated Amortization</u>	<u>Net Book Value 2007</u>	<u>Net Book Value 2006</u>
Incorporation costs	\$ 22,803	\$ 15,960	\$ 6,843	\$ 9,123

West Coast Huron Energy Inc.
Notes to the Financial Statements
December 31, 2007

7. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities consist of the following:

	<u>2007</u>	<u>2006</u>
Transition costs	\$ -	\$ 115,766
Settlement variances	(612,108)	(479,709)
Omers pension cost	54,854	52,500
Recovery - court order	125,769	409,522
Smart Meter Program	(18,325)	(6,428)
Other deferrals	98	98
Regulatory asset/liabilities recovery account	<u>40,474</u>	<u>13,469</u>
	<u>\$ (409,238)</u>	<u>\$ 105,218</u>

During the year, the company wrote off \$115,766 (2006 - \$Nil) of transition costs against an allowance for doubtful accounts previously set up by management based on their assessment of the pending recovery approval related to these costs.

8. LETTER OF CREDIT

The company has provided prudentials, in the form of an irrevocable letter of credit, in the amount of \$350,343 (2006 - \$525,000) in favour of the Independent Electricity System Operator. The prudentials serves as security for power purchased from the Independent Electricity Market Operator.

9. NOTE PAYABLE

The note is payable to the shareholder of the company, is due upon demand and bears interest at 7.25% per annum. The note is secured by a general security agreement over all of the Company's assets. The note has been classified as long-term because it is not the intent of the shareholder to demand repayment within the next year.

10. CORPORATE INCOME TAXES

The provision for PILs differs from the amount that would have been recorded using the combined Canadian federal and provincial statutory income tax rate. The reconciliation between the statutory and effective rates is provided as follows:

	<u>2007</u>	<u>2006</u>
Income from operations before PILS	\$ <u>117,061</u>	\$ <u>31,763</u>
Statutory Canadian federal and provincial income tax rate	18.6%	18.6%

West Coast Huron Energy Inc.
Notes to the Financial Statements
December 31, 2007

Expected tax provision (recovery) on income at statutory rates	\$ 21,773	\$ 5,908
Increase (decrease) in income taxes resulting from:		
Amortization/CCA differences	-	3,830
Other	8,015	(9,738)
Provision for PILS	\$ 29,788	\$ -

11. PENSION AGREEMENTS

The company makes contributions to the Ontario Municipal Employees Retirement Fund (OMERS), which is a multi-employer plan, on behalf of 9 (2006 - 10) members of its staff. The plan is a defined benefit plan which specifies the amount of the retirement benefit to be received by the employees based on the length of service and rates of pay.

The amount contributed to OMERS for the year was \$70,234 (2006 - \$72,737) for current service.

The Utility has no obligation on December 31, 2007 under the past service provisions of the OMERS agreement.

12. CONTINGENCIES

Griffith et al. v. Toronto Hydro-Electric Commission et al.

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

On April 22, 2004, the Supreme Court of Canada released a decision in the Consumers Gas case rejecting all of the 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 on 1994 challenging the validity of late payment penalties. The Supreme Court remitted the matter back to the Ontario Superior Court Justice for determination of the damages. At the end of 2006, a mediation process resulted in the settlement of the damages payable by Enbridge.

In 2007, Enbridge filed an application to the Ontario Energy Board to recover the Court-approved amount and related amounts from ratepayers over a five year period.

West Coast Huron Energy Inc.
Notes to the Financial Statements
December 31, 2007

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 LDC's. To date, no formal steps have been taken to move the action forward. The electric utilities intend to respond to the action if and when it proceeds on the basis that the LDC's situation may be distinguishable from that of Consumers Gas.

West Coast Huron Energy collected late payment penalties of \$205,372 from 1994 to 2001. No determination of the portion of these payments which may have constituted interest at an impermissible rate has been made. In 2002 the Company revised its late payment penalty to 1.5% per month on overdue balances.

13. CAPITAL STOCK	<u>2007</u>	<u>2006</u>
Authorized		
Unlimited number of common shares		
Stated capital		
1 common share	\$ <u>3,410,092</u>	\$ <u>3,410,092</u>

14. RELATED PARTY TRANSACTIONS

During the year, the company paid to its shareholder **\$70,648** (2006 - \$70,648) interest on the outstanding note payable. This amount is included as interest and bank charges expense on the statement of earnings and retained earnings.

The company collected sewage charges of **\$1,375,809** (2006 - \$1,176,009) and water charges of **\$1,543,401** (2006 - \$1,305,853) on behalf of the Shareholder of the company. A collection fee of **\$27,166** (2006 - \$26,432) was received for this service. At year end a balance of **\$242,084** (2006 - \$190,303) is owed to the Town of Goderich relating to water and sewage revenue collected.

The company paid rent to the shareholder of the company in the amount of **\$26,400** (2006 - \$26,400).

The company paid to the shareholder of the company an administration fee of **\$40,000** (2006 - \$40,000).

The company contributed **\$9,336** (2006 - \$9,092) toward the costs of an environmental officer employed by the shareholder of the company.

15. GUARANTEES

In the normal course of business, the Company enters into agreements that represent guarantees as defined by Canadian Accounting Guidelines. The primary types of such guarantees are as follows:

West Coast Huron Energy Inc.
Notes to the Financial Statements
December 31, 2007

a) Indemnity has been provided to all directors and officers of the Company for various items including but not limited to all costs to settle suits or actions incurred due to association with the Company, subject to certain restrictions. The Company has purchased directors' and officers' insurance to mitigate the cost of any potential future suits or legal actions. The term of indemnification is limited to the period over which the director and or officer served as director/officer of the Company. The maximum amount of any potential future payment cannot be reasonably estimated.

b) The Company has entered into agreements that include indemnities in favour of third parties such as engagement letters with advisors and consultants, outsourcing agreements, information technology and service agreements. These agreements may require the Company to compensate counter parties for losses as a result of breaches in representation and regulations or as a result of litigation claims or statutory sanctions that may be suffered by the counterparty as a result of the transaction. The maximum amount of any potential future reimbursement cannot be reasonably estimated.

The nature of these indemnity agreements prevents the Company from making a reasonable estimate of the maximum exposure due to difficulties in assessing the amount of liability which results from the unpredictability of future events.

The Company has not made any significant payments in the past under such circumstances and therefore no amount has been accrued on the balance sheet with respect to these agreements.

16. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Fair value of financial instruments

The Company's financial instruments include cash, receivables, accounts payables and accruals. The carrying value of these instruments approximates their fair value due to their immediate or short-term maturity.

Financial instruments also include a note payable with terms as disclosed in Note 8. The fair value is not determinable due to the related party nature and variable terms.

Concentration of credit risk

It is management's opinion that the company is not exposed to significant interest rate or credit risk arising from its financial instruments.

Insurance

The Company holds insurance with major insurers at appropriate types and levels as determined by management. It is a member of the Municipal Electricity Association Reciprocal Insurance Exchange (MEARIE) for its liability coverage. This reciprocal insurance exchange is formed to exchange reciprocal contracts of indemnity or inter-insurance among the members of the group. Insurance premiums are charged to each member as a fee per thousands of dollars of service revenue with an adjustment to reflect the member's claims experience. The coverage provided by this insurance is to a level of \$20,000,000 per occurrence.

West Coast Huron Energy Inc.
Notes to the Financial Statements
December 31, 2007

17. FUTURE ACCOUNTING CHANGES

The Canadian Institute of Chartered Accountants issued the following new sections: Section 1530, "Comprehensive Income", Section 3855, "Financial Instruments - Recognition and Measurement", Section 3862, "Financial Instruments - disclosures", and Section 3863, "Financial Instruments - presentation". These standards provide recommendations on recognition, measurement and disclosure of financial instruments. Adoption of these standards is implemented retrospectively without restatement of prior year results. These standards are effective for fiscal periods beginning on or after October 1, 2007.

Management is currently assessing the impact of these new standards on the financial statements.

**WEST COAST HURON ENERGY
PROFORMA BALANCE SHEET
AS AT DECEMBER 31ST 2008**

ASSETS

	YEAR ENDED 31-Dec-08
Current	
Bank	\$ 211,991
Accounts Receivable	263,103
Inventory	223,549
Unbilled Revenue	806,436
Prepaid Expenses	8,302
	<u>1,513,381</u>
Capital Assets	3,956,155
Investment	1
Note Receivable	6,843
Goodwill	<u>68,119</u>
	<u><u>\$ 5,544,499</u></u>

LIABILITIES AND SHAREHOLDER'S EQUITY

Current	
Accounts Payable and Accrued Liabilities (note 5)	\$ 683,178
Customer Deposits	50,000
	<u>733,178</u>
Long-term Debt	
Note Payable	974,454
Regulatory Liability	409,238
Customer Deposits	225,412
	<u>1,609,104</u>
Shareholders' Equity	
Share Capital	3,410,092
Retained Earnings	<u>(207,875)</u>
	<u>3,202,217</u>
	<u><u>\$ 5,544,499</u></u>

WEST COAST HURON ENERGY
PROFORMA STATEMENT OF INCOME
FOR THE TWELVE MONTHS ENDED DECEMBER 31ST 2008

	YEAR ENDED 31-Dec-08
Electricity Revenue	\$ 8,399,153
Cost of Power	<u>6,536,615</u>
Gross Margin	1,862,538
Miscellaneous Revenues	<u>88,300</u>
Total Revenues from Operations	1,950,838
Expenses	
Billing and Collecting	436,800
Community Relations	26,000
Regulatory and Professional	245,300
Office and Administration	640,600
Direct Operation	<u>472,550</u>
	1,821,250
Net Income from Operations Before Taxes, Interest & Amortization	129,588
Amortization	343,019
Shareholder Interest	164,390
Interest income on regulatory assets	<u>-</u>
Net Income from Operations Before Tax	(377,821)
Other Income	
Investment Income	-
Net Income Before Income Taxes	(377,821)
Current Taxes	-
PILS	<u>65,332</u>
Net Income (Loss)	(443,153)
Retained Earnings (deficit) Beginning of Period	<u>235,278</u>
Retained Earnings (deficit) End of Period	<u><u>\$ (207,875)</u></u>

**WEST COAST HURON ENERGY
PROFORMA BALANCE SHEET
AS AT DECEMBER 31ST 2009**

ASSETS

	YEAR ENDED 31-Dec-09
Current	
Bank	\$ 211,991
Accounts Receivable	263,103
Inventory	223,549
Unbilled Revenue	806,436
Prepaid Expenses	8,302
	<u>1,513,381</u>
Capital Assets	4,368,136
Investment	1
Note Receivable	6,843
Goodwill	<u>68,119</u>
	<u><u>\$ 5,956,480</u></u>

