BRANT County Power
your community owned hydro

November 5, 2010

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

Attention: Board Secretary, Kirsten Walli

Via Email: boardsec@oeb.gov.on.ca

RE: Brant County Power Inc. – Cost of Service Rate Application EB-2010-0125

Please find attached our Cost of Service Rate Application. A copy is filed via RESS online along with two paper copies and one electronic copy on CD which will be sent to your attention.

If you have any questions or concerns please contact me directly.

Sincerely,

Ed Glasbergen CGA, CPA
CFO – Brant County Power Inc.
519-442-2215 ext. 734
eglasbergen@brantcountypower.com

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APPLICATION

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 Brant County Power Inc. to the Ontario Energy Board for an Order or Orders approving or fixing just and reasonable rates and other service charges for the distribution of electricity as of May 1, 2011.

Title of Proceeding:	An application by Brant County Power Inc. for an Order or Orders approving or fixing just and reasonable distribution rates and other charges, effective May 1, 2011.
Applicant's Name:	Brant County Power Inc.
Address for Service:	65 Dundas Street East Paris ON N3L 3H1
Primary Contact:	Mr. Ed Glassbergen, Chief Financial Officer
Telephone:	1-877-871-2215 ext. 734 or (519) 442-2215
Fax:	(519) 442-3701
E-mail:	eglassbergen@brantcountypower.com

Introduction:

Brant County Power Inc. ("**BCP**" or the "**Applicant**") is a licensed electricity distributor, License No. ED-2002-0522 with its office in the Town of Paris Ontario. BCP carries on the business of distributing electricity within the County of Brant including the towns and villages of Paris, St. George, Cainsville and Burford. BCP does not distribute electricity within the City of Brantford. Schedule 1 of the Brant County Power's distribution license defines the service territory as follows:

Brant County Power Inc. **Electricity Distribution Licence ED-2002-0522**

Schedule 1 Definition of Distribution Service Area 103

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

1 The Town of Paris as of December 31, 1998, now within the County of Brant. 105

2 The Township of Brantford as of December 31, 1998, now within the County of Brant. 106

3 The Village of Burford as of December 31, 1998, now within the County of Brant. 107

4 The Police Village of St. George as of December 31, 1980, now within the County of Brant. 108

BCP 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, 2011.

Except where specifically identified in the Application, BCP followed Chapter 2 of the Filing Requirements for Transmission and Distribution Applications dated June 28, 2010 (the "**Filing Guidelines**" or "**Filing Requirements**") in order to prepare this application.

Proposed Distribution Rates and Other Service Charges:

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

Effective Date:

BCP requests that the OEB make its Rate Order effective May 1, 2011 in accordance with the Filing Requirements.

Reasonableness of Request:

BCP 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 BCP'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 BCP; and

(iv) other grounds as may be set out in the material accompanying this Application Summary.

Relief Sought:

BCP applies for:

1. an Order or Orders approving the proposed distribution rates and other charges set out in this Application to be effective May 1, 2011, or as soon as possible thereafter; and

2. an Order or Orders for the providing of notice of the Application and such procedural orders necessary for the appropriate conduct and disposition of the Application.

Form of Hearing

BCP requests the Board proceed by way of written hearing.

DATED at Paris Ontario, this 5th day of November, 2010.

ALL OF WHICH IS RESPECTFULLY SUBMITTED.

BRANT COUNTY POWER INC.

____

Bruce Noble
Chief Executive Officer

CONTACT INFORMATION

Bruce Noble
CHIEF EXECUTIVE OFFICER

Phone:	(519) 442-2215
Fax:	(519) 442-3701
E-mail:	bnoble@brantcountypower.com

Ed Glasbergen
CHIEF FINANCIAL OFFICER

Phone:	(519) 442-2215
Fax:	(519) 442-3701
E-mail:	eglasbergen@brantcountypower.com

SPECIFIC APPROVALS REQUESTED

- Approval to charge rates effective May 1, 2011 to return a revenue sufficiency of $300,388. (Exhibit 8, Tab 1, Schedule 7)

- Approval of BCP proposed capital structure, continuing BCPs deemed common equity component of 40%.

- Approval to continue the following deferral/variance accounts on May 1, 2011:
  - 1508 – Other Regulatory Assets (including various sub-accounts)
  - 1518 – Retail Cost Variance Accounts (Retail)
  - 1521 – Special Purpose Charge
  - 1525 – Miscellaneous Deferred Debits
  - 1548 – Retail Cost Variance Account (Service Transaction Request)
  - 1550 – Low Voltage Variance Account
  - 1555 – Smart Meter Capital and Recovery Offset Variance Account (including sub-accounts)
  - 1556 – Smart Meter OM&A Variance Account
  - 1562 – Deferred Payment in Lieu of Taxes
  - 1580 – Retail Service Variance Account – Wholesale Market Service
  - 1582 – Retail Service Variance Account – One Time
  - 1584 – Retail Service Variance Account – Network
  - 1586 – Retail Service Variance Account – Connection
  - 1588 – Retail Service Variance Account – Power (including sub-accounts)
  - 1590 – Recovery of Regulatory Asset Balances
  - 1592 – PILS and Tax Variance for 2006 an Subsequent Years

- Approval of the proposed loss factor of 4.82% Exhibit 8, Tab 1, Schedule 5.

- Approval for continued collection of $1.00 per metered customer per month for smart meter funding rate adder

- Approval to collect low voltage rate rider for all customer classes

- Approval to collect LRAM rate rider as provided in Exhibit 10.

- Approval to collect retail transmission rates for all customer classes

- Approval to continue to use the currently approved specific customer charges for miscellaneous services

DRAFT ISSUES LIST

This Application is the first cost of service application by the Applicant with the Ontario Energy Board. Based upon experience and other hearings, BCP would expect that the following matters pertaining to the 2011 Test Year may constitute issues in this Application:

- The reasonableness of the 2011 weather normalized forecast and customer forecast ;
- The reasonableness of the 2011 capital program;
- The reasonableness of the use of the Board's deemed capital structure, return on equity formula and the proposed cost of debt;
- The reasonableness of the proposed loss factor;
- The reasonableness of the 2011 operating, maintenance and administrative budget;
- The amount of BCP's proposed revenue requirement;
- The reasonableness of the proposed changes to the fixed variable split;
- The reasonableness of the disposal of the various deferral/variance accounts;
- The reasonableness of the proposed electricity distribution rates;
- The reasonableness of the LRAM

Accounting Orders / List of Non-Compliance with USoA

Accounting Orders

Brant County Power requests:

i) An order for the establishment of a CDM variance account.

Compliance with USoA

Brant County Power has followed the accounting principles and main categories of accounts as stated in the OEB's Accounting Procedures Handbook (the "APH") and the Uniform System of Accounts ("**USoA**") in the preparation of this Application.

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Description of Applicant's Operating Environment

List of Neighboring LDC

BCP is neighbored by Hydro One and Brantford Power.

Host / Embedded Distributors

BCP is embedded via Brantford Power through 3 specific supply points.
BCP is a host distributor to Brantford Power through 1 specific supply point

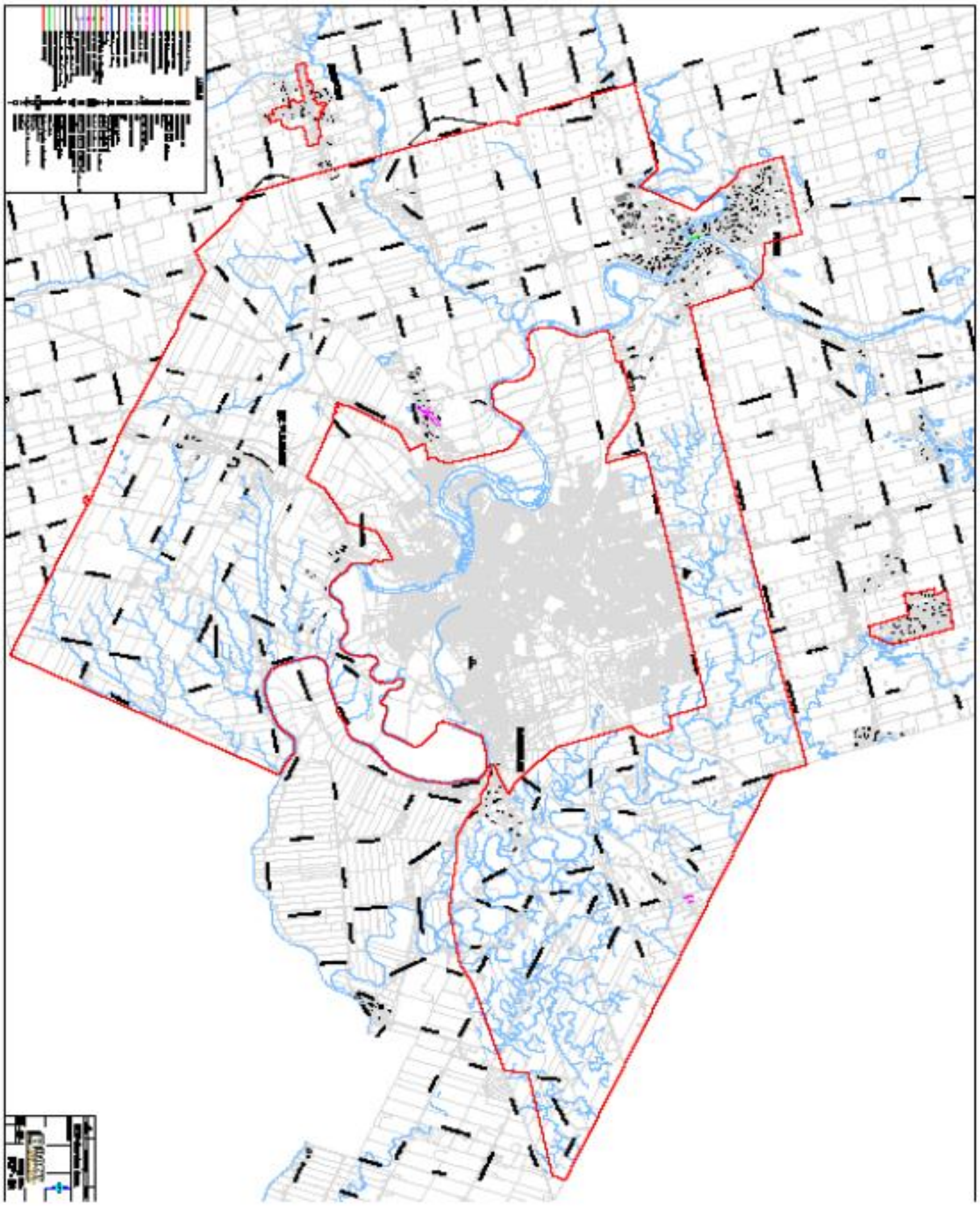
Communities Served:

- County of Brant
- Paris
- Burford
- St. George

See map attached.

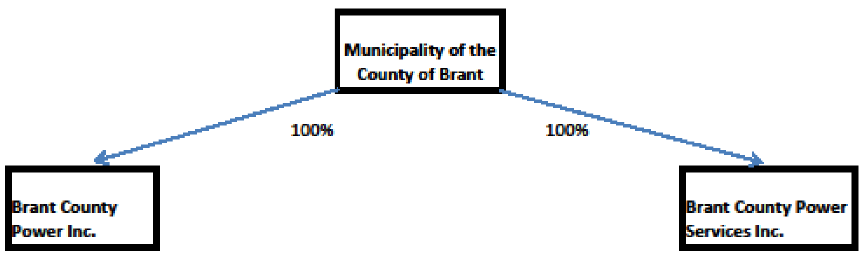
Service Area: 258.3 sq km
Rural Service Area: 254.0 sq km
Distribution Type: Electricity distribution

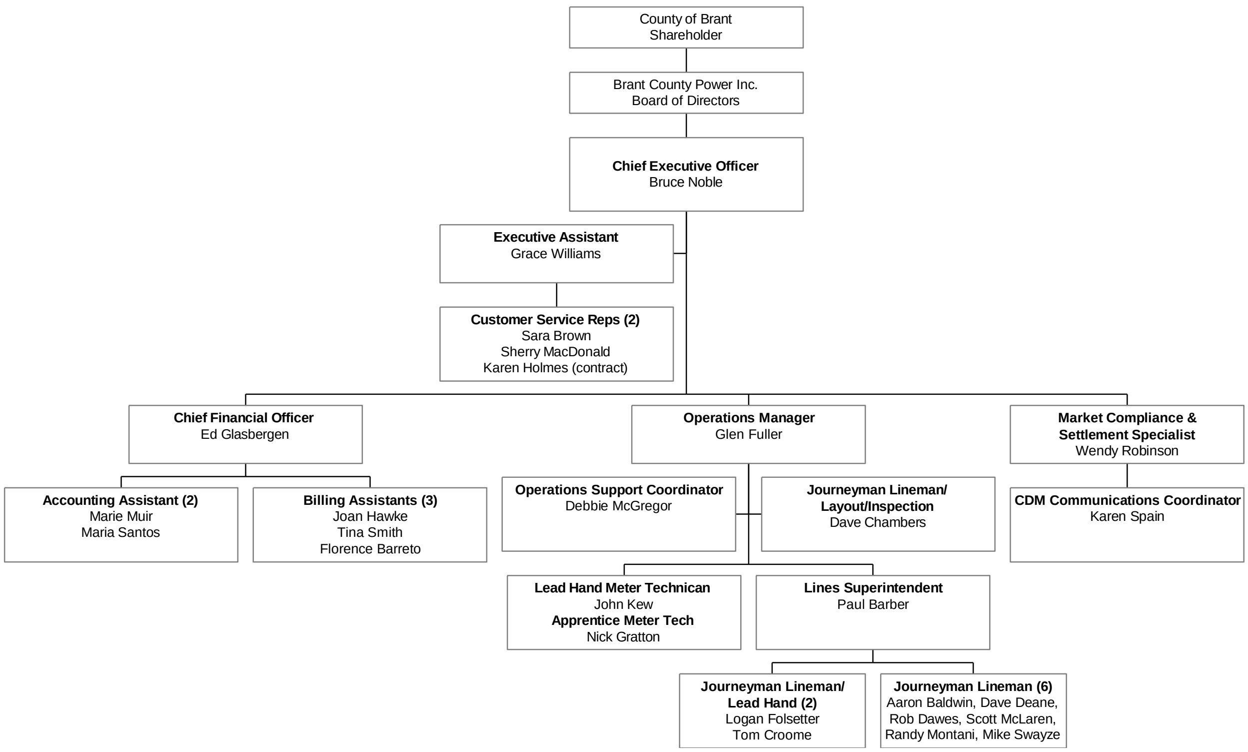
Map of Distribution Service Area



Corporate and Utility Organizational Structure

Organizational Structure





Representation of Municipality of Brant on Brant County Board of Directors

The Municipality of Brant is represented by two members on the Board of Directors, the Mayor and one other councilor representative.

Reporting Relationships between Utility Management and Parent Company Officials

All management and executives report directly to the CEO. The CEO reports to the Brant County Power Board of Directors directly and not to any Parent Company Officials.

Services Purchased from / Provided to Affiliates

Brant County Power Inc. has a sister company – Brant County Power Services Inc. ("BCPS"). BCP has loaned BCPS funds over the years to enable BCPS to get into certain lines of business – namely certain aspects of the water heater and water softener rental business. The amount of the loan outstanding as of Sep 30/10 is $563,800. BCPS pays interest at the prevailing market rate.

Certain of BCPs management team provide executive management services to BCPS. For this BCP charges BCPS for time spent on BCPS activities. The company has recently implemented a "time sheet" system to help more assist in this process. BCP is also taking steps to more clearly define the distinction between BCP and BCPS by separating the billing systems, and expects to have this in place by the end of calendar 2010.

Planned Changes to Corporate or Operational Structure

None Planned.

Identification of Board Directives

None

List of Witnesses and CV's

Bruce Noble
CEO – Brant County Power Inc.

QUALIFICATIONS

Bruce Noble is the Chief Executive Officer of Brant County Power and has served in this role since September of 2008. Prior to becoming CEO, he had served on the Company's Board of Directors.

Mr Noble came to Brant County Power with an extensive career in telecommunications. During more than 30 years in that regulated industry he has developed a strong background in finance, operations and regulatory affairs. Additionally, Mr. Noble has had interests in property development and property management, and involvement in agricultural enterprises amongst other business interests.

Mr. Noble is a community minded individual, being a founding member of the self declared "Ontario Green Energy Hub" and currently sits as a board member of the Brant Waterways Foundation, a charitable organization whose objective is to provide funding assistance for projects that preserve, protect, restore and improve the natural resources of the Grand River, and adjacent lands within the County of Brant.

Ed Glasbergen
CFO – Brant County Power Inc.

QUALIFICATIONS

Ed Glasbergen has been with Brant County Power as the Chief Financial Officer for just over one year.

Prior to joining BCP, he was with Research In Motion for 6 years serving in multiple finance roles as the company experienced significant growth during his tenure.

Other roles earlier in his career includes working in the corporate finance department of Burlington ON based Wescam Inc. (now L-3 Wescam) for 8 years, and with a regional based Chartered Accountants (CA) firm for the first five years of his career.

Ed is both a Certified General Accountant (Canada) and a Certified Public Accountant (USA).

Ed has served in numerous volunteer roles through his church and children's school and is currently a member of the board of directors and Treasurer of the church he attends.

Glen R. Fuller

446 Robinson Road
RR#4
Brantford, Ontario N3T 5L7

QUALIFICATIONS

Glen Fuller is the Operations Manager at Brant County Power Inc.

He has over 38 years of electrical utility experience in both Ontario and Alberta in roles including management and as a lineman.

His credentials immediately follow:

- Journeyman Power Lineman (Ontario)
- Journeyman Substation Electrician (MEA - Ontario)
- Journeyman Power Electrician (Province of Alberta - Interprovincial)
- Journeyman Powerline Technician (MEA - Ontario)
- Practical Metering Certificate (MEA – Ontario)

SUMMARY OF THE APPLICATION

PURPOSE AND NEED

BCP estimates that its present rates will produce a sufficiency in distribution revenue of $300,388 for the 2011 Test Year. Excluded from this estimate is the impact of energy costs. BCP 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 BCP sees them, are discussed below.

Through this Application, BCP seeks:

- To recover:
    - Revenue Deficiency arising from changes in OM&A, Amortization, Rate of Return and PILS
- To change:
    - Distribution Loss Factor
- To reflect:
    - 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 BCPs forecasted results for its 2011 Test Year. With the rates presently in effect, BCP estimates that its revenue for 2011 would not be sufficient to provide a reasonable return. BCP is also presenting the historical actual information for fiscal 2006, 2007, 2008, 2009 information for the current approved test year (2006) and forecasts for the fiscal 2010 bridge year.

TIMING

The financial information supporting the test Year for this Application will be BCPs fiscal year ending December 31, 2011 (the "2011 Test Year"). However, this information will be used to set rates for the period May 1, 2011 to April 30, 2012. 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, 2011.

CUSTOMER IMPACT

BCP will have impacts below 10%. As discussed in details later in this application, the majority of drivers causing these impacts are beyond the control of LDC management (HST, Regulated Embedded Distributor Charges) and therefore BCP is not proposing any rate mitigation measures.

Residential

The impact on a typical residential customer (800 kWh / month) is an increase of 5.48% on total bill. The overall bill impact on a typical Residential customer is shown in detail in Exhibit 8, Tab 1, Schedule 6.

General Service < 50 kW

The impact on a typical GS<50 kW (2,000 kWh / month) customer is an decrease of 0.25% on total bill. The overall bill impact on a typical GS<50 kW customer is shown in detail in Exhibit 8, Tab 1, Schedule 6.

General Service 50 to 4,999 kW

The impact on a typical GS>50 to 4,999 kW customer (1,000 kW) is a decrease of 5.51% on total bill. The overall bill impact on a typical GS>50 to 999 kW customer is shown in detail in Exhibit 8, Tab 1, Schedule 6.

Street Light

The impact on a typical Street Lighting connection is an increase of 222.8% on total bill. The overall bill impact on a typical Street Lighting connection is shown in detail in Exhibit 8, Tab 1, Schedule 6.

Sentinel Light

The impact on a typical Street Lighting connection is an increase of 44.98% on total bill. The overall bill impact on a typical Street Lighting connection is shown in detail in Exhibit 8, Tab 1, Schedule 6.

Unmetered Loads

The impact on a typical Street Lighting connection is an decrease of 3.48% on total bill. The overall bill impact on a typical Street Lighting connection is shown in detail in Exhibit 8, Tab 1, Schedule 6.

Specific Service Charges

BCP is not proposing any changes to its currently approved Specific Service Charges and a minor change to the loss factor listed below. Details can be found in Exhibit 8, Schedule 1, Tab 5. The Charges are listed below.

OTHER 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.

Return on Equity

BCP has assumed a return on equity of 9.85%. BCP understands the OEB will be finalizing the return on equity for 2011 rates based on January 2010 market interest rate information. BCP will use the deemed return on equity rates established upon final approval of distribution rates.

Budget Overview

The budgets for 2010 and 2011 is done in excel format and has been prepared by the CFO. Significant input to the budget was obtained from other BCP staff including the Board of Directors, CEO, Operations Manager and other BCP management. The budget numbers were compared to historical actual numbers to test for reasonability. Capital projects were assessed for based on requirement (i.e. preventative maintenance), but also considering further growth opportunities in BCP's service territory.

In addition to the items noted above, several assumptions as follows were considering when preparing these budgets:

- 2.5% wage increase across all wage categories
- Several staff additions as noted in other areas of this rate application
- Benefits were adjusted to account for wage and staff increases
- All other expense items were assessed based on need/requirement and estimated using historical trending.
- Where capital additions are significant – quotations from third parties were procured to assist with estimation.

Distribution revenue was budged using our approved load forecast and current rates to derive a revenue deficiency. This was then included in the bottom line revenue line.

Other revenue was projected to be consistent with 2009 results with the exception of the $135,000 related to green energy initiatives.

CHANGES IN METHODOLOGY

BCP is not proposing any methodology changes from previous applications or Board established policy or practices.

NUMERICAL DETAILS OF CAUSES OF SUFFICIENCY 2011 TEST YEAR

Determination of Net Utility Income			
	Existing Rates	Proposed Rates	Revenue (Surplus) or Defficiency
Revenue Sufficiency		-$300,388	
Distribution Revenue	$6,209,190	$6,209,190	$0
Transformer Allowance	-$49,168	-$49,168	
Other Operating Revenue	$606,494	$606,494	$0
Total Revenue	$6,766,516	$6,466,128	-$300,388
Costs and Expenses			$0
Distribution Costs	$2,331,729	$2,331,729	$0
Operation & Maintenance	$1,513,309	$1,513,309	$0
Depreciation & Amortization	$896,214	$896,214	$0
Deemed Interest	$735,548	$735,548	$0
Total Costs and Expenses	$5,476,800	$5,476,800	$0
Utility Income Before Income Taxes	$1,289,716	$989,329	-$300,388
Income Taxes (grossed up)	$367,569	$101,117	-$266,452
Utility Income (loss) After Taxes	$922,147	$888,212	-$33,935
Calculated 2011 RoE	$888,212		
Revenue Sufficiency	$33,935		
Add Tax Change	$266,452		
Total Revenue Deficiency	$300,388		
Existing Rates RoE	10.23%		

	2011 Test - applied for rates			
	Customers (Year-End)	Consumption (kWh / KW)	Distribution Revenues ($)	Unit Revenues $/kWh
Residential	8,290	80,122,583	$3,521,260.69	$0.043948
GS<50	1,315	39,095,551	$1,068,037.14	$0.027319
GS>50 to 499 kW	106	388,493	$1,031,309.84	$2.654642
Unmetered Scattered Load	51	493,370	$11,533.73	$0.023377
Sentinel Lighting	218	574	$17,768.25	$30.955136
Street Lighting	2,630	4,783	$258,892.60	$54.127661
TOTAL	12,610		$5,908,802.25	

	2011 Test - Existing Rates			
	Customers (Year-End)	Consumption (kWh / KW)	Distribution Revenues ($)	Unit Revenues $/kWh
Residential	8,290	80,122,583	$2,899,027.72	$0.036182
GS<50	1,315	39,095,551	$1,019,454.89	$0.026076
GS>50 to 499 kW	106	388,493	$2,217,863.95	$5.708890
Unmetered Scattered Load	51	493,370	$14,632.62	$0.029659
Sentinel Lighting	218	574	$11,502.53	$20.039253
Street Lighting	2,630	4,783	$46,708.29	$9.765479
TOTAL	12,610		$6,209,190.00	

Revenue Requirement Workform

Attached as excel file

AUDITED FINANCIAL STATEMENTS AT DECEMBER 31 2008 & 2009

BRANT COUNTY POWER INC.

FINANCIAL STATEMENTS

For the year ended December 31, 2009

Millard, Rouse & Rosebrugh LLP
Chartered Accountants

BRANT COUNTY POWER INC.

For the year ended December 31, 2009

INDEX

Millard, Rouse & Rosebrugh LLP
Chartered Accountants
P.O. Box 367, 96 Nelson Street
Brantford, Ontario N3T 5N3
Telephone (519) 759-3511
Facsimile: (519) 759-7961

AUDITORS' REPORT

To the Shareholder of
Brant County Power Inc.

We have audited the statement of financial position of Brant County Power Inc. as at December 31, 2009 and the statements of income, retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

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

In our opinion, these financial statements present fairly, in all material respects, the financial position of Brant County Power Inc. as at December 31, 2009 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Millard, Rouse & Rosebrugh LLP

April 29, 2010

CHARTERED ACCOUNTANTS
Licensed Public Accountants

BRANT COUNTY POWER INC.

STATEMENT OF FINANCIAL POSITION

As at December 31	2009	2008 (restated Note 3)
ASSETS		
Current Assets		
Cash and bank	2,356,414	1,816,242
Accounts receivable (Note 7)	2,163,840	2,160,225
Unbilled revenue	2,941,563	2,803,956
Income taxes recoverable	823,374	206,811
Inventory	234,314	293,097
Other current assets	110,028	76,052
Current portion of loan receivable	64,681	73,679
	8,694,214	7,430,062
Loan Receivable (Note 8)	538,169	546,835
Property, Plant and Equipment (Note 9)	15,567,127	15,175,647
Utility Plant Acquisition Adjustment	3,588,000	3,588,000
Future Income Tax Asset	491,661	-
	28,879,171	26,740,544
LIABILITIES		
Current Liabilities		
Accounts payable and accrued liabilities	5,069,695	3,065,512
Dividends payable	446,000	425,000
Current portion of long term liabilities	44,400	44,400
Current portion of other regulatory liabilities/credits	10,332	28,737
	5,570,427	3,563,649
Regulatory Liabilities (Note 10)	982,104	2,019,668
Long Term Liabilities (Note 11)	5,179,886	5,175,581
Employee Future Benefits Payable (Note 12)	646,300	617,500
	12,378,717	11,376,398
SHAREHOLDER'S EQUITY		
Capital Stock (Note 13)	9,512,193	9,512,193
Miscellaneous Paid in Capital	2,738,065	2,738,065
Retained Earnings	4,250,196	3,113,888
	16,500,454	15,364,146
	28,879,171	26,740,544

See accompanying notes

BRANT COUNTY POWER INC.

STATEMENT OF RETAINED EARNINGS

For the year ended December 31	2009	2008 (restated Note 3)
Retained Earnings - Beginning of Year as previously reported	3,113,888	2,562,103
Correction of prior period error (Note 3)	-	180,987
Adjustment for future income taxes (Note 4)	834,584	-
Retained Earnings - Adjusted	3,948,472	2,743,090
Net Income	747,724	795,798
Dividends	(446,000)	(425,000)
Retained Earnings - End of Year	4,250,196	3,113,888

See accompanying notes

BRANT COUNTY POWER INC.

STATEMENT OF INCOME

For the year ended December 31	2009	2008 (restated Note 3)
Revenue		
Distribution (Note 14)	5,640,621	5,815,531
Power, connection and transmission	15,685,092	18,562,207
	21,325,713	24,377,738
Less: Cost of Power supply	15,685,092	18,562,207
Gross Margin	5,640,621	5,815,531
Other Operating Revenue (Note 15)	442,602	499,130
	6,083,223	6,314,661
Distribution Operating and Maintenance Expense (Note 16)	1,234,295	1,250,643
Indirect Expenses		
Billing and collecting	720,925	778,857
General administration expense	1,541,434	1,219,940
Amortization	1,015,883	1,041,813
Community relations and sales expense	123,948	119,225
Interest expense	1,129	5,772
Interest on long term liabilities	326,162	365,832
	3,729,481	3,531,439
Income Before Undernoted Items	1,119,447	1,532,579
Loss on disposal of equipment	-	(9,578)
Employee future benefits	(28,800)	(28,640)
Income Before Income Taxes	1,090,647	1,494,361
Income taxes - current (Note 17)	-	(698,563)
- future	(342,923)	-
Net Income	747,724	795,798

See accompanying notes

BRANT COUNTY POWER INC.

STATEMENT OF CASH FLOWS

For the year ended December 31	2009	2008 (restated Note 3)
Cash Flows From Operating Activities		
Net Income	747,724	795,798
Charges (credits) to income not involving cash:		
Amortization	1,289,385	1,298,005
Amortization of contributed capital	(71,951)	(71,604)
Future income taxes	342,923	-
Loss on equipment under capital lease	-	9,578
	2,308,081	2,031,777
Net change in non cash working capital balances related to operations:		
Accounts receivable	(23,615)	323,908
Unbilled revenue	(137,607)	(48,956)
Inventory	58,783	(31,821)
Other current assets	(33,976)	67,099
Accounts payable, accrued liabilities and dividends payable	2,025,183	381,422
Income taxes payable/recoverable	(616,563)	(344,650)
Employee future benefits payable	28,800	28,640
	3,609,086	2,407,419
Cash Flows From Financing Activities		
Long term liabilities	4,305	(983,320)
Capital contributions received	8,661	90,610
Other regulatory liabilities/credits	(18,405)	(105,252)
Dividends	(446,000)	(425,000)
	(451,439)	(1,422,962)
Cash Flows From Investing Activities		
Purchase of property, plant and equipment	(1,617,575)	(1,441,910)
Regulatory assets/liabilities	(1,037,504)	713,020
Proceeds on disposal of property, plant and equipment	-	207,800
Loan receivable	37,664	47,754
	(2,617,475)	(473,336)
Net Increase in Cash and Cash Equivalents	540,172	511,121
Opening Cash and Cash Equivalents	1,816,242	1,305,121
Closing Cash and Cash Equivalents	2,356,414	1,816,242

See accompanying notes

BRANT COUNTY POWER INC.

NOTES TO THE FINANCIAL STATEMENTS
For the year ended December 31, 2009

1 NATURE OF ACTIVITIES

Brant County Power Inc. ("the Company") provides electricity distribution services to residents of The Corporation of the County of Brant. The Company is incorporated under the Ontario Business Corporations Act and is regulated by the Ontario Energy Board ("OEB") and the Ministry of Energy.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

These financial statements have been prepared in accordance with accounting principles for electrical utilities in Ontario as required by the OEB under the authority of Section 70(2) of the OEB Act, 1998, of The Energy Competition Act, 1998, and reflect the following policies as set forth in the OEB Accounting Procedures Handbook. All principles employed are in accordance with Canadian generally accepted accounting principles ("GAAP").

(a) Measurement
Financial statements are based on representations that may require estimates to be made in anticipation of future transactions and events and include measurement that may, by their nature, be approximations. These have been made using careful judgement.

(b) Inventory
Inventory is stated at the lower of cost or net realizable value. Cost is determined by using the first-in first out method.

(c) Revenue Recognition
Distribution revenue is based on OEB approved distribution rates and are recognized as electricity is delivered to customers and collection is reasonably assured. Distribution revenue includes an estimate of revenue based on electricity delivered but not yet invoiced to customers from the last meter reading date to the year end.

(d) Property, Plant and Equipment and Amortization
Property, plant and equipment are recorded at cost. Amortization is provided for in the accounts as follows:

Buildings	30-50	years straight line
Distribution lines - overhead	25	years straight line
Transformer station	40	years straight line
Distribution transformers	25	years straight line
Distribution meters	25	years straight line
Distribution services	25	years straight line
Rolling stock	4-8	years straight line
Computer systems	5	years straight line
Other equipment	5-25	years straight line

The Company acquired various property, plant and equipment from its shareholder when the former Commission was dissolved. Since these assets were already in service, the Company has continued to amortize the assets over their respective remaining estimated service lives.

BRANT COUNTY POWER INC.

NOTES TO THE FINANCIAL STATEMENTS
For the year ended December 31, 2009

2. **SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES** (continued)

(e) **Utility Plant Acquisition Adjustment**
Utility plant acquisition adjustment represents the cost of acquired local distribution assets from the County of Brant in excess of the book value of net identifiable assets purchased. The value of the utility plant acquisition adjustment amount is reviewed annually and charged to operations if there is a decline in value.

(f) **Payments in Lieu of Corporate Income Taxes (PILs)**
Under the Electricity Act, 1998, the Company makes payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation ("OEFC"). These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Corporations Tax Act (Ontario) as modified by the Electricity Act, 1998, and related regulations. Prior to October 1, 2001, the Company was not subject to income or capital taxes.

The Company accounts for payments in lieu of corporate taxes using the liability method. Under the liability method, future income taxes reflect the net tax effects of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes, as well as for tax losses available to be carried forward to future years that are likely to be realized.

(g) **Contributed Capital**
Contributed capital is capitalized and amortized to income at a rate consistent with the corresponding asset that the funds were used to acquire.

(h) **Financial Instruments**
Financial instruments are initially recognized at fair value. Subsequent measurement is based on the classification of the financial instrument. The Company has adopted a policy to classify all financial instruments as follows:

1. Cash and bank are classified as Held for Trading and measured at fair value.
2. Accounts receivable and unbilled revenue are classified as Loans and Receivables and measured at amortized cost using the effective interest rate method.
3. Accounts payable, amounts due from affiliates and long term liabilities are classified as Other Liabilities and measured at amortized cost.
4. Purchases and sales of financial instruments are accounted for at the trade date.
5. Transaction costs on financial assets and liabilities are expensed as incurred.

The Company has adopted the disclosure and presentation requirements of Canadian Institute of Chartered Accountants Handbook Section 3861 rather than Handbook Sections 3862 and 3863.

BRANT COUNTY POWER INC.

NOTES TO THE FINANCIAL STATEMENTS
For the year ended December 31, 2009

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(i) **Regulatory Policies**
The Company has adopted the following policies, as prescribed by the OEB for rate-regulated enterprises. The policies have resulted in accounting treatments differing from Canadian GAAP for enterprises operating in a non rate regulated environment:

1. Various regulatory costs have been deferred in accordance with criteria set out in the OEB's Accounting Procedures handbook. In the absence of such regulation, these costs would have been expensed when incurred under Canadian GAAP.
2. The Company has deferred certain retail settlement variance amounts under the provisions of Article 490 in the OEB's Accounting Procedures handbook.

3. CORRECTION OF PRIOR PERIOD ERROR

During the year, the Company discovered errors in the calculation of various regulatory asset/liability accounts. The prior year's figures, provided for purpose of comparison, have been restated to reflect corrections to these accounts. The effect of these changes is included in the table below. Opening retained earnings for 2008 have been adjusted to account for the changes relating to years prior to 2008.

	change to 2008	change to periods prior to 2008
Decrease in Regulatory liabilities	4,367	180,987
Decrease in general administrative expenses	4,367	180,987
Increase in net income / Retained Earnings for prior to 2008	4,367	180,987

4. CHANGE IN ACCOUNTING POLICIES

On January 1, 2009, in accordance with CICA Handbook section 3465 "Income Taxes", the Company adopted the policy of recording future income taxes, converting from the taxes payable method previously used, which is no longer permitted by GAAP. This change in policy was recorded prospectively without adjustment to prior year's figures.

BRANT COUNTY POWER INC.

NOTES TO THE FINANCIAL STATEMENTS
For the year ended December 31, 2009

5. FUTURE ACCOUNTING CHANGES

In 2008, the Accounting Standards Board ("AcSB") confirmed that rate-regulated enterprises will be required to adopt International Financial Reporting Standards ("IFRS") by January 1, 2011.

The Company continues to assess the impact of conversion to IFRS on its results of operations. The International Accounting Standards Board ("IASB") issued an exposure draft on rate regulated activities in July 2009. Responses to the IASB's request for comment varied substantially. At this time, the IASB continues to research and analyse the responses to this exposure draft. It is unclear at this time what the outcome of the Board's deliberations will be and how that will impact the Company's reporting under IFRS. The effect on the Company's future financial position and results of operations are not estimable at this time.

6. RATE SETTING

The rates of the Company's electricity distribution business are subject to regulation by the OEB.

With the commencement of the open market, the Company purchases electricity from the Independent Electricity System Operator ("IESO"), at spot market rates and charges its customers unbundled rates. The unbundled rates include the actual cost of generation and transmission of electricity and an approved rate for electricity distribution. The cost of generation, transmission and connection charges and debt retirement payments are collected by the Company and remitted to the IESO and the OEFC respectively. The Company retains the distribution charge on the customer hydro invoices. The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated Company.

Such change in timing gives rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities which represent amounts for expenses incurred in different periods than would be the case had the Company been unregulated. Specific regulatory assets and liabilities are disclosed in Note 10.

The Company's approved rate for distribution includes components for the recovery (refund) of regulatory assets (liabilities). The approved rates, effective November 1, 2008, were calculated on a 2004 rate base.

The Company will be completing a rebasing application for submission to the OEB in the summer of 2010.

BRANT COUNTY POWER INC.

NOTES TO THE FINANCIAL STATEMENTS
For the year ended December 31, 2009

7. ACCOUNTS RECEIVABLE

	2009	2008
Electrical energy	2,200,657	2,135,302
Sundry	117,183	84,923
	2,317,840	2,220,225
Allowance for doubtful accounts	(134,000)	(60,000)
	2,183,840	2,160,225

8. LOAN RECEIVABLE

	2009	2008
Loans to Brant County Power Services Inc. ("BSCPI") with an effective interest rate of Prime +1%. Regular monthly payments of $8,470 including principal and interest per month	582,850	620,514
Less: Current portion	44,081	73,679
	538,769	546,835

Effective January 1, 2009 the interest rate on the loan was converted to Prime plus 1.75%. During the year, the Company granted BCPSI six months of interest only payments from June to November 2009. In addition, in February 2010, the Company granted BCPSI six months of interest only payments.