LIABILITIES AND SHAREHOLDER'S EQUITY

Current	
Accounts Payable and Accrued Liabilities (note 5)	\$ 831,122
Customer Deposits	50,000
	<u>881,122</u>
Long-term Debt	
Note Payable	974,454
Regulatory Liability	409,238
Customer Deposits	225,412
	<u>1,609,104</u>
Shareholders' Equity	
Share Capital	3,410,092
Retained Earnings	56,161
	<u>3,466,253</u>
	<u><u>\$ 5,956,479</u></u>

WEST COAST HURON ENERGY
PROFORMA STATEMENT OF INCOME
FOR THE TWELVE MONTHS ENDED DECEMBER 31ST 2009

	YEAR ENDED 31-Dec-09
Electricity Revenue	\$ 9,227,507
Cost of Power	<u>6,672,242</u>
Gross Margin	2,555,266
Miscellaneous Revenues	<u>92,696</u>
Total Revenues from Operations	2,647,962
Expenses	
Billing and Collecting	436,800
Community Relations	26,000
Regulatory and Professional	361,400
Office and Administration	524,500
Direct Operation	<u>472,550</u>
	1,821,250
Net Income from Operations Before Taxes, Interest & Amortization	826,712
Amortization	343,019
Shareholder Interest	164,390
Interest income on regulatory assets	<u></u>
Net Income from Operations Before Tax	319,302
Other Income	
Investment Income	-
Net Income Before Income Taxes	319,302
Current Taxes	
PILS	<u>70,294</u>
Net Income (Loss)	264,036
Retained Earnings (deficit) Beginning of Period	<u>(207,875)</u>
Retained Earnings (deficit) End of Period	<u><u>\$ 56,161</u></u>

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Goderich Hydro

January 2008

Distribution System Assessment

for

Proposed Sifto Salt Load Expansion

Analysis of Operating Conditions, Redundancies

Potential Upgrade Recommendations

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DISCLAIMER

This report has been prepared by David Wills, P. Eng (“DW”). DW’s liability to any party or person, other than the party to whom this report is addressed with respect to the use of this report, is limited to damages that arise directly out of the gross negligence or the wilful misconduct of DW. Under no circumstances of any kind will DW be liable for any indirect or consequential damages, business interruption losses, loss of profit or revenues, any loss of contract or loss of goodwill, special damages, any punitive or exemplary damages, whether any of the said liability, loss or damages arises in contract, tort or otherwise and under no consequence will liability be accepted in excess of the value of the work performed.

ASSUMPTIONS AND RELIANCES

DW has prepared this report assuming the authenticity and accuracy of all documents, data and files submitted by or on behalf of Goderich Hydro and Sifto Salt and has relied on the representations and information made available to conduct the studies and prepare this report. I have performed appropriate due diligence but not undertaken any special or independent investigation to determine the accuracy, existence or absence of such facts or circumstances.

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Goderich Hydro Distribution System Assessment

1. Executive Summary

Goderich Hydro (the LDC) has two feeders, the M3 which peaks at 17 MW or 475 A and the M4 which peaks at 9.5 MW or 215 A. The feeders are 336 conductor which has a maximum current rating of 450 A. Refer to Section 5 for discussion. The load on the M3 is primarily one customer, Sifto Salt, whose load characteristic have a low power factor of about 0.78. Since at peak the 336 conductor exceeds its rating, the LDC has no operating flexibility or redundancy for the loss of critical feeder elements. Sifto has expansion plans and the LDC is concerned that a critical situation is going to get worse.

This report assesses the status quo and works through a number of potential options to reinforce supply, lower operating currents and provide operating flexibility and redundancy.

There are two approaches with some similar and some alternate options. The first is to maximize the facility of the two existing feeders. The second and preferred option is to add a third feeder.

The components of the approaches can be mixed and matched for interim relief providing the end point is kept in focus and to some extent the order of activities depending on the opportunity to do work, the timing available and working with Sifto's plans to integrate the upgrades to ensure the least disruption to the town's customers and Sifto.

In summary the upgrades recommended for consideration are:

a. Maximize Two Feeders

- Increase conductor size on M4 egress and line section from TS to MS 1 to 795 ACSR. Assess potential to increase breaker trip setting to 800 A at the same time.
- Tie between M3 and M4 at TS
- Split Sifto load by double circuiting into plant
- Build tie line between M3 and M4 circuits MS 1 to MS 2.
- Upgrade M3 conductor from TS to MS2 to 795 ACSR.
- Upgrade M4 egress from 750 kCMil Al to 1000 kCMil Cu.

b. Add Third Feeder

- Build tie line between M3 and M4 circuits MS 1 to MS 2.
- Add breaker position to TS.
- Build 3rd circuit from TS to MS2. Increase M3 conductor size to 556 from TS to MS2.
- Split Sifto load by double circuiting into plant
- Add ties between TS and splits for M3, M4 and 3rd feeder to increase operating flexibility.
- Upgrade M4 egress from 750 kCMil Al to 1000 kCMil Cu.

2. Background

The LDC has two feeders supplied by Goderich TS, the M3 and the M4. The feeders peak annually in August, the M3 at 17 MW and the M4 at 9.5 MW. The M3 has a large customer, Sifto Salt that influences the feeder characteristics significantly. Sifto's contribution to the peak load on the M3 is 9,5 MW. Sifto's load has a power factor ("PF") that varies between 0.65 and 0.85 and averages in the 0.78 range. At peak load, the feeder current on the M3 is 475 A because of the low PF and 215 A on the M4. The LDC feeders are 336 ACSR which is rated for a maximum operating current of 450 A¹. therefore at peak load the feeder current is at 102% of the maximum rated conductor current

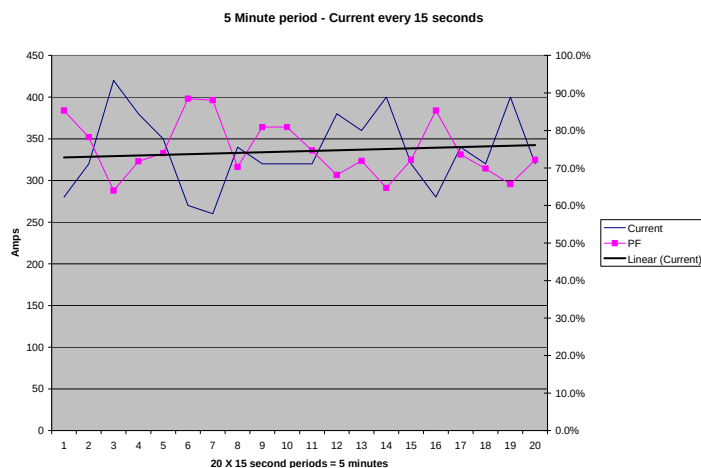
The system has a normally open point just to the south of the tap to Sifto Salt. When the system was designed and installed it was intended that if the either the M3 or M4 breaker was opened the entire load could be carried on the alternate feeder or that with sectionalization sections of the two feeders could be isolated in the event of equipment failure or to perform maintenance work on the system. That is now extremely limited or not possible on most days in the summer peak months.

Taking the data from above it is evident that any attempt to pick up the total LDC load with one breaker will result in a feeder current in the order of 690 A which exceeds the setting for the timed overcurrent protection on the TS 800 A breaker of 80% of the rating = 640A which was likely set with reference to a calculated 336 conductor extreme hot rating.

3. Sifto Load and Load Profile

The Sifto load is diverse but the major components are two hoists, one with 2 X 1300 HP motors and the other with 2 X 1500 HP motors, that transport salt to the surface and crushing equipment rated at about 1000 HP. When the hoists are accelerating the LDC notices a significant short term transient response on the feeder. While accurate records and data do not exist it is not unusual for the feeder to be at 280 A one minute and at over 440 A the next minute. These current excursions occur several times a minute. The thermal impact on the LDC is less than the peak so in a 5 minute period where the current has exceeded 400 A three times it is estimated that the feeder will see this as an integrated current of about 335 A. This is represented graphically in Figure 1.

Figure 1



¹ Bare conductor, Still Air, 40⁰ C Ambient, No Sun, 60⁰ C conductor temperature rise,
Goderich Hydro Distribution System Assessment
Prepared by David Wills, P.Eng. January 2008

When the hoists accelerate the current increases from 280 A to 440 A and back to 280 A in about one minute. Thermally this is equivalent to an integrated current of about 350 A. This is represented graphically in Figure 2.

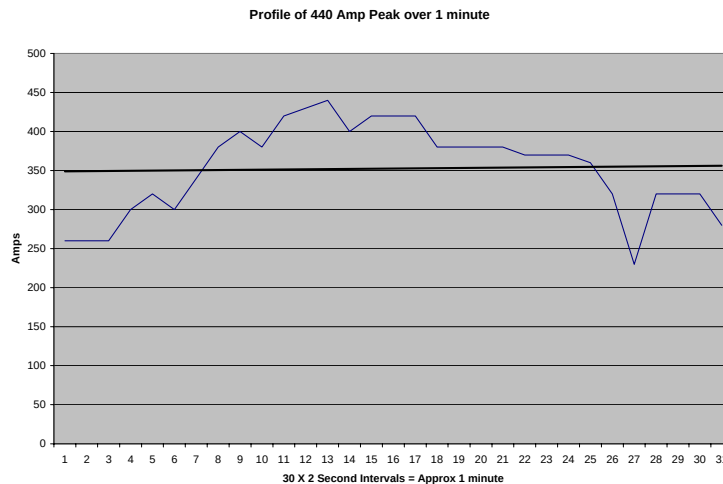


Figure 2

4. Sifto Load Expansion Plans

Sifto's existing load is 11.5 MW at peak. Sifto has advised the LDC that it plans to add about 1000 HP of additional crusher motor load in 2008 and a third hoist in about two to three years. It takes no analysis and no data to conclude that a tight operating situation will get even tighter but the stark numbers are that this load addition could increase the Sifto load to 14.5 MW (perhaps less with some diversity) but in the worst case the M3 load would increase to 549 A or 122% of the existing feeder conductor current capacity.

5. Conductor Rating

Much of the rationale for the following analyses is based on the current rating of the conductor. There are no hard and fast rules for rating conductors but there is prudence and good engineering judgement.

Essentially as current is passed through a conductor it heats up in relation to the equation I^2R but it also dissipates that heat which depends on the surface area, the ambient temperature, the wind the sun and other such variables. As the conductor heats it sags so an additional variable is how hot are you prepared to let it get.