9. PROPERTY, PLANT AND EQUIPMENT

	Cost	Accumulated Amortization	2009	2008
Land	173,688	-	173,688	167,308
Buildings	1,182,781	246,473	936,308	957,987
Transformer station	2,510,109	251,774	2,258,335	2,321,533
Distribution lines - overhead	8,366,642	2,806,731	5,559,911	5,203,610
Distribution lines - underground	2,655,264	1,060,869	1,594,395	1,663,114
Distribution transformers	4,465,199	1,515,781	2,949,418	2,914,431
Distribution meters	1,390,363	482,578	907,785	828,798
Distribution services	2,508,092	1,003,919	1,504,173	1,513,522
Rolling stock	1,052,006	359,122	692,884	653,538
Computer systems	899,152	791,889	107,263	133,709
Other equipment	508,015	308,838	199,177	197,397
Contributed capital	(1,798,770)	(482,560)	(1,316,210)	(1,379,500)
	23,912,541	8,345,414	15,567,127	15,175,647

BRANT COUNTY POWER INC.

NOTES TO THE FINANCIAL STATEMENTS
For the year ended December 31, 2009

10. REGULATORY ASSETS/LIABILITIES	**2009**	**2008** (restated Note 3)
Retail settlement variance accounts	(2,616,173)	(3,642,059)
Other regulatory assets	176,296	174,566
Deferred payments in lieu of taxes	1,143,600	1,133,652
Recovery of regulatory asset balances	314,173	314,173
	(982,104)	(2,019,668)

The retail settlement variance accounts represent differences between charges billed to customers using the OEB Board approved fixed reference price and the actual costs billed to the Company by the IESO.

Deferred payments in lieu of taxes represents the accumulated difference in the approved estimate of taxes to be paid and the actual taxes paid.

Other regulatory assets represents costs passed on to the Company from the OEB and Hydro One in accordance with decisions made by the OEB.

On April 12, 2006, the OEB announced its decision regarding the Company's rate application. As part of the rate application, the OEB allowed for a recovery (refund) of various regulatory assets (liabilities). These amounts are reported as the Recovery of regulatory asset balances account ("RAR"). The RAR is to be recovered over a two year period, ending April 2008. The RAR consists of various OEB approved regulatory asset (liability) account balances as at December 31, 2004.

The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made.

11. LONG TERM LIABILITIES	**2009**	**2008**
Committed revolving facility payable to The Toronto-Dominion Bank, interest only payable monthly, with the option to pay the differential and exit the swap available on May 31, 2010.	5,000,000	5,000,000
Customer deposits	224,286	219,981
	5,224,286	5,219,981
Less: Current portion (customer deposits)	44,400	44,400
	5,179,886	5,175,581

Millard, Rouse & Rosebrugh LLP
Chartered Accountants

BRANT COUNTY POWER INC.

NOTES TO THE FINANCIAL STATEMENTS
For the year ended December 31, 2009

11. LONG TERM LIABILITIES (Continued)

As security for the TD loan, the Company has provided a general security agreement, an assignment of fire insurance, evidence of adequate liability insurance, and indemnity agreement and an International Swap Dealer Agreement. Effective December 31, 2009, the Company entered into a swap agreement regarding the interest on the loan in exchange for a bankers' acceptance agreement.

12. EMPLOYEE FUTURE BENEFITS PAYABLE

The Company provides certain non-pension post retirement medical benefits to employees. An actuarial valuation of future liabilities was completed as at January 1, 2007 and forms the basis for the estimated liability reported in these financial statements. In prior years an actuarial valuation was not done. The effective date of the next required actuarial valuation is January 1, 2010. The significant assumptions adopted in estimating the Company's accrued benefit obligation for employee future benefits are as follows:

Discount rate	5.0%
Average compensation increase	3.3%

Healthcare cost increases	Health	Dental	Vision	Orthodontics
Initial rate	9%	5%	2%	2%
Ultimate rate	5%	5%	2%	2%
Grading period (years)	6	6	6	6

	2009	**2008**
Accrued benefit obligation - as at January 1	617,509	588,860
Current period benefit cost	24,099	22,952
Interest cost on accrued benefit obligations	31,463	29,983
Benefit payments	(26,762)	(24,295)
Accrued benefit obligation as at December 31	646,309	617,509

13. CAPITAL STOCK	**2009**	**2008**
Authorized		
unlimited number of common shares		
Issued		
9,512,193 common shares	9,512,193	9,512,193

BRANT COUNTY POWER INC.

NOTES TO THE FINANCIAL STATEMENTS
For the year ended December 31, 2009

14. DISTRIBUTION REVENUE	2009	2008
Residential	2,846,853	3,145,523
General	2,735,475	2,622,553
Streetlighting	46,800	35,586
Sentinel lighting	11,493	11,869
	5,640,621	5,815,531

15. OTHER OPERATING REVENUE	2009	2008
Late payment charges	96,584	86,045
Interest earned	25,245	49,023
Pole rentals	34,748	37,315
Collection/reconnection charges	53,996	50,100
Miscellaneous revenue	66,867	116,789
Water and sewer billing fees	165,162	159,858
	442,602	499,130

16. DISTRIBUTION OPERATION AND MAINTENANCE	2009	2008
Overhead distribution lines and feeders	594,273	528,370
Underground distribution lines and feeders	140,619	140,300
Distribution transformers	33,514	43,546
Distribution meters	122,435	180,767
General operations	343,454	357,660
	1,234,295	1,250,643

BRANT COUNTY POWER INC.

NOTES TO THE FINANCIAL STATEMENTS
For the year ended December 31, 2009

17. PROVISION FOR PAYMENT-IN-LIEU OF CORPORATE INCOME TAXES	2009	2008
The income tax provision was calculated based on taxable income.		
Taxable income is calculated as follows:		
Income (loss) before income taxes	1,090,647	1,494,361
Amortization in excess of Capital Cost Allowance	(79,047)	(38,524)
Net change in regulatory assets/liabilities	(1,241,323)	713,020
Loss (gain) on disposal of assets	-	9,578
Change in tax reserves	28,800	28,640
Other additions and deductions	-	(88,731)
Taxable income	(200,923)	2,118,344
Tax at 31% (2008 - 32.98%)	-	698,563

18. PRUDENTIAL SUPPORT

The company is required, through the IESO, to provide security to mitigate the Company's risk of default based on its expected activity in the electricity market. The IESO could draw on this guarantee if the Company fails to make a payment required by a default notice issued by the IESO. The maximum potential payment is the face value of the bank letters of credit. As at December 31, 2009 the Company provided prudential support in the form of letters of credit in the amount of $1,219,927 (2008 - $1,219,927).

19. RELATED PARTY TRANSACTIONS

The Company is wholly owned by The Corporation of the County of Brant ("Brant County"). Brant County also wholly owns BCPSI. Transactions between BCPSI and the Company occur in the normal course of operations and consideration paid is on similar terms as those to unrelated parties.

During the year, the Company provided various services to BCPSI, including meter reading, billing and collecting of rental units and water and sewer billings and collections. In addition, the Company advanced a long term loan to BCPSI. Further information regarding the loan is provided in Note 6.

BRANT COUNTY POWER INC.

NOTES TO THE FINANCIAL STATEMENTS
For the year ended December 31, 2009

19. RELATED PARTY TRANSACTIONS (Continued)

During the year the Company had the following transactions with related parties:

	2009	2008
Services provided to related parties	262,177	234,979
Interest on loan to related party	24,949	37,035

Accounts receivable include $2,625 (2008 - $21,165) due from related parties and accounts payable include $1,168,559 (2008 - $584,592) due to related parties.

20. FINANCIAL INSTRUMENTS

The Company's management and the Board of Director's monitor and respond as necessary to any risks arising from financial instruments.

Fair Value
The fair value of financial instruments such as cash and bank, accounts receivable, unbilled revenue and trade payables and accrued liabilities are determined to approximate their recorded value due to their short term maturity.

Credit Risk
The Company's exposure to credit risk relates to its accounts receivable and unbilled revenue. The Company collects security deposits from customers in accordance with direction provided by the OEB. The Company held security deposits of $224,286 at year end (2008 - 219,981) in order to mitigate credit risk.

Interest Rate Risk
The Company's exposure to interest rate risk relates to the terms of its long term liabilities as disclosed in Note 11.

BRANT COUNTY POWER INC.

NOTES TO THE FINANCIAL STATEMENTS
For the year ended December 31, 2009

21. CAPITAL MANAGEMENT

The Company's objectives when managing capital are to maintain financial stability such that it can continue to provide returns for the shareholder and benefits for other stakeholders. The Company meets its objectives for managing capital by management oversight and Board monitoring of total capital.

The Company's total capital as at December 31, consists of:

	2009	2008
Total long term liabilities	5,224,286	5,219,981
Less: cash and bank	2,356,414	1,816,242
Net long term liabilities	2,867,872	3,403,739
Total shareholder's equity	16,500,454	15,364,148
Total capital	19,368,326	18,767,887

22. CONTINGENCIES

General Liability Insurance
The Company is a member of the Municipal Electric Association Reciprocal Insurance Exchange ("MEARIE") which is a pooling of general liability insurance risks. Members of MEARIE would be assessed, on a pro-rata basis, based on the total of their respective deposit premiums should losses be experienced by MEARIE, in excess of reserves and supplementary insurance, for the years in which the Company was a member.

As at December 31, 2009, the company has not been made aware of any additional assessments.

BRANT COUNTY POWER INC.

NOTES TO THE FINANCIAL STATEMENTS
For the year ended December 31, 2009

22. CONTINGENCIES (Continued)

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

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

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

After the release by the Supreme Court of Canada of its 2004 decision in the Consumers Gas case, the plaintiffs in the LDC late payment penalties class action indicated their intention to proceed with their litigation against the LDCs. The parties are in settlement discussions but no settlement has been reached. At this time, it is not possible to quantify the effect, if any, on the financial statements.

Brantford Power LV Charges
In May 2008, Brantford Power Inc. began charging Brant County Power Inc. for the use of their distribution lines in delivering power to Brant County Power Inc. Brantford Power Inc. has charged Brant County Power Inc. their commercial/industrial rate, as approved by the OEB. Brant County Power Inc. is challenging this rate, as other utilities typically negotiate a rate which is lower than the regular commercial/industrial customer rate. Both parties have sought legal advice and both have submitted legal documentation to the OEB for review. Brantford Power Inc. has charged a total of $1,289,677 and the full amount has been recorded as an accrued liability at December 31, 2009. The outcome of this hearing may result in a reduction of the liability previously recorded.

PROFORMA STATEMENT OF INCOME	
FOR THE TWELEVE MONTHS ENDED DECEMBER 31ST 2010	
	YEAR ENDED 31-Dec-10
Service Revenue Requirement	5,204,094
Miscellaneous Revenues	557,326
Total Distribution Revenue	5,761,420
Expenses	
Operating & Maintenance	1,280,348
Billing & Collecting	866,131
Administration & General	1,083,453
Amortization	884,281
Interest	659,613
	4,773,826
Net Income from Operations Before Taxes	987,595
Income Tax	191,078
Net Income (Loss)	796,516

PROFORMA STATEMENT OF INCOME FOR THE TWELEVE MONTHS ENDED DECEMBER 31ST 2011	
	YEAR ENDED Dec 31, 2011
Service Revenue Requirement	5,908,802
Miscellaneous Revenues	557,326
Total Distribution Revenue	6,466,128
Expenses	
Operating & Maintenance	1,513,309
Billing & Collecting	944,294
Administration & General	1,387,435
Amortization	896,214
Interest	735,548
	5,476,800
Net Income from Operations Before Taxes	989,329
PILS	101,117
Net Income (Loss)	888,212

Detailed Reconciliations – Financial Statements to Regulatory Returns

	Brant County Power Inc.			
	Reconciliation of Audited Financial Statements to OEB Filed Balances			
	2006			
	Audited Financial Statements	OEB Filed Values	Difference	
Assets				
Gross Assets		$20,444,590		
Accumulated Depreciation		($5,312,709)		
Net Fixed Assets	$15,131,882	$15,131,881	$1	Reconciled
OM&A				
Operations and Maintenance	$1,164,887	$1,197,281	($32,394)	***Note 1***
Billing and Collecting	$862,851	$862,851	$0	Reconciled
General Administration	$1,039,172	$1,312,249	($273,077)	***Note 2***
Amortization	$969,174	$969,174	$0	Reconciled
Community Relations	$59,848	$59,848	$0	Reconciled
Interest (excl LT Debt)	$6,470		$6,470	***Note 2***
	$4,102,402	$4,401,403	($299,001)	
Miscellaneous Revenue	$516,041	$516,041	$0	Reconciled

Note 1	Difference per summary above	($32,394)
	OEB filed values includes amount for 6105 USOA - Taxes other than income taxes	$75,019
	Financial statements include net operations burden amounts not reflected in OEB filed values	($42,625)
		($0)
Note 2	Difference per summary above	($273,077)
	Employee future benefit expense shown as a separate line item on financial statements but included in G&A filed amounts	$299,000
	USOA 6105 value classification change (see above)	($75,019)
	interest expense included in OEB G&A filing but separate line item on financial statements	$6,470
	Financial statements include net operations burden amounts not reflected in OEB filed values	$42,626
		($0)

Brant County Power Inc.
Reconciliation of Audited Financial Statements to OEB Filed Balances

	2007 Audited Financial Statements	2007 OEB Filed Values	Difference	
Assets				
Gross Assets	$21,436,675	$21,436,674		
Accumulated Depreciation	($6,168,549)	($6,168,550)		
Net Fixed Assets	$15,268,126	$15,268,124	$2	Reconciled
OM&A				
Operations and Maintenance	$1,305,033	$1,387,869	($82,836)	***Note 1***
Billing and Collecting	$870,899	$870,899	($0)	Reconciled
General Administration	$1,126,053	($646,875)	$1,772,928	***Note 2***
Amortization	$1,006,228	$1,006,228	$0	Reconciled
Community Relations	$104,500	$104,500	($0)	Reconciled
Interest (excl LT Debt)	$21,047		$21,047	***Note 2***
	$4,433,760	$2,722,622	$1,711,138	
Miscellaneous Revenue	$535,149	$579,971	($44,822)	Note 3

Note 1	Difference per summary above	($82,836)
	OEB filed values includes amount for 6105 USOA - Taxes other than income taxes	$96,358
	Financial statements include net operations burden amounts not reflected in OEB filed values	($13,522)
		$0
Note 2	Difference per summary above	$1,772,928
	Employee future benefit credit shown as a separate line item on financial statements but included in G&A filed amounts	($1,711,140)
	USOA 6105 value classification change (see above)	($96,358)
	interest expense included in OEB G&A filing but separate line item on financial statements	$21,047
	Financial statements include net operations burden amounts not reflected in OEB filed values	$13,523
		($0)
Note 3	OEB filed value includes gain on disposal of fixed assets	
	Financial Statements show the gain as a separate line item on the Income Statement	

Brant County Power Inc.

Reconciliation of Audited Financial Statements to OEB Filed Balances

		2008 Audited Financial Statements	2008 OEB Filed Values	Difference	
Assets					
Gross Assets			$22,303,627		
Accumulated Depreciation			($7,127,980)		
Net Fixed Assets		$15,175,647	$15,175,647	$0	Reconciled
OM&A					
Operations and Maintenance		$1,250,643	$1,307,814	($57,171)	***Note 1***
Billing and Collecting		$778,857	$778,857	$0	Reconciled
General Administration		$1,219,940	$1,201,538	$18,402	***Note 2***
Amortization		$1,041,813	$1,041,813	$0	Reconciled
Community Relations		$119,225	$119,225	($0)	Reconciled
Interest (excl LT Debt)		$5,772		$5,772	***Note 2***
		$4,416,250	$4,449,246	($32,996)	
Miscellaneous Revenue		$499,130	$489,552	$9,578	Note 3
Note 1	Difference per summary above		($57,171)	$68,185	
				($11,004)	
	Taxes Other Included in O&M vs Admin		$68,185	($10)	
				$57,171	
	Reclass of OH burden to O&M vs Admin		($11,004)		
	Unreconciled difference		($10)		
			$0		
Note 2	Difference per summary above		$18,402		
	Taxes Other Included in O&M vs Admin		($68,185)		
	Reclass of OH burden to O&M vs Admin		$11,004		
	Misc reclass to OM vs Admin		$4,367		
	Other Interest reclass to Admin		$5,772		
	Benefits expense to Admin		$28,640		
			($0)		
Note 3	OEB filed value includes a loss on disposal of fixed assets				
	Financial Statements show the loss as a separate line item on the Income Statement				

Brant County Power Inc.

Reconciliation of Audited Financial Statements to OEB Filed Balances

	2009 Audited Financial Statements	2009 OEB Filed Values	Difference	
Assets				
Gross Assets	$23,912,541	$23,912,541		
Accumulated Depreciation	($8,345,414)	($8,345,414)		
Net Fixed Assets	$15,567,127	$15,567,127		Reconciled
OM&A				
Operations and Maintenance	$1,234,295	$1,081,186	$153,109	***Note 1***
Billing and Collecting	$720,925	$720,924	$1	Reconciled
General Administration	$1,541,434	$2,402,408	($860,974)	***Note 2***
Amortization	$1,015,883	$1,015,883	$0	Reconciled
Community Relations	$123,948	$123,948	$0	Reconciled
Interest (excl LT Debt)	$1,129	$0	$1,129	***Note 2***
	$4,637,614	$5,344,349	($706,735)	
Miscellaneous Revenue	$442,602	$442,602	$0	Reconciled

Note 1 $153,109 in operations related burdens categorized as O&M on financial statements included in G&A costs in OEB filings

Note 2

Difference per summary above	($860,974)
reclassification of operations burdens discussed in Note 1	$153,109
employee future benefits costs disclosed as separate line item on financial statements	$28,800
interest expense included in OEB G&A filing but separate line item on financial statements	$1,129
immaterial interest expense difference	$407
OEB filed USOA 5695 Contra Account not reflected in G&A historical values (reflects burden offset accounts)	$677,529
	$0

Annual Report and Management Discussions (Fiscal Year 2009)

BCP is including a presentation delivered to the County of Brant (shareholder) as the annual report and management discussion portion of the minimum filing requirements.

Our Vision statement speaks to these challenges

Our goal is to be an industry leader in safety, service, fiscal and environmental responsibility. We will achieve our goal of continuous improvement in everything we do. We reward common sense, encourage ingenuity, recognizing that the hard work of individuals leads to the success of our team.

We are developing a new corporate environmental and social consciousness.

As a well recognized and respected brand, we need to be supportive of the community. We must be viewed as Champions of Conservation and help our residential and business customers reduce consumption and related energy costs. This will help ensure our county continues to be a good place to live and a strong base to compete from.

Over the past year we have worked very hard to model ourselves into a progressive local distribution company
that is driven to be more successful than at any time in its past.

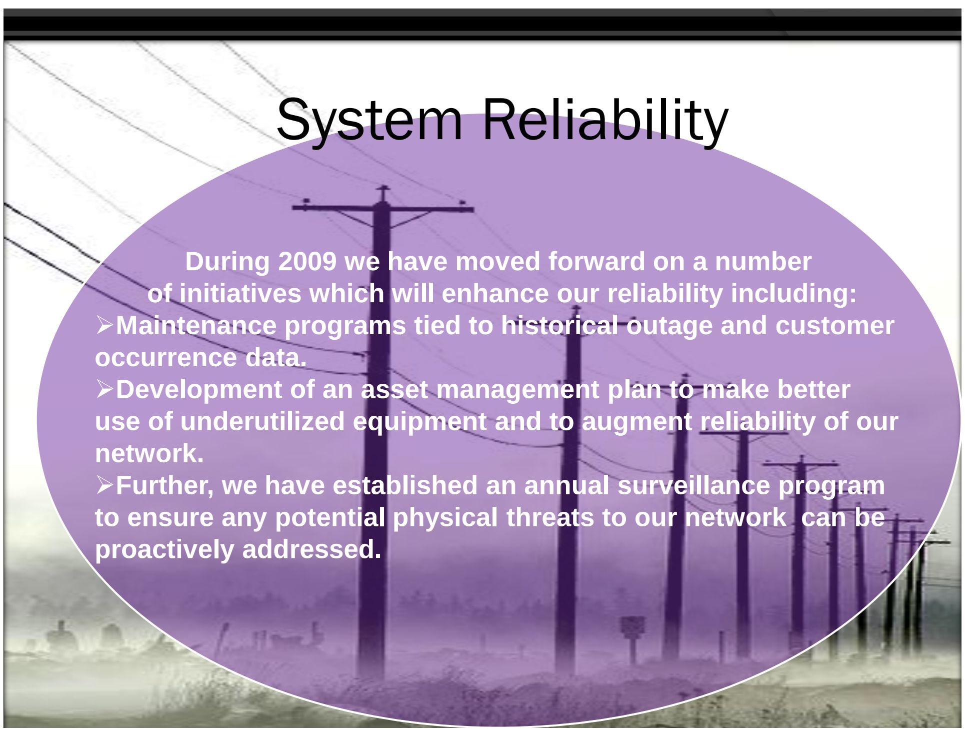
Our desire is to not only continue to grow the value of the corporation, and with that maximize our return on investment, but also to drive operational excellence while enhancing our position as a tool for economic development. This will help ensure we can keep our rates fair and equitable across all rate classes while continuing to invest in our employees, business processes, operations and communities.

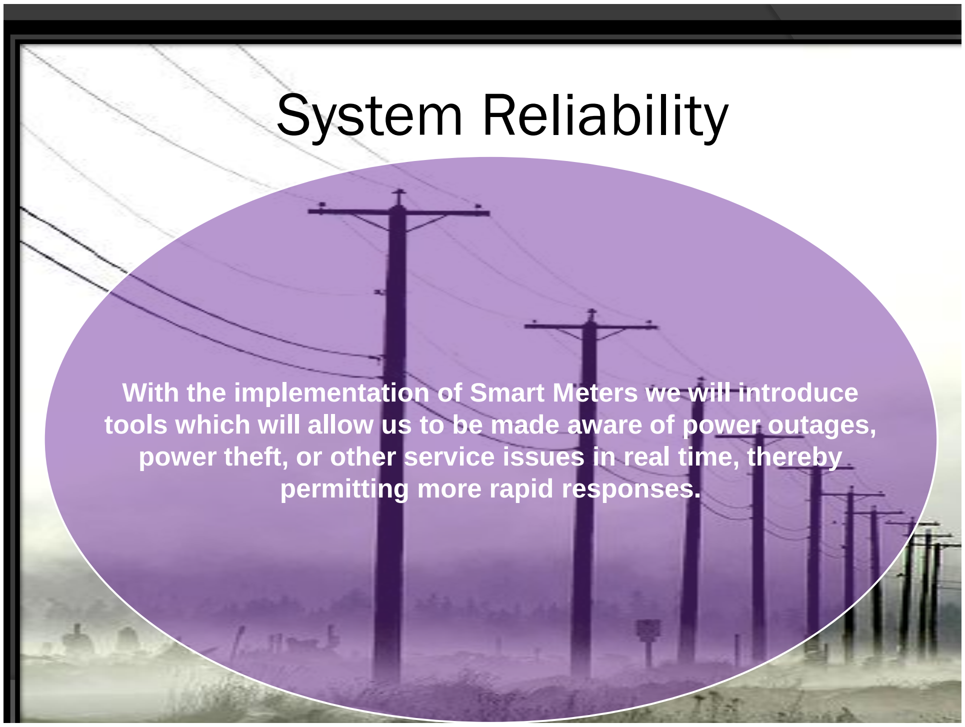
Our Objectives and Results

We have now achieved more than 330,000 hours with no lost time injuries.

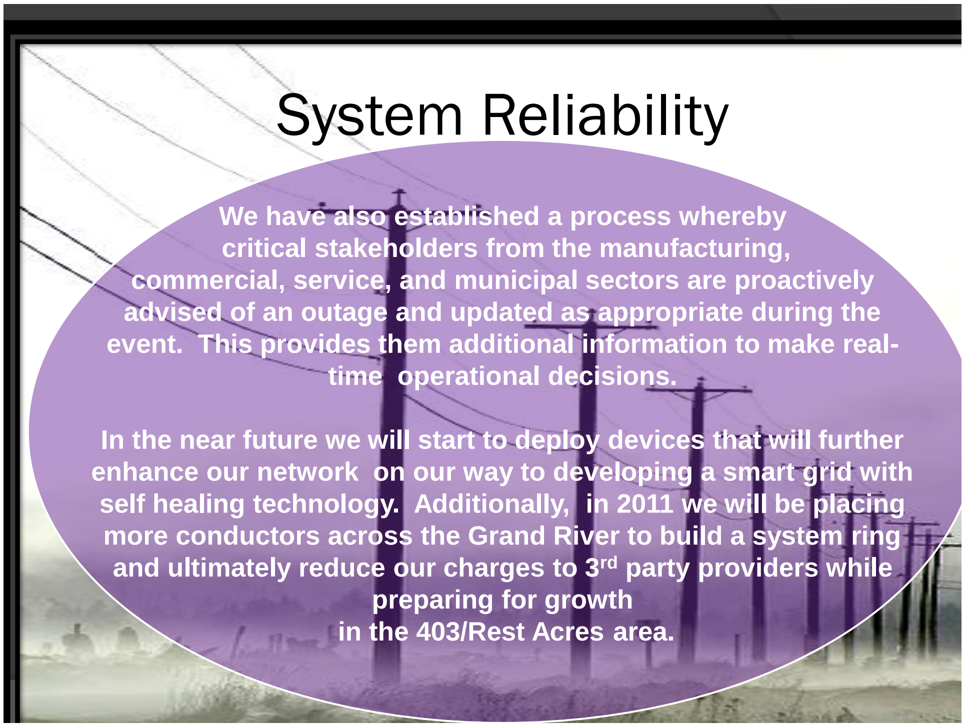
Productivity/Quality

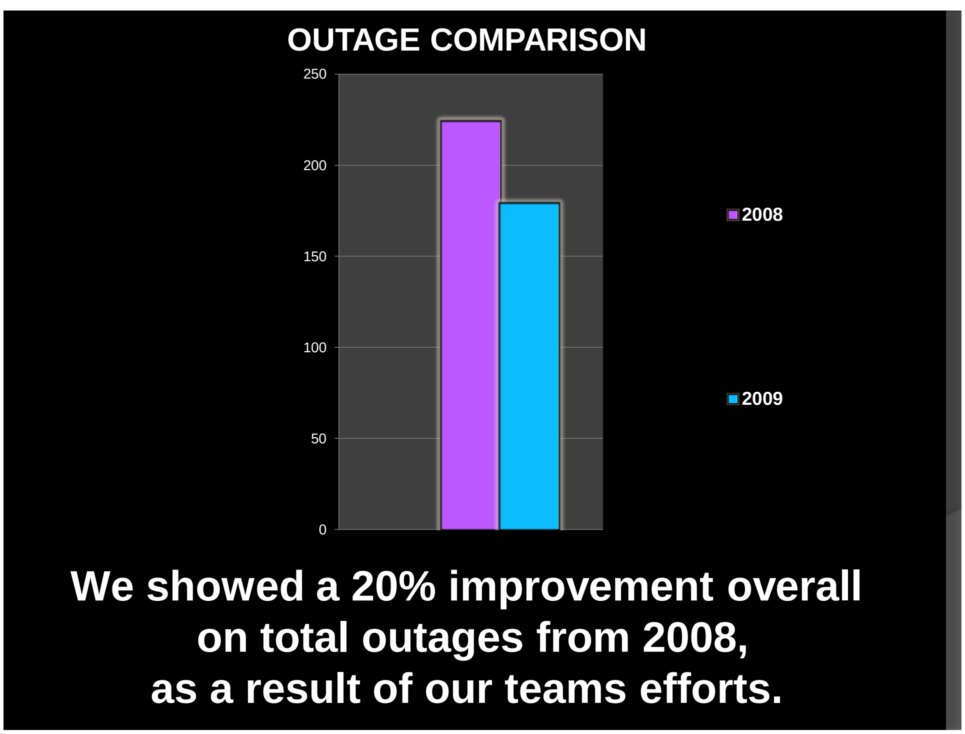
Productivity measures are a critical component to the success of any company. All team members have, or are in the process of having developed, quantifiable meaningful measures and associated objectives. These measures permit us to benchmark thereby allowing us to both recognize individual success and opportunities for improvement.

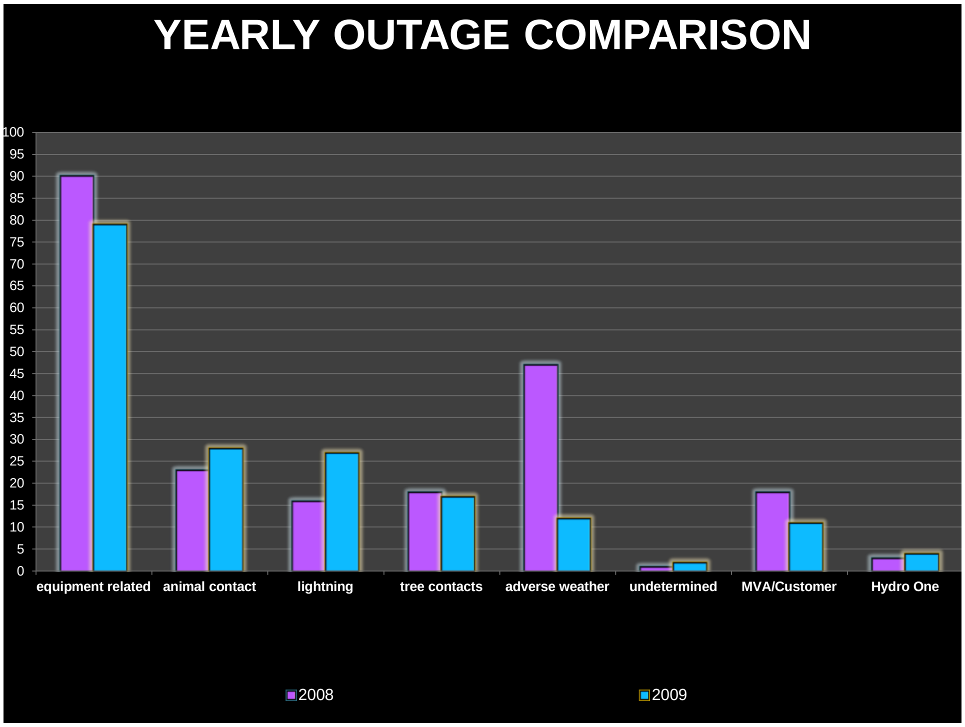



System Reliability
With the implementation of Smart Meters we will introduce tools which will allow us to be made aware of power outages, power theft, or other service issues in real time, thereby permitting more rapid responses.

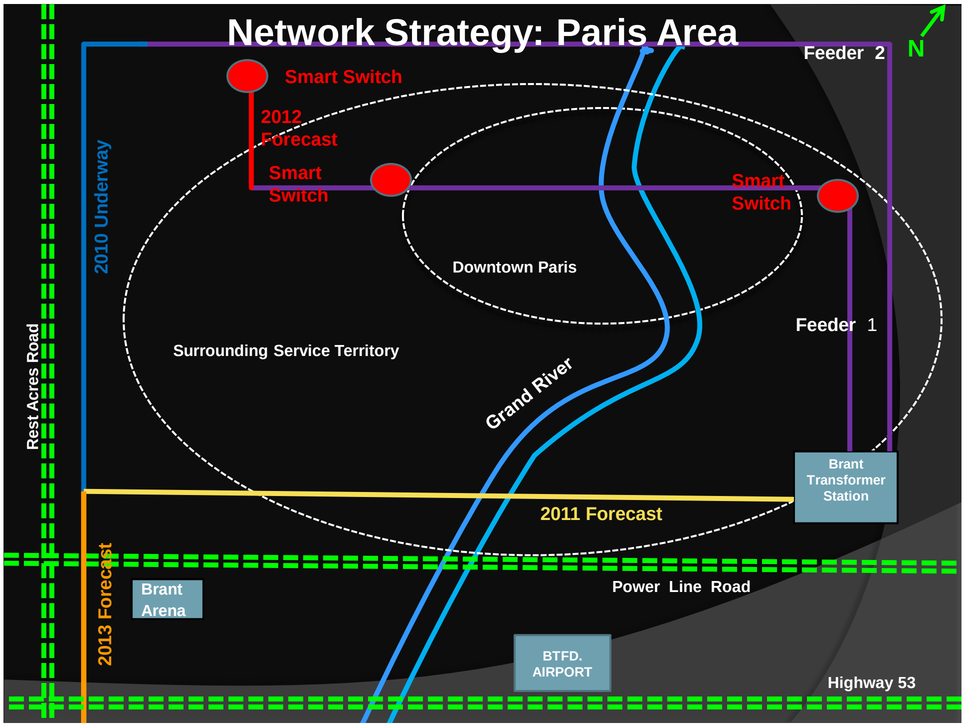

System Reliability
However, some of our most significant outages have been caused by upstream suppliers. We have met with those suppliers and demanded a higher level of service both in quality of supply and speed of response. In some circumstances we are now permitted to work on other lines to enhance the speed of restoration.


System Reliability
We have also established a process whereby critical stakeholders from the manufacturing, commercial, service, and municipal sectors are proactively advised of an outage and updated as appropriate during the event. This provides them additional information to make real-time operational decisions.
In the near future we will start to deploy devices that will further enhance our network on our way to developing a smart grid with self healing technology. Additionally, in 2011 we will be placing more conductors across the Grand River to build a system ring and ultimately reduce our charges to 3rd party providers while preparing for growth in the 403/Rest Acres area.


OUTAGE COMPARISON
250
200
150
100
50
0
2008
2009
We showed a 20% improvement overall on total outages from 2008, as a result of our teams efforts.



- As we move forward we expect our service levels to continue to improve as we work to build a more robust, self healing network



Employee value

Significant change has occurred in this area.

More than 20 percent of our team has changed. New team members have joined us from different industries and bring new insights and ideas into our corporate culture

We believe that the cohesiveness of the team has improved and that we are all “rowing in the same direction”.

One of our most significant changes was with the introduction of our new Chief Financial Officer, Ed Glasbergen, who is accredited with both a CGA and CPA. Ed came to us from RIM where he was accountable for all External Corporate Reporting.

He has had a positive impact on our financial controls, governance and reporting protocols.

Team development is a priority, all staff have;

- regular business and interpersonal skills development training with associated testing.
- Cross accountability training
- Positive coaching
- Commitment at all levels

This has generated a dynamic team environment with greater flexibility.

These accomplishments have been attained during a challenging labour negotiation which resulted in a three year settlement at 2.5% per year.
(the first settlement for less than three percent in recent memory with the Power Worker's Union)

CUSTOMER EXPERIENCE

We have worked hard to humanize the face of our corporation.

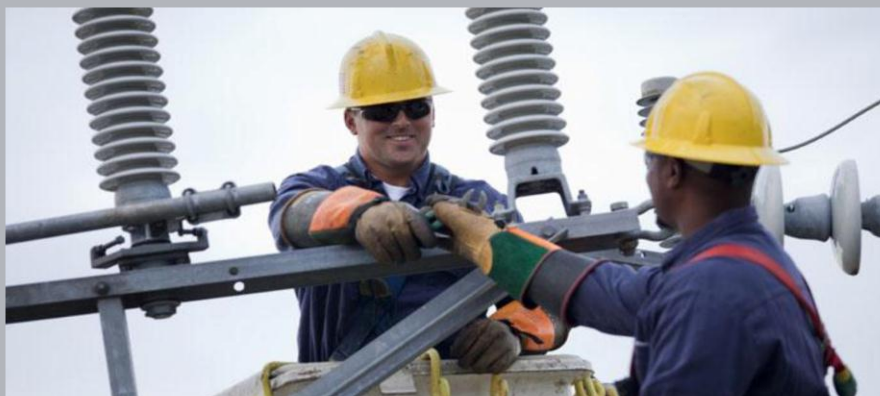
As partners in the community we must be diligent in our desire to serve.

We have both formalized and refocused our corporate giving program.

We have assisted many community based organizations and look forward to doing even more in the future.

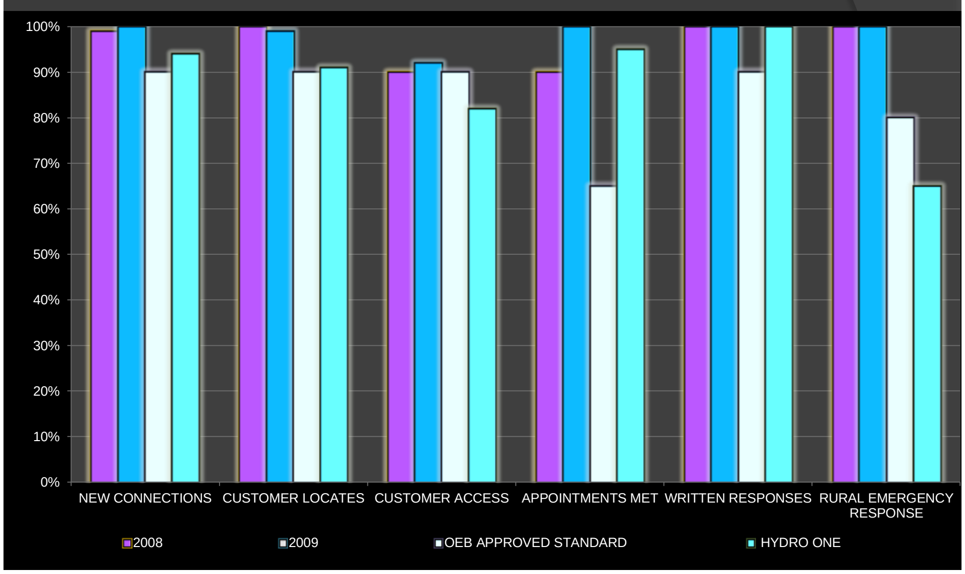
Wednesday Wash & Dry

Family Fun Day



In spite of numerous challenges, we were able to improve the customer experience while at the same time effectively manage costs.

ANNUAL SERVICE QUALITY INDICATOR REPORT CUSTOMER COMMITMENTS MET



Being a good neighbour and a good service provider is not enough. We must ensure our customers see financial value in what we provide.

Monthly Hydro Cost Comparison (800 kw Residential Customer)

Area	Electricity *	Delivery	Regulatory	DRC	GST	Total
Blandford-Blenheim - R1	@5.800 ¢/kWh=50.34	51.39	5.89	5.6	5.66	$118.89
Brant County Power	@5.800 ¢/kWh=48.70	35.23	5.71	5.6	4.76	$100.00
Brantford Power Inc	@5.800 ¢/kWh=48.35	32.74	5.67	5.6	4.62	$96.98
Guelph Hydro Electric Systems Inc.	@5.800 ¢/kWh=48.27	36.52	5.66	5.6	4.8	$100.85
Haldimand County Hydro Inc.	@5.800 ¢/kWh=49.02	44.5	5.74	5.6	5.24	$110.11
Lindsay - R1	@5.800 ¢/kWh=50.34	50.5	5.89	5.6	5.62	$117.95
Norfolk Power Distribution Inc.	@5.800 ¢/kWh=49.00	46.19	5.74	5.6	5.33	$111.85
Tillsonburg Hydro Inc.	@5.800 ¢/kWh=48.35	36.77	5.67	5.6	4.82	$101.21
Woodstock Hydro Services Inc.	@5.800 ¢/kWh=48.44	35.73	5.68	5.6	4.77	$100.23

* Commodity Price + System Loss

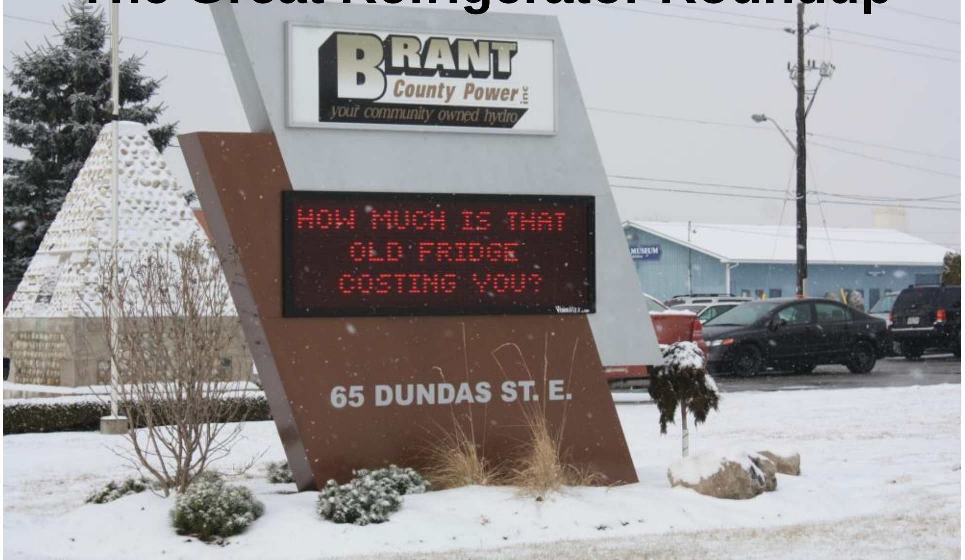
Conservation Initiatives

**As a power company,
conservation is a social and economic responsibility.
Our regulators establish objectives as part of our licensing agreement including….**

ELECTRIC RETROFIT INCENTIVE PROGRAM

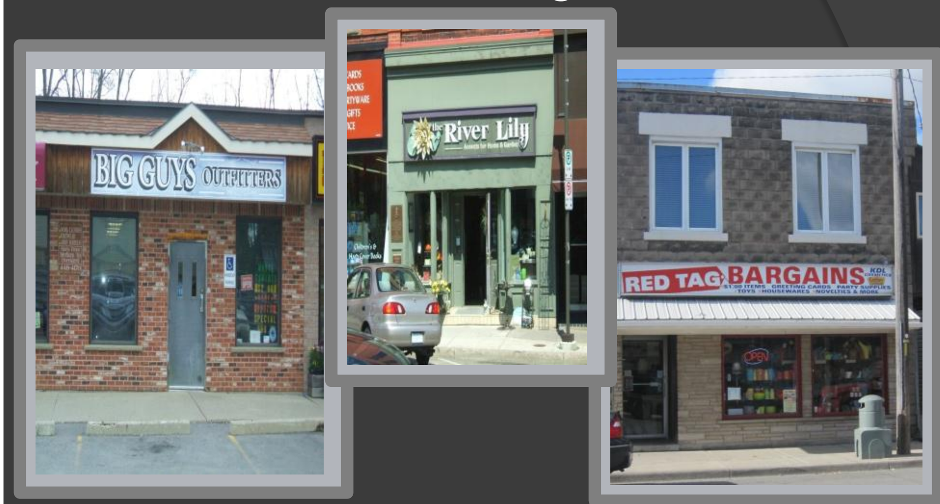
Encourages Industrial, Institutional and Agricultural customers to conserve energy and shift their loads from peak demand periods to lower cost times throughout the day and night.

The Great Refrigerator Roundup



Old inefficient refrigerators are picked up free of charge and recycled, thereby reducing customer power demand.

Power Savings Blitz



Up to $1,000 free for any qualifying business customer to assist in reducing their energy consumption.

Peaksaver

Home owners help reduce the strain on the electrical grid by installing a new free programmable thermostat, which during high demand periods can be adjusted remotely by the commodity provider. (Independent Electricity System Operator)

KILL A WATT

Available free at local libraries this device allows consumers to measure electricity being used by appliances in their homes.

Ontario Energy Board

OBJECTIVES

Program	Target	Results
Great Refrigerator Roundup	178	216
Peaksaver	168	194
ERIP (custom & prescriptive projects)	2	6
Power Savings Blitz	93	223

All Ontario Energy Board Objectives were not only met but exceeded.

Program	Target	Results
Great Refrigerator Roundup	178	216
Peaksaver	168	194
ERIP (custom & prescriptive projects)	2	6
Power Savings Blitz	93	223

Going forward the regulator will look to us to develop our own conservation plans. We have started proactive partnering with some neighboring utilities to develop a Green Energy Plan ahead of the mandate being established.

In addition, we have spoken with both individuals and groups throughout the county about conservation opportunities, as well as other areas of concern including safety, recycling and fraudulent behaviors.

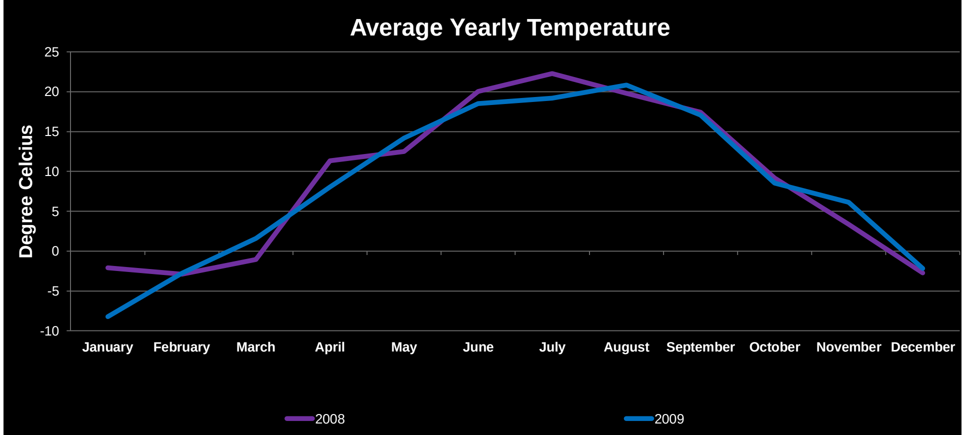
In fact, our CFL recycling program was nominated and ultimately in the final running for a conservation award by the Electrical Distributors Association.


May 2009 www.BusinessLinkBrantford.com

Conservation In Action

"Brant County Power Services is launching a new recycling initiative for Compact Fluorescent Lights (CFL)."

As is the case with reliability of service, weather impacts our bottom line and as stated previously 2009 was a challenging weather year.



Revenue

Brant County Power Inc.

Financial Information

Year Ended December 31, 2009

	2010	2009		2008	2007	2006	2005
	Budget	Actual	Budget	Actual	Actual	Actual	Actual
Revenue							
Distribution	$ 5,911,806	$ 5,640,621	$ 5,941,552	$ 5,815,531	$ 5,812,219	$ 5,049,949	$ 4,302,538
Other	473,902	442,602	462,033	499,130	535,149	516,041	480,015
	$ 6,385,708	$ 6,083,223	$ 6,403,585	$ 6,314,661	$ 6,347,368	$ 5,565,990	$ 4,782,553
Operating and Indirect Expenses	4,701,472	4,963,776	4,756,102	4,782,082	4,818,131	4,492,078	4,306,086
Net Income before other Items	$ 1,684,236	$1,119,447	$1,647,483	$ 1,532,579	$ 1,529,237	$ 1,073,912	$ 476,467
Other Items	(618,122)	(371,723)	(605,260)	(736,781)	1,025,093	(1,129,728)	(1,039,387)
Net Income (Loss)	1,066,114	747,724	1,042,223	795,798	2,554,330	(55,816)	(562,920)
Forecasted Dividend (October 2009)	$533,057	$446,000	$521,112				

Challenges ahead

•We deferred our Smart Meter implementation until after July 1 to take advantage of the HST (savings will be approximately 80K)

•HST and commodity (price of power) increases, implementation and communication.

• GIS/GPS, move to a digital mapping system which will work in conjunction with any product selected by the COB

•With OEB instruction close on Brantford/Brant litigation which could have a significant one time shareholder impact

- Develop and submit our rate application for 2011
- Continue to look for opportunities to increase revenue such as energy generation from methane at Biggar's lane landfill and water power from the Grand
- Seek out conservation opportunities within the Municipal Government.
- Work towards continued network modernization, system reliability and the economic development of our communities.

Identification of Materiality Thresholds

Brant County Power has a distribution revenue requirement of approximately $6.5 million (see exhibit 1, tab 3, schedule 3, page 2) which is below the $10 million threshold outlined by the OEB in the "*Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*" of September 17, 2008 (EB-2007-0673).

BCP is using the $50,000 threshold for major categories of expenses (rate base, capital expenditures, OM&A) however is using a $25,000 threshold by specific USoA details to discuss variances.

Conditions of Service

Issue date:	**September 15, 2004**
Revision date:	**June 19, 2007**

CONDITIONS OF SERVICE

TABLE OF CONTENTS

<u>SECTION 3 - CUSTOMER SPECIFIC</u>

SECTION 1 – INTRODUCTION

This document provides information regarding the services offered by Brant County Power Distribution Inc. and conditions associated with the supply of electrical energy to Customers. These Conditions convey Brant County Power Distribution Inc. policy with respect to service to buildings and associated matters.

1.1 Identification of Distributor and Service Area

Brant County Power Distribution Inc., referred to herein as "Brant County Power" is a corporation incorporated under the laws of the Province of Ontario and a Distributor of electricity.

Brant County Power is licenced by the Ontario Energy Board ("OEB") to supply electricity to Customers as described in the current Distribution Licence issued to Brant County Power by the OEB. Additionally, there are requirements imposed on Brant County Power by the various codes referred to in the Licence and by the Electricity Act, 1998 and Ontario Energy Board Act.

Brant County Power may only operate distribution facilities within its Licenced Service Area as defined in its Distribution Licence. This service area is subject to change with the OEB's approval.

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

1.2 Related Codes and Governing Laws

The supply of electricity or related services by Brant County Power to any Customer shall be subject to various laws, regulations and codes, including the provisions of the latest editions of the following documents:

1. Electricity Act, 1998 } part of the Energy Competition
2. Ontario Energy Board Act, 1998 } Act, 1998
3. Distribution Licence
4. Affiliate Relationships Code
5. Transmission System Code
6. Distribution System Code
7. Retail Settlement Code
8. Standard Service Supply Code

In the event of a conflict between this document and the Distribution Licence or regulatory codes issued by the OEB, or the Energy Competition Act, 1998 (the "Act"), the provisions of the Act, the Distribution Licence and associated regulatory codes shall prevail in the order of priority indicated above. If there is a conflict between a Connection Agreement with a Customer and this Conditions of Service, this Conditions of Service shall govern.

When planning and designing for electricity service, Customers and their agents must refer to all applicable provincial and Canadian electrical codes, and all other applicable federal, provincial, and municipal laws, regulations, codes and by-laws to also ensure compliance with their requirements. Without limiting the foregoing, the work shall be conducted in accordance with the latest edition of the Ontario Occupational Health and Safety Act (OHSA), the Regulations for Construction Projects and the harmonized Electrical & Utilities Safety Association of Ontario (E&USA) rulebook.

1.3 Interpretations

In these Conditions, unless the context otherwise requires:

- Headings, paragraph numbers and underlining are for convenience only and do not affect the interpretation of this Conditions;
- 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 this Conditions of Service and any amendments made from time to time form part of any Contract made between Brant County Power and any connected Customer, Retailer, or Generator and this Conditions of Service supersedes all previous conditions of service, oral or written, of Brant County Power or any of its predecessor municipal electric utilities as of its effective date.

In the event of changes to this Conditions of Service, a public notice shall be made in the form of either a notice in a local newspaper or a notice with the Customer's bill.

The Customer is responsible for contacting Brant County Power to ensure that the Customer has, or to obtain the current version of this Conditions of Service. Brant County Power may charge a reasonable fee for providing the Customer with a copy of this document.

1.5 Contact Information

Brant County Power and its agents can be contacted at:

(519) 442-2215 or 1 (877) 871-2215 or by fax at (519) 442-3701.

Normal working hours are Monday to Friday between 8:30 am and 4:30 pm excluding statutory holidays. The Corporate mailing address is 65 Dundas Street East, Paris, ON
N3L 3H1

1.6 Customer Rights

Brant County Power shall only be liable to a Customer and a Customer shall only be liable to Brant County Power for any damages that arise directly out of the willful misconduct or negligence:

- of Brant County Power in providing distribution services to the Customer;
- of the Customer in being connected to Brant County Power's distribution system; or
- of Brant County Power or Customer in meeting their respective obligations under this Conditions, their licences and any other applicable law.

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

The Customer or Embedded Generator shall indemnify and hold harmless Brant County Power, its directors, officers, employees and agents from any claims made by any third parties in connection with the construction and installation of a generator by or on behalf of the Customer or the Embedded Generator.

1.7 Distributor Rights

1.7.1 Access to Customer Property

Brant County Power shall have access to Customer property in accordance with section 40 of the *Electricity Act, 1998.*

1.7.2 Safety of Equipment

The Customer will comply with all aspects of the Ontario Electrical Safety Code with respect to insuring that equipment is properly identified and connected for metering and operation purposes and will take whatever steps necessary to correct any deficiencies, in particular cross wiring situations, in a timely fashion. If the Customer does not take such action within a reasonable time, Brant County Power may disconnect the supply of power to the Customer.

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 Brant County Power , interfere with the proper and safe operation of Brant County Power's facilities or adversely affect compliance with any applicable legislation in the sole opinion of Brant County Power.

The Customer shall not use or interfere with the facilities of Brant County Power except in accordance with a written agreement with Brant County Power. The Customer must also grant Brant County Power the right to seal any point where a connection may be made on the line side of the metering equipment.

1.7.3 Operating Control

The Customer will provide a convenient and safe place, satisfactory to Brant County Power, for installing, maintaining and operating its equipment in, on, or about the Customer's premises. Brant County Power assumes no risk and will not be liable for damages resulting from the presence of its equipment on the Customer’s premises or approaches thereto, or action, omission or occurrence beyond its control, or negligence of any Persons over whom Brant County Power has no control.

Unless an employee or an agent of Brant County Power, or other Person lawfully entitled to do so, no Person shall remove, replace, alter, repair, inspect or tamper with Brant County Power’s equipment.

Customers will be required to pay the cost of repairs or replacement of Brant County Power’s equipment that has been damaged or lost by the direct or indirect act or omission of the Customer or its agents.

The physical location on customer’s premises at which a distributor’s responsibility for operational control of distribution equipment ends is defined by the Distribution System Code as the “operational demarcation point”.

1.7.4 Repairs of Defective Customer Electrical Equipment

The Customer will be required to repair or replace any equipment owned by the Customer that may affect the integrity or reliability of Brant County Power's distribution system. If the Customer does not take such action within a reasonable time, Brant County Power may disconnect the supply of power to the Customer. Brant County Power’s policies and procedures with respect to the disconnection process are further described in this Conditions of Service. The determination of “reasonable time” shall be the sole discretion of Brant County Power.

1.7.5 Repairs of Customer’s Physical Structures

The Customer is responsible for maintaining, repairing and replacing, in a safe condition satisfactory to Brant County Power, all the Customer’s civil infrastructure on private property including but not limited to poles, underground conduits, cable chambers, cable pull rooms, transformer rooms, transformer vaults and transformer pads that Brant County Power deems required to house Brant County Power’s Connection Assets.

1.8 Disputes

Customer Dispute Resolution Process

1. In addition to other civil avenues that may be pursued to resolve disputes or other specific dispute resolution processes

   Step 1

   To resister a complaint, a customer must call or write the Manager of the applicable department.

Step 2

If the matter is not satisfactorily resolved in Step 1, the customer may refer the matter to the CEO who will address the matter in consultation with the applicable manager and Department Head.

Step 3

If the matter is not satisfactorily resolved in Step 2, the customer may refer the matter to the Board or a Committee of the Board. The Brant Coun ty Power Inc. Board of Directors will consider delegations and other customer dispute matters through written presentation. Written presentations must be submitted to the Secretary of the Board one week prior to the Board meeting. The Board will respond to delegations and other customer dispute matters in writing. Contact the Co-ordinator of Corporate Services at (519) 442-2215 ext. 742 or by e-mail at information@brantcountypower.com.

2. Brant County Power Inc. shall keep a record of all complaints whether resolved or not including the name of the complainant, the nature of the complaint, the date resolved or referred and the result of the dispute resolution.

SECTION 2 - DISTRIBUTION ACTIVITIES (GENERAL)

2.1 Connections

Under the terms of the Distribution System Code, Brant County Power has the obligation to either connect or to make an offer to connect any Customers that lie in its service area.

The Customer or their representative shall consult with Brant County Power concerning the availability of supply, the supply voltage, service location, metering, and any other details. These requirements are separate from and in addition to those of the Electrical Safety Authority. Brant County Power will confirm, in writing, the characteristics of the electric supply.

The Customer or their authorized representative shall apply for new or upgraded electric services and temporary power services in writing. The Customer is required to provide Brant County Power with 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.

Brant County Power shall make every reasonable effort to respond promptly to a Customer's request for connection. Brant County Power shall respond to a Customer's request for a Customer connection within 15 calendar days of receipt of the written request. Brant County Power will make an offer to connect within 60 calendar days of receipt of the written request, unless other necessary information is required from the Customer before the offer can be made.

Brant County Power shall make every reasonable effort to respond promptly to a generator’ s request for connection. In any event Brant County Power shall provide an initial consultation with a generator that wishes to connect to the distribution system regarding the connection process within thirty (30) calendar days of receiving a written request for connection. A final offer to connect a generator to its distribution system shall be made within ninety (90) calendar days of receiving a written request for connection, unless other necessary information outside the distributor’ s control is required before the offer can be made.

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

If special equipment is required or equipment delivery problems occur then longer lead times may be necessary. Brant County Power will notify the Customer of any extended lead times.

In addition to any other requirements in this Conditions of Service, the supply of electricity is conditional upon Brant County Power being permitted and able to provide such a supply, obtaining the necessary apparatus and material, and constructing works to provide the service. Should Brant County Power not be permitted or able to do so, it is under no responsibility to the Customer whatsoever and the Customer releases Brant County Power from any liability in respect thereto.

Brant County Power, in its discretion, may require a Customer, generator or distributor to enter into a Connection Agreement with Brant County Power including terms and conditions in addition to those expressed in this Conditions (refer to the sample in the Distribution System Code - Appendix D).

2.1.1 Building that Lies Along

For the purpose of this Condition "lies along”, means a Customer property or parcel of land that is directly adjacent to or abuts onto the public road allowance where Brant County Power has distribution facilities of the appropriate voltage and capacity.

Under the terms of the Distribution System Code, Brant County Power has the Obligation to connect (under Section 28 of the Electricity Act, 1998) a building or facility that “lies along” its distribution line, provided:

a) the building can be connected to Brant County Power’s distribution system without an Expansion or Enhancement; and
b) the service installation meets the conditions listed in the Conditions of Service of the Distributor that owns and operates the distribution line.

The location of the Customer's service entrance equipment will be subject to the approval of Brant County Power and the Electrical Safety Authority.

2.1.1.1 Connection Charges

Brant County Power shall recover costs associated with the installation of "Connection Assets", by Customer Class, via a Basic Connection Charge and a Variable Connection Charge, as applicable.

a) For Residential Customers, the Basic Connection Charge is recovered through Brant County Power's rates and covers the Standard Allowance to provide a basic connection consistent with the defined ownership demarcation point as outlined in Section 5. This point may differ from the "operational demarcation point".

b) Connection charges for General Service Class customers shall be variable based on the total cost of providing the connection.

<u>Note:</u> Subdivisions, multi units or townhouse type developments are considered General Service Class Customers with respect to connecting the development to the distribution system. Connection charges related to connection of the individual dwelling units in the development will be treated as Residential Class Customers.

c) For Non-Residential Customers, Brant County Power may recover the Basic Connection Charge either through Brant County Power's rates, or through a Basic Connection Fee levied from the Customer requesting the connection. The Basic Connection Fee is determined for each Customer Class as indicated in Section 5 of this Condition.

d) The Variable Connection Charge shall be calculated as the costs associated with the installation of Connection assets **above and beyond** the Standard Allowance for Basic Connection as described in Section 5. Brant County Power may recover this variable connection fee, which shall be based on actual cost.

<u>Note:</u> Basic Connection Fees are reviewed annually and are calculated based on the average costs to provide the Standard Allowance and the Basic Connection for each Customer Class as identified in Section 5 of this Conditions. Standard fees are determined using historical data from previous year(s) for all completed projects in each Customer Class.

2.1.2 Expansions / Offer to Connect

Under the terms of the Distribution System Code, Brant County Power is required to make an "Offer to Connect" if, in order to connect a Customer, Brant County Power must construct new distribution system facilities or increase the capacity of existing distribution facilities (i.e. an "Expansion" of its system). In making an "Offer to Connect", Brant County Power will include, without limitation, the following components, as applicable:

a) the Basic Connection Fee;
b) the Variable Connection Fee;
c) the Capital Contribution;
d) the Security Deposit.

The cost associated with the Expansion is to be fair and reasonable and is in addition to any Basic and/or Variable Connection Charges. Refer to Section 5 for Basic and Variable Connection Fees of each Customer Class and the respective ownership demarcation point.

Brant County Power may perform an economic evaluation to determine whether the future revenue from the Customer will pay for the capital and on-going maintenance costs of the Expansion project (refer to methodology and assumptions in the Distribution System Code – Appendix B). At the discretion of Brant County Power, the capital costs for the Expansion may include incremental costs associated with the full use of Brant County Power’s existing spare facilities or equipment, which may result in an adverse impact to future Customers. The economic evaluation will be based on the Customer’s proposed load (“Estimated Incremental Demand”).

In performing the economic evaluation, should the Net Present value (NPV) of the costs and revenues associated with the expansion be less than zero, a capital contribution in the amount of the shortfall is required. Brant County Power has the choice of either:

a) collecting this shortfall from the Customer; or
b) absorbing this shortfall.

2.1.2.1 Offer to Connect

If Brant County Power’s offer to connect is a firm offer, Brant County Power may provide one estimate to the Customer for any plans submitted to Brant County Power for an expansion project, at no expense to the Customer. If the Customer submits revised plans, Brant County Power may provide a new firm offer for revised plans at the Customer’ s expense.

If Brant County Power’s offer to connect is an estimate of the costs to construct the expansion and not a firm offer, the final amount charged to the Customer will be based on actual costs incurred. Brant County Power will calculate the first estimate and the final payment at no expense to the Customer.

Where the offer to connect meets the conditions identified in the Distribution System Code, Brant County Power will inform the Customer that the Customer may obtain other bids from qualified contractors.

Brant County Power may charge a Customer that chooses to pursue an alternative bid any costs incurred by Brant County Power associated with the expansion project, including but not limited to the following:

- costs for additional design, engineering, or installation of facilities required to complete the project that were made in addition to the original offer to connect;
- costs for inspection or approval of the work performed by the contractor hired by the Customer.

2.1.2.2 Capital Contributions

Customers, (including developers) may be required to pay a capital contribution to pay for a portion of Brant County Power costs incurred to provide service in compliance to section 3 of the Distribution System Code.

General Principles for All Classes of Customers

Brant County Power shall supply, install and maintain the following basic service at no charge to a new customer or group of customers.

- Basic KWH, KW /KVA meters as required.
- Interval meter supplied for loads over 500 KVA.
- 30 meters of overhead conductor to **Residential Class** Customers for connection to Brant County Power's primary distribution system or transformer or equivalent credit.
- Brant County Power may supply, install and maintain overhead road crossing facilities.
- Installed ***(lowest cost)*** transformation.

Related costs for basic service shall be recovered through the retail distribution service charge to all customers as part of Brant County Power's general revenue requirement.

The customer shall pay a capital contribution to pay for the ***incremental*** cost of metering, connections, transformation and distribution facilities that exceed the basic service provided by Brant County Power as follows:

General Terms and Conditions for all Classes of Customers.

- The customer shall pay all costs for service less a credit for the cost of basic service.
- Brant County Power is under no obligation to invest in infrastructure for speculation.
- In circumstances where a ***significant*** delay is expected (in the opinion of the Distributor) between construction of infrastructure and connection of metered retail consumers, the customer may be required to pay a deposit covering 100% of all Utility costs. A refund of the portion of the deposit related to Brant County Power contribution for basic service shall be paid to the customer at the time metered connection is completed.
- In the case of subdivision development, the deposit refunds shall be rebated for Brant County Power's share of related capital works, as metered service connections are completed.
- Deposit refunds to subdivision developers shall not be paid after five years from the date the final deposit was paid by the Developer.

Connection to Existing Brant County Power Distribution Facilities:

- **Residential Class:**
  The customer shall pay for all costs of providing the connection and metering less an allowance equal to the installed cost of providing an overhead service up to 30 meters in length plus the installed cost of a basic KWH meter *and road crossing facilities.* Installed *(lowest cost)* transformation is provided at no additional charge.

  (Under this guideline, the customer would be required to pay for the incremental cost of special metering plus the incremental cost of connection service beyond the basic 30 meters and/or the incremental cost of upgrading to an underground service and transformation costs that exceed the lowest cost option.)

- **General Service Class:**
  The customer shall pay for all costs of providing the connection including metering and modifications to transformer support structures and adjacent distribution facilities***, less*** the installed cost of (*lowest cost)* transformation, basic metering and road crossing facilities.

  1000 KVA transformation or greater shall be customer owned.

  (*Under this guideline the customer would be required to pay for the incremental cost of special metering, the full cost of connection including underground supply plus transformation costs in excess of the lowest cost option. At their sole discretion, where Brant County Power requires installation of a pad mount transformer, this may be considered the lowest cost option.).*

Service Upgrades

- **Residential Class:**
  Service upgrades as a result of an increase in customer energy requirements for residential class customers are provided at no charge. Brant County Power reserves the right to apply the 25 year net present value calculation *(per appendix B of the Distribution System Code)* to determine if a capital contribution is required, where in the opinion of Brant County Power the cost of upgrade is excessive

- **General Service Class: (Non demand less than 50 KW)**
  For small general service class customers (non demand less than 50 KW) service upgrades are provided at no charge. Brant County Power reserves the right to apply the 25 year net present value calculation to determine if a capital contribution is required, where in the opinion of Brant County Power the cost of upgrade is excessive.

- General Service Class (Demand of 50 KW or higher)
  Where large general service customers request an upgrade to their service the customer shall pay a capital contribution. The amount of the capital contribution will be determined using a 25 year net present value calculation (*per appendix B of the Distribution System Code*) comparing the present value of *incremental* revenue to the present value of the *incremental* cost of related capital works *including* transformation and metering upgrades.

- All *incremental* costs associated with service upgrades shall be included in the "Net Present Value" calculation including basic services supplied by Brant County Power. This method is required because the NPV of all future revenues must be adequate to recover Brant County Power's future cost of basic service as recovered through retail rates.

  By including all *incremental costs* and all *incremental* revenue, the cost sharing between the customer and Utility is fair and reasonable and in compliance to section 3 of the Distribution System Code.

<u>System Expansions</u>

Where customers request a system expansion (line extensions, conversion to three phase power, etc.) of the distribution system to accommodate their supply requirements, the customer shall pay a capital contribution. The amount of the capital contribution will be determined using a 25 year net present value calculation (*per appendix B of the Distribution System Code)* comparing the present value of *incremental* revenue to the present value of the *incremental* cost of related capital works.

A portion of the customer's capital contribution for system expansion shall be rebated in compliance to section 3.2.7 of the Distribution System Code where additional customers connect to the expanded distribution system within a subsequent five year period.

Where a system expansion (ie. line extension) directly benefits distribution system reliability or economically provides for the connection of future new customers within a five-year window, Brant County Power at its sole discretion may reduce the amount of capital contribution required as per section 3.2.6 of the Distribution System Code.

The initial offer shall include, at no cost to the customer:

- A statement as to whether the offer is a firm offer or is an estimate of the costs that would be revised in the future to reflect actual costs incurred.;
- A reference to our Condition's of Service and information on how the customer may obtain a copy of them,
- A statement as to whether a capital contribution will be required from the customer;
- A statement as to the amount of the expansion deposit the customer will have to provide; and
- A statement as to whether the connection charges will be charged separately and a description of, and if known, the amount for those connection charges.

If a capital contribution is required, Brant County Power Inc. will also include in its initial offer, at no cost to the customer:

- The amount of the capital contribution;
- The calculation used to determine the amount of the contribution to be paid by the customer;

- A statement as to whether the offer includes work for which the customer may obtain alternate bids and if so the process by which the customer may obtain alternate bids;
- A description of the costs for the contestable work and the uncontestable work associated with the expansion broken down into the following categories:
    - Labor (including design, engineering and construction);
    - Materials;
    - Equipment; and
    - Overhead (including administration)

<u>Subdivision Development:</u>

General:

With respect to subdivision development, there is a delay between investment in infrastructure (lines, services, meters, transformers etc) and the revenue stream from new connected customers. As a result of this delay, Developers will be required to pay 100% of all related costs to build the infrastructure and to be subsequently rebated for a prorated share of Brant County Power's portion of subdivision costs at the time metered customers are connected based on the 25 year net present value calculation.

Note: In circumstances where a subdivision has restricted access ie. "gated" community, Brant County Power shall be granted convenient unrestricted access for meter reading and emergency response. Easements shall be provided for Brant County Power electrical distribution facilities at the customer's expense.

Where Brant County Power constructs the subdivision electrical distribution facilities, at the Developer's request:

- The developer shall pay a capital contribution determined using the 25 year net present value calculation, per appendix B of the Distribution System Code.

- All Utility costs associated with servicing the subdivision shall be included in the net present value calculation including basic services supplied by Brant County Power. This method is required because the net present value of future revenues must be adequate to recover Brant County Power's future cost of basic service as recovered through retail rates.

  By including all costs and all revenue, the cost sharing between the Developer and Utility is fair and reasonable and in compliance to section 3 of the Distribution System Code.

- Any surplus of NPV revenue over costs accrues to the benefit of the Developer in reducing the amount of the capital contribution required.

- The Developer shall be required to pay a deposit equal to 100% of the Utilities estimated costs including the Utilities portion for basic services.

- The Developer shall be subsequently rebated for Brant County Power's share of related capital works *(per 25 year NPV calculation)* at the end of the 5 years or when the last lot is connected, whichever comes first.

- It is reasonable to expect that a subdivision development will be completed within five years. Any remaining portion of the calculated total rebate after five years from the start of electrical facilities construction is therefore not refundable.

Where the Developer constructs the subdivision electrical distribution facilities.

The Developer shall be reimbursed for Brant County Power's share of the total subdivision cost based on a 25-year net present value calculation per appendix B of the Distribution System Code, subject to the following terms and conditions.

- All costs associated with servicing the subdivision shall be included in the "Net Present Value" calculation including basic services supplied by Brant County Power. This method is required because the NPV of future revenues must be adequate to recover Brant County Power's future cost of basic service as recovered through retail rates.

  By including all costs and all revenue, the cost sharing between the Developer and Utility is fair and reasonable and in compliance to section 3 of the Distribution System Code.

- The total calculated rebate shall be divided by the number of individual metered residences to determine a rebate per residence.

- Rebates based on a 25 year Net Present Value calculation shall be paid to the developer as each lot is connected.

- It is reasonable to expect that a subdivision development will be completed within five years. Any remaining portion of the rebate after five years from the start of electrical facilities construction is therefore not refundable.

2.1.2.3 Rebates Related to Expansions

In scenarios where Brant County Power is required to install new plant solely for the connection of a Customer, the Customer will be required to pay Brant County Power 100% of the calculated shortfall. If within 5 years from the connection date, non-forecasted Customers are connected to this new plant without any further capital costs, non-forecasted Customers shall contribute their share and the first Customer may be entitled to a rebate as outlined in Brant County Power's rebate process.

2.1.2.4 Supply Agreement and Securities

To keep Brant County Power harmless as a result of Brant County Power agreeing to reduce the amount of capital contribution required for the Expansion, the General Service Class customer shall enter into a Supply agreement and provide a security deposit to cover for the difference between the actual costs incurred by Brant County Power and the capital contribution(s) paid by the Customer. With each subsequent renewal of the security deposit, an amount equal to the actual incremental revenue collected since the in-service date shall reduce the Customer’s liability. The residual debt, if any, is due 25 years after the in-service date, or upon termination of the Supply Agreement. The obligation to pay any outstanding amount shall survive the termination of the Supply Agreement. An irrevocable (standby) letter of credit or a letter of guarantee from a chartered bank, trust company or credit union is acceptable in lieu of a cash deposit. This security deposit is in addition to any other charges or deposits that may be required by Brant County Power and is to be provided **prior** to the connection of service.

2.1.3 Connection Denial

The Distribution System Code sets outs the conditions for Brant County Power to deny connections. Brant County Power is not obligated to connect a building within its service area if the connection would result in any of the following:

- Contravention of existing laws of Canada and the Province of Ontario.
- Violations of conditions in Brant County Power’s Licence.
- Use of a distribution system line for a purpose that it does not serve and that Brant County Power does not intend to serve.
- Adverse effect on the reliability and safety of the distribution system.
- Public safety reasons or imposition of an unsafe work situation beyond normal risks inherent in the operation of the distribution system.
- A material decrease in the efficiency of Brant County Power’ s 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 Brant County Power.
- If the person requesting the connection owes Brant County Power money for distribution services.
- If an electrical connection to Brant County Power’s distribution system does not meet Brant County Power’s design requirements.
- Any other conditions documented in Brant County Power's Conditions of Service document that are consistent with the conditions identified above and with the goals delineated in the Energy Competition Act, 1998.

If Brant County Power refuses to connect a building in its service area that lies along one of its distribution lines, Brant County Power shall inform the person requesting the connection of the reasons for the denial, and where Brant County Power is able to provide a remedy, make an offer to connect. If Brant County Power is unable to provide a remedy to resolve the issue, it is the responsibility of the customer to do so before a connection can be made.

2.1.4 Inspections Before Connections

All customer electrical installations shall be inspected and approved by the Electrical Safety Authority and must also meet Brant County Power’s requirements. Brant County Power requires notification from the Electrical Safety Authority of this approval prior to energizing a Customer’s supply of electricity. Services that have been disconnected for a period of six months or longer must also be re-inspected and approved by the Electrical Safety Authority prior to reconnection.

Temporary services, typically used for construction purposes and for a period of twelve months or less, must be approved by the Electrical Safety Authority and must be re-inspected should the period of use exceed twelve months.

Customer owned substations must be inspected by both the Electrical Safety Authority and Brant County Power.

Transformer rooms are not permitted by Brant County Power. All new underground installations must be padmount transformer type installation.

Duct banks shall be inspected and approved by Brant County Power prior to the pouring of concrete and again before backfilling. The completed ducts must be rodded by the site contractor in the presence of a Brant County Power inspector, and shall be clear of all extraneous material. A mandrel, appropriately sized, to nominal diameter of duct, will be supplied by the contractor and be passed through each duct. In the event of ducts blocked any extraneous material, the owner's representative will be responsible for clearing the ducts prior to the cable installation. Connection to existing concrete duct banks or manholes will be done only by an approved contractor. All work done on existing duct banks must be authorized by Brant County Power and carried out in accordance with all applicable safety acts and regulations.

Provision for metering shall be inspected and approved by Brant County Power prior to energization.

2.1.5 Relocation of Plant

When requested to relocate distribution plant, Brant County Power may exercise its rights and discharge its obligations in accordance with existing acts, by-laws and regulations including the *Public Service Works on Highways Act*, formal agreements, easements and law. In the absence of existing agreements, Brant County Power is not obligated to relocate the plant. However, Brant County Power shall resolve the issue in a fair and reasonable manner. Resolution in a fair and reasonable manner may include a response to the requesting party that explains the feasibility or unfeasibility of the relocation and a fair and reasonable charge for relocation based on cost recovery principles.

2.1.6 Easements

To maintain the reliability, integrity and efficiency of the distribution system, Brant County Power has the right to have supply facilities on private property and to have easements registered against title to the property. Easements are required whenever Brant County Power's underground or overhead plant is to be located on private property.

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

The Customer will prepare at its own cost a reference plan and associated easement documents to the satisfaction of Brant County Power's solicitor prior to its registration and registering of the easement plan. Details will be provided upon application for service.

2.1.7 Contracts

2.1.7.1 Contract for New or Modified Electricity Service

Brant County Power shall only connect a Building for a new or modified supply of electricity upon receipt by Brant County Power of a completed and signed contract for service in a form acceptable to Brant County Power, payment to Brant County Power of any applicable connection charge or security deposit, and an inspection and approval by the Electrical Safety Authority of the electrical equipment for the new service.

2.1.7.2 Implied Contract

In all cases, notwithstanding the absence of a written contract, Brant County Power has an implied contract with any Customer that is connected to Brant County Power’s distribution system and receives distribution services from Brant County Power. The terms of the implied contract are embedded in Brant County Power’s Conditions of Service, the Rate Handbook, Brant County Power’s rate schedules, Brant County Power’s licence, the Distribution System Code, the Standard Supply Service Code and the Retail Settlement Code, all as amended from time to time.

Any Person(s) who take or use electricity from Brant County Power shall be liable for payment for such electricity. Any implied contract for the supply of electricity by Brant County Power shall be binding upon the heirs, administrators, executors, successors or assigns of the Person(s) who took and/or used electricity supplied by Brant County Power.