The rating in DESS, the software used for analyzing the Goderich system, is based on an approximation that can be considered a reasonable "rule of thumb" for the maximum current carrying capacity of the conductor and it originates from a well respected engineering "bible" originally published by Westinghouse and now by ABB.

These values are as follows:

Conductor Size	Maximum Current Rating (Amps) ABB
336 ACSR	530 A
556 ACSR	730 A
795 ACSR	900 A
336 AL	530 A
556 AL	730 A
795 AL	900 A

Another source that takes a more scientific approach and calculates the rating over a range of conditions is more conservative.

Conductor Size	Maximum Current Rating (Amps) Still Air ¹	Maximum Current Rating (Amps) 2 ft. per sec wind ¹
336 ACSR	450 A	480 A
556 ACSR	640 A	680 A
795 ACSR	820 A	850 A
336 AL	580 A	640 A
556 AL	820 A	850 A
795 AL	1100 A	1130 A

¹ 40° C Ambient, No Sun, 60° C temperature rise.

As mentioned the DESS rating is an approximation and an upper limit and actual current carrying ability is determined by ambient temperature, wind, sun and acceptable temperature rise for the conductor.

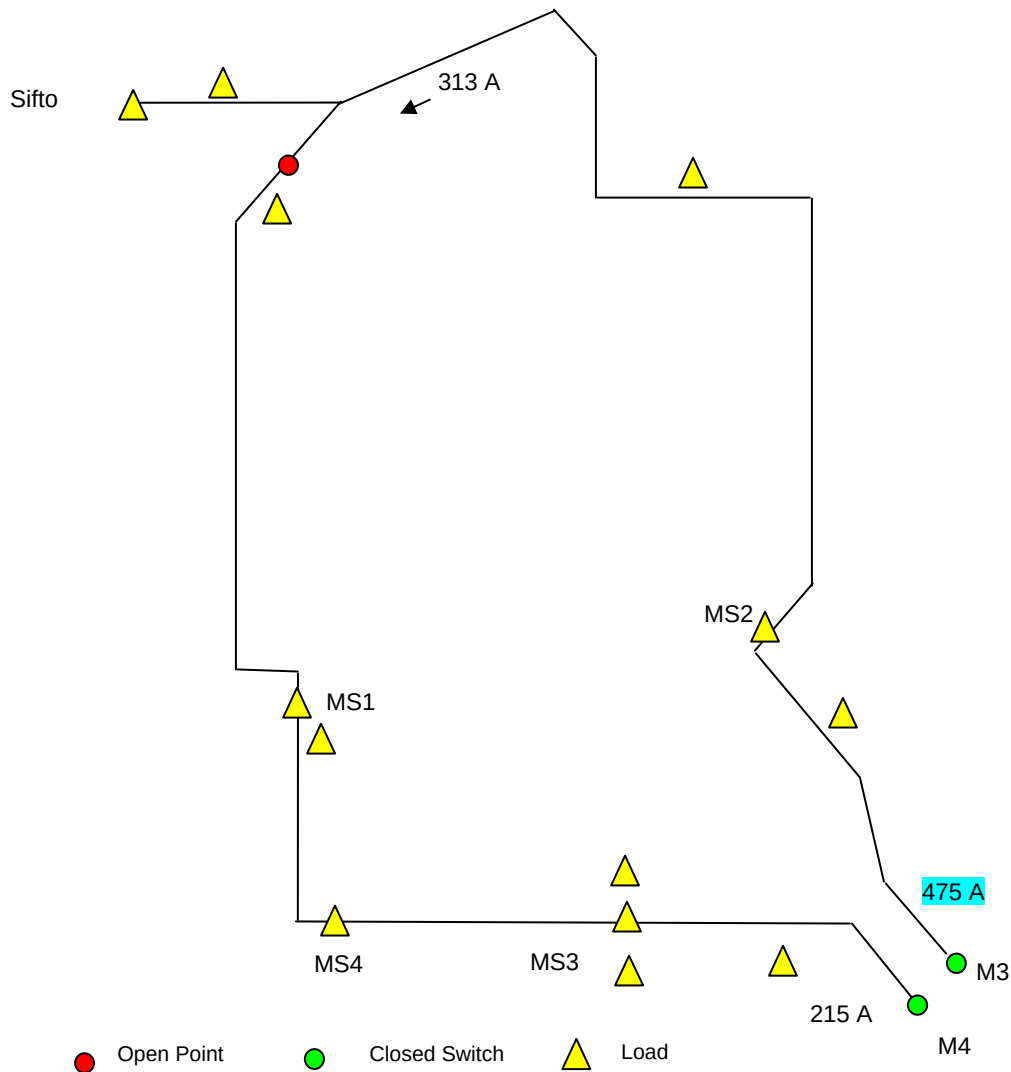
Variation of these factors produces different results as shown in the last chart. The effect of higher currents is higher losses and sagging of the conductor. Since not all clearances are known and there may be sections of aluminum rather than ACSR some safety factor is required to ensure the phase conductors don't touch or sag into the neutral. For this reason the rating for aluminum conductor in still air has been used as a maximum in this report.

With a maximum of 450 A for 336 and 640 A for 556 A a design criteria of 300 A for 336 and 425 A for 556 for normal operation and economic system operation, to reduce losses, has been chosen.

6. Potential Solutions

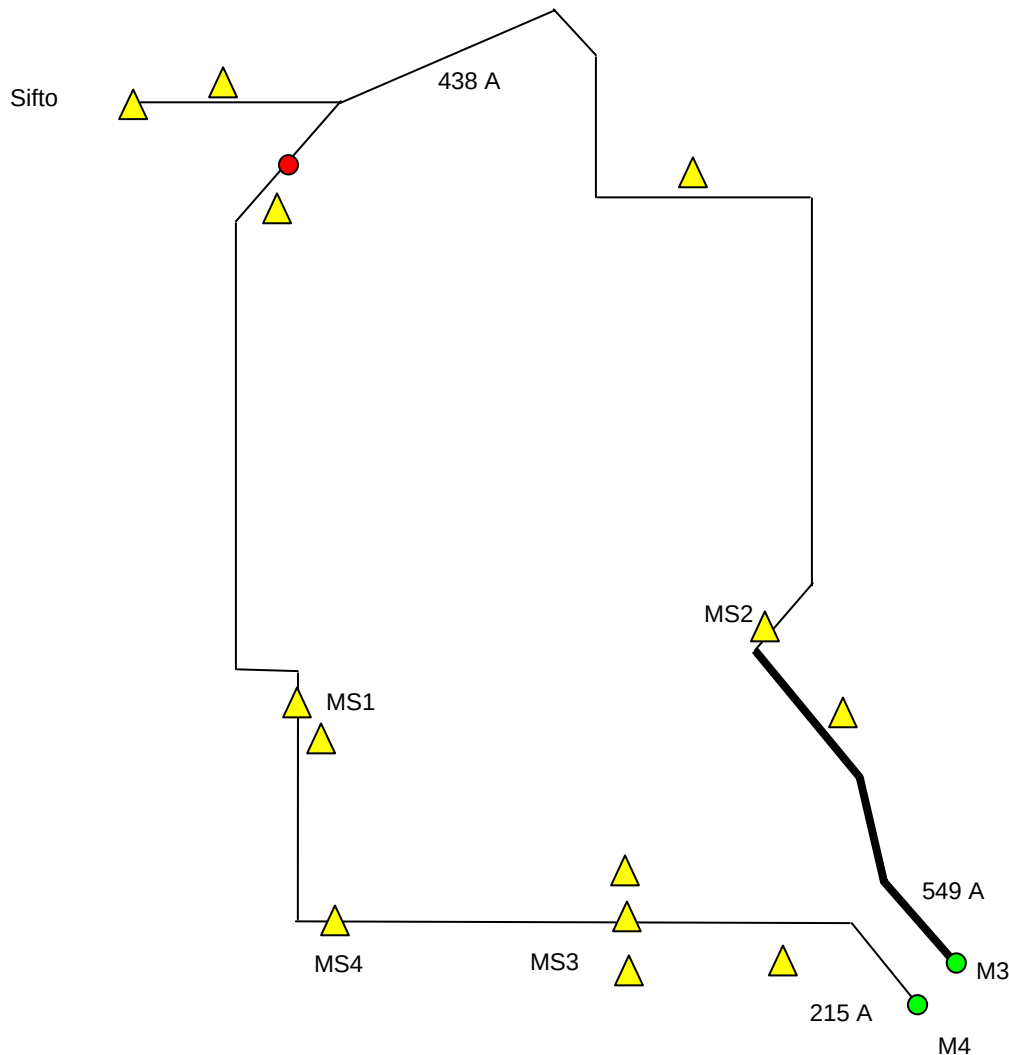
The LDC 27.6 kV system can be represented graphically by the following simplified drawing. The status quo currents at peak are shown at several key points. The first obvious concern is the line section from the TS to MS2 which exceeds the rating for 336 conductor.

a. Status Quo



b. Upgrade Conductor TS to MS2 on M3

This scenario is illustrated below with a load increase at Sifto.