In the absence of a contract for electricity with a tenant, or in the event the electricity is used by a person(s) unknown to Brant County Power, then the cost for electricity consumed by such person(s) is due and payable by the owner(s) of such property.

2.1.7.3 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

2.1.7.4 Connection Agreements

Brant County Power may require a Customer to enter into a Connection Agreement in a form acceptable to Brant County Power (Refer to the sample in the Distribution System Code – Appendix D)

An Embedded Generator and/or Embedded Retail Generator shall enter into a Connection Agreement in a form acceptable to Brant County Power (Refer to the Distribution System Code – Appendix E and F)

A Wholesale Market Participant shall enter into a Connection Agreement in a form acceptable to Brant County Power

An Embedded Distributor shall enter into a Connection Agreement in a form acceptable to Brant County Power (Refer to the Distribution System Code – Appendix G)

Brant County Power shall make a good faith effort to enter into a Connection Agreement with a distributor connected to the distributor's distribution system in accordance with the requirements in the Distribution System Code issued by the Ontario Energy Board.

2.1.7.5 Payment by Building Owner

The owner of a building is responsible for paying for the supply of electricity except where a tenant or occupant has a supply contract with Brant County Power.

A building owner wishing to terminate the supply of electricity to their building must notify Brant County Power in writing. Until Brant County Power receives such written notice from the building owner, the building owner or the occupant(s), as applicable, shall be responsible for payment to Brant County Power for the supply of electricity to such building. Brant County Power may refuse to terminate the supply of electricity to an owner's building when there are occupant(s) in the building (i.e. during certain periods of the winter).

2.1.7.6 Opening and Closing of Accounts

A Customer who wishes to open or close an account for the supply of electricity by Brant County Power shall contact Brant County Power’s office by phone, by written request (including requests submitted by facsimile), or other means acceptable to Brant County Power.

The Customer shall be responsible for payment to Brant County Power for the supply of electricity to the property up to the date Brant County Power is notified of the termination of the account.

2.2 Disconnection

Brant County Power reserves the right to disconnect the supply of electrical energy for causes not limited to:

- Contravention of the laws of Canada or the Province of Ontario.
- Adverse effect on the reliability and safety of the distribution system.
- Imposition of an unsafe worker situation beyond normal risks inherent in the operation of the distribution system.
- A material decrease in the efficiency of the distributor's distribution system.
- A materially adverse effect on the quality of distribution services received by an existing connection.
- Discriminatory access to distribution services.
- Inability of Brant County Power to perform planned inspections and maintenance.
- Failure of the Consumer or Customer to comply with a directive of Brant County Power that Brant County Power makes for purposes of meeting its licence obligations.
- Overdue amounts payable to Brant County Power for the distribution or retail of electricity.
- Electrical disturbance propagation caused by Customer equipment that are not corrected in a timely fashion.
- Any other conditions identified in this Conditions of Service document.

Brant County Power may disconnect the supply of electricity to a Customer without notice in accordance with a court order, or for emergency, safety or system reliability reasons or at the direction of the Electrical Safety Authority.

2.2.1 Disconnection and Reconnection – Process and Charges

Immediately following the due date, steps will be taken to collect the full amount of the bill. If the bill is still unpaid twenty-one calendar days after the due date (including seven calendar days after a disconnect notice has been given to the Customer), the service may be disconnected and not restored until satisfactory payment arrangements have been made, including costs of reconnection. Such discontinuance of service does not relieve the Customer of the liability for arrears or minimum bills for the balance for the term of contract, nor shall Brant County Power be liable for any damage to the Customer’s premises resulting from such discontinuance of service. Disconnect notices will be in writing and if given by mail should be deemed to be received on the third business day after mailing.

Upon discovery that a hazardous condition or disturbance propagation (feedback) exists, Brant County Power will notify the Customer to rectify the condition at once. In case the Customer fails to make satisfactory arrangements to remedy the condition within seven calendar days after a disconnect notice has been given to the Customer, the service may be disconnected and not restored until satisfactory arrangements to remedy the condition have been made. Brant County Power shall not be liable for any damage to the Customer's premises resulting from such discontinuance of service. Disconnect notices will be in writing and if given by mail shall be deemed to be received on the third business day after mailing.

Upon receipt of a Disconnection request by the Customer, Brant County Power may disconnect and/or remove Brant County Power's connection assets at the Customer's cost.

2.2.2 Unauthorized Energy Use

Brant County Power reserves the right to disconnect the supply of electrical energy to a Customer for causes not limited to energy diversion, fraud or abuse on the part of the Customer. Such service may not be reconnected until the Customer rectifies the condition and provides full payment to Brant County Power including all costs incurred by Brant County Power arising from unauthorized energy use, including inspections, repair costs, and the cost of disconnection and reconnection.

2.3 Conveyance of Electricity

2.3.1 Limitations on the Guarantee of Supply

Brant County Power will endeavor 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 higher degree of security than that of normal supply are responsible to provide their own back-up or standby facilities. Customers may require special protective equipment on their premises to minimize the effect of momentary power interruptions.

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 Distributor's supply.

During an emergency, Brant County Power may interrupt supply to a Customer in response to a shortage of supply, or to effect repairs on the distribution system, or while repairs are being made to Customer-owned equipment.

Brant County Power shall have rights to access to a property in accordance with section 40 of the *Electricity Act, 1998* and any successor acts thereto.

To assist with distribution system outages or emergency response, Brant County Power may require a Customer to provide Brant County Power with emergency access to Customer-owned distribution equipment that normally is operated by Brant County Power or Brant County Power-owned equipment on Customer's property.

2.3.2 Power Quality

2.3.2.1 Power Quality Testing

In response to a Customer power quality concern, where the utilization of electric power affects the performance of electrical equipment, Brant County Power or a designated contractor will perform investigative analysis to identify the underlying cause. Depending on the circumstances, this may include review of relevant power interruption data, trend analysis, and/or use of diagnostic measurement tools.

Upon determination of the cause resulting in the power quality concern, where it is deemed a system delivery issue and where industry standards are not met, Brant County Power may recommend and/or take appropriate mitigation measures. If Brant County Power is unable to correct the problem due to the impact on other Customers, then it is not obligated to make the corrections. Brant County Power will use appropriate industry standards (such as IEC or IEEE standards) as a guideline. If the problem lies on the Customer side of the system, Brant County Power may seek reimbursement for the time spent in investigating the problem.

If an undesirable system disturbance is being caused by Customer's equipment, the Customer will be required to cease operation of the equipment until satisfactory remedial action has been taken. If the Customer does not take such action within a reasonable time, Brant County Power may disconnect the supply of power to the Customer.

It is the responsibility of the Customer to provide protection from voltage variations and transient operations.

2.3.2.2 Prevention of Voltage Distortion on Distribution

Customers having non-linear load shall not be connected to Brant County Power's distribution system unless power quality is maintained by implementing proper corrective measures such as installing proper filters, and/or grounding. Further, to ensure the distribution system is not adversely affected, power electronics equipment installed must comply with IEEE Standard 519-1992. The limit on individual harmonic distortion is 3%, while the limit on total harmonic distortion is 5%.

2.3.2.3 Obligation to Help in the Investigation

If Brant County Power determines the Customer's equipment may be the source causing unacceptable harmonics, voltage flicker or voltage level on Brant County Power's distribution system, the Customer is obligated to help Brant County Power by providing required equipment information, relevant data and necessary access for monitoring the equipment.

2.3.2.4 Timely Correction of Deficiencies

If an undesirable system disturbance is being caused by Customer's equipment, the Customer will be required to cease operation of the equipment until satisfactory remedial action has been taken by the Customer at the Customer's cost. If the Customer does not take such action within a reasonable time, Brant County Power may disconnect the supply of power to the Customer.

2.3.2.5 Notification for Interruptions

Although it is Brant County Power's policy to minimize inconvenience to Customers it is necessary to occasionally interrupt a Customer's supply to allow work on the electrical system. Brant County Power will endeavour to provide such Customers with reasonable notice of planned power interruptions. However, interruption times may change due to inclement weather or other unforeseen circumstances.

Brant County Power shall not be liable in any manner to such Customers for failure to provide such notice of planned power interruptions or for any change to the schedule for planned power interruptions.

Notice may not be given where work is of an emergency nature involving the possibility of injury to persons or damage to property or equipment.

During an emergency, Brant County Power may interrupt supply to a Customer in response to a shortage of supply or to effect repairs on Brant County Power's distribution system or while repairs are being made to Customer-owned equipment.

2.3.2.6 Notification to Customers on Life Support

Customers who require an uninterrupted source of power for **human** life support equipment must provide their own equipment for these purposes. Customers with life support system are encouraged to inform Brant County Power of their medical needs and their available backup power. These Customers are responsible for ensuring that the information they provide Brant County Power is accurate and up-to-date.

With planned interruptions, the same procedure as prescribed in section 2.3.2.5 will be observed. For those unplanned power interruptions that extend beyond two hours and the time expected to restore power is longer than what was indicated by Customers (registered on life support) as their available backup power, Brant County Power will endeavor to contact these Customers but will not be liable in any manner to the Customers for failure to do so.

2.3.2.7 Emergency Interruptions for Safety

Brant County Power will endeavor to notify Customers prior to interrupting the supply to any 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 Brant County Power or the public, service may be interrupted without notice.

2.3.2.8 Emergency Service (Trouble Calls)

Brant County Power may exercise reasonable diligence and care to deliver a continuous supply of electrical energy to the Customer. However, Brant County Power cannot guarantee a supply that is free from interruption.

When power is interrupted, the Customer should first ensure that failure is not due to blown fuses or breakers within their premises. If there is a partial power failure outside of normal business hours, the Customer should obtain the services of an electrical contractor to carry out necessary repairs. If, on examination, it appears that Brant County Power's main source of supply has failed, the Customer should report these conditions to Brant County Power.

Brant County Power operates a 24-hour a day phone line to provide emergency service to Customers. Brant County Power will initiate restoration efforts as rapidly as practicable.

2.3.2.9 Outage Reporting

Depending on the outage, duration and the number of Customers affected, Brant County Power may issue a news release to advise the general public of the outage. In turn, news radio stations may call for information on a 24-hour basis when they hear of an outage.

2.3.3 Electrical Disturbances

Brant County Power shall not be held liable for the failure to maintain supply voltages within standard levels due to Force Majeure as defined in Section 2.3.5 of the Conditions.

Voltage fluctuations and other disturbances can cause flickering of lights and other serious difficulties for Customers connected to Brant County Power's distribution system. Customers must ensure that their equipment does not cause disturbances such as harmonics and spikes that might interfere with the operation of adjacent Customer equipment. Equipment that may cause disturbances include large motors, welders and variable speed drives, etc. In planning the installation of such equipment, the Customer ***must consult*** with Brant County Power.

Some types of electronic equipment, such as video display terminals, can be affected by the close proximity of high electrical currents. Brant County Power may assist in attempting to resolve any such difficulties at the Customer's expense.

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

2.3.4 Standard Voltage Offerings

2.3.4.1 Primary Voltage

The primary voltage to be used will be determined by Brant County Power for both Brant County Power-owned and Customer-owned transformation. Depending on what voltage of the plant that "lies along", the preferred primary voltage will be at 27.6/16 kV grounded wye, three phase, four-wire system. However, in some areas the primary voltage will be 8.3/4.8 kV or 4.16/2.4 kV grounded wye, three phase, four wire.

2.3.4.2 Supply Voltage

Depending on what voltage of plant "lies along" Brant County Power's distribution system, the preferred secondary voltage will be at 120/240 V, single phase, 120/208 V, three phase; and 347/600V, three phase.

The limit of supply capacity for any customer is governed by the supply voltage. General guidelines for supply from overhead circuits are as follows:

i) at 120/240 V, single phase up to 167 kVA demand load, or
ii) 120/208 V, three phase, four wire or 347/600 V, three phase, four wire up to 300 kVA demand load.

<u>OR</u>

Where circuits are buried, the supply voltage and limits will be determined upon application to Brant County Power.

<u>OR</u>

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

i) at 120/240 V, single phase, supply is available up to 100 kVA, or
ii) at 120/208 V, three phase, four wire, supply is available for loads up to 1000 kVA demand load, or

OR

When the Customer requires voltages other than at the available Supply Voltage, or demands by a single occupant exceed 750 kVA, transformation requirements may be determined by Brant County Power.

2.3.5 Voltage Guidelines

Brant County Power maintains service voltage at the customer's service entrance within the guidelines of C.S.A. Standard CAN3-C235-87 (latest edition), which allows variations from nominal voltage of,

5% for normal operating conditions
8% for extreme operating conditions

Definitions of these conditions are:

a) Normal Operating Conditions. Where voltages lie within the indicated limits under this heading no improvement or corrective action is required. It is recognized that special situations may call for closer voltage control, but such cases are considered to be outside the application scope of this Standard; and

b) 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 should 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, improvements or corrective action should be taken out on an emergency basis. The urgency for such action will depend on many factors such as location and nature of load or circuit involved, extent to which limits are exceeded with respect to voltage levels and duration, etc.

Brant County Power shall practice reasonable diligence in maintaining voltage levels, but is not responsible for variations in voltage from external forces such as operating contingencies, exceptionally high loads and low voltage supply from the transmitter or host Distributor. Brant County Power shall not be liable for any delay or failure in the performance of any of its obligations under this Conditions of Supply due to any events or causes beyond the reasonable control of Brant County Power, including, without limitation, severe weather, flood, fire, lightning, other forces of nature, acts of animals, epidemic, quarantine restriction, war, sabotage, act of a public enemy, earthquake, insurrection, riot, civil disturbance, strike, restraint by court order or public authority, or action or non-action by or inability to obtain authorization or approval from any governmental authority, or any combination of these causes ("Force Majeure").

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 Brant County Power's system to the satisfaction of Brant County Power's requirements.

Customers with permanently connected emergency generation equipment shall notify Brant County Power regarding the presence of such equipment.

2.3.7 Metering - General Information

Specifics to be determined further in Section 3.

Customers will provide a convenient and safe location, reserved solely for metering equipment with outside access, acceptable to Brant County Power and Electrical Safety Authority for the installation of Brant County Power revenue metering equipment, free of charge or rent.

Customers will allow, no one, except a properly identified employee or authorized agent of Brant County Power to remove, inspect or tamper with Brant County Power metering, service entrance equipment, or other plant located on the Customer's premises.

Customers will allow Brant County Power employees and agents free access at all reasonable hours to Brant County Power meters, wires and other equipment. Where safety or reliability of the electrical distribution system is at risk, free access will be required at all times.

All Brant County Power metering equipment located on the Customer's premises is in the care and at the risk of the Customer. If Brant County Power metering equipment is destroyed or damaged, other than by normal usage, it will be at the expense of the Customer to be repaired or replaced.

The Customer will provide and maintain all civil works on private property and other facilities to accommodate Brant County Power service equipment, as outlined further in the Service Sections of this manual.

2.3.7.1 General

Generally, metering will be at utilization voltage. Where Brant County Power provides primary transformation, primary voltage metering may be allowed only in special circumstances following full discussion with Brant County Power. However, primary transformation supplied and owned by the Customer must be primary-metered, unless the building qualifies for individual tenant metering.

The meter shall be located as near as possible to the service entrance box.

The meters shall be grouped where practical and be accessible from a public area. Either a dual locking arrangement or a key box arrangement will be required on the access door. In any case, a copy of the metering layout plan shall be forwarded to Brant County Power for review.

When a disconnect device has been locked and tagged in the "OFF" position by Brant County Power, under no circumstances shall anyone remove the lock and tag and energize it without first receiving approval from Brant County Power.

Regardless of any charges for metering installations, all revenue metering equipment shall remain the property of Brant County Power and maintenance of this equipment shall be Brant County Power responsibility.

2.3.7.2 Multi-Unit Sites

Residential Class customers in multi unit town houses or condominiums shall be individual metered.

General Service class customers in multi unit sites shall be individual metered. Central metering or bulk metering may be allowed under special circumstances.

2.3.7.3 Interval Metering

Interval meters will be installed for all new or upgraded services where the peak demand is forecast to be 500 kW or greater, or for any Customer wishing to participate in the spot market pass-through pricing. Prior to the installation of an interval meter, the Customer must provide a ½ inch conduit from their telephone room to the meter cabinet and will arrange for the installation of a telephone line, terminated in the meter cabinet for the exclusive use of Brant County Power to retrieve interval meter data. The Customer will be responsible for the installation and ongoing monthly costs of operating the phone line. The phone line will be direct dial voice quality, active 24 hours per day, and energized prior to meter installation.

All Customers that request interval metering shall compensate Brant County Power 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 reverification of the meter, installation and ongoing provision of communication line or communication link with the Customer' s meter, and cost of metering made redundant by the Customer requesting interval metering.

2.3.7.4 Meter Reading

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

2.3.7.5 Final Meter Reading

When a service is no longer required, the Customer shall provide sufficient notice of the date the service is to be discontinued so that Brant County Power can obtain a final meter reading as close as possible to the final reading date. The Customer shall provide access to Brant County Power 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.

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. Brant County Power's revenue meters are required to comply with the accuracy specifications established by the regulations under the above Act.

In the event of incorrect electricity usage registration, Brant County Power 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 Brant County Power, due regard being given to any change in the characteristics of the installation and/or the demand. If Measurement Canada, Industry Canada determines that the Customer was overcharged, Brant County Power will reimburse the Customer for the amount incorrectly billed.

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

2.3.7.7 Meter Dispute Testing

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

Either Brant County Power or the Customer may request the service of Measurement Canada to resolve a dispute. If the Customer initiates the dispute, Brant County Power may charge the Customer a meter dispute fee if the meter is found to be accurate and Measurement Canada rules in favor of Brant County Power.

2.4 Tariffs and Charges

2.4.1 Service Connection

Charges for distribution services are made as set out in the Schedule of Rates available from Brant County Power. Notice of Rate revisions shall be published in major local newspapers. Information about changes will also be mailed to all Customers with the first billing issued at revised rates.

2.4.1.1 Customers Switching to Retailer

There are no physical service connection differences between Standard Service Supply (SSS) Customers and third party retailers’ Customers. Both Customer energy supplies are delivered through the local Distributor with the same distribution requirements. Therefore, all service connections requirements applicable to the SSS Customers are applicable to third party retailers’ Customers.

2.4.2 Energy Supply

The Ontario Energy Board approves all Brant County Power Inc. Service and connection rates, which are listed in the current "Schedule of Rates and Charges".

In addition to the monthly service charge for distribution services, the distribution volumetric charge, and competitive electricity charges, miscellaneous charges include:

- New Account set-up fee;
- returned cheque;
- collection visit;
- reconnection after hours;
- reconnection during regular working hours;
- Secondary Service installation;
- Temporary Service installation;
- pole relocation;
- arrears certificates;
- credit check fee;
- overdue account interest charges;
- street lighting;
- cogeneration charges;
- transformers;
- various equipment rentals; and
- service calls.

2.4.2.1 Standard Service Supply (SSS)

Brant County Power will provide Standard Supply Service. Standard Supply Service is the electricity that the Customer will automatically be provided with if he or she chooses NOT to sign with an electricity retailer. The cost of the commodity will be charged to consumers on a pass-through basis.

2.4.2.2 Retailer Supply

Customer transferring from Standard Service Supply (SSS) to a retailer shall comply with the Service Transfer Request (STR) requirements as outlined in sections 10.5 through 10.5.6 of the Retail Settlement Code.

All requests shall be submitted as electronic file and transmitted through an EBT (electronic business transaction). Service Transfer Request (STR) shall contain information as set out in section 10.3 of the Retail Settlement Code.

If the information is incomplete, Brant County Power shall notify the Retailer or Customer about the specific deficiencies and await a reply before proceeding to process the transfer.

2.4.2.3 Wheeling of Energy

All Customers considering delivery of electricity through the Brant County Power distribution system are required to contact Brant County Power for technical requirements and applicable tariffs.

2.4.3 Security Deposits

The following outlines the security deposit requirements of a customer who is not billed by a competitive retailer under the retailer-consolidated billing method, as outlined in the Distribution System Code.

For Residential Customers

The form of payment of a security deposit for residential customers shall be in the form of cash, cheque, certified cheque, or debit transaction.

The maximum amount of a security deposit will be calculated as follows:

> "billing cycle factor" x "estimated bill based on the customer's avg. monthly load with BCP during the most recent 12 consecutive months within the last 2 years"
>
> OR
>
> "If actual load data is unavailable, a reasonable estimate of the average monthly load is acceptable"
>
> The billing cycle factor for BCP is 2.5. This factor is based on BCP's billing frequency, which is monthly.

Every customer's security deposit shall be reviewed at least once in a calendar year. This review will determine whether the entire amount of the security deposit is to be returned, retained, or whether the amount is to be adjusted based on a re-calculation of the maximum amount.

If BCP determines some or all of the security deposit is to be returned to the customer, BCP will promptly do so by crediting their BCP account, or by another mutually agreeable method.

If BCP determines the security amount needs to be adjusted upwards BCP will require the customer to pay this additional amount at the same time as the customer's next regular bill comes due.

A security deposit shall be returned when a customer proceeds to close their account with BCP. The amount will be used to offset any amount owing by the customer to BCP. If the customer moves from one location to another within BCP's service territory the security deposit plus any applicable interest will be transferred to the new location.

Interest shall accrue monthly on security deposits made by way of cash or cheque, starting after the entire deposit is obtained. The interest rate shall be at the Prime Business Rate, less 2 percent, which is updated quarterly. The interest shall be paid out at least once every twelve (12) months or on return or application of the security deposit or closure of the account, whichever comes first, and may be paid by crediting the account of the customer or otherwise.

At the discretion of BCP the security deposit may be waived provided the residential customer meets the following requirements:

1. Has a Good Payment History (GPH) of 1 year. The review period must be the most recent period of time and, some of the time period must have occurred within the previous 24 months or,

   Provides a reference letter from another Local Distribution Company (LDC), or gas distributor in Canada confirming GPH for the most recent relevant time period as outlined or,
   A residential customer may provide a satisfactory credit check, at their own expense.

   Plus:

2. Provides two major pieces of identification, one of which must be photo ID.

3. Accurately completes the appropriate Application for Service. (Tenant or Homeowner)

BCP will allow thirty days to supply a letter of reference. If the letter of reference is not received or does not reflect a GPH a security deposit will then be required.

A customer may be allowed to provide the security deposit in equal installments paid over a four (4) month period. A customer may choose to pay the security deposit over a shorter time period. If a customer defaults on payment arrangements they will be subjected to our collection process. This non-compliance can lead to the electrical service being disconnected.

A customer is deemed to have a GPH during the relevant time period, unless they have:

-received more than one(1) “Door Hanger”
-received more than one (1) “Disconnection Notice”
-issued more than one (1) NSF cheque
-issued more than one (1) NSF pre-authorized payment

A customer must apply in <u>writing</u> to request BCP to undertake a review to determine whether a portion or the entire amount of the security deposit is to be returned to the customer. The customer must meet all qualifying criteria to be eligible for any refund.

A customer, no earlier than 12 months after payment of a security deposit or making of a prior demand for review, request a review of their account to determine eligibility for a refund.

For Non-Residential Customers

This group is divided into the following:
-<50kW demand rate class
->50kW demand rate class

The form of payment of a security deposit for non-residential customers shall be in the form of cash, cheque or an automatically renewing, irrevocable letter of credit from a bank as defined in the Bank Act, 1991, c46.

The maximum amount of a security deposit will be calculated as follows:

“billing cycle factor” x “estimated bill based on the customer’s avg. monthly load with BCP during the most recent 12 consecutive months within the last 2 years”

or,

“If actual load data is unavailable, a reasonable estimate of the average monthly load is acceptable”

The billing cycle factor for BCP is 2.5. This factor is based on BCP’s billing frequency, which is monthly.

Every customer’s security deposit shall be reviewed at least once in a calendar year. This review will determine whether the entire amount of the security deposit is to be returned, retained, or whether the amount is to be adjusted based on a re-calculation of the maximum amount.

If BCP determines some or all of the security deposit is to be returned to the customer, BCP will promptly do so by crediting their BCP account, or by another mutually agreeable method. Full return does not apply to those customers who are in the >5000kW rate class. If BCP determines they are now in a position that it would be exempt from paying a deposit, BCP is only required to return 50% of the security deposit being held.

If BCP determines the security amount needs to be adjusted upwards BCP will require the customer to pay this additional amount at the same time as the customer’s next regular bill comes due.

A security deposit shall be returned when a customer proceeds to close their account with BCP. The amount will be used to offset any amount owing by the customer to BCP. If the customer moves from one location to another within BCP’s service territory the security deposit plus any applicable interest will be transferred to the new location.

Interest shall accrue monthly on security deposits made by way of cash or cheque, starting after the entire deposit is obtained. The interest rate shall be at the Prime Business Rate, less 2 percent, which is updated quarterly. The interest shall be paid out at least once every twelve (12) months or on return or application of the security deposit or closure of the account, whichever comes first, and may be paid by crediting the account of the customer or otherwise.

At the discretion of BCP the security deposit may be waived provided the non-residential customer meets the following requirements:

1. Provides two major pieces of identification, one of which must be photo ID, if applicable.

2. Accurately completes the Application for Service (Business).

3. Has a Good Payment History (GPH) of:
   5 years for customers in the <50kW rate class
   7 years for customers in the >50kW rate class
   The review period must be the most recent period of time and, some of the time period must have occurred within the previous 24 months or,

   Provides a reference letter from another Local Distribution Company (LDC), or gas distributor in Canada confirming GPH for the most recent relevant time period as outlined or,
   A customer, other than a customer in a >5000kW or <50kW demand rate class, may provide a satisfactory credit check at their own expense.

   Provided the credit rating is from a recognized agency, the maximum amount of a security deposit, which the distributor may require to pay, shall be reduced in accordance with the following table.

Credit Rating (Using Standard and Poor's Rating Terminology)	Allowable Reduction in Security Deposit
AAA- and above or equivalent	100%
AA-, AA, AA+ or equivalent	95%
A-, From A, A+ to below AA or equivalent	85%
BBB-, From BBB, BBB+ to below A or equivalent	75%
Below BBB- or equivalent	0%

BCP will allow thirty days to supply a letter of reference. If the letter of reference is not received or does not reflect a GPH a security deposit will then be required.

A customer may be allowed to provide the security deposit in equal installments paid over a four (4) month period. A customer may choose to pay the security deposit over a shorter time period. If a customer defaults on payment arrangements they will be subjected to our collection process. This non-compliance can lead to the electrical service being disconnected.

A customer is deemed to have a GPH during the relevant time period, unless they have:

-received more than one(1) "Door Hanger"
-received more than one (1) "Disconnection Notice"
-issued more than one (1) NSF cheque
-issued more than one (1) NSF pre-authorized payment

A customer must apply in <u>writing</u> to request BCP to undertake a review to determine whether a portion or the entire amount of the security deposit is to be returned to the customer. The customer must meet all qualifying criteria to be eligible for any refund.

A customer, no earlier than 12 months after payment of a security deposit or making of a prior demand for review, request a review of their account to determine eligibility for a refund.

2.4.4. Billing

Brant County Power may, at its option, render bills to its Customers on either a monthly, every two months, quarterly or annual basis. Bills for the use of electrical energy may be based on either a metered rate or a flat rate, as determined by Brant County Power.

A Customer may elect aggregated billing for multiple services provided all of the following conditions are met:

- **The premises and businesses are situated on one contiguous parcel of land i.e. not separated by public roadway.**
- **All premises are under one ownership**
- **The services are supplied at the same voltage**
- **The meters are of the interval type, allowing logical totalization of the coincident demands. If interval meters are not already in place, the Customer will install the necessary equipment, at the Customer's own cost, to Brant County Power specifications.**

The Customer may dispute charges shown on the Customer's bill or other matters by contacting and advising Brant County Power of the reason for the dispute. Brant County Power will promptly investigate all disputes and advise the Customer of the results.

2.4.5 Payments and Overdue Account Interest Charges

Bills are rendered for energy services provided to the Customer. Bills are payable in full by the due date; otherwise, overdue interest charges will apply. Where the Customer on or before the due date has made a partial payment, the interest charge will apply only to the amount of the bill outstanding at the due date including arrears.

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

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

The Customer will be required to pay additional charges for the processing of returned or rejected payments.

Customers will be required to pay additional charges, on request, which may arise from a variety of conditions such as:

<u>Transfer Charge:</u> A change of occupancy charge will apply to all accounts taken over by a new Customer.

<u>Collection Charge:</u> A collection charge will apply when an account is overdue and collection procedures are initiated.

<u>Reconnection Charge:</u> A Consumer disconnected for non-payment shall be required to pay a reconnection fee.

Customer Information

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

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

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

Upon receiving an inquiry from a Customer connected to its distribution system, Brant County Power will either respond to the inquiry if it deals with its own distribution services or provide the Customer with contact information for the entity responsible for the item of inquiry, in accordance with chapter 7 of the Retail Settlement Code.

An embedded distributor that receives electricity from Brant County Power shall provide load forecasts or any other information related to the embedded distributor's system load to Brant County Power, as determined and required by Brant County Power. A Distributor shall not require any information from another Distributor unless it is required for the safe and reliable operation of either Distributor's distribution system or to meet a Distributor's licence obligations.

2.6 General Information

2.6.1 House, Equipment and Vessel Moving

All costs incurred by Brant County Power relating to the moving of a house, equipment or vessel, will be provided based on the proposed route and the dimensions of the house, equipment or vessel being moved.

A deposit based on the estimated cost, will be required prior to moving.

Any house, equipment or vessel moving may or may not be approved by Brant County Power.

All requests for house moving must be accompanied with proper permits and licences. If the height of the house being moved is higher than provided for in the estimate, the move will be cancelled until a new estimate is done based on the actual height.

2.6.2 Customer Owned Primary Lines

Owners of private primary lines are encouraged to perform regular line maintenance and tree maintenance so that public safety and system reliability are not compromised.

To facilitate and encourage the maintenance of these lines, it is Brant County Power’s policy to provide one power interruption per year at no charge during regular working hours.

For power interruptions arranged on weekends and for times other than as outlined above, there will be a charge to offset the cost of overtime paid to Brant County Power crews.

The customer shall be charged for the full cost of service calls to restore service following a power outage if in the opinion of Brant County Power the outage was the result of inadequate line and tree maintenance.

2.6.3 Customer Owned Substations

Owners of private substations are encouraged to perform regular maintenance to the electrical equipment so that inconvenience to themselves and to other customers is not caused through equipment failure.

To facilitate and encourage the maintenance of this equipment, it is Brant County Power’s policy to provide one power interruption, at no charge, once each year at the Customer’s substation. This no charge service will occur during normal working hours, Monday to Friday, 7:30 a.m. to 3:30 p.m., holidays excepted.

For power interruptions arranged on weekends and for times other than as outlined above, there will be a charge to offset the cost of overtime paid to Brant County Power crews.

Should a customer be required to operate their three phase load break switch, Brant County Power must be notified in advance of the operation.

SECTION 3 - CUSTOMER SPECIFIC

3.1 Residential Service

This section refers to the supply of electrical energy to residential Customers residing in detached or semi-detached dwelling units, as defined in the local zoning by-law.

3.1.1 General Information

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

Standard residential services will include all services up to and including 200 amp, 120/240 volt, (1) single phase, (3) three wire. Large residential services will include all services up to and including 400 amp, 120/240 volt, (1) single phase, (3) three wire. For new connections and upgrades, standard conductor size shall be #2 triplex for 100 Amp overhead service or # 1/0 triplex for 200 Amp overhead service. For underground service, #3/0 AL shall be the standard. Underground conductor size for 400 Amp service to be in compliance to ESA (Electrical Safety Authority) and Brant County Power requirements.

Where revenue metering is located inside a residence, it will be relocated by the owner to the exterior of the building at the time of upgrading.

Infill residential services are those new residential services not considered to be part of a subdivision development.

Infill residential services may be installed underground.

Exceptionally long underground or overhead privately owned services shall be constructed to Electrical Safety Authority requirements in order to provide adequate secondary supply voltage.

Where upgrades are required to existing standard residential services, the upgrade will be allowed to remain overhead provided adequate ampacity standard conductor is available.

3.1.1.1 Secondary Services in Overhead Distribution Area

Where Brant County Power specifies that the building is in an overhead distribution area, the following shall apply:

- The maximum service entrance capacity that will be connected overhead is 400 amperes;
- The Customer is responsible for the supply and installation of the portion of the service beyond the first point of connection to customer-owned equipment;
- If a pole line or other attachments are required on the Customer’s property to support the service wires, these shall be supplied, installed and maintained by the Customer. This pole line shall be in accordance with the Electrical Safety Code;

- For services up to 30 meters the demarcation point shall be at the Customer's stack.
- For services over 30 meters the customer shall own the secondary cables and the demarcation point shall be at Brant County Power's transformer as connected by Brant County Power.
- The Customer is also responsible for the provision of pole or structure and dead-end terminations suitable for terminating the incoming aerial service, and any guying required to make it safe and serviceable.
- At the Customer's request and where practical, secondary services 400 amperes and less may be installed underground to Brant County Power's overhead distribution system. In this case the Customer, at his own expense, shall install the entire service from the service entrance at the building to Brant County Power's distribution pole less an allowance for Utility supplied basic services. If there is no pole on the same side of the street as the building, then Brant County Power may provide one on the road right-of-way. Brant County Power may bring an overhead service to this pole. All work by the Customer must be in accordance to Brant County Power specifications and the Electrical Safety Code. Restrictions may apply to avoid having customer owned underground conductor on the public road allowance.

3.1.1.1.1 Services Over Swimming Pools

The Ontario Electrical Safety Code allows electrical conductors to be located at adequate height above swimming pools. Brant County Power discourages this practice

3.1.1.2 New Infill

New infill shall be treated as a new customer as per section 3.1.1.1

3.1.1.3 Upgrades

Brant County Power may provide material, installation and labour for the upgrade of existing overhead standard residential services (maximum 30 meters) from the point of supply to the first attachment point on customer property.

Meter base minimum size requirement will be dictated as per main service capacity.

Where revenue metering is located inside a residence, it will be relocated by the owner to the exterior of the building at the time of upgrading.

3.1.1.4 Standard Underground Services (Secondary)

Standard underground secondary services will be terminated as shown on Brant County Power's layout sheet.

Standard underground secondary services will be installed in either of the following manners:

Brant County Power Installed and Owned: Brant County Power may supply, install and maintain conductor for new infill standard underground residential services from point of supply to meter location. All material, labour, and installation costs (less an allowance for basic services) will be at the owner's expense. Cost of installation will be calculated by Brant County Power at the time of designing the customer service layout.

Standard underground conductor for services shall be 3/0 AL. The total length of 3/0 AL underground cable may not exceed 80 metres in length, if 250 MCM is used length shall not exceed 100 metres. All measurements are to initiate from point of transformation.

All meter bases will be of 200 Amp capacity and allow up to 250 MCM for underground cable connections. The meter base to be used is "jumbo size" (18 x 12 x 4 7/8 inches) for underground services. For services greater than 200 Amp. Brant County Power is to be contacted for appropriate meter base specifications.

Note: Brant County Power may allow the customer to supply and install underground secondary service to Brant County Power specifications at the customer's expense less a credit for Utility supplied basic services. At the customer's expense, these facilities are subject to inspection by Brant County Power.

Customer Installed and Owned: All utility locates and permissions from the relevant road authority required for the trenching are the responsibility of the property owner, as is the proper location of the trench with regard to neighbouring properties.

Restrictions may apply to avoid having customer owned underground conductor on the public road allowance.

Customer supplied, installed and maintained conductor to be approved by the Electrical Safety Authority.

The trench must be inspected and approved by the Electrical Safety Authority.

Up to and including 200 Amp services with max 4/0 conductor, the customer is required to provide 2 inch PVC conduit, steel guard complete with steel straps, ¼ x 3 inch lag bolts and appropriate weather head for cover-up at the Utility pole.

Customer shall install one length of conduit, guard and associated cable on the pole.

Brant County Power will complete the installation of the supplied conduit and cable and make the necessary connections. The customer must supply sufficient conduit to reach to within 6 inches below the final secondary cable height. Instances where 250 MCM conductor is used, customers are to provide 2 ½ inch conduit.

Connection at the weather head will be completed by Brant County Power and become the demarcation point.

A "jumbo" (18 x 12 x 4 7/8 inch) meter base is required for underground services.

Brant County Power will not consider themselves liable for any problems resulting from the cable size selected, or to be responsible for the detection and/or repair of any defects in the cable(s).

Voltage problems resulting from the cable selected is the responsibility of the owner.

At the customer's request, Brant County Power may provide assistance to locate cable faults for a fee. The repair and/or replacement of damaged cables will remain the responsibility of the customer.

3.1.1.5 Large Residential Services (Secondary)

Refer to Section 3.2.1.3

3.1.1.6 Primary Residential Services (Standard & Large)

Refer to Section 3.2.1.4

3.1.2 Early Consultation and Notification

Well in advance of installation commencement, the Customer shall make a request for electrical service. Such request must provide adequate lead-time to permit acquisition of major materials. This shall apply for the installation of a new service and the upgrade of an existing service. At the time the request is made, the Customer shall submit the following:

New Residential Service:

- address (municipal address and street name);
- name of owner and electrician;
- a site plan to scale, showing the building in relation to existing and proposed property lines, any existing easements, other buildings, streets and driveways, and the location of other services, gas, telephone, water and cable T.V.;
- amperage of service required;
- preferred location of service entry as per Section 3.1.6 requirements;
- type of heat and any significant loads.

Upgrade of an Existing Residential Service:

- address (municipal address and street name);
- name of owner and electrician;
- amperage of service required;
- preferred location of service entry as per Section 3.1.6 requirements;
- type of heat and any significant loads.

Brant County Power will review the request and advise the Customer as to whether or not his / her request has been accepted or denied. If the request is denied, Brant County Power will give reasons for denying the request and offer assistance in modifying the proposed service.

The Customer or Brant County Power may request a site meeting to review the service. In consultation with the Customer, Brant County Power will make the final determination of where the service will connect to Brant County Power distribution system, the route that the service will take, and the location of the Service Entrance at the building.

3.1.3 Point of Demarcation

A residential customer delivery point is at the meter for underground installations if the conductor is owned and maintained by Brant County Power and the service stack for overhead installations. This supply point might be located on an adjacent property from which the Distributor has an authorized easement. In all cases the final delivery point will be the decision of the Distributor.

The location of supply (connection to the distribution system) service entrance point and meter base will be established through consultation with Brant County Power for both new and upgraded electrical services. Failure to comply may result in relocation of the service at the owner's expense.