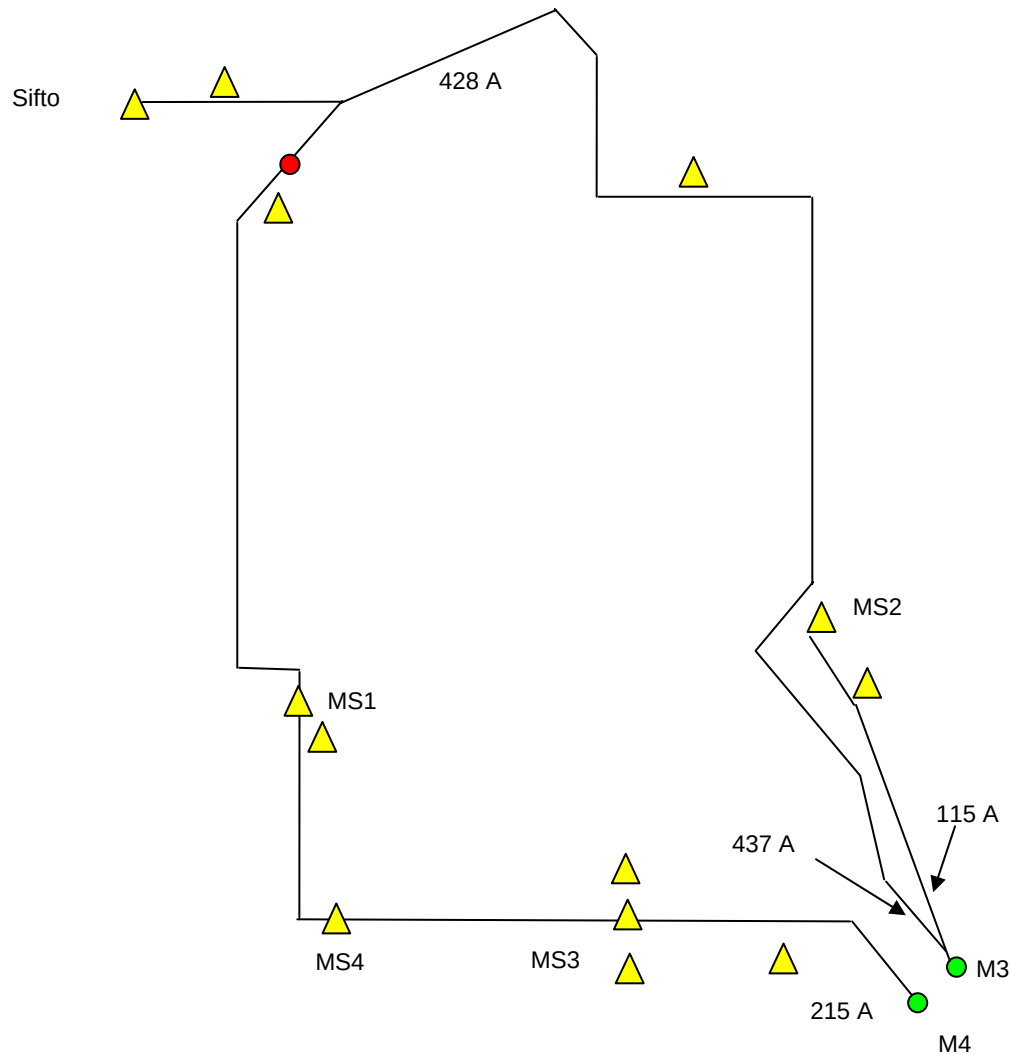


Discussion

One option is to upgrade the 336 conductor but unless this is done from the TS to Sifto any section that is not upgraded will be near capacity. For example the conductor as far as MS 2 could be replaced with 556 or 795 ACSR which would alleviate peak loading with both breakers in service but does nothing for operating flexibility in peak months and leaves the section from MS 2 to Sifto at close to its rated capacity leaving no room for additional load.

c. Alternative to Upgrade from TS to MS2 on M3

Another option is to relieve load from the M3. For example if the M3 is parallel/"double" circuited from the TS to MS 2 and MS 2 and the industrial load to the east of the M3 transferred to the new circuit this relieves the current in the first section of the feeder but it does not resolve the loading of the feeder section from MS2 to Sifto or resolve operating flexibility.



Discussion

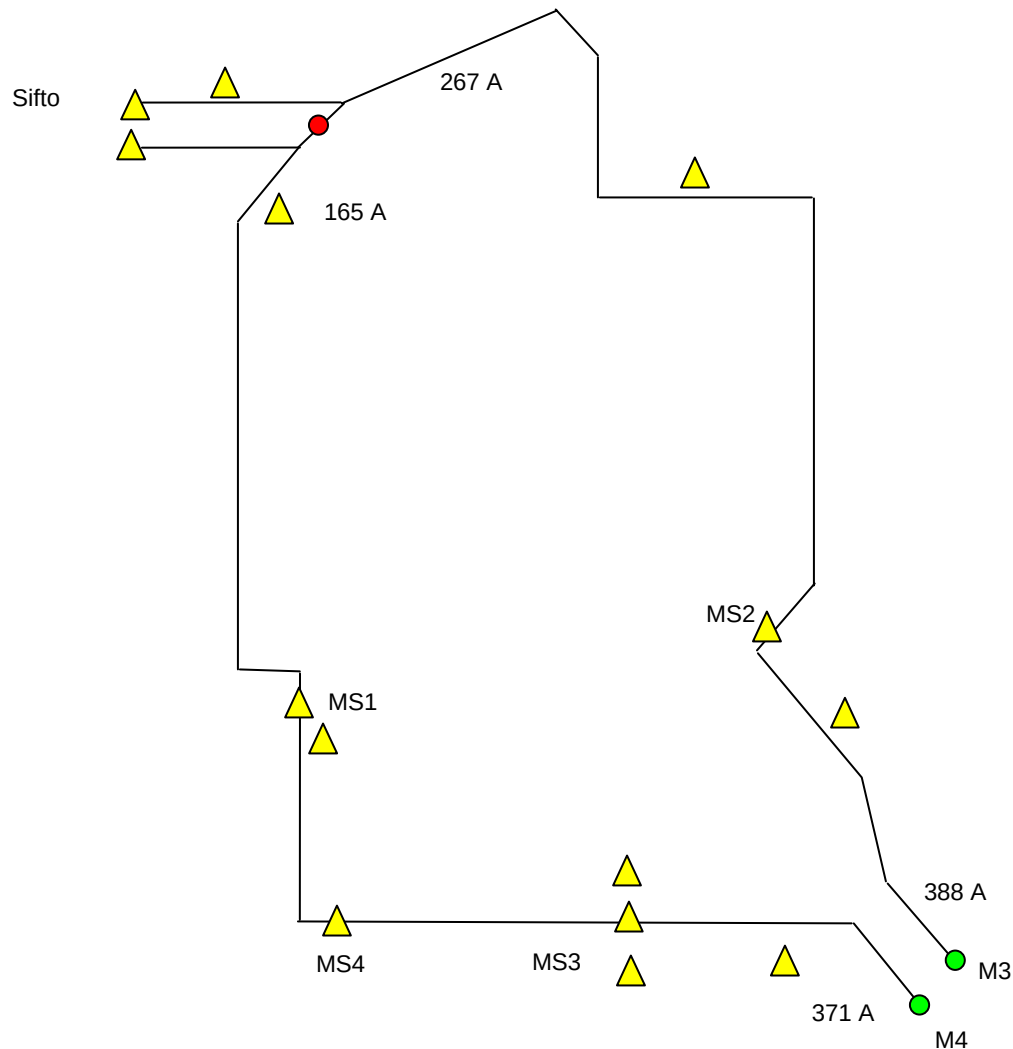
All of the above options have one thing in common – they attempt to resolve the problem by leaving Sifto unchanged as a single load entity.

Sifto is in fact a load that is split at the plant into one 12.5 MVA transformer which supplies the crushers and plant load and two 4 MVA transformers which supply one hoist each.

d. Double Circuit Sifto Line

If the line to Sifto were double circuited and for example the 12.5 MVA transformer with the new crusher and the new hoist picked up off the M3 and the two 4 MVAs with the existing hoists picked up off the M4 this would split the load between the M3 and the M4

This is illustrated as follows.



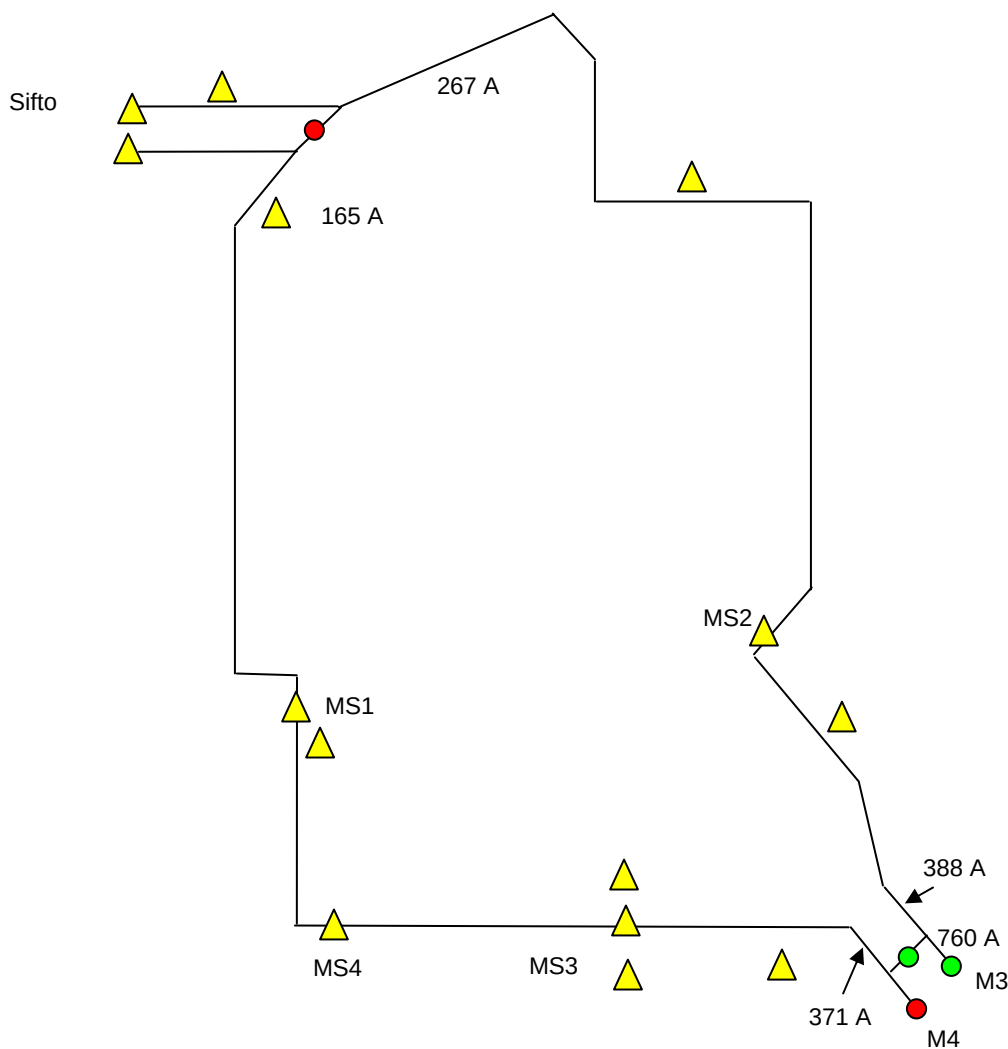
Discussion

This works for normal operating conditions but not for loss of the M3 or M4 feeder breaker. In this situation the combined current on the remaining feeder exceeds 750 A.

e. Tie Switch between M3 and M4

This can be resolved by the addition of a tie switch beyond the point where the egresses from the TS connect to the M3 and M4 feeders but this only works if everything upstream of the switches is rated accordingly. Unfortunately the M4 is supplied by 750 kCMil AL underground which becomes a weak link in the chain with a rating of 560 A. If this conductor was upgraded to 1000 kCMil Cu it would have a capacity for 900 A.

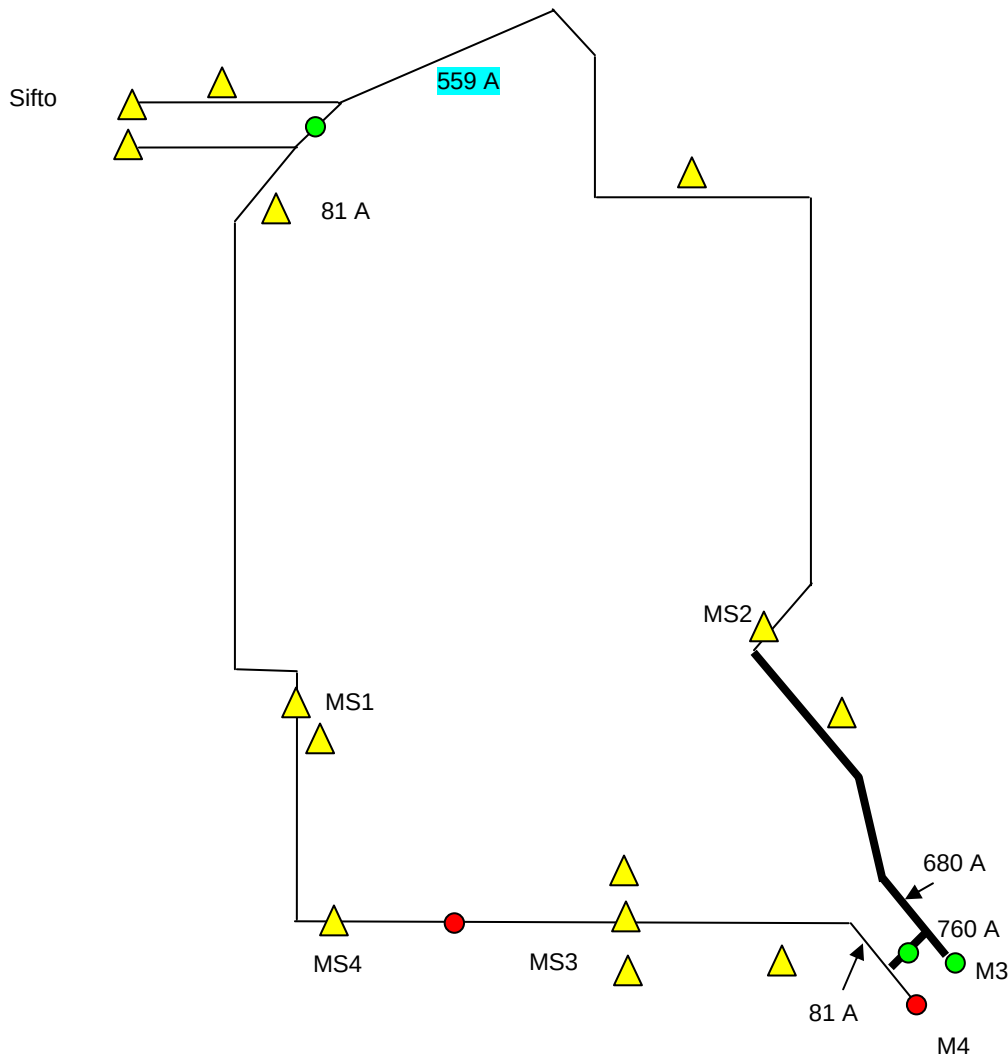
With this worst case scenario the current in the first section up to the tie switch would be 760 A which would be within the capacity of 795 ACSR.



Discussion

The other assumption in this operating arrangement is that the breaker settings at the TS can be increased to 800 A. It is clear that this is pushing the limits of what is possible with two feeders and planning for a contingency where one is not available and the LDC wants to maintain temporary supply on the single remaining feeder. It should be noted that the Sifto load has been modelled at the maximum likely. It is possible that when it is added, with diversity, it will be less than forecast.

This works providing all the sections on both feeders are available but if the section, say between MS3 and MS4 is not available the 336 in the M3 again becomes the weak link as follows.

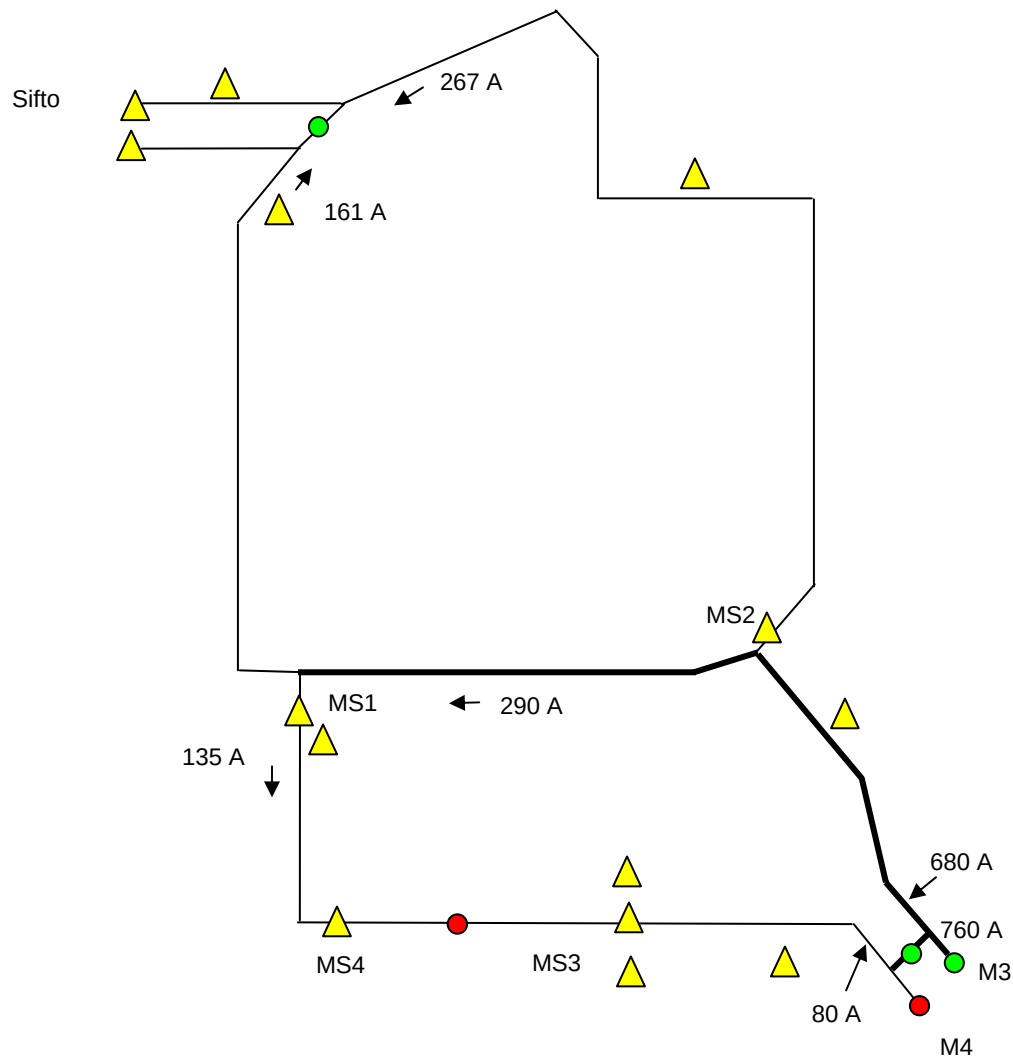


f. Tie Line between M3 and M4

This can be mitigated by building a tie line between the M3 and the M4 from MS 2 to MS 1 and increasing conductor size of the M3 from the TS to MS 2. With this configuration the flexibility of the operating conditions that can be supported is significantly increased.

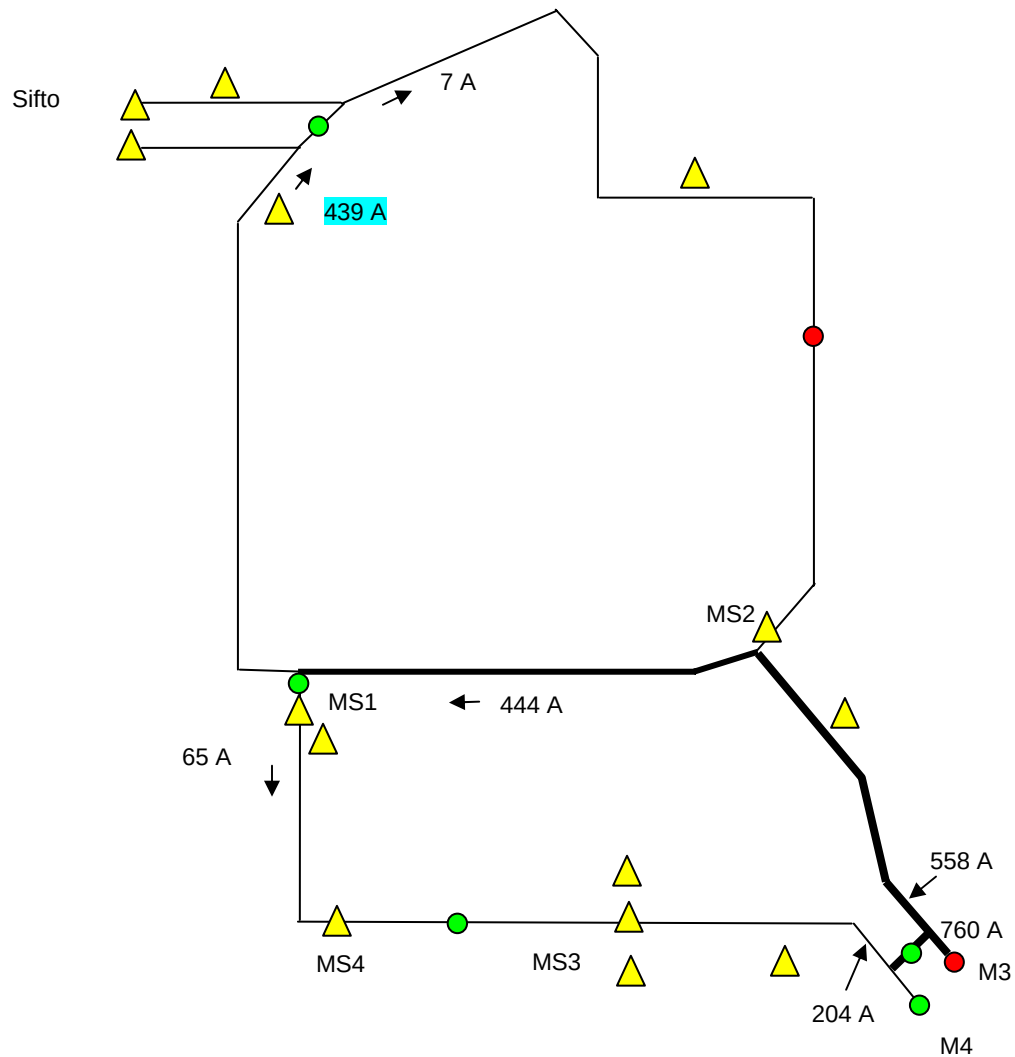
i. Example 1

Starting with the example from the Discussion in e) above for illustration the ability of the tie line to split load is evident. All 336 line sections are now well within their maximum rating.