For customer supplied, installed and maintained conductor the point of supply is considered to be the connection point to Brant County Power distribution system. (ie. Brant County Power transformer for overhead secondary installation or weather head for underground secondary)

3.1.4 Access

Service locations requiring access to adjacent properties (mutual drives, narrow side setbacks, etc.) will require the completion of a legal easement and 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.

3.1.5 Metering

Meter sockets will be directly accessible from the street by Brant County Power staff and mounted on the exterior of the building within 10ft (3m) of the front face of the building and 5ft, 6in (1.68m) from final grade to centre of the meter. Meter sockets will be installed ahead of (on the line side of) the main disconnect switch. Meter sockets found to be inaccessible by Brant County Power will be relocated at the owners expense.

3.1.6 Inspection

All electrical installations inside the home and out to the delivery point must be inspected and approved in accordance with Brant County Power and Electrical Safety Authority requirements. Brant County Power requires notification from the Electrical Safety Authority prior to energization.

Brant County Power requires a minimum **(5) five days** notification prior to date of energization.

3.2 General Service

Commercial buildings are defined as buildings which are used for purposes other than single family dwellings.

3.2.1 General Information

One single phase and/or one three phase general service per lot, per customer.

Where upgrades are required to existing general services, the upgrade may be allowed to remain overhead provided overhead conductor ampacity is available.

Brant County Power will supply, install and maintain all road crossing facilities.

General Service class customers shall pay all costs of providing service including upgrades.

Brant County Power shall maintain all services supplied and installed to the meter base by Brant Coun ty Power Inc.

The Customer shall own and maintain all services the customer installs

In circumstances where multiple services are installed to a general service customer, and one service is to be upgraded, the upgraded service will conform to one single phase and/or one three phase general service per lot, per customer.

3.2.1.1 Standard Overhead Services (Secondary)

Allowable limit will be maximum 400 amp, 120/240 volt, single (1) phase, three (3) wire, , 120/208 volt or 347/600 volt, three (3) phase, four (4) wire services.

For 400 amp 120/240 volt single phase services, the owner will supply and install a self contained meter base complete with a 4 Jaw transformer rated meter socket with self shorting CT link on left side and a 400 & 400:5, 3 wire bar type CT transformers.

APPROVED 400 AMP METER SOCKET
Micro Electric Cat #JS4A-4-400:5

Note: Meter socket is adaptable to both overhead and underground services.

Connection of meter base to secondary service wires is the responsibility of the owner.

Where upgrades are required to existing general services, the upgrade will be allowed to remain overhead provided overhead conductor ampacity is available.

3.2.1.2 Standard Underground Services (Secondary)

Standard underground secondary services will be terminated as shown on Brant County Power's layout sheet.

Standard underground secondary services will be installed in either of the following manners:

Brant County Power Installed: Brant County Power may supply, install and maintain conductor for new infill standard underground residential services from point of supply to meter location. All material, labour, and installation by Brant County Power or its agent will be at the owner's expense. Cost of installation will be calculated by Brant County Power at the time of designing the customer service layout.

Standard underground conductor for services shall be 3/0 AL. The total length of 3/0 AL underground cable may not exceed 80 metres in length, if 250 MCM is used length shall not exceed 100 metres. All measurements are to initiate from point of transformation.

All meter bases will be of 200 Amp capacity and allow up to 250 MCM for underground cable connections. The meter base to be used is “jumbo size” (18 x 12 x 4 7/8 inches) for underground services. For services greater than 200 Amp. Brant County Power is to be contacted for appropriate meter base and conductor specifications.

Customer Installed and Owned: All utility locates and permissions from the relevant road authority required for the trenching are the responsibility of the property owner, as is the proper location of the trench with regard to neighbouring properties.

Restrictions may apply to avoid having customer owned underground conductor on the public road allowance.

Customer supplied, installed and maintained conductor and related material such as conduit, guards and weather head to be approved by the Electrical Safety Authority.

The trench must be inspected and approved by the Electrical Safety Authority.

Customers must also install one length of conduit, guard and associated cable on the pole.

Brant County Power will complete the installation of the supplied conduit and cable and make the necessary connections. The customer must supply sufficient conduit to reach to within 6 inches below the final secondary cable height and appropriate weather head.

The connection at the weather head shall be completed by Brant County Power and become the demarcation point.

A “jumbo” (18 x 12 x 4 7/8 inch) meter base is required for underground services.

Brant County Power will not consider themselves liable for any problems resulting from the cable size selected, or to be responsible for the detection and/or repair of any defects in the cable(s).

Voltage problems resulting from the cable selected is the responsibility of the owner.

At the request of the customer, Brant County Power will locate cable faults for a fee, but the repair and/or replacement of damaged cables will remain the responsibility of the customer.

3.2.1.3 Large General Services (Secondary)

Where general services are required to be larger than 400 amps, the maximum allowable limit will be **600** Amp, 120/240 volt, (1) single phase, (3) three wire service. The customer is to consult with Brant County Power regarding specifications.

All large general services are to be supplied, installed and maintained to Brant County Power and Electrical Safety Authority specification and requirements at the customer’s expense.

For 400 amp 120/240 volt single phase services, the owner will supply and install a self contained meter base complete with a 4 Jaw transformer rated meter socket with self shorting CT link on left side and a 400 & 400:5, 3 wire bar type CT transformers.

APPROVED 400 AMP METER SOCKET
Micro Electric Cat #JS4A-4-400:5

Note: Meter socket is adaptable to both overhead and underground services.

Connection of meter base to secondary service wires is the responsibility of the owner.

3.2.1.4 Primary Services

General Information. Where it is determined through consultation with Brant County Power that a primary supply is required, the customer will supply, install and maintain the service to Brant County Power and Electrical Safety Authority specifications and requirements at the owner's expense. ESA Inspection documentation is to be provided to Brant County Power.

Customers will supply, maintain and retain ownership of primary and secondary cables, poles, anchors, terminations, grounding and transformer pads.

It is the customer's responsibility to ensure that all transformers located on private property are kept clear of any obstacles in order to facilitate regular and emergency maintenance.

Any repairs completed on customer owned equipment will require Electrical Safety Authority approval before energization.

Underground. Cables terminating on the supply pole will be, where applicable, rise on the opposite side of the flow of traffic.

Primary cables terminating on poles up to 45 feet require 45 feet of approved cable, poles in excess of 45feet will require consultation with Brant County Power

Customers must supply and install at their expense all ducts and underground cable to ESA requirements up to and including the first length of cable guard on Brant County Power pole. The customer is also required to supply additional guards to protect cable beyond the first length.

The underground cable is also to be terminated at the customers expense.

Brant County Power will complete the installation (cable and additional guards) hi-pot the termination and cable and make the necessary connections at the demarcation point at the customer's expense.

Brant County Power may provide assistance to a fault locate for a fee in order to assure restoration of service in a reasonable time frame subject to having required materials in stock.

Overhead. The customer will supply, install and maintain the primary services from the demarcation point in compliance to Brant County Power and Electrical Safety Authority requirements.

Brant County Power will connect the primary cable at the demarcation point.

3.2.1.5 Transformation

<u>General Information.</u> Transformation will be required to be installed within 10ft (3m) of an accessible road way capable of carrying heavy trucks. This roadway is to facilitate the installation, repair or replacement of the transformer by Brant County Power approved personnel. This roadway when required will be installed and maintained by the customer.

Transformers up to 750 kVA will be supplied and installed by Brant County Power Transformers greater than 750 kVA will be customer owned. Connection to the distribution system must be in compliance to Utility specifications.

Primary Voltage supplied to padmount transformers or customer owned substations will be one of the following as determined by Brant County Power:

- 2400/4160 Volts – 3 phase, 4 wire
- 4,800/8,320 Volts - 3 phase, 4 wire
- 16,000/27,600 Volts - 3 phase, 4 wire

Dual voltage transformation will be required for primary voltages other than 16,000 Grd Y/27,600 volts, in order to facilitate voltage conversions.

When transformers are rated at or less than:

- 167 kVA single (1) phase
- 750 kVA three (3) phase
  the transformers will be provided by Brant County Power.

3.2.2 Early Consultation

Prior to the establishing new general service details to a building or lot, Brant County Power will require the following information from the owner:

- a grading and site plan showing the building(s) in relation to existing and proposed property lines, other buildings, streets and driveways, and the location of other sources, gas, telephone, and water;
- a floor plan indicating unit numbers and corresponding service requirements;
- amperage of main source and/or sub services;
- voltage level;
- metering requirements - individual or bulk;
- a single line diagram showing the provision for metering facilities and a listing of all significant loads such as lighting, motors, cooling, heating, welders, etc.;
- requested energization date;
- preferred location of electrical room, and routing of primary conductors.

Brant County Power will review the request and advise the Customer as to whether or not his / her request has been accepted or denied. If the request is denied, Brant County Power will give reasons for denying the request and offer assistance in modifying the proposed service.

The Customer or Brant County Power may request a site meeting to review the service. In consultation with the Customer, Brant County Power will make the final determination of where the service will connect to Brant County Power distribution system, the route that the service will take, and the location of the Service Entrance at the building.

3.2.3 Point of Demarcation

A general service customer delivery point is dependent on customer ownership in the applicable general service section. For the purposes of this document, the point of supply will be:

1. For customer owned conductor, the point of connection will be Brant County Power distribution system at the bottom of the switch on the Utility pole.
2. For utility owned conductor, the point of connection will be the service attachment point and/or meter.

3.2.4 Supply Voltage

The service voltage will be established by the owner and will be one of the following:

- 120/240 volts - 1 phase 3 wire (maximum **400** amp)
- 120Y/208 volts - 3 phase 4 wire
- 347Y/600 volts - 3 phase 4 wire

3.2.5 Underground Service

See Section 3.2.1 .1 through 3.2.1.4

3.2.6 Location of Transformers

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

3.2.7 Supply of Equipment

The Distributor will supply, install and maintain equipment as specified in the applicable general service section.

The owner will supply, install and maintain equipment as specified in the applicable general service section.

3.2.8 Short Circuit Capacity

The Owner shall ensure that his service entrance equipment has an adequate short-circuit interrupting capability. Brant County Power will advise, on request, the maximum available short-circuit symmetrical in-rush Amperes at any specific location.

Customer's protective equipment shall include:

27600/16000 Volt supply: 3 phase, short circuit rating of 835 MVA symmetrical.
8000/4800 Volt supply: 3 phase, short circuit rating of 500 MVA symmetrical.
4160/2400 Volt supply: 3 phase, short circuit rating of 250 MVA symmetrical.
600/347 and 208/120 Volt supply: - Available on request.

3.2.9 Access

Service locations requiring access to adjacent properties (mutual drives, narrow side setbacks, etc.) will require the completion of a legal easement and 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.

3.2.10 Metering

The owner will make provisions acceptable to Brant County Power for revenue metering equipment.

This provision could be one, or a combination of the following as established by Brant County Power for each service:

- appropriate meter socket; as specified further in this Section.
- a lockable metal enclosure, with removable back plate of dimensions; as specified further in this Section.
- a lockable compartment within metal enclosed switchgear to accommodate Brant County Power instrument transformers, as specified further in this Section.

Metering will be installed as per Revenue Metering Specifications as outlined further in this Section.

Prior to energization of service, Brant County Power will require notification of approval from the Electrical Safety Authority.

3.2.10.1 Revenue Metering Specifications

Brant County Power will install revenue meters, instrument transformers, test panels and all interconnecting wiring.

The owner will provide at his expense, as outlined further in this section:

- Space acceptable to Brant County Power, as outlined further in this section, for the installation of revenue metering equipment.

- Where metering equipment is required to be installed in a locked environment, the customer shall supply Brant County Power with a key.

- Facilities for attachment including meter sockets.

- A pad lockable metal enclosure with removable back plate.

- Installation of conduit for instrument wiring, where required.

- All metering installations and/or rooms must be inspected and approved by the Electrical Safety Authority to Brant County Power requirements.

- All meters shall be grouped in a central location which is readily accessible to and approved by Brant County Power.

- If electrical service room is to be located above the main floor level, a stairway built in accordance with the Ontario Building Code shall be installed.

Note: Ladders are not acceptable.

All locations accessible to the general public will have a lockable enclosure or room for the service equipment and meters provided by the owner as follows:

- An electrical room;
- A metal metering cabinet approved by Brant County Power; or
- A metal enclosed switchgear approved by Brant County Power and the Electrical Safety Authority.

All locations will be clear and safe with working space of not less than 1.2m (48") in front of the equipment.

Where the possibility of danger exists to workmen, or damage to equipment from moving machinery, vibration, dust, fumes or moisture, protective arrangements shall be provided by the customer to the approval of Brant County Power.

3.2.10.2 Meter Socket Specifications

120/240V, single (1) phase three (3) wire services up to and including 200A require:

- A 4 JAW, square type meter socket base.
- To be installed on the load side of the disconnect switch supplying each individual service.
- Meter base shall be “jumbo’ (18 x 12 x 4 7/8 inch") for underground services.

120/240V, single (1) phase three (3) wire 400A service will require:

- A 4 Jaw 400 and 400:5, 3 wire, bar type current transformer rated meter base complete with self shorting device on the left side, 400:5 current transformers and twin covers suitable for 120/240V (1) single phase service is required.

APPROVED 400 AMP METER SOCKET
Micro Electric Cat #JS4-2

Note: Services with suspected poor power factor will be required to install the appropriate meter facilities for metering both watt and kVA demand.

120/208V, two (2) phase with a neutral wire service up to and including 200A require:

- A 5 JAW, square type meter socket base (5th JAW to be installed in the 9 o'clock position).

- To be installed on the load side of the disconnect switch supplying each individual service.

600Y/347 or 208Y/120V, three (3) phase, four (4) wire services up to and including 200A require:

- A 7 JAW, square type meter socket base complete with an isolated neutral connection.
- 208Y/120V services meter sockets will be allowed to be installed on the exterior of the building on the load side of the disconnect switch.
- 600Y/347V services meter sockets are to be installed on the load side of the disconnect switch supplying each individual service.

Meter mounting height shall be 5'6" (1.68meters) from final grade to center of meter.

The customer/contractor shall permanently and legibly identify all metered services with respect to municipal address and/or unit #. The identification shall apply to all disconnect switches, and meter mounting devices.

Services will not be connected unless service identification on the disconnect switches and meter mounting devices, correspondence with the appropriate addresses and/or unit #'s. Owners of the multiple unit buildings are required to inform Brant County Power of any changes made to municipal address and/or unit #.

Where required by these conditions of supply, the owner shall supply, install and maintain a meter cabinet to Brant County Power specifications.

3.2.10.3 Commercial and Industrial Meter Cabinet Specifications

208Y/120V (3) three phase, four wire service over 200A require:

- Current Transformer Cabinet as outlined further in this Section.

600Y/347V (3) three phase, (4) four wire service over 200A require:

- Combination Current Transformer and Potential Transformer Cabinet as outlined further in this Section.

3.2.10.4 Meter Cabinet

The meter cabinet will be supplied to Brant County Power specifications at the customer's expense**.**

If required, a voice grade telephone line is to be installed from customer's main telecommunication panel to meter cabinet by the customer for Brant County Power remote interrogation.

3.2.10.5 Current Transformer Cabinet

36" (914mm)w x 36" (914mm)h x 10" (254mm)d CEMA/NEMA-1 current transformer cabinet for services up to 800A.

Current transformer cabinet is to be complete with the provision for padlocking and a removable steel back plate.

Notes:

- Current transformer cabinet is to be installed on the load side of the main disconnect switch.
- Top of current transformer cabinet is to be mounted at a height of 6' (1828mm) from final grade.
- Current transformer cabinet location must not exceed a distance of 50' (15.2m) from the meter cabinet.
- The location of the indoor current transformer cabinet is to be readily accessible to and approved by Brant County Power.
- Electrical contractor to supply,, install and connect conductor termination lugs for current transformers and appropriate size neutral.
- Removable back plate must be submitted to Brant County Power at least ten (10) working days prior to the date of energizing.
- 1 1/4" (32mm) PVC conduit to be installed in one continuous run from current transformer cabinet to meter cabinet complete with a minimum of 1/4" poly rope from current transformer to meter cabinet. Access type fittings are not acceptable.
- Back plate to be marked, top line, and load for current transformer polarity.
- Line side conductors are to enter at center left and center right of current transformer cabinet.

3.2.10.6 Combination Current Transformer and Potential Transformer Cabinet

36" (914mm)w x 36" (914mm)h x 10" (254mm)d CEMA/NEMA-1 current transformer cabinet for services up to 800A.

Current transformer cabinet is to be complete with the provision for padlocking and a removable steel back plate.

Notes:

- Current transformer cabinet is to be installed on the load side of the main disconnect switch.
- Top of current transformer cabinet is to be mounted at a height of 6' (1828mm) from final grade.
- Current transformer cabinet location must not exceed a distance of 50' (15.2m) from the meter cabinet.
- The location of the indoor current transformer cabinet is to be readily accessible to and approved by Brant County Power.
- Electrical contractor to supply, install and connect conductor termination lugs for current transformers and appropriate size neutral.
- Removable back plate must be submitted to Brant County Power at least ten (10) working days prior to the date of energizing.
- 1 1/4" (32mm) PVC conduit to be installed in one continuous run from combination current transformer and potential transformer cabinet to meter cabinet. Access type fittings are not acceptable. The contractor is to install a minimum of 1/4" poly rope from current transformer to meter cabinet.

- Line side conductors are to enter at center left and center right of current transformer cabinet.

3.2.10.7 Meter Enclosed Switchgear

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

Brant County Power will, install revenue meters, instrument transformers, test panels and all interconnecting wiring.

The owner shall:

- Consult with Brant County Power regarding metering equipment to be provided, which may include:
  - potential transformers
  - current transformers
- Brant County Power will use Schlumberger MV-7 current transformers or
- similar bar type CT's for services up to 1200 amps (347/600V)
- terminal test block
- All metal enclosed switchgear metering compartments will be equipped with a neutral bus bar for provision of connecting metering equipment.
- Submit two (2) copies of the manufactures switchboard drawings for approval. Drawing to indicate provisions for Brant County Power metering arrangement complete with dimensions.
- Install meter cabinet and conduit.

3.2.10.8 Instrument Transformers

Instrument transformers shall be supplied and installed by Brant County Power in a separate switchgear compartment on the load side of a main switch to permit removal or replacement of equipment. The compartment door shall have provision for a Brant County Power padlock.

3.2.10.9 Meter Cabinet Specifications

Meter cabinet to be installed as outlined earlier in this Section.

3.2.10.10 Interval Demand

Brant County Power will install, at the owners expense, interval metering on all new 3 phase, 4 wire services, with a usage greater than 500kW.

A 13mm (1/2in.) conduit from the telephone entrance equipment and a 1 ML direct dial voice quality telephone line supplied and maintained by the Customer which is active 24 hours a day to the metering location extension jack which is mounted on the metering board. This phone line must be installed and functioning prior to the new service being energized.

A voice grade telephone line, for the purpose of remote interrogation, will be supplied by the customer .

Existing services will, at the owners expense, be considered for interval metering if a review of the customers usage for the previous year shows a consistent demand greater than 500kW. A voice grade telephone line, for the purpose of remote interrogation, will be supplied by the customer.

3.3 General Services (Above 50 kW)

A customer classified as being over 50kW by is one that identified the billing system as registering over 50kW on a demand meter.

3.4 General Services (Above 1000 kW)

A customer is classified as being above a 1000kW if they have a service of 1200 amps (347/600 volts) or larger.

Customer Owned
Installations with a capacity larger than:

750 kVA three (3) phase

The transformers shall be supplied and installed by the owner to Electrical Safety Authority and Brant County Power requirements.

3.5 Net Metered Generators and Embedded Generation

Brant County Power will make net metering available to eligible generators in accordance with the Net Metering regulation, on a first come first served bass, unless the cumulative generation capacity from net metered generators equals one per cent of our peak load for our service area. The customer will be billed in accordance with the Net Metering Regulations, provided that the net metered generator meets the requirements of section 2(2) of the Net Metering regulation.

Brant County Power will provide a connection to the distribution system where it is technically feasible for embedded generators for the purpose of selling energy or for load displacement within the customers premise. The cost of the connection and related protection to assure the safety of the public, employees and security of the system will be charged to the customer. The requirements for embedded generation are set out in the Embedded Generation Agreement, which must be signed between Brant County Power and the embedded generator. Brant County Power and the Generator must comply with regulators relating to Generation. Sufficient time (see section 2.1) must be provided to Brant County Power to respond to connection requests. Early consultation is encouraged. Charges may apply for Utility backup support.

3.6 Embedded Market Participant

Embedded Market Participants are subject to the terms and conditions of the Independent Electricity Market Operator. Market participants are responsible for all LDC charges as approved by the Ontario Energy Board.

3.7 Embedded Distributor

The following terms and conditions apply to the connection of an Embedded Distributor.

3.7.1 Contact Information

The contact information will be reviewed annually. Each Party will notify each other by November 1 of each year to confirm or update such information. If either party proposes to make a change affecting the embedded connected point, then notice of such change will be given in writing. Such notice will be given a minimum of thirty (30) days prior to any planned implementation of the change. Any change will require the approval of both Parties.

The Customer acknowledges and agrees that Brant County Power may provide any information provided by the Customer under the terms of the Standard Embedded Distributor Agreement to Brant County Power's representatives, provided that Brant County Power:

- provides such information to only those of Brant County Power's representatives who need to know the information; and
- has directed such representatives to use the information in accordance with the terms hereof.

3.7.2 Energy Supply

As the Host Distributor, Brant County Power reserves the right to limit the amount of energy that it agrees to supply the Customer at each embedded connection/delivery point, and this amount shall be agreed upon by both Parties.

The Customer shall notify and include Brant County Power in any discussion, planning and interconnection design of any proposed embedded generation facility that the Customer proposes to connect to its portion of the distribution system.

3.7.3 Billing

Brant County Power shall bill the Customer on a billing cycle each month for the provision of distribution services by Brant County Power, and for all other applicable charges approved or authorized by the Ontario Energy Board, pursuant to Brant County Power's rate orders or any codes issues by the Ontario Energy Board.

Brant County Power shall settle non-competitive electricity services based on the rates approved by the Ontario Energy Board and by the requirements of the Retail Settlement Code. Brant County Power shall adjust the Customer's usage by the applicable total loss factor for purposes of determining the Customer's noncompetitive electricity costs.

If the Customer is not a Wholesale Market Participant, then Brant County Power shall provide revenue metering for the settlement and monthly billing of the Customer. If the Customer is or becomes a Wholesale Market Participant Distributor, then the Independent Market Operator shall settle the Customer's monthly energy bill.
If the Customer is or becomes a Wholesale Market Participant Distributor, then the Corporation shall act as the default Metering Service Provider (MSP) and as such, enter into a Metering Service Provider Agreement with the Customer.

3.7.4 Ownership

All Brant County Power-owned equipment, including the revenue metering equipment and instrument transformers, shall continue to be vested in Brant County Power, unless the Parties have specified otherwise in the Embedded Distributor Agreement. (Note: presently Hydro One may own the wholesale metering installation.).

All Customer equipment and facilities shall continue to be vested in the Customer, unless the Parties have specified otherwise in the Embedded Distributor Agreement.

3.7.5 Assignment of Responsibility

The electrical distribution systems shall be under the operating control of a controlling authority at all times.

The responsibility for regular maintenance of equipment rests with the owner.
Brant County Power and the Customer shall ensure that only qualified persons perform the operation and maintenance of their respective electrical distribution systems.
Each Party shall be responsible for maintenance, protection and power quality of each Party's portion of the shared distribution feeder that each party owns. Each Party shall ensure that its portion of the feeder has proper fault protection and voltage within proper limits.

Brant County Power and the Customer shall maintain their respective equipment in efficient condition with proper devices, according to electrical distribution utility standards. If, in the opinion of Brant County Power or the Customer, maintenance is not properly performed, the identifying Party will notify the other in writing.

3.7.6 Normal Operations

Control Authorities will inform each other at least seven calendar days in advance of any planned work which would have an effect on the other Parties electrical distribution systems. Applications for work involving load interruptions shall be initiated at least ten (10) calendar days in advance, to permit proper notification of other customers who would be interrupted for, and the co-ordination of, switching on the equipment under its control.

The control authority of the equipment under its control shall issue work protection on the equipment when work is done on that equipment. Each control authority is responsible for establishing a safe work environment, in accordance with industry standards, for their forces while carrying out planned or emergency maintenance.

Each Party is responsible for providing isolation at devices under their operating control to assist the other Party.

3.7.7 Communication

Communications between controlling authorities must be readily available to deal with routine and unforeseen system conditions.

The Controlling Authority of each Party agrees to communicate for the following reasons:

- For normal operating communications with regard to outage planning, work protection and switching, etc.
- Provide each other with information relative to prearranged outages, power
- interruptions or system problems which materially affect the supply of power to each others distribution system.
- Provide each other with information relative to feeder trips or recloser operations caused by equipment under each Parties ownership or control.

- Following an A (*auto)* / or A/R/A *(auto/reslose/auto*) during regular working hours Brant County Power's Controlling Authority will not authorize the Hydro One Controlling Authority to reenergize a feeder owned by Brant County Power until contact has been made with the Customer's Controlling Authority.
- Following an A/ or A/R/A after regular working hours, and if no "Hold Off" is in effect, Brant County Power has authorized the Hydro One Controlling Authority to allow one minute prior to attempting re-energization. After one attempt at re-energization, no further attempts to re-energize a feeder owned by Brant County Power will be made until contact has been made with the Customer and Hydro One. It will be the responsibility of the Hydro One Controlling Authority to contact Brant County Power's Controlling Authority after hours.
- When a permanent fault occurs on a feeder which supplies Brant County Power and Customer load, the Brant County Power Controlling Authority will notify the Customer's Controlling Authority during regular working hours, and the Customer's Line Superintendent on call for after hours permanent faults. Once communication is established and the location of the fault is not known, Brant County Power and/or Customer staff will be dispatched to patrol their systems, and may assist each other in sectionalizing the faulted feeder.

Since Brant County Power and the Customer each own portions of, and share, a common feeder, both Parties agree to provide each other with the following information:

- Brant County Power shall provide the Customer with fault current information and protection settings of upstream protective devices.
- The Customer shall provide Brant County Power with load forecasting information.
- Brant County Power and the Customer agree to maintain phase balance within generally acceptable industry standards.
- Brant County Power and the Customer agree to adhere to generally acceptable standards pertaining to power quality and voltage levels on the section of feeder each Party owns.
- Brant County Power and the Customer agree to provide each other, on request, with maintenance schedules and records on the section of feeder each party owns.

3.7.8 Emergency Operations

Each Party will co-operate fully in case of emergencies in order to facilitate restoration of the system back to normal, and to permit the organization of possible repairs.

Switching agreements with Hydro One are in place to accommodate emergency restoration.

On the request of one Controlling Authority, the other Controlling Authority's staff or agents will provide the required timely isolation of equipment as required for emergency switching, or to establish a Condition Guarantee.

3.7.9 Metering and Fault Protection

Brant County Power agrees to deliver electricity to the Customer's distribution system through a bulk meter or interval meter for settlement purposes.

If the Customer is, or becomes, a Wholesale Market Participant Distributor registered with the Independent Market Operator, the Customer will be responsible for the wholesale metering installation(s) metering data as per the Ontario Market rules.

Brant County Power shall have read-only access to such wholesale metering installations.

The Parties shall act at all times in accordance with the Distribution System Code, for situations where Brant County Power or the Customer provides distribution services through a load transfer.

Brant County Power and the Customer shall each manage its own portion of a supply feeder, and ensure that its portion of the feeder has proper fault protection and voltage within proper limits in accordance with industry standards.

The owner of the feeder breaker would be responsible for maintaining appropriate relay settings for overall feeder protection, and both Brant County Power and the Customer would be responsible to provide the required information to accomplish this.

3.7.10 Costs

Once the request for connection has been approved, and upon receipt of a Purchase Order or equivalent from the Customer, Brant County Power shall prepare detailed engineering specifications for required system enhancements, obtain cost estimates for the specified work, and determine cost-sharing arrangements.

Brant County Power agrees to provide the Customer, in writing, a Project Description and Letter of Intent that includes:

1. a description of the work to be performed by Brant County Power Inc.
2. a summary of the work to be performed by the Customer
3. Brant County Power Inc.'s capital investment in the project; and
4. the Customer's financial contribution to the package.

Brant County Power Inc. shall only be liable to the Customer, and the Customer shall only be liable to Brant County Power Inc., for any damages which arise directly out of the willful misconduct or negligence:

- of Brant County Power Inc. in providing distribution services to the Customer;
- of the Customer in being connected to Brant County Power Inc.'s distribution system; or
- of Brant County Power Inc. or the Customer in meeting their respective obligations under the Distributed System Code, their licences, and any other applicable law.

The Distributor-Customer agrees to take out liability insurance in the amount of $5,000,000 to which the Corporation of the County of Brant on the Grand and Brant County Power Inc. are added as additional named insured, and to provide proof of such insurance.

Despite the above, neither Brant County Power Inc. nor the Customer shall be liable under any circumstances whatsoever for any loss of goodwill or for any indirect, consequential, incidental or special damages, including but not limited to punitive or exemplary damages, whether any of the said liability, loss or damages arise in contract, tort or otherwise notwithstanding the Customer financial contribution as per section 3.7.3.

3.7.11 Force Majeure

Subject to the items below, neither Party shall be held to have committee an event of default in respect of any obligation under the Embedded Distributor agreement if prevented from performing that obligation, in whole or in part, because of a force majeure event.
If a force majeure event prevents a Party from performing any of its obligation under the DSC and the Embedded Distributor agreement, that Party shall:

- promptly notify the other Party of the force majeure event and its assessment, in good faith, of the effect that the event will have on its ability to perform any of its obligations. If the immediate notice is not in writing, it shall be confirmed in writing as soon as reasonably practicable;
- not be entitled to suspend performance of any of its obligations under the Embedded Distributor Agreement to any greater extent, or for any longer time, than the force majeure event requires it to do;
- use its best efforts to mitigate the effects of the force majeure event, remedy its inability to perform, and resume full performance of its obligations;
- keep the other Party continually informed of its efforts; and
- provide written notice to the other Party when it resumes performance of any obligations affected by the force majeure event.

Notwithstanding any of the foregoing, settlement of any strike, lockout or labour dispute constituting a force majeure event shall be within the sole discretion of the Party to the Embedded Distribution Agreement involved in the strike, lockout or labour dispute. The requirement that a Party must use its best efforts to remedy the cause of the force majeure event, mitigates its effects, and resume full performance under the Embedded Distributor Agreement and the DSC shall not apply to strikes, lockouts or labour disputes.

3.8 Unmetered Connections

3.8.1 Street Lighting

Street lighting is owned by the County of Brant and maintained by their authorized contractor, which may be Brant County Power Inc. Attachment of street lights to Brant County Power Inc.-owned poles and electrical supply to street lights is subject to approval of Brant County Power Inc.
The service to streetlights will be unmetered. Street lighting is supplied at a rate to be approved by the OEB. Energy consumption will be based on connected wattage information submitted by the Customer and calculated as per hours of use, subject to the approval of Brant County Power Inc. It is the responsibility of the Customer to report to Brant County Power Inc. in writing any change of consumption.

3.8.2 Other Small Services Traffic Control Signals

This section pertains to the supply of electrical energy to various traffic control signals and crosswalks telephone booths, cable T.V. amplifiers, bill boards and similar small- loads. The method of supply will vary and will be established for each application through consultation with Brant Coun ty Power Inc. Where transformation does not exist, it will be provided and considered an expansion of the system. A capital contribution may be required.

The service will be metered. This service will be classed as a General Service Customer under 50 kW. The rates charged will be as per Under 50 kW General Service Class, as approved by the Ontario Energy Board. Energy consumption will be based on connected wattage information submitted by the Customer and calculated as per hours of use. It is the responsibility of the Customer to report to Brant County Power Inc. in writing any change of consumption to the installation.

Service conductors will be supplied by the Road Authority. Prior to energization of service, Brant County Power Inc. will require connection authorization from the Electrical Safety Authority.

Where transformation does not exist, a contribution in aid of will be required.

Service conductors will be supplied by the owner.

Prior to energization of service, Brant County Power will require notification of approval from the Electrical Safety Authority.

3.9 Small Metered Connections

3.9.1 Temporary Services (Construction Power)

This section pertains to the supply of electrical energy on a temporary basis to facilitate construction work. This includes pole mounted service equipment, trailers, cranes and similar applications.

Such services would be in place for a period of less than 12 months, extensions will be at the discretion of Brant County Power.

All other temporary services will be dealt with as general services outlined in Section 3.2. For applicable charges refer to Section 5.

At the discretion of Brant County Power one or more temporary services may be provided for a construction project.

The nominal service voltage will be one of the following:

120/240 volts, 1 phase, 3 wire (Max. 200 amp)
120/208 volts, 3 phase, 4 wire (Max. 200 amp)
347/600 volts, 3 phase, 4 wire (Max. 400 amp)

The location of the service entrance point and metering details will be established through consultation with Brant County Power. Failure to comply may result in modifications at the owner's expense.

The owner will pay the total cost of the temporary service installation and removal, prior to the commencement of any work being initiated by Brant County Power.

Primary or secondary pole lines required to be constructed on private property will be the responsibility of the customer. All pole lines will be built in accordance to Ontario Electrical Safety Code and be approved by the Electrical Safety Authority.

The following information will be provided by the owner:

- requested energization and removal dates;
- amperage of service;
- preferred voltage;
- preferred point of service entrance;
- estimated kilowatt demand;
- a listing of all significant loads such as large motors;
- a site plan showing the location of the delivery point relative to lot lines and the street.

3.9.1.1 Metering

The owner will make provision, acceptable to Brant County Power, for revenue metering equipment. The provision for metering could be one or a combination of the following as established by Brant County Power:

- approved meter sockets as outlined in Section 3.2.10;

- a lockable metal enclosure as outlined in Sections 3.2.10.

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

- safe and adequate working space not less than 1.2m (48") in front of equipment;
- protected against the adverse effects of moving machinery, vibration, dust, moisture or fumes.

Prior to energization of service, Brant County Power will require notification of approval the Electrical Safety Authority. The service entrance and metering provision shall be inspected and accepted by Brant County Power prior to energization.