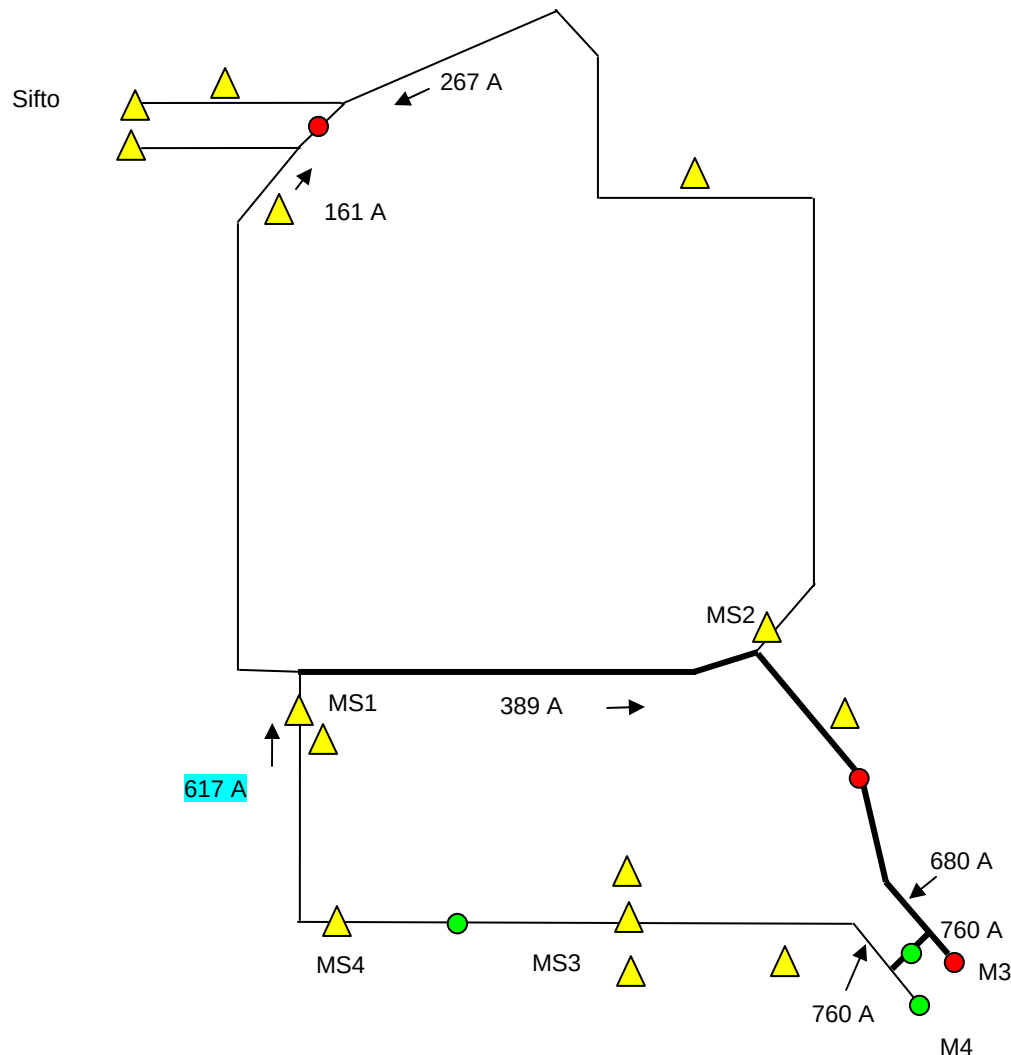
ii. Example 2

The above example is fine for normal operating conditions but for an open point in the line section above MS 2 the resultant current north of MS1 is pushing the limit of the 336 conductor 1 as it picks up all the load from Sifto.



iii. Example 3

If the open point is below MS 2 the situation changes significantly and the 336 conductor supplying MS 1, 3 and 4 is not adequate.



Discussion

If the 336 conductor in the line section between the TS and MS1 were upgraded to 795 ACSR this figure eight configuration would offer about as much operating flexibility as was possible with two feeders.

One more alternative to this last option is to consider whether picking up the tie line more directly might be less expensive but there is a point where options layered on options become unrealistic.

8. Options and Alternatives

The above order of recommendations considers primarily the engineering benefits as the order of priority. There may be other considerations that would warrant a different order. For example if the tie line from MS1 to MS2 is built earlier it allows the line sections from the TS out to be isolated for upgrade purposes which will lower the cost of construction and reduce the time they are out of service.

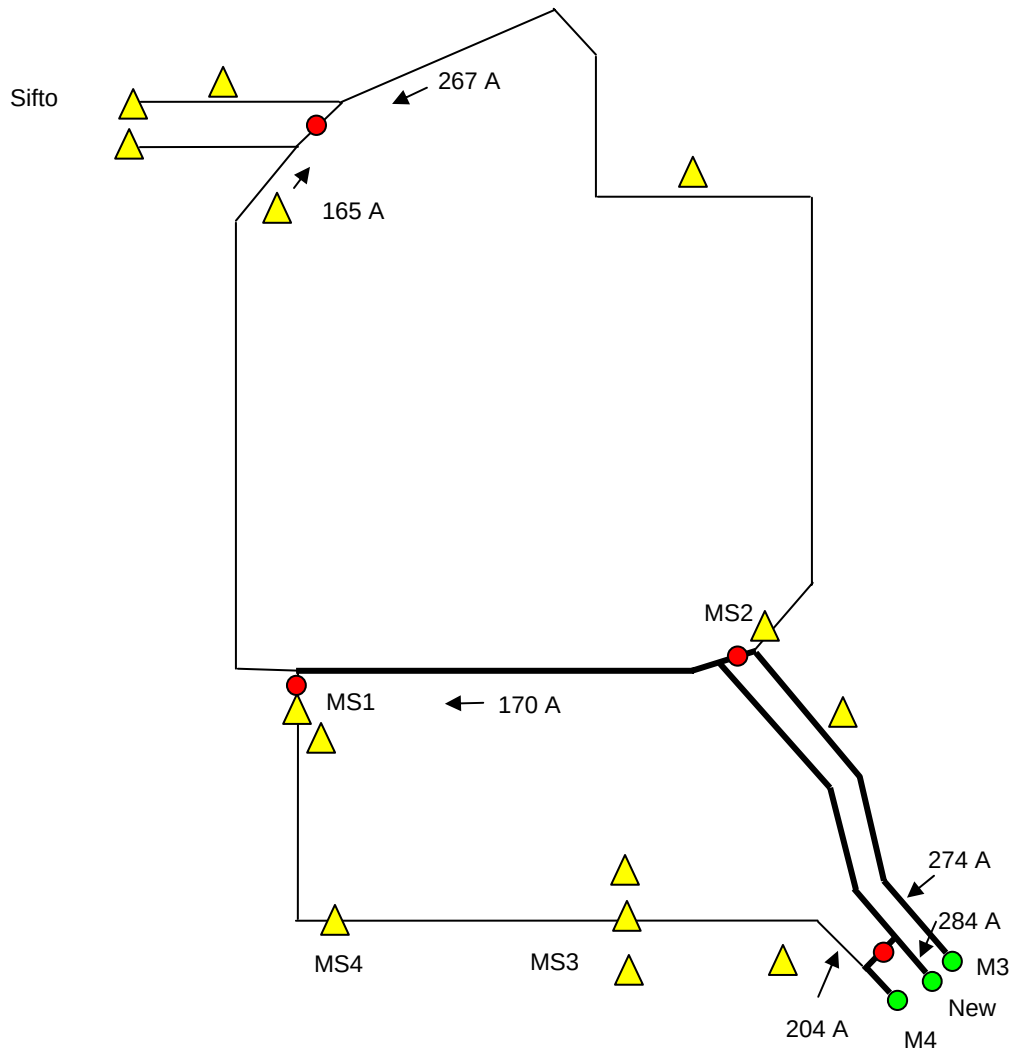
The above scenarios also focus on how to improve and extend the capacity of the existing two circuits but they virtually exhaust the ability of one circuit to back up the other.

If a breaker position is available at the TS the next option would be to consider a new breaker position and a third feeder. This would alter the options considered for the two feeders alone. Now the double circuiting of the line section to MS2 makes more sense because it can be the backbone of the third feeder.

With a third feeder as an option the order of priorities could be:

- Build tie line between M3 and M4 circuits MS 1 to MS 2.
- Add breaker position to TS.
- Build 3rd circuit from TS to MS2. Increase M3 conductor size to 556 from TS to MS2.
- Split Sifto load by double circuiting into plant
- Add ties between TS and splits for M3, M4 and 3rd feeder to increase operating flexibility.
- Upgrade M4 egress from 750 kCMil Al to 1000 kCMil Cu.

The end point would be as in the following



All new construction should use 556 ACSR conductor as a minimum but depending on the amount of redundancy required some existing 336 sections may be adequate. A further analysis of operating configurations and required conductor sizes can be undertaken to determine the optimum sizing for conductors and the limitations of various operating configurations with existing conductor.

Appendix 1

Current rating of Conductors Reference Data

Procedure

Annual Distribution System Inspections & Maintenance

All Printed Quality Documents shall be considered uncontrolled

1.0 PURPOSE

- 1.1 To describe the process for Goderich Hydro Annual Inspection and Maintenance Practices for the Overhead & Underground Distribution System.
- 1.2 To ensure compliance with the Ontario ESA Regulation 22/04, Electrical Distribution Safety.

2.0 SCOPE

- 2.1 This procedure applies to Goderich Hydro Overhead and Underground Distribution System Inspection & Maintenance Practices.
- 2.2 Inspections will be done on the Distribution System each year as per following schedule:
 - Overhead & Underground Distribution System Inspections Poles/Overhead Lines/Underground Lines/Ancillary Equipment <750volts (1/3 of system annually)
 - Padmount Transformers (1/3 of system annually)
 - Tree Trimming Maintenance (1/3 of system annually)
 - Distribution Sub-Station Inspections (bi-monthly)
 - Oil Analysis of Distribution Sub-Station Transformers (annual written report on results required)
- 2.3 Ancillary Equipment operating at <750volts and third party attachments that are not a direct part of the Distribution System
(i.e. Telecommunications Equipment/Street Lights/Traffic Lights/Signs/Decorations, etc.)
- 2.4 When a problem is identified, the condition will be graded on the severity of the situation as follows:
 - Grade 1 - requires immediate attention and corrective action shall not exceed 10 working days. (i.e. broken pole/potential shock hazards/ limb on line/floating conductor/low wires padmount transformer off base)
 - Grade 2 - requires attention within 90 days (i.e. OH or UG connections or terminations heating up/ rotten pole/signage)
 - Grade 3 - continue monitoring/work as schedule allows/budget for (i.e. equipment deterioration/transformer painting required/tree trimming)

Procedure

Annual Distribution System Inspections & Maintenance

All Printed Quality Documents shall be considered uncontrolled

3.0 REFERENCE

- 3.1 Ontario ESA Regulation 22/04 section 4

4.0 PROCEDURE

- 4.1 Goderich Hydro will develop and maintain an ongoing Maintenance Schedule for the overhead and underground distribution system, refer to Appendix "A"- (Goderich Hydro Distribution System Inspection/Maintenance Schedule).
- 4.2 Goderich Hydro will perform inspections of a third of its service area on Poles/Overhead & Underground lines/Ancillary Equipment/Padmout Transformers/Switch Gear annually , grading the severity of problems identified (see Form: 68 – 00 Goderich Hydro Distribution System Inspection Log). Goderich Hydro will also perform tree trimming of a third of the service area in the first quarter of every year.
- 4.3 All Grade 1 issues found will be reported to the Line Foreman or Designate immediately.
- 4.4 Line Foreman will notify Asset Manager or the appropriate party of any Grade 1 issues requiring immediate corrective action.
- 4.5 Distribution Substation Inspections will be completed bi-monthly and Oil Analysis on each Transformer within the substation done once annually with a written report submitted to Goderich Hydro identifying any problems found.
- 4.6 Asset Manager or designate for Goderich Hydro will evaluate all inspections and approve maintenance projects. The work required to correct the issues identified is to be completed in the time line that is appropriate with the severity of the situation.
- 4.7 Tree trimming will be completed annually in the 1st quarter year.
- 4.8 Completion of all Inspections and Maintenance issues will be recorded and kept on file by Goderich Hydro for a three year period.

WEST COAST HURON ENERGY INC (Goderich Hydro)

Date: July 28, 2006

Revision: 00

Page: 1 of 4

Procedure

CAPITAL & MAINTENANCE PROJECT WORK FLOWS

All Printed Quality Documents shall be considered uncontrolled

1.0 PURPOSE

To describe the work flow process for Goderich Hydro's Capital and Maintenance projects both planned and reactive work types on the Distribution System.

2.0 SCOPE

This procedure applies to the following types of customer/utility driven work types:

2.1 CARE Orders

- Cut and Reconnects
- Investigation of various hydro service/power quality related issues.
- Hydro Meter Insatallations/Repairs/Changeouts.
- New Residential Service Connections/Infill < \$1000.

2.2 Call-Out Trouble work types

2.3 Planned Capital and Maintenance work types

3.0 PROCEDURE

WEST COAST HURON ENERGY INC (Goderich Hydro)

Date: July 28, 2006

Revision: 00

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Procedure

CAPITAL & MAINTENANCE PROJECT WORK FLOWS

All Printed Quality Documents shall be considered uncontrolled

3.1 CArE Order Procedure

Office Staff receive call from customer and prepare CArE Order
ESA authorization to connect new service will require new account to
be set up in customers name



CArE Order is forwarded to applicable department for investigation
and/or completion of work



CArE order will be signed off by a competent person declaring site
safe and no undue hazard exists this will constitute as a record of
inspection
If site is deemed unsafe immediate supervisor will be notified and
corrective action will be required



CArE order is returned to Office Staff for Closing and filing
File retention will be no less than one year after the annual audit,
following construction completion and made available for ESA upon
request

WEST COAST HURON ENERGY INC (Goderich Hydro)

Date: July 28, 2006

Revision: 00

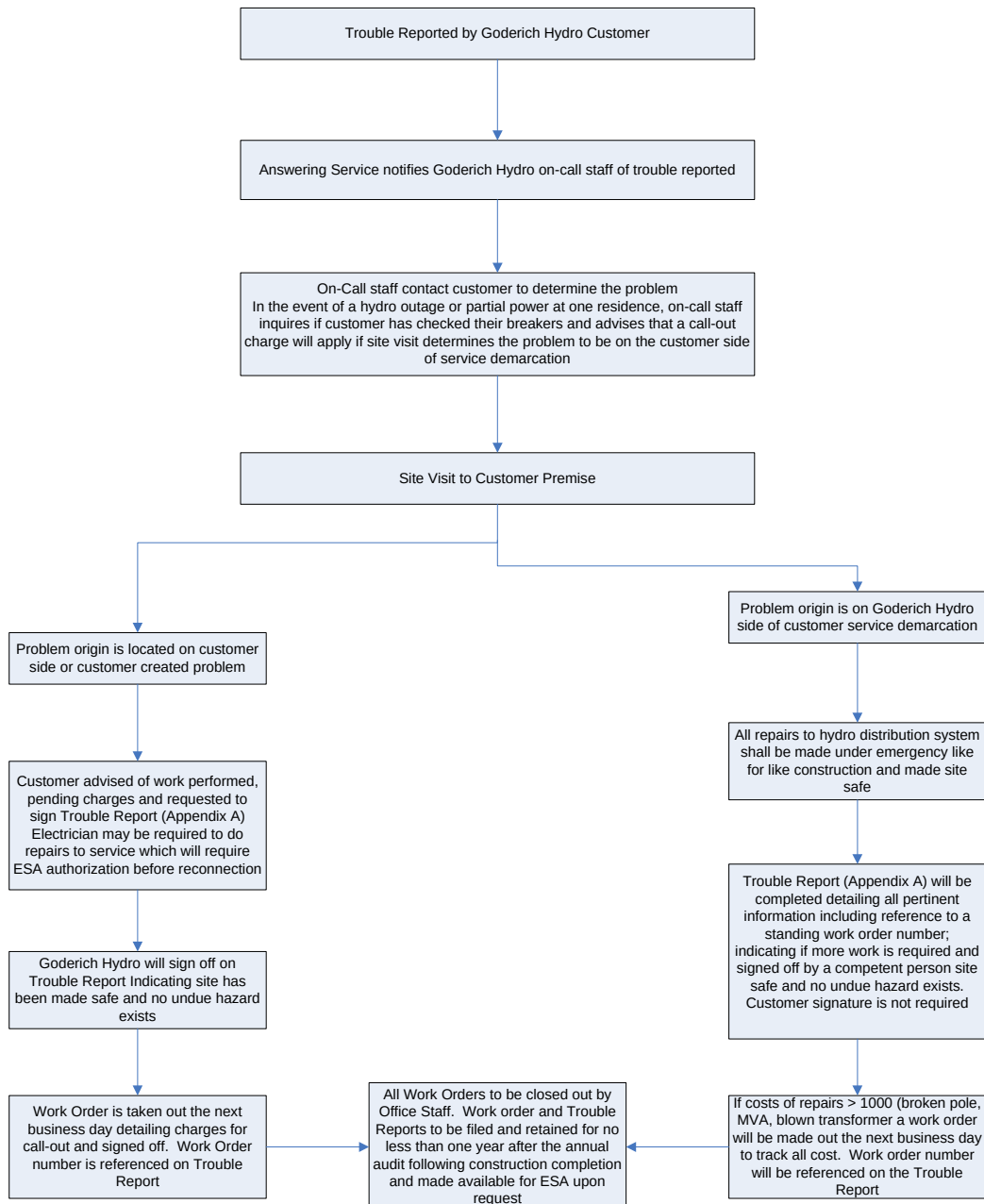
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Procedure

CAPITAL & MAINTENANCE PROJECT WORK FLOWS

All Printed Quality Documents shall be considered uncontrolled

3.2 Call-Out Trouble Procedure



WEST COAST HURON ENERGY INC (Goderich Hydro)