SECTION 4 - GLOSSARY OF TERMS

4.1 Definitions

Sources for Definitions:

A	Electricity Act, 1998, Schedule A, Section 2, Definitions
MR	Market Rules for the Ontario Electricity Market, Chapter 11, Definitions
TDL	Transitional Distribution Licence, Part I, Definitions
TTL	Transitional Transmission Licence, Part I, Definitions
DSC	Distribution System Code Definitions
RSC	Retail Settlement Code Definitions

"Accounting Procedures Handbook" means the handbook approved by the Board and in effect at the relevant time, which specifies the accounting records, accounting principles and accounting separation standards to be followed by the distributor; (TDL, DSC)

"Affiliate Relationships Code" means the code, approved by the Board and in effect at the relevant time, which among other things, establishes the standards and conditions for the interaction between electricity distributors or transmitters and their respective affiliated companies; (TDL, DSC)

"ancillary services" means services necessary to maintain the reliability of the IMO controlled grid; including frequency control, voltage control, reactive power and operating reserve services; (MR, TDL, DSC)

"apartment building" means a structure containing four or more dwelling units having access from an interior corridor system or common entrance;

"apparent power" means the total power measured in kiloVolt Amperes (kVA);
"application for service" means the agreement or contract with Brant County Power under which electrical service is requested;

"bandwidth" means a distributor's defined tolerance used to flag data for further scrutiny at the stage in the VEE (validating, estimating and editing) process where a current reading is compared to a reading from an equivalent historical billing period. For example, a 30 percent bandwidth means a current reading that is either 30 percent lower or 30 percent higher than the measurement from an equivalent historical billing period will be identified by the VEE process as requiring further scrutiny and verification; (DSC)

"billing demand" means the metered demand or connected load after necessary adjustments have been made for power factor, intermittent rating, transformer losses and minimum billing. A measurement in kiloWatts (kW) of the maximum rate at which electricity is consumed during a billing period;

"Board" or "OEB" means the Ontario Energy Board; (A, TDL, DSC)

"building" means a building, portion of a building, structure or facility;

"complex metering installation" means a metering installation where instrument transformers, test blocks, recorders, pulse duplicators and multiple meters may be employed; (DSC)

“Conditions of Service” means the document developed by a distributor in accordance with subsection 2.4 of the Code that describes the operating practices and connection rules for the distributor; (DSC)

“connection” means the process of installing and activating connection assets in order to distribute electricity to a Customer; (DSC)

“Connection Agreement” means an agreement entered into between a distributor and a person connected to its distribution system that delineates the conditions of the connection and delivery of electricity to that connection; (DSC)

“connection assets” means that portion of the distribution system used to connect a Customer to the existing main distribution system, and consists of the assets between the point of connection on a distributor’ s main distribution system and the ownership demarcation point with that Customer; (DSC)

“Consumer” means a person who uses, for the person’ s own consumption, electricity that the person did not generate; (A, MR, TDL, DSC)

“Customer” means a person that has contracted for or intends to contract for connection of a building. This includes developers of residential or commercial subdivisions; (DSC)

"demand" means the average value of power measured over a specified interval of time, usually expressed in kilowatts (kW). Typical demand intervals are 15, 30 and 60 minutes; (DSC)

“demand meter” means a meter that measures a Consumer’s peak usage during a specified period of time; (DSC)

"developer" means a person or persons owning property for which new or modified electrical services are to be installed;

“disconnection” means a deactivation of connection assets that results in cessation of distribution services to a Consumer; (DSC)

“distribute”, with respect to electricity, means to convey electricity at voltages of 50 kilovolts or less; (A, MR, TDL, DSC)

“distribution losses” means energy losses that result from the interaction of intrinsic characteristics of the distribution network such as electrical resistance with network voltages and current flows; (DSC)

“distribution loss factor” means a factor or factors by which metered loads must be multiplied such that when summed equal the total measured load at the supply point(s) to the distribution system; (RSC)

“distribution services” means services related to the distribution of electricity and the services the Board has required distributors to carry out, for which a charge or rate has been approved by the Board under section 78 of the Ontario Energy Board Act; (RSC, DSC)

“distribution system” means a system for distributing electricity, and includes any structures, equipment or other things used for that purpose. A distribution system is comprised of the main system capable of distributing electricity to many Customers and the connection assets used to connect a Customer to the main distribution system; (A, MR, TDL, DSC)

“Distribution System Code” means the code, approved by the Board, and in effect at the relevant time, which, among other things, establishes the obligations of 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; (TDL, DSC)

“distributor” means a person who owns or operates a distribution system; (A, MR, TDL, DSC)

"duct bank" means two or more ducts that may be encased in concrete used for the purpose of containing and protecting underground electric cables;

“Electricity Act” means the Electricity Act, 1998, S.O. 1998, c.15, Schedule A; (MR, TDL, DSC)

“Electrical Safety Authority” or “ESA” means the person or body designated under the Electricity Act regulations as the Electrical Safety Authority;(A)

"electric service" means the Customer’s conductors and equipment for energy from Brant County Power;
“embedded distributor” means a distributor who is not a wholesale market participant and that is provided electricity by a host distributor; (RSC, DSC)

“embedded generator” or “embedded generation facility” means a generator whose generation facility is not directly connected to the IMO-controlled grid but instead is connected to a distribution system; (DSC)

“embedded retail generator” means an embedded generator that settles through a distributor’s retail settlements system and is not a wholesale market participant; (DSC)

“embedded wholesale Consumer” means a Consumer who is a wholesale market participant whose facility is not directly connected to the IMO-controlled grid but is connected to a distribution system; (DSC)

“embedded wholesale generator” means an embedded generator that is a wholesale market participant; (DSC)

“emergency” means any abnormal system condition that requires remedial action to prevent or limit loss of a distribution system or supply of electricity that could adversely affect the reliability of the electricity system; (DSC)

“emergency backup” means a generation facility that has a transfer switch that isolates it from a distribution system; (DSC)

"energy" means the product of power multiplied by time, usually expressed in kilowatt-hours (kWH);

“Energy Competition Act” means the Energy Competition Act, 1998, S.O. 1998, c. 15; (MR)

"energy diversion" means the electricity consumption unaccounted for but that can be quantified through various measures upon review of the meter mechanism, such as unbilled meter readings, tap off load(s) before revenue meter or meter tampering;

“enhancement” means a modification to an existing distribution system that is made for purposes of improving system operating characteristics such as reliability or power quality or for relieving system capacity constraints resulting, for example, from general load growth; (DSC)
apartments buildings supplied through one service (bulk-metered);

“generate”, with respect to electricity, means to produce electricity or provide ancillary services, other than ancillary services provided by a transmitter or distributor through the operation of a transmission or distribution system; (A, TDL, DSC)

“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; (A, MR, TDL, DSC)

“generator” means a person who owns or operates a generation facility; (A, R, TDL, DSC)

“geographic distributor,” with respect to a load transfer, means the distributor that is licenced to service a load transfer Customer and is responsible for connecting and billing the load transfer Customer; (DSC)

“good utility practice” means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry in North America during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good practices, reliability, safety and expedition. Good utility practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in North America; (MR, DSC)

“host distributor” means the registered wholesale market participant distributor who provides electricity to an embedded distributor; (RSC, DSC)

"house service" means that portion of the electrical service in a multiple occupancy facility which is common to all occupants, (i.e. parking lot lighting, sign service, corridor and walkway lighting, et cetera);

“IEC” means International Electrotechnical Commission;

“IEEE” means Institute of Electrical and Electronics Engineers;

“IMO” means the Independent Electricity Market Operator established under the Electricity Act; (A, TDL, DSC)

“IMO-controlled grid” means the transmission systems with respect to which, pursuant to agreements, the IMO has authority to direct operation; (A, TDL, DSC)

“interval meter” means a meter that measures and records electricity use on an hourly or sub-hourly basis; (RSC, DSC)

"large user" means a Customer with a monthly peak demand of 5000 kW or greater, regardless the demand occurs in the peak or off-peak periods, averaged over 12 months;

"load factor" means the ratio of average demand for a designated time period (usually one month) to the maximum demand occurring in that period;

“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; (DSC)

“load transfer Customer” means a Customer that is provided distribution services through a load transfer; (DSC)

"main service" refers to Brant County Power’s incoming cables, bus duct, disconnecting and protective equipment for a Building or from which all other metered sub-services are taken;

“Market Rules” means the rules made under section 32 of the Electricity Act; (MR, TDL, DSC)

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

“meter service provider” means any entity that performs metering services on behalf of a distributor; (DSC)

“meter installation” means the meter and, if so equipped, the instrument transformers, wiring, test links, fuses, lamps, loss of potential alarms, meters, data recorders, telecommunication equipment and spin-off data facilities installed to measure power past a meter point, provide remote access to the metered data and monitor the condition of the installed equipment; (RSC, DSC)

"meter socket" means the mounting device for accommodating a socket type revenue meter;

“metering services” means installation, testing, reading and maintenance of meters; (DSC)
“MIST meter” means an interval meter from which data is obtained and validated within a designated settlement timeframe. MIST refers to “Metering Inside the Settlement Timeframe;” (RSC, DSC)

“MOST meter” means an interval meter from which data is only available outside of the designated settlement timeframe. MOST refers to “Metering Outside the Settlement Timeframe;” (RSC, DSC)

"multiple dwelling" means a Building which contains more than one self-contained dwelling unit;

"municipal street lighting" means all services supplied to street lighting equipment owned and operated for a municipal corporation;

“non-competitive electricity costs” means costs for services from the IMO that are not deemed by the Board to be competitive electricity services plus costs for distribution services, other than Standard Supply Service (SSS); (RSC)

"normal operating conditions" means the operating conditions comply with the standards set by the Canadian Standards Association ("CSA") Standard CAN3-C235- 87 (latest edition);

“Ontario Energy Board Act” means the Ontario Energy Board Act, 1998, S.O. 1998, c.15, Schedule B; (MR, DSC)

“operational demarcation point” means the physical location at which a distributor’s responsibility for operational control of distribution equipment including connection assets ends at the Customer; (DSC) "ownership demarcation point" means the physical location at which a distributor's ownership of distribution equipment including connection assets ends at the Customer; (DSC)

"performance standards" means the performance targets for the distribution and connection activities of the distributor as established by the Board pursuant to the Ontario Energy Board Act and in the Rate Handbook; (DSC)

"person" includes an individual, a corporation, sole proprietorship, partnership, unincorporated organization, unincorporated association, body corporate, and any other legal entity;

"physical distributor," with respect to a load transfer, means the distributor that provides physical delivery of electricity to a load transfer Customer, but is not responsible for connecting and billing the load transfer Customer directly; (DSC)

"plaza" means any Building containing two or more commercial business tenants;

"point of supply," with respect to an embedded generator, means the connection point where electricity produced by the generator is injected into a distribution system; (DSC)
"power factor" means the ratio between Real Power and Apparent Power (i.e. kW/kVA);

"primary service" means any service which is supplied with a nominal voltage greater than 1000 volts;

"private property" means the property beyond the existing public street allowances;

"rate" means any rate, charge or other consideration, and includes a penalty for late payment; (TDL, DSC)

"Rate Handbook" means the regulatory mechanisms that will be applied in the setting of distributor rates; (RSC, DSC)

"reactive power" means the power component which does not produce work but is necessary to allow some equipment to operate, and is measured in kiloVolt Amperes Reactive (kVAR);

"real power" means the power component required to do real work, which is measured in kiloWatts (kW);

"Regulations" means the regulations made under the *Ontario Energy Board Act* or the *Electricity Act*; (TDL, DSC)

"residential service" means a service which is less than 50kW supplied to single family dwelling units that is for domestic or household purposes, including seasonal occupancy. At Brant County Power's discretion, residential rates may be applied to apartment buildings with 6 or less units by simple application of the residential rate or by blocking the residential rate by the number of units;

“retail”, with respect to electricity means,
a) to sell or offer to sell electricity to a Consumer
b) to act as agent or broker for a retailer with respect to the sale or offering for sale of electricity, or
c) to act or offer to act as an agent or broker for a Consumer with respect to the sale or offering for sale of electricity; (A, MR, TDL, DSC)

“Retail Settlement Code” means the code approved by the Board and in effect at the relevant time, which, among other things, establishes a distributor’s obligations and responsibilities associated with financial settlement among retailers and Consumers and provides for tracking and facilitating Consumers transfers among competitive retailers; (TDL, DSC)

“retailer” means a person who retails electricity; (A, MR, TDL, DSC)

"secondary service" means any service which is supplied with a nominal voltage less than 1000 Volts;

“service agreement” means the agreement that sets out the relationship between a licenced retailer and a distributor, in accordance with the provisions of Chapter 12 of the Retail Settlement Code; (RSC)

“service area,” with respect to a distributor, means the area in which the distributor is authorized by its licence to distribute electricity; (A, TDL, DSC)

"service date" means the date that the Customer and Brant County Power mutually agree upon to begin the supply of electricity by Brant County Power;

“Standard Supply Service Code” means the code approved by the Board and in effect at the relevant time, 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; (TDL)

"sub-service" means a separately metered service that is taken from the main Building service;

"supply voltage" means the voltage measured at the Customer's main service entrance equipment (typically below 1000 volts). Operating conditions are defined in the Canadian Standards Association ("CSA") Standard CAN3-C235 (latest edition);

"temporary service" means an electrical service granted temporarily for such purposes as construction, real estate sales, trailers, et cetera;

"terminal pole" refers to the Brant County Power’s distribution pole on which the service supply cables are terminated;

“total losses” means the sum of distribution losses and unaccounted for energy; (DSC)

"transformer room" means an isolated enclosure built to applicable codes to house transformers and associated electrical equipment;

“transmission system” means a system for transmitting electricity, and includes any structures, equipment or other things used for that purpose; (A, MR, TDL, DSC)

"Transmission System Code" means the code, approved by the Board, 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; (DSC)

"transmit", with respect to electricity, means to convey electricity at voltages of more than 50 kilovolts; (A, TDL, DSC)

"transmitter" means a person who owns or operates a transmission system; (A, MR, TDL, DSC)

"unaccounted for energy" means all energy losses that can not be attributed to distribution losses. These include measurement error, errors in estimates the document approved by the Board that outlines of distribution losses

SECTION 5 - RATES AND CHARGES

Residential Class	
Service not requiring transformation on customer's property	Basic service includes up to 30m overhead conductor, connections, overhead transformation and a basic kWh meter. Brant County Power shall also provide road crossing facilities at no charge. (See section 3.1 for details).
Charge Notes	No charge for basic service. Customer pays all costs in excess of basic service allowance.
Demarcation Point	Overhead - Top of Customer's Service Mast Underground – Line side of customer's meter base.

Residential Services Requiring Transformation on Customer Property	
Overhead Primary Service	Customer supplies, owns and maintains service, including poles.
Underground Primary Service	Customer supplies, owns and maintains service including pad for transformer.
Charge Notes	Customer pays all Utility costs over "basic" service cost. Brant County Power shall provide road crossing facilities at no charge.
Demarcation Point	Bottom of switch on Utility pole

Residential Services Requiring Transformation on Customer Property	
Overhead Primary Service	Customer supplies, owns and maintains service, including poles.
Underground Primary Service	Customer supplies, owns and maintains service including pad for transformer.
Charge Notes	Customer pays all Utility costs over "basic" service cost. Brant County Power shall provide road crossing facilities at no charge.

General Service Class	
Overhead or Underground Secondary Service	Basic service for General Service Class customers includes overhead transformation plus a basic KWH or KWH/ KVA demand meter or interval metering for loads over 500 KVA at no charge. See section 3.2 for details
Charge Notes	Customer pays incremental costs in excess of basic service. Where

	applicable, the 25-year Net Present Value Capital Contribution calculation will be applied.
Demarcation Point	Overhead - Top of Customer's Service Mast Underground – Line side of customer meter base. Note: For exceptions see sections 3.2.1.1. and 3.2.1.2 for customer owned secondary services.
Overhead or Underground Primary Service (Customer Owned)	Owner responsible to supply, own and maintain all customer primary cable and related equipment (ie.switchgear.) See section 3.2 for details.
Charge Notes	Customer pays incremental costs in excess of basic service. Where applicable, the 25-year Net Present Value Capital Contribution calculation will be applied.
Demarcation point	Bottom of switches on Utility pole or load side of inline switches

Temporary Service	
Overhead -Single Service	Temporary Service is defined as a short duration service up to 12 months.
Charge Notes	Customer to pay all costs to install and remove temporary service and transformation in advance. Transformer provided at no cost.

Residential Subdivisions	
Developer or Utility Installed	Brant County Power to design and connect the new subdivision to the Brant County Power distribution system.
Charge Notes	See Capital contribution section 2.1.2.2
Demarcation Point	Overhead - Top of Customer's Service Mast Underground – Line side of customer meter base.

Flat Rate UnMetered Services
All new services **MUST** be metered other than streetlights and cable TV power suppliers. Exceptions shall be at the sole discretion of Brant County Power subject to OEB regulations.

Rate Base Overview

Rate Base over the 2006 to 2011 period continued to grow. The net book value of fixed assets component increases as annual capital expenditures exceed annual depreciation. The growth in Net Fixed Assets varies from year to year depending upon the required expenditures. Growth in 2010 and 2011 are partly attributed to Smart Meters and the proposed river crossing. The net fixed assets include those distribution assets that are associated with activities that enable the conveyance of electricity for distribution purposes. The Brant County Power rate base calculation excludes any non-distribution assets.

Similarly the working capital component increases due to cost increases from commodity, non-competitive charges, and OM&A costs.

Details are provided below regarding the net investment in fixed assets over the period and the determination of the working capital component of rate base. Brant County Power utilizes 15% of allowable expenses (expenses include operations and maintenance, billing and collecting and administration expenses) to determine the working capital allowance.

Rate Base Summary

Rate Base Summary - Average Year Balances	2006 Actual Opening Balance	2006 Actual Closing Balance	2006 Actual Average	2007 Actual Opening Balance	2007 Actual Closing Balance	2006 Actual Average	2008 Actual Opening Balance	2008 Actual Closing Balance	2008 Actual Average	2009 Actual Opening Balance	2009 Actual Closing Balance	2009 Actual Average	2010 Bridge Opening Balance	2010 Bridge Closing Balance	2010 Bridge Average	2011 Test Opening Balance	2011 Test Closing Balance	2011 Test Average
Gross Assets	$18,743,113	$20,444,590	$19,593,851	$20,444,590	$21,436,674	$20,940,632	$21,436,674	$22,303,627	$21,870,151	$22,303,627	$23,912,542	$23,108,084	$23,912,542	$27,099,112	$25,505,827	$27,099,112	$29,992,266	$28,545,689
Accumulated Depreciation	($4,158,441)	($5,312,709)	($4,735,575)	($5,312,709)	($6,168,550)	($5,740,629)	($6,168,550)	($7,127,980)	($6,648,265)	($7,127,980)	($8,345,415)	($7,736,697)	($8,345,415)	($9,463,932)	($8,904,673)	($9,463,932)	($10,609,998)	($10,036,965)
Net Fixed Assets	$14,584,672	$15,131,881	$14,858,276	$15,131,881	$15,268,125	$15,200,003	$15,268,125	$15,175,647	$15,221,886	$15,175,647	$15,567,127	$15,371,387	$15,567,127	$17,635,180	$16,601,153	$17,635,180	$19,382,267	$18,508,724
Allowance for Working Capital	$3,170,522	$3,067,802	$3,119,162	$3,067,802	$3,167,024	$3,117,413	$3,167,024	$3,284,352	$3,225,688	$3,284,352	$3,047,710	$3,166,031	$3,047,710	$3,995,475	$3,521,592	$3,995,475	$4,073,972	$4,034,723
Rate Base	$17,755,193	$18,199,683	$17,977,438	$18,199,683	$18,435,149	$18,317,416	$18,435,149	$18,459,999	$18,447,574	$18,459,999	$18,614,837	$18,537,418	$18,614,837	$21,630,655	$20,122,746	$21,630,655	$23,456,239	$22,543,447

Rate Base Continuity Schedule

Appendix 2-B
Fixed Asset Continuity Schedule
2006

CCA Class	OEB	Description	Depreciation Rate	Cost O/B	Cost Additions	Cost Disposals	Cost C/B	Accumulated Depreciation O/B	Accumulated Depreciation Additions	Accumulated Depreciation Disposals	Accumulated Depreciation C/B	Net Book Value	
N/A	1805	Land	0%	$ 94,642.90			$ 94,642.90	$ -			$ -	$ 94,642.90	
47	1806	Land Rights	0%				$ -	$ -			$ -	$ -	
13	1808	Buildings & Fixtures	2%	$ 753,037.97	$ 39,250.92		$ 792,288.89	$ 50,413.54	$ 31,846.66		$ 82,260.20	$ 710,028.69	
47	1810	Leasehold Improvements	2%				$ -				$ -	$ -	
47	1815	TS Equipment	2.5%	$ 2,440,513.09	$ 67,053.65		$ 2,507,566.74	$ -	$ 62,689.17		$ 62,689.17	$ 2,444,877.57	
47	1820	DS Equipment	3%	$ 116,080.26			$ 116,080.26	$ 30,139.03	$ 6,200.84		$ 36,339.87	$ 79,740.39	
47	1825	Storage Battery Equipment					$ -				$ -	$ -	
47	1830	Poles, Towers & Fixtures	4%	$ 3,132,818.63	$ 456,927.29		$ 3,589,745.92	$ 763,064.48	$ 184,865.84		$ 947,930.32	$ 2,641,815.60	
47	1835	OH Conductors & Devices	4%	$ 2,611,586.13	$ 254,506.45		$ 2,866,092.58	$ 627,090.28	$ 146,934.87		$ 774,025.15	$ 2,092,067.43	
47	1840	UG - Conduit	4%	$ 444,358.43	$ 33,622.14		$ 477,980.57	$ 84,119.89	$ 23,058.94		$ 107,178.83	$ 370,801.74	
47	1845	UG - Conductors & Devices	4%	$ 1,914,076.39	$ 47,083.69		$ 1,961,160.08	$ 457,408.55	$ 103,996.16		$ 561,404.71	$ 1,399,755.37	
47	1850	Line Transformers	4%	$ 3,345,151.55	$ 378,354.18		$ 3,723,505.73	$ 709,062.51	$ 186,222.26		$ 895,284.77	$ 2,828,220.96	
47	1855	Services	4%	$ 2,178,522.02	$ 91,903.58		$ 2,270,425.60	$ 523,776.47	$ 119,295.41		$ 643,071.88	$ 1,627,353.72	
47	1860	Meters	4%	$ 1,048,552.42	$ 90,638.68		$ 1,139,191.10	$ 243,237.78	$ 56,213.10		$ 299,450.88	$ 839,740.22	
47	1861	Smart Meters	4%				$ -				$ -	$ -	
47	1861	Smart Metes / Communication Equipment	4%				$ -				$ -	$ -	
47	1865	Other Installations on Customer Premises					$ -				$ -	$ -	
47	1870	Leased Property on Customer Premises					$ -				$ -	$ -	
47	1875	Street Lighting & Signal Systems					$ -				$ -	$ -	
N/A	1905	Land	0%	$ 72,665.11			$ 72,665.11	$ -			$ -	$ 72,665.11	
CEC	1906	Land Rights					$ -	$ -			$ -	$ -	
47	1908	Buildings & Fixtures	2%	$ 227,732.56			$ 227,732.56	$ 31,284.97	$ 6,713.99		$ 37,998.96	$ 189,733.60	
13	1910	Leasehold Improvements					$ -				$ -	$ -	
8	1915	Office Furniture & Equipment	10%	$ 84,612.64	$ 7,349.47		$ 91,962.11	$ 41,444.56	$ 9,235.20		$ 50,679.76	$ 41,282.35	
8	1920	Compter Hardware	20%	$ 431,640.87	$ 9,129.67		$ 440,770.54	$ 234,615.62	$ 72,233.99		$ 306,849.61	$ 133,920.93	
10	1921	Computer Hardware- Post Mar 22, 2004	20%				$ -				$ -	$ -	
45	1921	Computer Hardware- Post Mar 19, 2007	20%				$ -				$ -	$ -	
45.1	1925	Computer Software	2000%	$ 249,459.17	$ 20,868.85		$ 270,328.02	$ 186,920.73	$ 25,223.81		$ 212,144.54	$ 58,183.48	
10	1930	Transportation Equipment	25% / 20% / 12.5%	$ 1,019,409.08	$ 202,831.54		$ 1,222,240.62	$ 290,027.96	$ 165,143.68		$ 455,171.64	$ 767,068.98	recovered via overhead charges
8	1935	Stores Equipment		$ 1,148.58			$ 1,148.58	$ 1,148.58			$ 1,148.58	$ -	recovered via overhead charges
8	1940	Tools, Shop & Garage Equipment	10%	$ 99,263.33	$ 12,724.08		$ 111,987.41	$ 44,928.12	$ 9,836.51		$ 54,764.63	$ 57,222.78	recovered via overhead charges
8	1945	Measurement & Testing Equipment		$ 41,176.91			$ 41,176.91	$ 20,103.85	$ 3,891.03		$ 23,994.88	$ 17,182.03	recovered via overhead charges
8	1950	Power Operated Equipment		$ 2,674.95			$ 2,674.95	$ 906.82	$ 196.45		$ 1,103.27	$ 1,571.68	recovered via overhead charges
8	1955	Communication Equipment		$ 39,995.62			$ 39,995.62	$ 19,833.86	$ 3,886.60		$ 23,720.46	$ 16,275.16	recovered via overhead charges
8	1960	Misc. Equipment		$ 22,122.94			$ 22,122.94	$ 4,382.40	$ 2,139.29		$ 6,521.69	$ 15,601.25	recovered via overhead charges
47	1970	Load Management Controls - Customer Premises					$ -				$ -	$ -	
47	1975	Load Management Controls - Utility Premises					$ -				$ -	$ -	
47	1980	System Supervisory Equipment					$ -				$ -	$ -	
47	1985	Sentinel Light Rental Units					$ -				$ -	$ -	
47	1990	Other Tangible Property					$ -				$ -	$ -	
47	1995	Contributions & Grants - Credit		-$ 1,628,128.65	-$ 10,767.25		-$ 1,638,895.90	-$ 205,468.71	-$ 65,555.84		-$ 271,024.55	-$ 1,367,871.35	
	Grand Total			**$ 18,743,112.90**	**$ 1,701,476.94**	**$ -**	**$ 20,444,589.84**	**$ 4,158,441.29**	**$ 1,154,267.96**	**$ -**	**$ 5,312,709.25**	**$ 15,131,880.59**	

Reconciliation of Continuity Schedule (based on Audited F/S) to RRR filed TB

Description	USOA	Annual Depreciation Expense	RRR Expense	F/S Expense	Variance
Transportation Equipment	1930	$165,144			
Stores Equipment	1935	$0			
Tools, Shop & Garage Equipment	1940	$9,837			
Measurement & Testing Equipment	1945	$3,891			
Power Operated Equipment	1950	$196			
Communication Equipment	1955	$3,887			
Misc. Equipment	1960	$2,139			
Total		**$185,094**	**$969,174**	**$1,154,268**	**$185,094**

Appendix 2-B
Fixed Asset Continuity Schedule
2007

CCA Class	OEB	Description	Depreciation Rate	Cost O/B	Cost Additions	Cost Disposals	Cost C/B	Accumulated Depreciation O/B	Accumulated Depreciation Additions	Accumulated Depreciation Disposals	Accumulated Depreciation C/B	Net Book Value	
N/A	1805	Land		$ 94,642.90			$ 94,642.90	$ -			$ -	$ 94,642.90	
47	1806	Land Rights		$ -			$ -	$ -			$ -	$ -	
13	1808	Buildings & Fixtures		$ 792,288.89	$ 7,066.58		$ 799,355.47	$ 82,260.20	$ 32,082.21		$ 114,342.41	$ 685,013.06	
47	1810	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -	
47	1815	TS Equipment		$ 2,507,566.74			$ 2,507,566.74	$ 62,689.17	$ 62,689.17		$ 125,378.34	$ 2,382,188.40	
47	1820	DS Equipment		$ 116,080.26			$ 116,080.26	$ 36,339.87	$ 6,200.82		$ 42,540.69	$ 73,539.57	
47	1825	Storage Battery Equipment		$ -			$ -	$ -			$ -	$ -	
47	1830	Poles, Towers & Fixtures		$ 3,589,745.92	$ 437,857.24		$ 4,027,603.16	$ 947,930.32	$ 196,602.39		$ 1,144,532.71	$ 2,883,070.45	
47	1835	OH Conductors & Devices		$ 2,866,092.58	$ 158,780.23		$ 3,024,872.81	$ 774,025.15	$ 150,067.83		$ 924,092.98	$ 2,100,779.83	
47	1840	UG - Conduit		$ 477,980.57	$ 26,002.16		$ 503,982.73	$ 107,178.83	$ 25,499.03		$ 132,677.86	$ 371,304.87	
47	1845	UG - Conductors & Devices		$ 1,961,160.08	$ 19,743.18		$ 1,980,903.26	$ 561,404.71	$ 103,225.89		$ 664,630.60	$ 1,316,272.66	
47	1850	Line Transformers		$ 3,723,505.73	$ 313,219.93		$ 4,036,725.66	$ 895,284.77	$ 198,751.06		$ 1,094,035.83	$ 2,942,689.83	
47	1855	Services		$ 2,270,425.60	$ 89,532.01		$ 2,359,957.61	$ 643,071.88	$ 120,437.69		$ 763,509.57	$ 1,596,448.04	
47	1860	Meters		$ 1,139,191.10	$ 84,060.17		$ 1,223,251.27	$ 299,450.88	$ 59,575.51		$ 359,026.39	$ 864,224.88	
47	1861	Smart Meters		$ -			$ -	$ -			$ -	$ -	
47	1861	Smart Metes / Communication Equipment		$ -			$ -	$ -			$ -	$ -	
47	1865	Other Installations on Customer Premises		$ -			$ -	$ -			$ -	$ -	
47	1870	Leased Property on Customer Premises		$ -			$ -	$ -			$ -	$ -	
47	1875	Street Lighting & Signal Systems		$ -			$ -	$ -			$ -	$ -	
N/A	1905	Land		$ 72,665.11			$ 72,665.11	$ -			$ -	$ 72,665.11	
CEC	1906	Land Rights		$ -			$ -	$ -			$ -	$ -	
47	1908	Buildings & Fixtures		$ 227,732.56	$ 17,272.16		$ 245,004.72	$ 37,998.96	$ 7,289.72		$ 45,288.68	$ 199,716.04	
13	1910	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -	
8	1915	Office Furniture & Equipment		$ 91,962.11	$ 2,305.54		$ 94,267.65	$ 50,679.76	$ 9,465.75		$ 60,145.51	$ 34,122.14	
8	1920	Compter Hardware		$ 440,770.54	$ 76,210.56		$ 516,981.10	$ 306,849.61	$ 78,139.37		$ 384,988.98	$ 131,992.12	
10	1921	Computer Hardware- Post Mar 22, 2004		$ -			$ -	$ -			$ -	$ -	
45	1921	Computer Hardware- Post Mar 19, 2007		$ -			$ -	$ -			$ -	$ -	
45.1	1925	Computer Software		$ 270,328.02	$ 16,377.01		$ 286,705.03	$ 212,144.54	$ 24,181.21		$ 236,325.75	$ 50,379.28	
10	1930	Transportation Equipment		$ 1,222,240.62	$ 147,261.49	$ 365,717.46	$ 1,003,784.65	$ 455,171.64	$ 194,371.93	$ 365,717.46	$ 283,826.11	$ 719,958.54	recovered via overhead charges
8	1935	Stores Equipment		$ 1,148.58			$ 1,148.58	$ 1,148.58			$ 1,148.58	$ -	recovered via overhead charges
8	1940	Tools, Shop & Garage Equipment		$ 111,987.41	$ 15,725.62		$ 127,713.03	$ 54,764.63	$ 10,708.94		$ 65,473.57	$ 62,239.46	recovered via overhead charges
8	1945	Measurement & Testing Equipment		$ 41,176.91	$ 6,957.84		$ 48,134.75	$ 23,994.88	$ 4,023.56		$ 28,018.44	$ 20,116.31	recovered via overhead charges
8	1950	Power Operated Equipment		$ 2,674.95	$ 33.02		$ 2,707.97	$ 1,103.27	$ 199.75		$ 1,303.02	$ 1,404.95	recovered via overhead charges
8	1955	Communication Equipment		$ 39,995.62			$ 39,995.62	$ 23,720.46	$ 3,886.60		$ 27,607.06	$ 12,388.56	recovered via overhead charges
8	1960	Misc. Equipment		$ 22,122.94			$ 22,122.94	$ 6,521.69	$ 2,139.29		$ 8,660.98	$ 13,461.96	recovered via overhead charges
47	1970	Load Management Controls - Customer Premises		$ -			$ -	$ -			$ -	$ -	
47	1975	Load Management Controls - Utility Premises		$ -			$ -	$ -			$ -	$ -	
47	1980	System Supervisory Equipment		$ -			$ -	$ -			$ -	$ -	
47	1985	Sentinel Light Rental Units		$ -			$ -	$ -			$ -	$ -	
47	1990	Other Tangible Property		$ -			$ -	$ -			$ -	$ -	
47	1995	Contributions & Grants - Credit		-$ 1,638,895.90	-$ 60,602.80		-$ 1,699,498.70	-$ 271,024.55	-$ 67,979.95		-$ 339,004.50	-$ 1,360,494.20	
	Grand Total			**$ 20,444,589.84**	**$ 1,357,801.94**	**$ 365,717.46**	**$ 21,436,674.32**	**$ 5,312,709.25**	**$ 1,221,557.77**	**$365,717.46**	**$ 6,168,549.56**	**$ 15,268,124.76**	

Reconciliation of Continuity Schedule (based on Audited F/S) to RRR filed TB

Description	USOA	Annual Depreciation Expense	RRR Expense	F/S Expense	Variance
Transportation Equipment	1930	($171,346)			
Stores Equipment	1935	$0			
Tools, Shop & Garage Equipment	1940	$10,709			
Measurement & Testing Equipment	1945	$4,024			
Power Operated Equipment	1950	$200			
Communication Equipment	1955	$3,887			
Misc. Equipment	1960	$2,139			
Total		**($150,387)**	**$1,006,228**	**$855,840**	**($150,387)**

Appendix 2-B
Fixed Asset Continuity Schedule
2008

CCA Class	OEB	Description	Depreciation Rate	Cost O/B	Cost Additions	Cost Disposals	Cost C/B	Accumulated Depreciation O/B	Accumulated Depreciation Additions	Accumulated Depreciation Disposals	Accumulated Depreciation C/B	Net Book Value	
N/A	1805	Land		$ 94,642.90			$ 94,642.90	$ -			$ -	$ 94,642.90	
47	1806	Land Rights		$ -			$ -	$ -			$ -	$ -	
13	1808	Buildings & Fixtures		$ 799,355.47	$ 3,640.00		$ 802,995.47	$ 114,342.41	$ 32,203.54		$ 146,545.95	$ 656,449.52	
47	1810	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -	
47	1815	TS Equipment		$ 2,507,566.74	$ 2,542.64		$ 2,510,109.38	$ 125,378.34	$ 63,197.70		$ 188,576.04	$ 2,321,533.34	
47	1820	DS Equipment		$ 116,080.26			$ 116,080.26	$ 42,540.69	$ 6,200.84		$ 48,741.53	$ 67,338.73	
47	1825	Storage Battery Equipment		$ -			$ -	$ -			$ -	$ -	
47	1830	Poles, Towers & Fixtures		$ 4,027,603.16	$ 378,246.20		$ 4,405,849.36	$ 1,144,532.71	$ 209,106.22		$ 1,353,638.93	$ 3,052,210.43	
47	1835	OH Conductors & Devices		$ 3,024,872.81	$ 207,302.11		$ 3,232,174.92	$ 924,092.98	$ 155,041.91		$ 1,079,134.89	$ 2,153,040.03	
47	1840	UG - Conduit		$ 503,982.73	$ 32,979.88		$ 536,962.61	$ 132,677.86	$ 25,178.22		$ 157,856.08	$ 379,106.53	
47	1845	UG - Conductors & Devices		$ 1,980,903.26	$ 72,416.84		$ 2,053,320.10	$ 664,630.60	$ 106,122.57		$ 770,753.17	$ 1,282,566.93	
47	1850	Line Transformers		$ 4,036,725.66	$ 177,596.68		$ 4,214,322.34	$ 1,094,035.83	$ 205,854.93		$ 1,299,890.76	$ 2,914,431.58	
47	1855	Services		$ 2,359,957.61	$ 37,098.94		$ 2,397,056.55	$ 763,509.57	$ 120,025.65		$ 883,535.22	$ 1,513,521.33	
47	1860	Meters		$ 1,223,251.27	$ 25,154.55		$ 1,248,405.82	$ 359,026.39	$ 60,581.69		$ 419,608.08	$ 828,797.74	
47	1861	Smart Meters		$ -			$ -	$ -			$ -	$ -	
47	1861	Smart Metes / Communication Equipment		$ -			$ -	$ -			$ -	$ -	
47	1865	Other Installations on Customer Premises		$ -			$ -	$ -			$ -	$ -	
47	1870	Leased Property on Customer Premises		$ -			$ -	$ -			$ -	$ -	
47	1875	Street Lighting & Signal Systems		$ -			$ -	$ -			$ -	$ -	
N/A	1905	Land		$ 72,665.11			$ 72,665.11	$ -			$ -	$ 72,665.11	
CEC	1906	Land Rights		$ -			$ -	$ -			$ -	$ -	
47	1908	Buildings & Fixtures		$ 245,004.72	$ 112,874.10		$ 357,878.82	$ 45,288.68	$ 11,052.19		$ 56,340.87	$ 301,537.95	
13	1910	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -	
8	1915	Office Furniture & Equipment		$ 94,267.65			$ 94,267.65	$ 60,145.51	$ 9,465.42		$ 69,610.93	$ 24,656.72	
8	1920	Compter Hardware		$ 516,981.10	$ 38,346.50		$ 555,327.60	$ 384,988.98	$ 81,561.12		$ 466,550.10	$ 88,777.50	
10	1921	Computer Hardware- Post Mar 22, 2004		$ -			$ -	$ -			$ -	$ -	
45	1921	Computer Hardware- Post Mar 19, 2007		$ -			$ -	$ -			$ -	$ -	
45.1	1925	Computer Software		$ 286,705.03	$ 22,377.00		$ 309,082.03	$ 236,325.75	$ 27,825.03		$ 264,150.78	$ 44,931.25	
10	1930	Transportation Equipment		$ 1,003,784.65	$ 313,663.16	$ 484,347.84	$ 833,099.97	$ 283,826.11	$ 162,705.30	$ 266,969.38	$ 179,562.03	$ 653,537.94	recovered via overhead charges
8	1935	Stores Equipment		$ 1,148.58			$ 1,148.58	$ 1,148.58			$ 1,148.58	$ -	recovered via overhead charges
8	1940	Tools, Shop & Garage Equipment		$ 127,713.03	$ 14,950.07		$ 142,663.10	$ 65,473.57	$ 11,360.30		$ 76,833.87	$ 65,829.23	recovered via overhead charges
8	1945	Measurement & Testing Equipment		$ 48,134.75	$ 2,137.26		$ 50,272.01	$ 28,018.44	$ 4,237.29		$ 32,255.73	$ 18,016.28	recovered via overhead charges
8	1950	Power Operated Equipment		$ 2,707.97			$ 2,707.97	$ 1,303.02	$ 199.75		$ 1,502.77	$ 1,205.20	recovered via overhead charges
8	1955	Communication Equipment		$ 39,995.62	$ 584.28		$ 40,579.90	$ 27,607.06	$ 3,944.98		$ 31,552.04	$ 9,027.86	recovered via overhead charges
8	1960	Misc. Equipment		$ 22,122.94			$ 22,122.94	$ 8,660.98	$ 2,139.29		$ 10,800.27	$ 11,322.67	recovered via overhead charges
47	1970	Load Management Controls - Customer Premises		$ -			$ -	$ -			$ -	$ -	
47	1975	Load Management Controls - Utility Premises		$ -			$ -	$ -			$ -	$ -	
47	1980	System Supervisory Equipment		$ -			$ -	$ -			$ -	$ -	
47	1985	Sentinel Light Rental Units		$ -			$ -	$ -			$ -	$ -	
47	1990	Other Tangible Property		$ -			$ -	$ -			$ -	$ -	
47	1995	Contributions & Grants - Credit		-$ 1,699,498.70	-$ 90,609.89		-$ 1,790,108.59	-$ 339,004.50	-$ 71,604.34		-$ 410,608.84	-$ 1,379,499.75	
	Grand Total			**$ 21,436,674.32**	**$ 1,351,300.32**	**$ 484,347.84**	**$ 22,303,626.80**	**$ 6,168,549.56**	**$ 1,226,399.60**	**$ 266,969.38**	**$ 7,127,979.78**	**$ 15,175,647.02**	

Reconciliation of Continuity Schedule (based on Audited F/S) to RRR filed TB

Description	USOA	Annual Depreciation Expense	RRR Expense	F/S Expense	Variance
Transportation Equipment	1930	($104,264)			
Stores Equipment	1935	$0			
Tools, Shop & Garage Equipment	1940	$11,360			
Measurement & Testing Equipment	1945	$4,237			
Power Operated Equipment	1950	$200			
Communication Equipment	1955	$3,945			
Misc. Equipment	1960	$2,139			
Total		**($82,382)**	**$1,041,813**	**$959,430**	**($82,382)**

Appendix 2-B
Fixed Asset Continuity Schedule
2009

				Cost				Accumulated Depreciation					
CCA Class	OEB	Description	Depreciation Rate	O/B	Additions	Disposals	C/B	O/B	Additions	Disposals	C/B	Net Book Value	
N/A	1805	Land		$ 94,642.90	$ 6,380.00		$ 101,022.90	$ -			$ -	$ 101,022.90	
47	1806	Land Rights		$ -			$ -	$ -			$ -	$ -	
13	1808	Buildings & Fixtures		$ 802,995.47			$ 802,995.47	$ 146,545.95	$ 32,204.00		$ 178,749.95	$ 624,245.52	
47	1810	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -	
47	1815	TS Equipment		$ 2,510,109.38			$ 2,510,109.38	$ 188,576.04	$ 63,198.00		$ 251,774.04	$ 2,258,335.34	
47	1820	DS Equipment		$ 116,080.26			$ 116,080.26	$ 48,741.53	$ 6,201.00		$ 54,942.53	$ 61,137.73	
47	1825	Storage Battery Equipment		$ -			$ -	$ -			$ -	$ -	
47	1830	Poles, Towers & Fixtures		$ 4,405,849.36	$ 428,137.00		$ 4,833,986.36	$ 1,353,638.93	$ 219,998.00		$ 1,573,636.93	$ 3,260,349.43	
47	1835	OH Conductors & Devices		$ 3,232,174.92	$ 300,481.00		$ 3,532,655.92	$ 1,079,134.89	$ 152,320.00		$ 1,231,454.89	$ 2,301,201.03	
47	1840	UG - Conduit		$ 536,962.61	$ 72,833.00		$ 609,795.61	$ 157,856.08	$ 25,564.00		$ 183,420.08	$ 426,375.53	
47	1845	UG - Conductors & Devices		$ 2,053,320.10	$ 55,349.00		$ 2,108,669.10	$ 770,753.17	$ 108,337.00		$ 879,090.17	$ 1,229,578.93	
47	1850	Line Transformers		$ 4,214,322.34	$ 250,877.00		$ 4,465,199.34	$ 1,299,890.76	$ 215,890.00		$ 1,515,780.76	$ 2,949,418.58	
47	1855	Services		$ 2,397,056.55	$ 47,836.00		$ 2,444,892.55	$ 883,535.22	$ 120,384.00		$ 1,003,919.22	$ 1,440,973.33	
47	1860	Meters		$ 1,248,405.82	$ 141,958.00		$ 1,390,363.82	$ 419,608.08	$ 62,970.00		$ 482,578.08	$ 907,785.74	
47	1861	Smart Meters		$ -			$ -	$ -			$ -	$ -	
47	1861	Smart Metes / Communication Equipment		$ -			$ -	$ -			$ -	$ -	
47	1865	Other Installations on Customer Premises		$ -			$ -	$ -			$ -	$ -	
47	1870	Leased Property on Customer Premises		$ -			$ -	$ -			$ -	$ -	
47	1875	Street Lighting & Signal Systems		$ -			$ -	$ -			$ -	$ -	
N/A	1905	Land		$ 72,665.11			$ 72,665.11	$ -			$ -	$ 72,665.11	
CEC	1906	Land Rights		$ -			$ -	$ -			$ -	$ -	
47	1908	Buildings & Fixtures		$ 357,878.82	$ 21,907.00		$ 379,785.82	$ 56,340.87	$ 11,382.00		$ 67,722.87	$ 312,062.95	
13	1910	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -	
8	1915	Office Furniture & Equipment		$ 94,267.65	$ 25,000.00		$ 119,267.65	$ 69,610.93	$ 8,199.00		$ 77,809.93	$ 41,457.72	
8	1920	Compter Hardware		$ 555,327.60	$ 26,990.00		$ 582,317.60	$ 466,550.10	$ 38,857.00		$ 505,407.10	$ 76,910.50	
10	1921	Computer Hardware- Post Mar 22, 2004		$ -			$ -	$ -			$ -	$ -	
45	1921	Computer Hardware- Post Mar 19, 2007		$ -			$ -	$ -			$ -	$ -	
45.1	1925	Computer Software		$ 309,082.03	$ 7,752.00		$ 316,834.03	$ 264,150.78	$ 22,331.00		$ 286,481.78	$ 30,352.25	
10	1930	Transportation Equipment		$ 833,099.97	$ 218,906.00		$ 1,052,005.97	$ 179,562.03	$ 179,560.00		$ 359,122.03	$ 692,883.94	recovered via overhead charges
8	1935	Stores Equipment		$ 1,148.58			$ 1,148.58	$ 1,148.58			$ 1,148.58	$ -	recovered via overhead charges
8	1940	Tools, Shop & Garage Equipment		$ 142,663.10	$ 12,346.00		$ 155,009.10	$ 76,833.87	$ 12,088.00		$ 88,921.87	$ 66,087.23	recovered via overhead charges
8	1945	Measurement & Testing Equipment		$ 50,272.01	$ 824.00		$ 51,096.01	$ 32,255.73	$ 3,958.00		$ 36,213.73	$ 14,882.28	recovered via overhead charges
8	1950	Power Operated Equipment		$ 2,707.97			$ 2,707.97	$ 1,502.77	$ 200.00		$ 1,702.77	$ 1,005.20	recovered via overhead charges
8	1955	Communication Equipment		$ 40,579.90			$ 40,579.90	$ 31,552.04	$ 3,606.00		$ 35,158.04	$ 5,421.86	recovered via overhead charges
8	1960	Misc. Equipment		$ 22,122.94			$ 22,122.94	$ 10,800.27	$ 2,139.00		$ 12,939.27	$ 9,183.67	recovered via overhead charges
47	1970	Load Management Controls - Customer Premises		$ -			$ -	$ -			$ -	$ -	
47	1975	Load Management Controls - Utility Premises		$ -			$ -	$ -			$ -	$ -	
47	1980	System Supervisory Equipment		$ -			$ -	$ -			$ -	$ -	
47	1985	Sentinel Light Rental Units		$ -			$ -	$ -			$ -	$ -	
47	1990	Other Tangible Property		$ -			$ -	$ -			$ -	$ -	
47	1995	Contributions & Grants - Credit		-$ 1,790,108.59	-$ 8,661.00		-$ 1,798,769.59	-$ 410,608.84	-$ 71,951.00		-$ 482,559.84	-$ 1,316,209.75	
	Grand Total			**$ 22,303,626.80**	**$ 1,608,915.00**	**$ -**	**$ 23,912,541.80**	**$ 7,127,979.78**	**$ 1,217,435.00**	**$ -**	**$ 8,345,414.78**	**$ 15,567,127.02**	

Reconciliation of Continuity Schedule (based on Audited F/S) to RRR filed TB

Description	USOA	Annual Depreciation Expense	RRR Expense	F/S Expense	Variance
Transportation Equipment	1930	$179,560			
Stores Equipment	1935	$0			
Tools, Shop & Garage Equipment	1940	$12,088			
Measurement & Testing Equipment	1945	$3,958			
Power Operated Equipment	1950	$200			
Communication Equipment	1955	$3,606			
Misc. Equipment	1960	$2,139			
Total		**$201,551**	**$1,015,883**	**$1,217,435**	**$201,552**

Appendix 2-B
Fixed Asset Continuity Schedule
2010 - Bridge

CCA Class	OEB	Description	Depreciation Rate	Cost O/B	Cost Additions	Cost Disposals	Cost C/B	Accumulated Depreciation O/B	Accumulated Depreciation Additions	Accumulated Depreciation Disposals	Accumulated Depreciation C/B	Net Book Value	
N/A	1805	Land		$ 101,022.90			$ 101,022.90	$ -			$ -	$ 101,022.90	
47	1806	Land Rights		$ -			$ -	$ -			$ -	$ -	
13	1808	Buildings & Fixtures		$ 802,995.47			$ 802,995.47	$ 178,749.95	$ 28,114.00		$ 206,863.95	$ 596,131.52	
47	1810	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -	
47	1815	TS Equipment		$ 2,510,109.38			$ 2,510,109.38	$ 251,774.04	$ 62,753.00		$ 314,527.04	$ 2,195,582.34	
47	1820	DS Equipment		$ 116,080.26			$ 116,080.26	$ 54,942.53	$ 4,643.21		$ 59,585.74	$ 56,494.52	
47	1825	Storage Battery Equipment		$ -			$ -	$ -			$ -	$ -	
47	1830	Poles, Towers & Fixtures		$ 4,833,986.36	$ 425,616.00		$ 5,259,602.36	$ 1,573,636.93	$ 186,009.61		$ 1,759,646.54	$ 3,499,955.82	
47	1835	OH Conductors & Devices		$ 3,532,655.92	$ 368,960.00		$ 3,901,615.92	$ 1,231,454.89	$ 134,552.46		$ 1,366,007.35	$ 2,535,608.57	
47	1840	UG - Conduit		$ 609,795.61	$ 63,598.00		$ 673,393.61	$ 183,420.08	$ 26,935.74		$ 210,355.82	$ 463,037.79	
47	1845	UG - Conductors & Devices		$ 2,108,669.10	$ 71,158.00		$ 2,179,827.10	$ 879,090.17	$ 87,193.08		$ 966,283.25	$ 1,213,543.85	
47	1850	Line Transformers		$ 4,465,199.34	$ 195,428.00		$ 4,660,627.34	$ 1,515,780.76	$ 128,249.36		$ 1,644,030.12	$ 3,016,597.22	
47	1855	Services		$ 2,444,892.55	$ 84,660.00		$ 2,529,552.55	$ 1,003,919.22	$ 88,889.43		$ 1,092,808.65	$ 1,436,743.90	
47	1860	Meters		$ 1,390,363.82	$ 1,461,350.00		$ 2,851,713.82	$ 482,578.08	$ 114,068.55		$ 596,646.63	$ 2,255,067.19	
47	1861	Smart Meters		$ -			$ -	$ -			$ -	$ -	
47	1861	Smart Metes / Communication Equipment		$ -			$ -	$ -			$ -	$ -	
47	1865	Other Installations on Customer Premises		$ -			$ -	$ -			$ -	$ -	
47	1870	Leased Property on Customer Premises		$ -			$ -	$ -			$ -	$ -	
47	1875	Street Lighting & Signal Systems		$ -			$ -	$ -			$ -	$ -	
N/A	1905	Land		$ 72,665.11			$ 72,665.11	$ -			$ -	$ 72,665.11	
CEC	1906	Land Rights		$ -			$ -	$ -			$ -	$ -	
47	1908	Buildings & Fixtures		$ 379,785.82	$ 10,000.00		$ 389,785.82	$ 67,722.87	$ 13,032.00		$ 80,754.87	$ 309,030.95	
13	1910	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -	
8	1915	Office Furniture & Equipment		$ 119,267.65	$ 500.00		$ 119,767.65	$ 77,809.93	$ 7,336.93		$ 85,146.86	$ 34,620.79	
8	1920	Compter Hardware		$ 582,317.60	$ 162,300.00		$ 744,617.60	$ 505,407.10	$ 57,235.25		$ 562,642.35	$ 181,975.25	
10	1921	Computer Hardware- Post Mar 22, 2004		$ -			$ -	$ -			$ -	$ -	
45	1921	Computer Hardware- Post Mar 19, 2007		$ -			$ -	$ -			$ -	$ -	
45.1	1925	Computer Software		$ 316,834.03	$ -		$ 316,834.03	$ 286,481.78	$ 17,472.80		$ 303,954.58	$ 12,879.45	
10	1930	Transportation Equipment		$ 1,052,005.97	$ 325,000.00		$ 1,377,005.97	$ 359,122.03	$ 220,187.03		$ 579,309.06	$ 797,696.91	recovered via overhead charges
8	1935	Stores Equipment		$ 1,148.58			$ 1,148.58	$ 1,148.58			$ 1,148.58	$ -	recovered via overhead charges
8	1940	Tools, Shop & Garage Equipment		$ 155,009.10	$ 13,000.00		$ 168,009.10	$ 88,921.87	$ 5,181.76		$ 94,103.63	$ 73,905.47	recovered via overhead charges
8	1945	Measurement & Testing Equipment		$ 51,096.01	$ 15,000.00		$ 66,096.01	$ 36,213.73	$ 5,092.50		$ 41,306.23	$ 24,789.78	recovered via overhead charges
8	1950	Power Operated Equipment		$ 2,707.97			$ 2,707.97	$ 1,702.77	$ 194.55		$ 1,897.32	$ 810.65	recovered via overhead charges
8	1955	Communication Equipment		$ 40,579.90			$ 40,579.90	$ 35,158.04	$ 1,440.56		$ 36,598.60	$ 3,981.30	recovered via overhead charges
8	1960	Misc. Equipment		$ 22,122.94			$ 22,122.94	$ 12,939.27	$ 2,139.29		$ 15,078.56	$ 7,044.38	recovered via overhead charges
47	1970	Load Management Controls - Customer Premises		$ -			$ -	$ -			$ -	$ -	
47	1975	Load Management Controls - Utility Premises		$ -			$ -	$ -			$ -	$ -	
47	1980	System Supervisory Equipment		$ -			$ -	$ -			$ -	$ -	
47	1985	Sentinel Light Rental Units		$ -			$ -	$ -			$ -	$ -	
47	1990	Other Tangible Property		$ -			$ -	$ -			$ -	$ -	
47	1995	Contributions & Grants - Credit		-$ 1,798,769.59	-$ 10,000.00		-$ 1,808,769.59	-$ 482,559.84	-$ 72,204.00		-$ 554,763.84	-$ 1,254,005.75	
	Grand Total			**$ 23,912,541.80**	**$ 3,186,570.00**	**$ -**	**$ 27,099,111.80**	**$ 8,345,414.78**	**$ 1,118,517.13**	**$ -**	**$ 9,463,931.91**	**$ 17,635,179.89**	

Reconciliation of Continuity Schedule (based on Audited F/S) to 2010 Budget

Description	USOA	Annual Depreciation Expense	Budget Expense	F/S Expense	Variance
Transportation Equipment	1930	$220,187			
Stores Equipment	1935	$0			
Tools, Shop & Garage Equipment	1940	$5,182			
Measurement & Testing Equipment	1945	$5,093			
Power Operated Equipment	1950	$195			
Communication Equipment	1955	$1,441			
Misc. Equipment	1960	$2,139			
Total		**$234,236**	**$884,281**	**$1,118,517**	**$234,236**

Appendix 2-B
Fixed Asset Continuity Schedule
2011 - Test

				Cost				Accumulated Depreciation					
CCA Class	**OEB**	**Description**	**Depreciation Rate**	**O/B**	**Additions**	**Disposals**	**C/B**	**O/B**	**Additions**	**Disposals**	**C/B**	Net Book Value	
N/A	1805	Land		$ 101,022.90			$ 101,022.90	$ -			$ -	$ 101,022.90	
47	1806	Land Rights		$ -			$ -	$ -			$ -	$ -	
13	1808	Buildings & Fixtures		$ 802,995.47			$ 802,995.47	$ 206,863.95	$ 26,516.00		$ 233,379.95	$ 569,615.52	
47	1810	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -	
47	1815	TS Equipment		$ 2,510,109.38			$ 2,510,109.38	$ 314,527.04	$ 62,753.00		$ 377,280.04	$ 2,132,829.34	
47	1820	DS Equipment		$ 116,080.26			$ 116,080.26	$ 59,585.74	$ 4,643.21		$ 64,228.95	$ 51,851.31	
47	1825	Storage Battery Equipment		$ -			$ -	$ -			$ -	$ -	
47	1830	Poles, Towers & Fixtures		$ 5,259,602.36	$ 1,257,839.00		$ 6,517,441.36	$ 1,759,646.54	$ 205,931.96		$ 1,965,578.50	$ 4,551,862.86	
47	1835	OH Conductors & Devices		$ 3,901,615.92	$ 379,930.00		$ 4,281,545.92	$ 1,366,007.35	$ 124,834.93		$ 1,490,842.28	$ 2,790,703.64	
47	1840	UG - Conduit		$ 673,393.61	$ 66,059.00		$ 739,452.61	$ 210,355.82	$ 29,578.10		$ 239,933.93	$ 499,518.68	
47	1845	UG - Conductors & Devices		$ 2,179,827.10	$ 302,955.00		$ 2,482,782.10	$ 966,283.25	$ 99,311.28		$ 1,065,594.54	$ 1,417,187.56	
47	1850	Line Transformers		$ 4,660,627.34	$ 197,599.00		$ 4,858,226.34	$ 1,644,030.12	$ 105,739.21		$ 1,749,769.33	$ 3,108,457.01	
47	1855	Services		$ 2,529,552.55	$ 87,309.00		$ 2,616,861.55	$ 1,092,808.65	$ 78,144.80		$ 1,170,953.45	$ 1,445,908.10	
47	1860	Meters		$ 2,851,713.82	$ 130,963.00		$ 2,982,676.82	$ 596,646.63	$ 117,446.41		$ 714,093.05	$ 2,268,583.77	
47	1861	Smart Meters		$ -			$ -	$ -			$ -	$ -	
47	1861	Smart Metes / Communication Equipment		$ -			$ -	$ -			$ -	$ -	
47	1865	Other Installations on Customer Premises		$ -			$ -	$ -			$ -	$ -	
47	1870	Leased Property on Customer Premises		$ -			$ -	$ -			$ -	$ -	
47	1875	Street Lighting & Signal Systems		$ -			$ -	$ -			$ -	$ -	
N/A	1905	Land		$ 72,665.11			$ 72,665.11	$ -			$ -	$ 72,665.11	
CEC	1906	Land Rights		$ -			$ -	$ -			$ -	$ -	
47	1908	Buildings & Fixtures		$ 389,785.82	$ 60,000.00		$ 449,785.82	$ 80,754.87	$ 14,243.00		$ 94,997.87	$ 354,787.95	
13	1910	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -	
8	1915	Office Furniture & Equipment		$ 119,767.65	$ 500.00		$ 120,267.65	$ 85,146.86	$ 5,906.80		$ 91,053.65	$ 29,214.00	
8	1920	Compter Hardware		$ 744,617.60	$ 165,000.00		$ 909,617.60	$ 562,642.35	$ 75,788.46		$ 638,430.81	$ 271,186.79	
10	1921	Computer Hardware- Post Mar 22, 2004		$ -			$ -	$ -			$ -	$ -	
45	1921	Computer Hardware- Post Mar 19, 2007		$ -			$ -	$ -			$ -	$ -	
45.1	1925	Computer Software		$ 316,834.03	$ 15,000.00		$ 331,834.03	$ 303,954.58	$ 15,428.04		$ 319,382.62	$ 12,451.41	
10	1930	Transportation Equipment		$ 1,377,005.97	$ 130,000.00		$ 1,507,005.97	$ 579,309.06	$ 236,271.39		$ 815,580.45	$ 691,425.52	recovered via overhead charges
8	1935	Stores Equipment		$ 1,148.58			$ 1,148.58	$ 1,148.58			$ 1,148.58	$ -	recovered via overhead charges
8	1940	Tools, Shop & Garage Equipment		$ 168,009.10	$ 10,000.00		$ 178,009.10	$ 94,103.63	$ 5,362.01		$ 99,465.64	$ 78,543.46	recovered via overhead charges
8	1945	Measurement & Testing Equipment		$ 66,096.01			$ 66,096.01	$ 41,306.23	$ 4,804.28		$ 46,110.51	$ 19,985.50	recovered via overhead charges
8	1950	Power Operated Equipment		$ 2,707.97			$ 2,707.97	$ 1,897.32	$ 163.32		$ 2,060.65	$ 647.32	recovered via overhead charges
8	1955	Communication Equipment		$ 40,579.90			$ 40,579.90	$ 36,598.60	$ 1,111.92		$ 37,710.52	$ 2,869.38	recovered via overhead charges
8	1960	Misc. Equipment		$ 22,122.94			$ 22,122.94	$ 15,078.56	$ 2,139.29		$ 17,217.86	$ 4,905.08	recovered via overhead charges
47	1970	Load Management Controls - Customer Premises		$ -			$ -	$ -			$ -	$ -	
47	1975	Load Management Controls - Utility Premises		$ -			$ -	$ -			$ -	$ -	
47	1980	System Supervisory Equipment		$ -			$ -	$ -			$ -	$ -	
47	1985	Sentinel Light Rental Units		$ -			$ -	$ -			$ -	$ -	
47	1990	Other Tangible Property		$ -	$ 100,000.00		$ 100,000.00	$ -	$ 2,500.00		$ 2,500.00	$ 97,500.00	
47	1995	Contributions & Grants - Credit		-$ 1,808,769.59	-$ 10,000.00		-$ 1,818,769.59	-$ 554,763.84	-$ 72,551.00		-$ 627,314.84	-$ 1,191,454.75	
	Grand Total			**$ 27,099,111.80**	**$ 2,893,154.00**	**$ -**	**$ 29,992,265.80**	**$ 9,463,931.91**	**$ 1,146,066.43**	**$ -**	**$ 10,609,998.34**	**$ 19,382,267.46**	

Reconciliation of Continuity Schedule (based on Audited F/S) to 2011 Budget

Description	USOA	Annual Depreciation Expense	Budget Expense	F/S Expense	Variance
Transportation Equipment	1930	$236,271			
Stores Equipment	1935	$0			
Tools, Shop & Garage Equipment	1940	$5,362			
Measurement & Testing Equipment	1945	$4,804			
Power Operated Equipment	1950	$163			
Communication Equipment	1955	$1,112			
Misc. Equipment	1960	$2,139			
Total		**$249,852**	**$896,214**	**$1,146,066**	**$249,852**

Variance Analysis on Rate Base

Brant County Power (BCP), like all other LDCs, has changes year over year in capital plans (both project costs and internal workforce effort). All changes in the capital expenditures are related to BCP Board Approval and is vetted through a capital spend process (asset management plan can be found in schedule 6 of this exhibit).

BCP is providing Appendix 2-A (which outlines annual capital spend by project by USoA) and our 5-year review of capital projects to provide insight to annual capital expenditures.

Gross Assets – Property Plant and Equipment

	2006 Board Approved	2006 Actual	Variance form 2006 Board Approved	2006 Actual	2007 Actual	Variance form 2006 Actual	2007 Actual	2008 Actual	Variance form 2007 Actual	2008 Actual	2009 Actual	Variance form 2008 Actual	2009 Actual	2010 Bridge	Variance form 2009 Actual	2010 Bridge	2011 Test	Variance form 2010 Bridge
	($'s)	($'s)		($'s)	($'s)		($'s)	($'s)		($'s)	($'s)		($'s)	($'s)		($'s)	($'s)	
Distribution Plant																		
1805-Land	$0	$94,643	$94,643	$94,643	$94,643	$0	$94,643	$94,643	$0	$94,643	$94,643	$0	$94,643	$94,643	$0	$94,643	$94,643	$0
1806-Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-Buildings and Fixtures	$137,544	$792,289	$654,745	$792,289	$799,355	$7,067	$799,355	$802,995	$3,640	$802,995	$802,995	$0	$802,995	$802,995	$0	$802,995	$802,995	$0
1905-Land	$72,665	$72,665	$0	$72,665	$72,665	$0	$72,665	$72,665	$0	$72,665	$79,045	$6,380	$79,045	$79,045	$0	$79,045	$79,045	$0
1906-Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810-Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Sub-Total-Land and Buildings	$210,209	$959,597	$749,388	$959,597	$966,663	$7,067	$966,663	$970,303	$3,640	$970,303	$976,683	$6,380	$976,683	$976,683	$0	$976,683	$976,683	$0
1815-Transformer Station Equipment - Normally Primary above 50 kV	$0	$2,507,567	$2,507,567	$2,507,567	$2,507,567	$0	$2,507,567	$2,510,109	$2,543	$2,510,109	$2,510,109	$0	$2,510,109	$2,510,109	$0	$2,510,109	$2,510,109	$0
1820-Distribution Station Equipment - Normally Primary below 50 kV	$100,712	$116,080	$15,368	$116,080	$116,080	$0	$116,080	$116,080	$0	$116,080	$116,080	$0	$116,080	$116,080	$0	$116,080	$116,080	$0
1830-Poles, Towers and Fixtures	$2,685,855	$3,548,746	$862,891	$3,548,746	$3,986,603	$437,857	$3,986,603	$4,364,849	$378,246	$4,364,849	$4,792,986	$428,137	$4,792,986	$5,218,602	$425,616	$5,218,602	$6,476,441	$1,257,839
1835-Overhead Conductors and Devices	$2,271,897	$2,866,093	$594,196	$2,866,093	$3,024,873	$158,780	$3,024,873	$3,232,175	$207,302	$3,232,175	$3,532,656	$300,481	$3,532,656	$3,901,616	$368,960	$3,901,616	$4,281,546	$379,930
1840-Underground Conduit	$358,573	$477,981	$119,408	$477,981	$503,983	$26,002	$503,983	$536,963	$32,980	$536,963	$609,796	$72,833	$609,796	$673,394	$63,598	$673,394	$739,453	$66,059
1845-Underground Conductors and Devices	$1,753,896	$2,002,160	$248,264	$2,002,160	$2,021,903	$19,743	$2,021,903	$2,094,320	$72,417	$2,094,320	$2,149,669	$55,349	$2,149,669	$2,220,827	$71,158	$2,220,827	$2,523,782	$302,955
Sub-Total-Poles and Wires	$7,070,220	$8,894,979	$1,824,759	$8,894,979	$9,537,362	$642,383	$9,537,362	$10,228,307	$690,945	$10,228,307	$11,085,107	$856,800	$11,085,107	$12,014,439	$929,332	$12,014,439	$14,021,222	$2,006,783
1850-Line Transformers	$2,941,348	$3,723,506	$782,158	$3,723,506	$4,036,726	$313,220	$4,036,726	$4,214,322	$177,597	$4,214,322	$4,465,199	$250,877	$4,465,199	$4,660,627	$195,428	$4,660,627	$4,858,226	$197,599
1855-Services	$2,043,245	$2,270,426	$227,181	$2,270,426	$2,359,958	$89,532	$2,359,958	$2,397,057	$37,099	$2,397,057	$2,444,892	$47,835	$2,444,892	$2,529,552	$84,660	$2,529,552	$2,616,861	$87,309
1860-Meters	$975,192	$1,139,191	$163,999	$1,139,191	$1,223,251	$84,060	$1,223,251	$1,248,406	$25,155	$1,248,406	$1,390,364	$141,958	$1,390,364	$2,851,714	$1,461,350	$2,851,714	$2,982,677	$130,963
Sub-Total-Services and Meters	$3,018,437	$3,409,617	$391,180	$3,409,617	$3,583,209	$173,592	$3,583,209	$3,645,462	$62,253	$3,645,462	$3,835,256	$189,794	$3,835,256	$5,381,266	$1,546,010	$5,381,266	$5,599,538	$218,272
Distribution Plant Total	**$13,340,927**	**$19,611,345**	**$6,270,419**	**$19,611,345**	**$20,747,607**	**$1,136,262**	**$20,747,607**	**$21,684,585**	**$936,978**	**$21,684,585**	**$22,988,434**	**$1,303,849**	**$22,988,434**	**$25,659,204**	**$2,670,770**	**$25,659,204**	**$28,081,858**	**$2,422,654**
General Plant																		
1908-Buildings and Fixtures	$227,733	$227,733	$0	$227,733	$245,005	$17,272	$245,005	$357,879	$112,874	$357,879	$379,785	$21,906	$379,785	$389,785	$10,000	$389,785	$449,785	$60,000
1910-Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Sub-Total-Buildings	$227,733	$227,733	$0	$227,733	$245,005	$17,272	$245,005	$357,879	$112,874	$357,879	$379,785	$21,906	$379,785	$389,785	$10,000	$389,785	$449,785	$60,000
1920-Computer Equipment - Hardware	$388,030	$440,771	$52,740	$440,771	$516,981	$76,211	$516,981	$555,328	$38,347	$555,328	$582,318	$26,990	$582,318	$644,618	$62,300	$644,618	$824,618	$180,000
1925-Computer Software	$205,180	$270,328	$65,149	$270,328	$286,705	$16,377	$286,705	$309,082	$22,377	$309,082	$316,834	$7,752	$316,834	$416,834	$100,000	$416,834	$416,834	$0
Sub-Total-IT Assets	$593,210	$711,099	$117,889	$711,099	$803,686	$92,588	$803,686	$864,410	$60,724	$864,410	$899,152	$34,742	$899,152	$1,061,452	$162,300	$1,061,452	$1,241,452	$180,000
1915-Office Furniture and Equipment	$81,081	$91,962	$10,881	$91,962	$94,268	$2,306	$94,268	$94,268	$0	$94,268	$119,268	$25,000	$119,268	$119,768	$500	$119,768	$120,268	$500
1930-Transportation Equipment	$886,565	$1,222,241	$335,676	$1,222,241	$1,003,785	-$218,456	$1,003,785	$833,100	-$170,685	$833,100	$1,052,006	$218,906	$1,052,006	$1,377,006	$325,000	$1,377,006	$1,507,006	$130,000
1935-Stores Equipment	$1,149	$1,149	$0	$1,149	$1,149	$0	$1,149	$1,149	$0	$1,149	$1,149	$0	$1,149	$1,149	$0	$1,149	$1,149	$0
1940-Tools, Shop and Garage Equipment	$81,825	$111,987	$30,162	$111,987	$127,713	$15,726	$127,713	$142,664	$14,951	$142,664	$155,011	$12,347	$155,011	$168,011	$13,000	$168,011	$168,011	$0
1945-Measurement and Testing Equipment	$41,177	$41,177	$0	$41,177	$48,135	$6,958	$48,135	$50,272	$2,137	$50,272	$51,096	$824	$51,096	$66,096	$15,000	$66,096	$76,096	$10,000
1950-Power Operated Equipment	$710	$2,675	$1,965	$2,675	$2,708	$33	$2,708	$2,708	$0	$2,708	$2,708	$0	$2,708	$2,708	$0	$2,708	$2,708	$0
1955-Communication Equipment	$37,212	$39,996	$2,784	$39,996	$39,996	$0	$39,996	$40,580	$584	$40,580	$40,580	$0	$40,580	$40,580	$0	$40,580	$40,580	$0
1960-Miscellaneous Equipment	$15,861	$22,123	$6,262	$22,123	$22,123	$0	$22,123	$22,123	$0	$22,123	$22,123	$0	$22,123	$22,123	$0	$22,123	$22,123	$0
Sub-Total-Equipment	$1,145,580	$1,533,309	$387,729	$1,533,309	$1,339,875	-$193,434	$1,339,875	$1,186,863	-$153,012	$1,186,863	$1,443,941	$257,078	$1,443,941	$1,797,441	$353,500	$1,797,441	$1,937,941	$140,500
1825-Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1970-Load Management Controls - Customer Premises	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1975-Load Management Controls - Utility Premises	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1980-System Supervisory Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1985-Sentinel Lighting Rental Units	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1990-Other Tangible Property	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$100,000	$100,000
1995-Contributions and Grants - Credit	$0	-$1,638,896	-$1,638,896	-$1,638,896	-$1,699,499	-$60,603	-$1,699,499	-$1,790,109	-$90,610	-$1,790,109	-$1,798,770	-$8,661	-$1,798,770	-$1,808,770	-$10,000	-$1,808,770	-$1,818,770	-$10,000
Sub-Total-Other Distribution Assets	$0	-$1,638,896	-$1,638,896	-$1,638,896	-$1,699,499	-$60,603	-$1,699,499	-$1,790,109	-$90,610	-$1,790,109	-$1,798,770	-$8,661	-$1,798,770	-$1,808,770	-$10,000	-$1,808,770	-$1,718,770	$90,000
General Plant Total	**$1,966,522**	**$833,244**	**-$1,133,278**	**$833,244**	**$689,067**	**-$144,177**	**$689,067**	**$619,043**	**-$70,024**	**$619,043**	**$924,108**	**$305,065**	**$924,108**	**$1,439,908**	**$515,800**	**$1,439,908**	**$1,910,408**	**$470,500**
GROSS ASSET TOTAL	$15,307,449	$20,444,590	$5,137,141	$20,444,590	$21,436,674	$992,085	$21,436,674	$22,303,628	$866,954	$22,303,628	$23,912,542	$1,608,914	$23,912,542	$27,099,112	$3,186,570	$27,099,112	$29,992,266	$2,893,154

Transmission Plant

BCP does not have any assets identified as Transmission Plant (USoA 1700 series).

Distribution Plant

BCP for the 2011 test year has an increase in Distribution Plant of approximately $2,422,654 or 9.1% over projected 2010 gross asset value ($27 million). The addition of distribution plant pertains to the following general categories:

- Poles and Wires - $2,006,783
- Transformers - $197,599
- Services and Meters - $218,272

Details of the specific capital expenditures relating to 2011 test year can be found in Tab 5 of this exhibit.

General Plant

BCP for the 2011 test year has an increase in General Plant of approximately $470 thousand or 1.7% over projected 2010 gross asset value ($27.06 million). The addition of gross assets pertains to the following general categories:

- Building - $60,000
- IT Assets - $180,000
- Equipment - $140,500
- Other Distribution Assets - $90,000

Details of the specific capital expenditures relating to 2011 test year can be found in Tab 5 of this exhibit.

Other Plant

BCP does not have any assets identified as Other Plant (USoA 2005 - 2075).

Accumulated Depreciation

ACCUMULATED DEPRECIATION TABLE	2006 Board Approved	2006 Actual	Variance from 2006 Board Approved	2006 Actual	2007 Actual	Variance from 2006 Actual	2007 Actual	2008 Actual	Variance from 2007 Actual	2008 Actual	2009 Actual	Variance from 2008 Actual	2009 Actual	2010 Bridge	Variance from 2009 Actual	2010 Bridge	2011 Test	Variance from 2010 Bridge
	($'s)	($'s)		($'s)	($'s)		($'s)	($'s)		($'s)	($'s)		($'s)	($'s)		($'s)	($'s)	
Land and Buildings																		
1805-Land-Depreciation		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806-Land Rights-Depreciation		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-Buildings and Fixtures-Depreciation	$50,414	$82,260	$31,847	$82,260	$114,342	$32,082	$114,342	$146,546	$32,204	$146,546	$178,750	$32,204	$178,750	$206,864	$28,114	$206,864	$233,380	$26,516
1905-Land-Depreciation		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1906-Land Rights-Depreciation		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810-Leasehold Improvements-Depreciation		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Sub-Total-Land and Buildings	$50,414	$82,260	$31,847	$82,260	$114,342	$32,082	$114,342	$146,546	$32,204	$146,546	$178,750	$32,204	$178,750	$206,864	$28,114	$206,864	$233,380	$26,516
TS Primary Above 50																		
1815-Transformer Station Equipment - Normally Primary above 50 kV-Depreciation	$0	$62,689	$62,689	$62,689	$125,378	$62,689	$125,378	$188,576	$63,198	$188,576	$251,774	$63,198	$251,774	$314,527	$62,753	$314,527	$377,280	$62,753
DS																		
1820-Distribution Station Equipment - Normally Primary below 50 kV-Depreciation	$30,139	$36,340	$6,201	$36,340	$42,541	$6,201	$42,541	$48,742	$6,201	$48,742	$54,943	$6,201	$54,943	$59,586	$4,643	$59,586	$64,229	$4,643
Poles and Wires																		
1830-Poles, Towers and Fixtures-Depreciation	$761,424	$947,930	$186,506	$947,930	$1,144,533	$196,602	$1,144,533	$1,353,639	$209,106	$1,353,639	$1,573,637	$219,998	$1,573,637	$1,759,647	$186,010	$1,759,647	$1,965,579	$205,932
1835-Overhead Conductors and Devices-Depreciation	$627,090	$774,025	$146,935	$774,025	$924,093	$150,068	$924,093	$1,079,135	$155,042	$1,079,135	$1,231,455	$152,320	$1,231,455	$1,366,007	$134,552	$1,366,007	$1,490,842	$124,835
1840-Underground Conduit-Depreciation	$84,120	$107,179	$23,059	$107,179	$132,678	$25,499	$132,678	$157,856	$25,178	$157,856	$183,420	$25,564	$183,420	$210,356	$26,936	$210,356	$239,934	$29,578
1845-Underground Conductors and Devices-Depreciation	$459,049	$561,405	$102,356	$561,405	$664,631	$103,226	$664,631	$770,753	$106,123	$770,753	$879,090	$108,337	$879,090	$966,283	$87,193	$966,283	$1,065,595	$99,311
Sub-Total-Poles and Wires	$1,931,683	$2,390,539	$458,856	$2,390,539	$2,865,934	$475,395	$2,865,934	$3,361,383	$495,449	$3,361,383	$3,867,602	$506,219	$3,867,602	$4,302,293	$434,691	$4,302,293	$4,761,949	$459,656
Line Transformers																		
1850-Line Transformers-Depreciation	$709,063	$895,285	$186,222	$895,285	$1,094,036	$198,751	$1,094,036	$1,299,891	$205,855	$1,299,891	$1,515,781	$215,890	$1,515,781	$1,644,030	$128,249	$1,644,030	$1,749,769	$105,739
Services and Meters																		
1855-Services-Depreciation	$523,776	$643,072	$119,295	$643,072	$763,510	$120,438	$763,510	$883,535	$120,026	$883,535	$1,003,919	$120,384	$1,003,919	$1,092,809	$88,889	$1,092,809	$1,170,953	$78,145
1860-Meters-Depreciation	$243,238	$299,451	$56,213	$299,451	$359,026	$59,576	$359,026	$419,608	$60,582	$419,608	$482,578	$62,970	$482,578	$596,647	$114,069	$596,647	$714,093	$117,446
Sub-Total-Services and Meters	$767,014	$942,523	$175,509	$942,523	$1,122,536	$180,013	$1,122,536	$1,303,143	$180,607	$1,303,143	$1,486,497	$183,354	$1,486,497	$1,689,455	$202,958	$1,689,455	$1,885,046	$195,591
General Plant																		
1908-Buildings and Fixtures-Depreciation	$31,285	$37,999	$6,714	$37,999	$45,289	$7,290	$45,289	$56,341	$11,052	$56,341	$67,723	$11,382	$67,723	$80,755	$13,032	$80,755	$94,998	$14,243
1910-Leasehold Improvements-Depreciation			$0	$0	$0	$0	$0		$0	$0	$0	$0	$0		$0	$0	$0	$0
Sub-Total-General Plant	$31,285	$37,999	$6,714	$37,999	$45,289	$7,290	$45,289	$56,341	$11,052	$56,341	$67,723	$11,382	$67,723	$80,755	$13,032	$80,755	$94,998	$14,243
IT Assets																		
1920-Computer Equipment - Hardware-Depreciation	$234,616	$306,850	$72,234	$306,850	$384,989	$78,139	$384,989	$466,550	$81,561	$466,550	$505,407	$38,857	$505,407	$562,642	$57,235	$562,642	$638,431	$75,788
1925-Computer Software-Depreciation	$186,921	$212,145	$25,224	$212,145	$236,326	$24,181	$236,326	$264,151	$27,825	$264,151	$286,482	$22,331	$286,482	$303,955	$17,473	$303,955	$319,383	$15,428
Sub-Total-IT Assets	$421,536	$518,994	$97,458	$518,994	$621,315	$102,321	$621,315	$730,701	$109,386	$730,701	$791,889	$61,188	$791,889	$866,597	$74,708	$866,597	$957,813	$91,216
Equipment																		
1915-Office Furniture and Equipment-Depreciation	$41,445	$50,680	$9,235	$50,680	$60,146	$9,466	$60,146	$69,611	$9,465	$69,611	$77,810	$8,199	$77,810	$85,147	$7,337	$85,147	$91,054	$5,907
1930-Transportation Equipment-Depreciation	$290,028	$455,172	$165,144	$455,172	$283,826	-$171,346	$283,826	$179,562	-$104,264	$179,562	$359,122	$179,560	$359,122	$579,309	$220,187	$579,309	$815,580	$236,271
1935-Stores Equipment-Depreciation	$1,149	$1,149	$0	$1,149	$1,149	$0	$1,149	$1,149	$0	$1,149	$1,149	$0	$1,149	$1,149	$0	$1,149	$1,149	$0
1940-Tools, Shop and Garage Equipment-Depreciation	$44,928	$54,765	$9,837	$54,765	$65,474	$10,709	$65,474	$76,834	$11,360	$76,834	$88,922	$12,088	$88,922	$94,104	$5,182	$94,104	$99,466	$5,362
1945-Measurement and Testing Equipment-			$0	$0		$0	$0		$0	$0		$0	$0	$0	$0	$0	$0	$0
1945-Measurement and Testing Equipment-Depreciation	$20,104	$23,995	$3,891	$23,995	$28,018	$4,024	$28,018	$32,256	$4,237	$32,256	$36,214	$3,958	$36,214	$41,306	$5,093	$41,306	$46,111	$4,804
1950-Power Operated Equipment-Depreciation	$907	$1,103	$196	$1,103	$1,303	$200	$1,303	$1,503	$200	$1,503	$1,703	$200	$1,703	$1,897	$195	$1,897	$2,061	$163
1955-Communication Equipment-Depreciation	$19,834	$23,720	$3,887	$23,720	$27,607	$3,887	$27,607	$31,552	$3,945	$31,552	$35,158	$3,606	$35,158	$36,599	$1,441	$36,599	$37,711	$1,112
1960-Miscellaneous Equipment-Depreciation	$4,382	$6,522	$2,139	$6,522	$8,661	$2,139	$8,661	$10,800	$2,139	$10,800	$12,939	$2,139	$12,939	$15,079	$2,139	$15,079	$17,218	$2,139
Sub-Total-Equipment	$422,777	$617,105	$194,328	$617,105	$476,183	-$140,922	$476,183	$403,266	-$72,917	$403,266	$613,016	$209,750	$613,016	$854,589	$241,573	$854,589	$1,110,348	$255,759
Other Distribution Assets																		
1825-Storage Battery Equipment-Depreciation			$0	$0		$0	$0		$0	$0		$0	$0		$0	$0		$0
1970-Load Management Controls - Customer Premises-Depreciation			$0	$0		$0	$0		$0	$0		$0	$0		$0	$0		$0
1975-Load Management Controls - Utility Premises-Depreciation			$0	$0		$0	$0		$0	$0		$0	$0		$0	$0		$0
1980-System Supervisory Equipment-Depreciation			$0	$0		$0	$0		$0	$0		$0	$0		$0	$0		$0
1985-Sentinel Lighting Rental Units-Depreciation			$0	$0		$0	$0		$0	$0		$0	$0		$0	$0		$0
1990-Other Tangible Property-Depreciation			$0	$0		$0	$0		$0	$0		$0	$0		$0	$0	$2,500	$2,500
1995-Contributions and Grants - Credit-Depreciation	-$58,732	-$271,025	-$212,292	-$271,025	-$339,005	-$67,980	-$339,005	-$410,609	-$71,604	-$410,609	-$482,560	-$71,951	-$482,560	-$554,764	-$72,204	-$554,764	-$627,315	-$72,551
Sub-Total-Other Distribution Assets	-$58,732	-$271,025	-$212,292	-$271,025	-$339,005	-$67,980	-$339,005	-$410,609	-$71,604	-$410,609	-$482,560	-$71,951	-$482,560	-$554,764	-$72,204	-$554,764	-$624,815	-$70,051
ACCUMULATED DEPRICIATION TOTAL	$4,305,178	$5,312,709	$1,007,531	$5,312,709	$6,168,550	$855,840	$6,168,550	$7,127,980	$959,430	$7,127,980	$8,345,415	$1,217,435	$8,345,415	$9,463,932	$1,118,517	$9,463,932	$10,609,998	$1,146,066

Allowance for Working Capital – Appendix 2-F

	2006 Actual			2007 Actual			2008 Actul			2009 Actual			2010 Bridge			2011 Test		
WORKING CAPITAL ALLOWANCE CALCULATION BY ACCOUNT	**Expense**	**15%**	**Allowance for Working Capital**	**Expense**	**15%**	**Allowance for Working Capital**	**Expense**	**15%**	**Allowance for Working Capital**	**Expense**	**15%**	**Allowance for Working Capital**	**Expense**	**15%**	**Allowance for Working Capital**	**Expense**	**15%**	**Allowance for Working Capital**
Operation (Working Capital)																		
5005-Operation Supervision and Engineering	$45,441.24	15%	$6,816.19	$47,208.69	15%	$7,081.30	$48,487.43	15%	$7,273.11	$30,131.00	15%	$4,519.65	$30,049.00	15%	$4,507.35	$29,509.00	15%	$4,426.35
5010-Load Dispatching	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
5012-Station Buildings and Fixtures Expense	$40,172.96	15%	$6,025.94	$56,515.31	15%	$8,477.30	$67,078.81	15%	$10,061.82	$74,737.00	15%	$11,210.55	$90,067.00	15%	$13,510.05	$93,806.00	15%	$14,070.90
5014-Transformer Station Equipment - Operation Labour	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
5015-Transformer Station Equipment - Operation Supplies and Expenses	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
5016-Distribution Station Equipment - Operation Labour	$2,442.67	15%	$366.40	$1,663.32	15%	$249.50	$1,886.69	15%	$283.00	$8,534.00	15%	$1,280.10	$4,491.00	15%	$673.65	$4,751.00	15%	$712.65
5017-Distribution Station Equipment - Operation Supplies and Expenses	$41,762.28	15%	$6,264.34	$19,616.16	15%	$2,942.42	$45,919.10	15%	$6,887.87	$54,678.00	15%	$8,201.70	$53,500.00	15%	$8,025.00	$53,500.00	15%	$8,025.00
5020-Overhead Distribution Lines and Feeders - Operation Labour	$39,477.67	15%	$5,921.65	$23,147.25	15%	$3,472.09	$23,899.67	15%	$3,584.95	$27,126.00	15%	$4,068.90	$35,168.00	15%	$5,275.20	$37,079.00	15%	$5,561.85
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$769.21	15%	$115.38	$8,461.18	15%	$1,269.18	$1,200.96	15%	$180.14	$7.00	15%	$1.05	$5,000.00	15%	$750.00	$5,000.00	15%	$750.00
5030-Overhead Sub transmission Feeders - Operation	$4,430.48	15%	$664.57	$45,447.66	15%	$6,817.15	-$413.77	15%	-$62.07	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
5035-Overhead Distribution Transformers- Operation	$43,293.47	15%	$6,494.02	$54,605.99	15%	$8,190.90	$10,538.93	15%	$1,580.84	$1,241.00	15%	$186.15	$18,710.00	15%	$2,806.50	$19,767.00	15%	$2,965.05
5040-Underground Distribution Lines and Feeders - Operation Labour	$6,622.42	15%	$993.36	$3,495.92	15%	$524.39	$2,605.32	15%	$390.80	$2,514.00	15%	$377.10	$5,237.00	15%	$785.55	$5,516.00	15%	$827.40
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$905.37	15%	$135.81	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
5050-Underground Sub transmission Feeders - Operation	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
5055-Underground Distribution Transformers - Operation	$7,566.70	15%	$1,135.01	$3,625.84	15%	$543.88	$12,999.79	15%	$1,949.97	$2,252.00	15%	$337.80	$9,479.00	15%	$1,421.85	$10,011.00	15%	$1,501.65
5060-Street Lighting and Signal System Expense	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
5065-Meter Expense	$28,963.41	15%	$4,344.51	$27,296.48	15%	$4,094.47	$17,205.30	15%	$2,580.80	$5,824.00	15%	$873.60	$17,582.00	15%	$2,637.30	$18,443.00	15%	$2,766.45
5070-Customer Premises - Operation Labour	$88,965.24	15%	$13,344.79	$112,906.05	15%	$16,935.91	$106,501.15	15%	$15,975.17	$112,588.00	15%	$16,888.20	$140,145.00	15%	$21,021.75	$148,229.00	15%	$22,234.35
5075-Customer Premises - Materials and Expenses	$937.36	15%	$140.60	$1,245.91	15%	$186.89	$493.95	15%	$74.09	$894.00	15%	$134.10	$0.00	15%	$0.00	$0.00	15%	$0.00
5085-Miscellaneous Distribution Expense	$219,811.46	15%	$32,971.72	$221,307.12	15%	$33,196.07	$197,654.18	15%	$29,648.13	$164,704.00	15%	$24,705.60	$222,276.00	15%	$33,341.40	$417,861.00	15%	$62,679.15
5090-Underground Distribution Lines and Feeders - Rental Paid	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
5095-Overhead Distribution Lines and Feeders - Rental Paid	$15,512.36	15%	$2,326.85	$10,013.50	15%	$1,502.03	$0.00	15%	$0.00	$18,064.00	15%	$2,709.60	$20,000.00	15%	$3,000.00	$20,000.00	15%	$3,000.00
5096-Other Rent	$30.00	15%	$4.50	$300.00	15%	$45.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
Sub-Total	$587,104.30		$88,065.65	$636,856.38		$95,528.46	$536,057.51		$80,408.63	$503,294.00		$75,494.10	$651,704.00		$97,755.60	$863,472.00		$129,520.80
Maintenance (Working Capital)																		
5105-Maintenance Supervision and Engineering	$45,352.88	15%	$6,802.93	$47,525.82	15%	$7,128.87	$48,306.21	15%	$7,245.93	$48,630.00	15%	$7,294.50	$30,049.00	15%	$4,507.35	$29,509.00	15%	$4,426.35
5110-Maintenance of Buildings and Fixtures - Distribution Stations	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$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	$45,120.92	15%	$6,768.14	$40,801.00	15%	$6,120.15	$37,000.00	15%	$5,550.00	$37,000.00	15%	$5,550.00
5114-Maintenance of Distribution Station Equipment	$766.07	15%	$114.91	$459.60	15%	$68.94	$8,956.46	15%	$1,343.47	$7,773.00	15%	$1,165.95	$0.00	15%	$0.00	$0.00	15%	$0.00
5120-Maintenance of Poles, Tow ers and Fixtures	$16,154.99	15%	$2,423.25	$40,736.73	15%	$6,110.51	$37,117.42	15%	$5,567.61	$31,104.00	15%	$4,665.60	$75,868.00	15%	$11,380.20	$79,307.00	15%	$11,896.05
5125-Maintenance of Overhead Conductors and Devices	$79,617.65	15%	$11,942.65	$97,354.19	15%	$14,603.13	$66,986.35	15%	$10,047.95	$113,326.00	15%	$16,998.90	$148,106.00	15%	$22,215.90	$155,272.00	15%	$23,290.80
5130-Maintenance of Overhead Services	$105,140.86	15%	$15,771.13	$97,803.89	15%	$14,670.58	$97,425.26	15%	$14,613.79	$95,972.00	15%	$14,395.80	$77,763.00	15%	$11,664.45	$81,996.00	15%	$12,299.40
5135-Overhead Distribution Lines and Feeders - Right of Way	$204,579.69	15%	$30,686.95	$218,287.04	15%	$32,743.06	$185,399.43	15%	$27,809.91	$71,620.00	15%	$10,743.00	$133,741.00	15%	$20,061.15	$134,195.00	15%	$20,129.25
5145-Maintenance of Underground Conduit	$623.11	15%	$93.47	$0.00	15%	$0.00	$3,518.74	15%	$527.81	$1,746.00	15%	$261.90	$898.00	15%	$134.70	$950.00	15%	$142.50
5150-Maintenance of Underground Conductors and Devices	$6,701.46	15%	$1,005.22	$4,206.20	15%	$630.93	$6,280.73	15%	$942.11	$9,348.00	15%	$1,402.20	$10,477.00	15%	$1,571.55	$11,021.00	15%	$1,653.15
5155-Maintenance of Underground Services	$11,192.88	15%	$1,678.93	$20,681.18	15%	$3,102.18	$20,900.37	15%	$3,135.06	$13,528.00	15%	$2,029.20	$21,452.00	15%	$3,217.80	$22,553.00	15%	$3,382.95
5160-Maintenance of Line Transformers	$36,084.98	15%	$5,412.75	$31,251.02	15%	$4,687.65	$20,006.87	15%	$3,001.03	$30,021.00	15%	$4,503.15	$38,787.00	15%	$5,818.05	$40,817.00	15%	$6,122.55
5165-Maintenance of Street Lighting and Signal Systems	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
5170-Sentinel Lights - Labour	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$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	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
5175-Maintenance of Meters	$28,943.65	15%	$4,341.55	$96,348.85	15%	$14,452.33	$163,552.12	15%	$24,532.82	$116,611.00	15%	$17,491.65	$48,503.00	15%	$7,275.45	$51,217.00	15%	$7,682.55
5178-Customer Installations Expenses- Leased Property	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$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	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
5186-Water Heater Rentals - Materials and Expenses	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
5190-Water Heater Controls - Labour	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
5192-Water Heater Controls - Materials and Expenses	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
5195-Maintenance of Other Installations on Customer Premises	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
Sub-Total	$535,158.22		$80,273.73	$654,654.52		$98,198.18	$703,570.88		$105,535.63	$580,480.00		$87,072.00	$622,644.00		$93,396.60	$643,837.00		$96,575.55
Billing and Collections																		
5305-Supervision	$13,396.29	15%	$2,009.44	$82,318.22	15%	$12,347.73	$57,090.78	15%	$8,563.62	$8.00	15%	$1.20	$0.00	15%	$0.00	$0.00	15%	$0.00
5310-Meter Reading Expense	$214,297.79	15%	$32,144.67	$215,994.70	15%	$32,399.21	$214,213.89	15%	$32,132.08	$162,510.00	15%	$24,376.50	$139,536.00	15%	$20,930.40	$144,362.00	15%	$21,654.30
5315-Customer Billing	$279,106.98	15%	$41,866.05	$268,137.88	15%	$40,220.68	$275,358.14	15%	$41,303.72	$278,614.00	15%	$41,792.10	$286,833.00	15%	$43,024.95	$347,894.00	15%	$52,184.10
5320-Collecting	$262,674.56	15%	$39,401.18	$215,638.11	15%	$32,345.72	$144,610.12	15%	$21,691.52	$151,318.00	15%	$22,697.70	$152,723.00	15%	$22,908.45	$153,216.00	15%	$22,982.40
5325-Collecting- Cash Over and Short	$139.26	15%	$20.89	-$244.09	15%	-$36.61	$580.79	15%	$87.12	-$377.00	15%	-$56.55	$120.00	15%	$18.00	$120.00	15%	$18.00
5330-Collection Charges	$530.34	15%	$79.55	$3,097.66	15%	$464.65	$737.40	15%	$110.61	$2,176.00	15%	$326.40	$1,500.00	15%	$225.00	$1,500.00	15%	$225.00
5335-Bad Debt Expense	$48,556.78	15%	$7,283.52	$48,356.14	15%	$7,253.42	$54,869.23	15%	$8,230.38	$79,500.00	15%	$11,925.00	$75,000.00	15%	$11,250.00	$75,000.00	15%	$11,250.00
5340-Miscellaneous Customer Accounts Expenses	$44,148.76	15%	$6,622.31	$37,600.87	15%	$5,640.13	$31,396.23	15%	$4,709.43	$47,175.00	15%	$7,076.25	$44,890.00	15%	$6,733.50	$44,183.00	15%	$6,627.45
Sub-Total	$862,850.76		$129,427.61	$870,899.49		$130,634.92	$778,856.58		$116,828.49	$720,924.00		$108,138.60	$700,602.00		$105,090.30	$766,275.00		$114,941.25

	2006 Actual			2007 Actual			2008 Actul			2009 Actual			2010 Bridge			2011 Test		
WORKING CAPITAL ALLOWANCE CALCULATION BY ACCOUNT	**Expense**	**15%**	**Allowance for Working Capital**	**Expense**	**15%**	**Allowance for Working Capital**	**Expense**	**15%**	**Allowance for Working Capital**	**Expense**	**15%**	**Allowance for Working Capital**	**Expense**	**15%**	**Allowance for Working Capital**	**Expense**	**15%**	**Allowance for Working Capital**
Community Relations																		
5405-Supervision	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$30,543.00	15%	$4,581.45	$0.00	15%	$0.00	$0.00	15%	$0.00
5410-Community Relations - Sundry	$3,957.80	15%	$593.67	$11,244.44	15%	$1,686.67	$39,606.10	15%	$5,940.92	$0.00	15%	$0.00	$30,000.00	15%	$4,500.00	$35,000.00	15%	$5,250.00
5415-Energy Conservation	$34,849.54	15%	$5,227.43	$83,754.82	15%	$12,563.22	$67,671.54	15%	$10,150.73	$80,445.00	15%	$12,066.75	$109,529.00	15%	$16,429.35	$117,019.00	15%	$17,552.85
5420-Community Safety Program	$17,067.66	15%	$2,560.15	$7,750.05	15%	$1,162.51	$11,947.37	15%	$1,792.11	$8,960.00	15%	$1,344.00	$20,000.00	15%	$3,000.00	$20,000.00	15%	$3,000.00
5425-Miscellaneous Customer Service and Informational Expenses	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
5505-Supervision	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$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	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
5515-Advertising Expense	$3,972.70	15%	$595.91	$1,750.74	15%	$262.61	$0.00	15%	$0.00	$4,000.00	15%	$600.00	$6,000.00	15%	$900.00	$6,000.00	15%	$900.00
5520-Miscellaneous Sales Expense	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
Sub-Total	$59,847.70		$8,977.16	$104,500.05		$15,675.01	$119,225.01		$17,883.75	$123,948.00		$18,592.20	$165,529.00		$24,829.35	$178,019.00		$26,702.85
Administrative and General Expenses																		
5605-Executive Salaries and Expenses	$295,258.53	15%	$44,288.78	$316,534.81	15%	$47,480.22	$445,083.13	15%	$66,762.47	$411,959.00	15%	$61,793.85	$332,855.00	15%	$49,928.25	$332,929.00	15%	$49,939.35
5610-Management Salaries and Expenses	$68,895.19	15%	$10,334.28	$66,876.58	15%	$10,031.49	$72,573.31	15%	$10,886.00	$76,600.00	15%	$11,490.00	$76,989.00	15%	$11,548.35	$77,709.00	15%	$11,656.35
5615-General Administrative Salaries and Expenses	$104,684.96	15%	$15,702.74	$122,401.28	15%	$18,360.19	$182,115.00	15%	$27,317.25	$148,455.00	15%	$22,268.25	$141,026.00	15%	$21,153.90	$316,586.00	15%	$47,487.90
5620-Office Supplies and Expenses	$28,068.62	15%	$4,210.29	$14,337.92	15%	$2,150.69	$17,684.09	15%	$2,652.61	$16,703.00	15%	$2,505.45	$19,400.00	15%	$2,910.00	$20,400.00	15%	$3,060.00
5625-Administrative Expense Transferred Credit	-$4,928.10	15%	-$739.22	-$47,790.09	15%	-$7,168.51	-$66,455.95	15%	-$9,968.39	-$51,192.00	15%	-$7,678.80	-$48,400.00	15%	-$7,260.00	-$48,400.00	15%	-$7,260.00
5630-Outside Services Employed	$119,905.11	15%	$17,985.77	$120,698.35	15%	$18,104.75	$156,764.39	15%	$23,514.66	$122,185.00	15%	$18,327.75	$86,500.00	15%	$12,975.00	$129,000.00	15%	$19,350.00
5635-Property Insurance	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
5640-Injuries and Damages	$53,962.24	15%	$8,094.34	$53,220.43	15%	$7,983.06	$32,632.40	15%	$4,894.86	$31,525.00	15%	$4,728.75	$33,000.00	15%	$4,950.00	$45,000.00	15%	$6,750.00
5645-Employee Pensions and Benefits	$299,000.00	15%	$44,850.00	-$1,711,140.00	15%	-$256,671.00	$28,640.00	15%	$4,296.00	$856,850.00	15%	$128,527.50	$0.00	15%	$0.00	$0.00	15%	$0.00
5650-Franchise Requirements	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
5655-Regulatory Expenses	$65,876.14	15%	$9,881.42	$96,979.78	15%	$14,546.97	$42,657.99	15%	$6,398.70	$115,770.00	15%	$17,365.50	$120,875.00	15%	$18,131.25	$150,000.00	15%	$22,500.00
5660-General Advertising Expenses	$3,279.10	15%	$491.87	$2,334.35	15%	$350.15	$0.00	15%	$0.00	$1,622.00	15%	$243.30	$0.00	15%	$0.00	$0.00	15%	$0.00
5665-Miscellaneous General Expenses	$195,036.59	15%	$29,255.49	$208,888.12	15%	$31,333.22	$219,910.05	15%	$32,986.51	$622,460.00	15%	$93,369.00	$277,908.00	15%	$41,686.20	$320,911.00	15%	$48,136.65
5670-Rent	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
5675-Maintenance of General Plant	$76,740.31	15%	$11,511.05	$88,736.47	15%	$13,310.47	$64,161.52	15%	$9,624.23	$47,936.00	15%	$7,190.40	$43,300.00	15%	$6,495.00	$43,300.00	15%	$6,495.00
5680-Electrical Safety Authority Fees	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$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	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
Sub-Total	$1,305,778.69		$195,866.80	-$667,922.00		-$100,188.30	$1,195,765.93		$179,364.89	$2,400,873.00		$360,130.95	$1,083,453.00		$162,517.95	$1,387,435.00		$208,115.25
Cost of Power																		
4705-Power Purchased	$13,206,104.11	15%	$1,980,915.62	$16,089,184.93	15%	$2,413,377.74	$15,654,293.50	15%	$2,348,144.03	$12,535,062.00	15%	$1,880,259.30	$18,937,733.42	15%	$2,840,660.01	$18,863,907.20	15%	$2,829,586.08
4708-Charges-WMS	$1,214,971.31	15%	$182,245.70	$1,538,296.60	15%	$230,744.49	$1,697,949.03	15%	$254,692.35	$1,761,282.00	15%	$264,192.30	$1,419,374.66	15%	$212,906.20	$1,413,841.42	15%	$212,076.21
4710-Cost of Power Adjustments	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
4712-Charges-One-Time	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
4714-Charges-NW	$1,519,028.55	15%	$227,854.28	$1,062,252.24	15%	$159,337.84	$679,953.77	15%	$101,993.07	$798,847.00	15%	$119,827.05	$1,364,528.57	15%	$204,679.29	$1,359,861.40	15%	$203,979.21
4715-System Control & Load Dispatching	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
4716-Charges-CN	$1,161,169.66	15%	$174,175.45	$824,773.61	15%	$123,716.04	$530,010.67	15%	$79,501.60	$589,901.00	15%	$88,485.15	$1,004,556.96	15%	$150,683.54	$1,001,100.59	15%	$150,165.09
4720-Other Expenses	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
4725-Competition Transition Expense	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
4730-Rural Rate Assistance Expense	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
4750-LV charges	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$303,455.00	15%	$45,518.25	$686,372.47	15%	$102,955.87	$682,064.84	15%	$102,309.73
5205-Purchase of Transmission and System Services	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
5210-Transmission Charges	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
5215-Transmission Charges Recovered	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$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	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
Sub-Total	$17,101,273.63		$2,565,191.04	$19,514,507.38		$2,927,176.11	$18,562,206.97		$2,784,331.05	$15,988,547.00		$2,398,282.05	$23,412,566.08		$3,511,884.91	$23,320,775.45		$3,498,116.32
WORKING CAPITAL ALLOWANCE TOTAL			**$3,067,802.00**			**$3,167,024.37**			**$3,284,352.43**	**$21,333,949.00**		**$3,047,709.90**	**$27,520,779.21**		**$3,995,474.71**	**$28,056,027.45**		**$4,073,972.02**

COP and Retail Transmission Rates used for 2011 COP Projections

Rates 2011	Network Service	Conncection Service	Wholesale Market	Rural Rate Protection	Commodity	L/V
RESIDENTIAL						
Regular	$0.0052	$0.0039	$0.0042	$0.0010	$0.0694	$0.0023
GENERAL SERVICE						
Less than 50 kW	$0.0048	$0.0034	$0.0042	$0.0010	$0.0694	$0.0023
Greater than 50 to 4,999 kW	$1.9188	$1.4110	$0.0042	$0.0010	$0.0694	$1.0401
Unmetered Scattered Load	$0.0048	$0.0034	$0.0042	$0.0010	$0.0694	$0.0023
Sentinel Lighting	$1.4544	$1.1137	$0.0042	$0.0010	$0.0694	$0.6665
Street Lighting	$1.4472	$1.0908	$0.0042	$0.0010	$0.0694	$0.7791

BCP has utilized the 2010 IRM (EB-2009-0258) approved retail transmission rates for 2010 and 2011 projections. If and when the OEB approves a generic change in wholesale rates for 2011, BCP will mirror these changes for both retail transmission rates and working capital allowance.

BCP has utilized the 2010 IRM (EB-2009-0258) approved wholesale market and rural rate protection for 2010 and 2011 projections.

BCP has utilized a weighted average commodity rate of $0.0694 per kWh for all customer classes. This rate is derived from the May 1, 2010 RPP rates of $0.065 per kWh below 600 kWh / month and $0.075 per kWh above 600 kWh / month.

BCP has calculated new Low Voltages rates as shown below:

Customer Class	2009 LV Rates	2011 Billing Determinents	2011 Draft Revenue (current rates)	2011 LV Expense	2011 Proposed LV Rates	2011 LV Revenue
Residential	0.0007	80,122,583	56,085.81		0.0023	184,281.94
GS < 50	0.0007	39,095,551	27,366.89		0.0023	89,919.77
GS > 50	0.3196	388,493	124,162.36		1.0364	402,634.15
Street Light	0.2394	4,783	1,145.05		0.7763	3,713.04
Sentinel Light	0.2048	574	117.56		0.6641	381.19
Unmetered	0.0007	493,370	345.36		0.0023	1,134.75
Total			209,223.02	678,455.00		682,064.84

BCP had the 2009 LV rates approved as part of the 2006 EDR process. These rates do not recover the new Brantford Power charges resulting from EB-2009-0063 (approximately $375,000 per year).

BCP has adjusted the 2011 LV retail rates to capture the new BP charges in the 2011 LV expense projection.
(i.e. expenses increase by $375,000, (from $305,332 to $680,332) which represents a 123% increase in expenses. The retail rates are adjusted by this ratio as well as well as historical under recovery amounts.

Capital Expenditures

Year : 2006 Actual

USoA Account	Description	CCA Class	Ball St. Conversion	Brant Rod & Gun Relocation	Burford Alexander ST Ext.	Colbourne St. W	Colbourne ST E	Grant River S - 1	Grand River S- 2	McBay Rd. Conversion	Mud Rd Line Ext.	Lightning Arresters	Paris Rd. Conversion	Rotted Poles	Reclosures	Rest Acres Rd Conv	River Crossing	Shaver Rd	St. George Conversion	Misc. Projects	Non-Project Capital	Total
			Project																			
1805	Land																				-	-
1806	Land Rights																				-	-
1808	Buildings & Fixtures	1																			39,251	39,251
1810	Leasehold Improvements																					-
1815	TS Equipment	1	5,586							22,369			30,122			1,995			6,982			67,054
1820	DS Equipment	8																				-
1825	Storage Battery Equipment																					-
1830	Poles, Towers & Fixtures	47	3,467	19,250	15,000	96,224	11,099	22,132	11,420	2,943	5,680			187,695		3,602	56,453	15,000		6,963		456,928
1835	OH Conductors & Devices	47	5,604	15,750	6,000		14,544	12,367	7,267	12,693	7,953	29,000		22,395	30,000	2,402	78,547	7,500		2,485		254,506
1840	UG - Conduit	47																	7,475	26,147		33,622
1845	UG - Conductors & Devices	47																		47,084		47,084
1850	Line Transformers	47	9,982				70,357			64,965	54,867		117,514			1,201		7,500	5,180	46,789		378,355
1855	Services	47	3,362		9,000			20,501	2,076	9,163			3,363	39,910		801				3,727		91,904
1860	Meters	47																	15,363			15,363
1865	Other Installations on Customer Premises					75,276																75,276
1870	Leased Property on Customer Premises																					-
1875	Street Lighting & Signal Systems																					-
1905	Land																					-
1906	Land Rights																					-
1908	Buildings & Fixtures	1																				-
1910	Leasehold Improvements																					-
1915	Office Furniture & Equipment	8																			7,349	7,349
1920	Compter Hardware	50																			9,130	9,130
1925	Computer Software	50																			20,869	20,869
1930	Transportation Equipment	10																			202,832	202,832
1935	Stores Equipment	8																				-
1940	Tools, Shop & Garage Equipment	8																			12,724	12,724
1945	Measurement & Testing Equipment	8																				-
1950	Power Operated Equipment	8																				-
1955	Communication Equipment	8																				-
1960	Misc. Equipment	8																				-
1970	Load Management Controls - Customer Premises																					-
1975	Load Management Controls - Utility Premises																					-
1980	System Supervisory Equipment																					-
1985	Sentinel Light Rental Units																					-
1990	Other Tangible Property																					-
1995	Contributions & Grants - Credit																			- 10,767		- 10,767
2005	Property Under Capital Lease																					-
2010	Electric Plant Purchased or Sold	47																				-
2020	Experimental Electric Plant Unclassified																					-
2030	Electric Plant and Equipment Leased to Others																					-
2040	Electric Plant Held for Future Use																					-
2050	Completed Construction Not-Classified --Electric																					-
2055	Construction WIP Electric																					-
2060	Electric Plant Adjustment																					-
2065	Other Electric Plant Adjustment																					-
2070	Other Utility Plant																					-
2075	Non-Utility Property Owned or Under Captial Lease																					-
Grand Total			28,000	35,000	30,000	171,500	96,000	55,000	20,763	112,133	68,500	29,000	151,000	250,000	30,000	10,000	135,000	30,000	35,000	122,428	292,155	1,701,479

Year : 2007 Actual

												Project										
USoA Account	Description	CCA Class	Colbourne St. W	McBay Rd	St. George	Powerline Rd	Oak Park Rd	Misc. Engineering	Rest Acres Rd	Misc. Projects	Non-Project Capital											Total
1805	Land																					-
1806	Land Rights																					-
1808	Buildings & Fixtures	1									7,067											7,067
1810	Leasehold Improvements																					-
1815	TS Equipment	1																				-
1820	DS Equipment	8																				-
1825	Storage Battery Equipment																					-
1830	Poles, Towers & Fixtures	47	35,000	30,000	32,796	125,435	93,273	10,000	20,000	91,353												437,857
1835	OH Conductors & Devices	47	35,000	6,000		64,522	19,227		20,000	14,031												158,780
1840	UG - Conduit	47								26,002												26,002
1845	UG - Conductors & Devices	47								19,743												19,743
1850	Line Transformers	47	25,000	7,500	43,187		30,000			207,532												313,219
1855	Services	47	5,000	6,500			7,500			70,532												89,532
1860	Meters	47			24,017	60,043																84,060
1865	Other Installations on Customer Premises																					-
1870	Leased Property on Customer Premises																					-
1875	Street Lighting & Signal Systems																					-
1905	Land																					-
1906	Land Rights																					-
1908	Buildings & Fixtures	1									17,272											17,272
1910	Leasehold Improvements																					-
1915	Office Furniture & Equipment	8									2,306											2,306
1920	Compter Hardware	50									76,211											76,211
1925	Computer Software	50									16,377											16,377
1930	Transportation Equipment	10									147,261											147,261
1935	Stores Equipment	8																				-
1940	Tools, Shop & Garage Equipment	8									15,726											15,726
1945	Measurement & Testing Equipment	8									6,958											6,958
1950	Power Operated Equipment	8									33											33
1955	Communication Equipment	8																				-
1960	Misc. Equipment	8																				-
1970	Load Management Controls - Customer Premises																					-
1975	Load Management Controls - Utility Premises																					-
1980	System Supervisory Equipment																					-
1985	Sentinel Light Rental Units																					-
1990	Other Tangible Property																					-
1995	Contributions & Grants - Credit									- 60,603												- 60,603
2005	Property Under Capital Lease																					-
2010	Electric Plant Purchased or Sold	47																				-
2020	Experimental Electric Plant Unclassified																					-
2030	Electric Plant and Equipment Leased to Others																					-
2040	Electric Plant Held for Future Use																					-
2050	Completed Construction Not-Classified --Electric																					-
2055	Construction WIP Electric																					-
2060	Electric Plant Adjustment																					-
2065	Other Electric Plant Adjustment																					-
2070	Other Utility Plant																					-
2075	Non-Utility Property Owned or Under Captial Lease																					-
Grand Total			100,000	50,000	100,000	250,000	150,000	10,000	40,000	368,590	289,210	-	-	-	-	-	-	-	-	-	-	1,357,800

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Year : 2008 Actual

												Project										
USoA Account	Description	CCA Class	Highland Estates	Papple Rd. Conv	Mount Pleasant Rd	St. George - Victor Blvd	Line Transformers	Rotted Poles	Capital/Road work	Misc. Projects	Non-Project Capital	10	11	12	13	14	15	16	17	18	19	Total
1805	Land																					-
1806	Land Rights																					-
1808	Buildings & Fixtures	1									3,640											3,640
1810	Leasehold Improvements																					-
1815	TS Equipment	1								2,543												2,543
1820	DS Equipment	8																				-
1825	Storage Battery Equipment																					-
1830	Poles, Towers & Fixtures	47	14,354	45,264	95,449			109,780	40,500	72,899												378,246
1835	OH Conductors & Devices	47	13,056	15,088	27,105			79,840	40,500	31,713												207,302
1840	UG - Conduit	47	9,097			23,883																32,980
1845	UG - Conductors & Devices	47	19,974			52,442																72,417
1850	Line Transformers	47	15,491			66,687	92,118			3,302												177,597
1855	Services	47			15,312			9,980	9,000	2,807												37,099
1860	Meters	47								25,155												25,155
1865	Other Installations on Customer Premises																					-
1870	Leased Property on Customer Premises																					-
1875	Street Lighting & Signal Systems																					-
1905	Land																					-
1906	Land Rights																					-
1908	Buildings & Fixtures	1									112,874											112,874
1910	Leasehold Improvements																					-
1915	Office Furniture & Equipment	8																				-
1920	Compter Hardware	50									38,347											38,347
1925	Computer Software	50									22,377											22,377
1930	Transportation Equipment	10									313,663											313,663
1935	Stores Equipment	8																				-
1940	Tools, Shop & Garage Equipment	8									14,950											14,950
1945	Measurement & Testing Equipment	8									2,137											2,137
1950	Power Operated Equipment	8																				-
1955	Communication Equipment	8									584											584
1960	Misc. Equipment	8																				-
1970	Load Management Controls - Customer Premises																					-
1975	Load Management Controls - Utility Premises																					-
1980	System Supervisory Equipment																					-
1985	Sentinel Light Rental Units																					-
1990	Other Tangible Property																					-
1995	Contributions & Grants - Credit		- 18,453			- 2,500				- 69,657												- 90,610
2005	Property Under Capital Lease																					-
2010	Electric Plant Purchased or Sold	47																				-
2020	Experimental Electric Plant Unclassified																					-
2030	Electric Plant and Equipment Leased to Others																					-
2040	Electric Plant Held for Future Use																					-
2050	Completed Construction Not-Classified --Electric																					-
2055	Construction WIP Electric																					-
2060	Electric Plant Adjustment																					-
2065	Other Electric Plant Adjustment																					-
2070	Other Utility Plant																					-
2075	Non-Utility Property Owned or Under Captial Lease																					-
Grand Total			53,519	60,352	137,866	140,512	92,118	199,600	90,000	68,762	508,572	-	-	-	-	-	-	-	-	-	-	1,351,301

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Year : 2009 Actual

USoA Account	Description	CCA Class	Project: Rotted Pole Replacement	Colboune St W Pole Replacement	Jane, Alexander & Jury St	Padmount Trans. Paris	Padmount Trans. St. George	Switch Valults	Oakhill Dr	Ball St	Re-Pole Old Onondaga Rd	Robinson Rd Load Convert	Shaver Rd	King Edward St. feeder	Misc. Small Project	Non-Project Capital	15	16	1			Total
1805	Land																					-
1806	Land Rights																					-
1808	Buildings & Fixtures	1																				-
1810	Leasehold Improvements																					-
1815	TS Equipment	1																				-
1820	DS Equipment	8																				-
1825	Storage Battery Equipment																					-
1830	Poles, Towers & Fixtures	47	139,080	11,925	22,029				44,720	23,231	20,950	16,923	7,350	14,630	127,299							428,137
1835	OH Conductors & Devices	47	131,080	11,925	15,735				17,888	16,594	20,950	16,923	7,350	16,720	45,316							300,481
1840	UG - Conduit	47		2,650											70,183							72,833
1845	UG - Conductors & Devices	47				7,980	25,025	17,746							4,598							55,349
1850	Line Transformers	47			15,735	9,120	44,591	85,254	26,832	16,594				5,180	47,571							250,877
1855	Services	47	10,018		9,441	5,700	1,884			9,956				5,270	5,567							47,836
1860	Meters	47													141,958							141,958
1865	Other Installations on Customer Premises																					-
1870	Leased Property on Customer Premises																					-
1875	Street Lighting & Signal Systems																					-
1905	Land																					-
1906	Land Rights																					-
1908	Buildings & Fixtures	1																				-
1910	Leasehold Improvements																					-
1915	Office Furniture & Equipment	8																				-
1920	Compter Hardware	50																				-
1925	Computer Software	50																				-
1930	Transportation Equipment	10																				-
1935	Stores Equipment	8																				-
1940	Tools, Shop & Garage Equipment	8																				-
1945	Measurement & Testing Equipment	8																				-
1950	Power Operated Equipment	8																				-
1955	Communication Equipment	8																				-
1960	Misc. Equipment	8																				-
1970	Load Management Controls - Customer Premises																					-
1975	Load Management Controls - Utility Premises																					-
1980	System Supervisory Equipment																					-
1985	Sentinel Light Rental Units																					-
1990	Other Tangible Property																					-
1995	Contributions & Grants - Credit														- 8,661							- 8,661
2005	Property Under Capital Lease																					-
2010	Electric Plant Purchased or Sold	47																				-
2020	Experimental Electric Plant Unclassified																					-
2030	Electric Plant and Equipment Leased to Others																					-
2040	Electric Plant Held for Future Use																					-
2050	