Date: July 28, 2006

Revision: 00

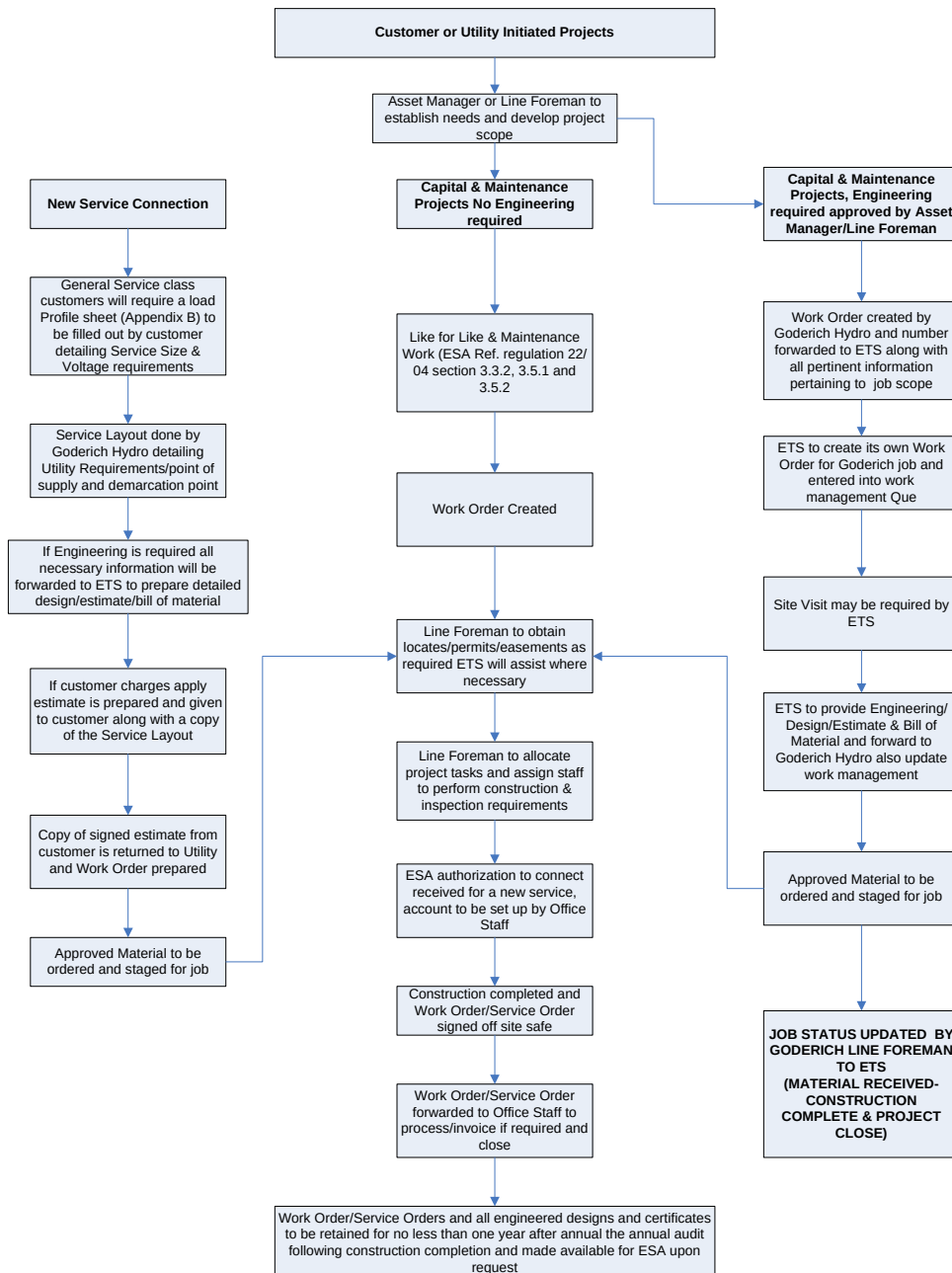
Page: 4 of 4

Procedure

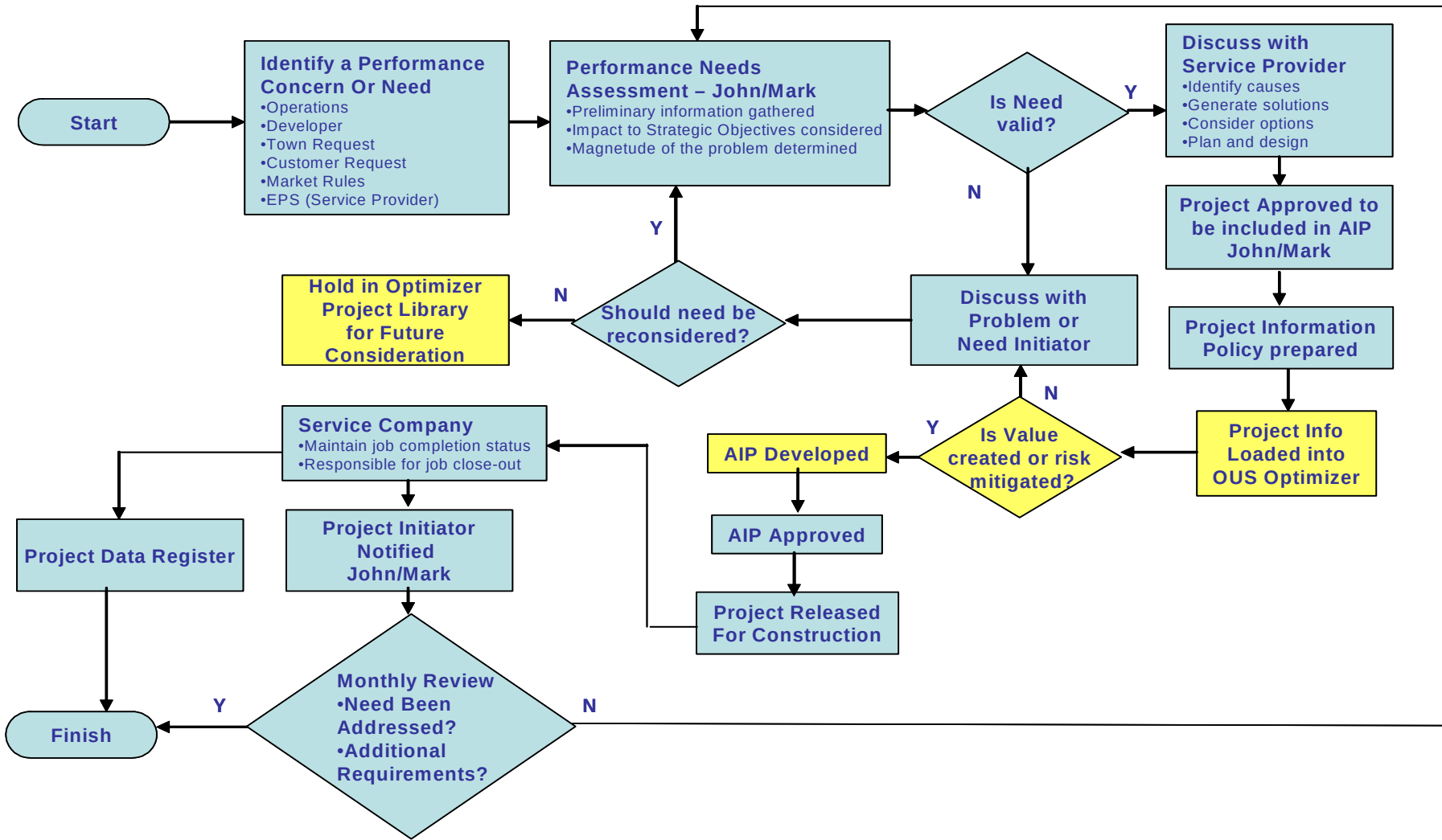
CAPITAL & MAINTENANCE PROJECT WORK FLOWS

All Printed Quality Documents shall be considered uncontrolled

3.3 Planned Capital & Maintenance Procedure



WCHE Asset Investment Strategy (AIS) Process



FIELD TROUBLE REPORT

Cause of Damage Code			
0	Unknown/Other	5	Defective Equipment
1	Scheduled Outage	6	Adverse Weather
2	Loss of Supply	7	Adverse Environment
3	Tree Contacts	8	Human Element
4	Lightning	9	Foreign Interference
		10	Emergency (police/fire)

Date _____ Damage Code _____

Time of Call _____ Time of Outage _____

Time Restored _____ Outage Duration _____

Location of Outage _____ Location # _____

Feeder _____ Phase _____

of Customers _____

Customer's Name _____ Phone Number _____

Cust. Address _____

Trouble Crew _____ Electricians Name _____

_____ Phone Number _____

Type of Damage _____

Explanation _____

Repairs Made _____

Follow Up Required _____

This worksite has been left in a safe condition as per Section 5.0, Regulation 22/04

Signature _____ Date _____

Position _____

Inspected as per Regulation 22/04 by

Signature _____ Date _____

Position _____

**Cornerstone Hydro Electric Concepts Association Inc.****Policy #: FIN-00001****Revision Number:****Title: Capital Expenditure Policy**
Issued by: CHEC Finance**Revised Date:**
Policy Owner:
CFO / Finance Mgr
Issued: July 1, 2008**LDC Name: LDC Name****APPLICABILITY**

This policy applies to the capitalization of assets for Cornerstone Hydro Electric Concepts Association (CHEC) LDCs ("The Company").

POLICY STATEMENT & PURPOSE

It is the policy of the company to maintain strong financial control over expenditures for capital assets by evaluating and approving capital requests for projects that enhance or improve the efficiency of the Company's assets. The policy describes the process used for determining if expenditures should be capitalized or expensed. A materiality amount is used and any expenditure below that threshold will be expensed to operations in the current year.

GUIDELINES**Capital Assets**

Capital Assets include tangible assets which include property, plant, and equipment provided they are held for use in the production or supply of goods and services. Intangible assets are also considered capital assets and are identified as assets that lack physical substance.

Betterment

A betterment is a cost which enhances the service potential of a capital asset and is therefore capitalized. This enhancement can result in an increase in physical output or service capacity, a decrease to operating costs, extension of the useful life of the asset, or improvement in the quality of the asset's output.

Repair

A repair is a cost incurred to maintain the service potential of a capital asset. Expenditures for repairs are expensed to the current operating period.



Cornerstone Hydro Electric Concepts Association Inc.

MATERIALITY

All additions to capital assets and betterments will be capitalized subject to materiality limits as set out in this policy. At times the administrative costs of capitalizing an asset may outweigh the intended benefits. While the expenditure may meet the definition to qualify as a capital asset, a level is set, which if an expenditure falls below, it is not capitalized but charge to expense in the current period. This level is known as a materiality limit.

Materiality Limits

Identifiable Assets

Distribution Plant	\$ 500
General Plant	\$ 200

Grouped Assets

Distribution Plant	\$ 1,000
General Plant	\$ 200

Identifiable Assets

An identifiable capital asset that has a sufficiently high unit cost and is easily identifiable for the asset to be individually tracked and recorded.

Grouped Assets

For efficiency, capital assets may be grouped if, by their nature, it would be impractical to identify individual units. These grouped assets are managed as a pool for the purposes of amortization.

CAPITAL ASSET RECORDS

Cost

Cost is the amount of consideration given up to acquire, construct, develop or better a capital asset. Capital assets will be recorded at the fully allocated cost including Allowance for Funds Used During Construction (AFUDC).

Fully Allocated costs

Fully allocated costs include all expenditures necessary to put a capital asset in service including all overhead cost based on full absorption costing.

AFUDC

For projects with a duration greater than 2 months, an ongoing financing charge will be applied against the project and capitalized until the project is declared in-service or ready for use at which time the finance charge will cease. The financing charge will be at the rate deemed by the Ontario Energy Board (OEB) for rate setting purposes.

***Cornerstone Hydro Electric Concepts Association Inc.*****Amortization**

Capital assets are generally amortized based on a method and life set by the OEB which is considered a suitable indicator of estimated useful life for the electrical distribution industry. Large and unique capital expenditures will be reviewed on an individual basis to determine the expected life and appropriate method of depreciation.

Capital Spares

Spare transformers and meters will be accounted for as capital assets since they form an integral part of the reliability program for a distribution system. These spares are held for the purpose of backing up transformers and meters in-service for a distribution system. Transformers and meters received for the purpose of expanding the distribution system will only be capitalized once they are put in-service and will remain in inventory until that time.

Extraordinary Items

Extraordinary items will be identified separately provided they exceed the materiality threshold established by the OEB. Recovery of extraordinary items through rates as a "Z" Factor expense will follow OEB guidelines.

POLICY COMPLIANCE

All current practices will comply with OEB Accounting Procedures Handbook and the CICA Handbook. Employees must report incidents of non-compliance relating to this policy in a timely manner to the Policy Owner. Non-compliance of a serious nature will be immediately reported to the President/COO. Determination of non-compliance issues of a serious nature will be the responsibility of the Policy Owner.

Signed: President / COOPolicy OwnerLDC NameDated: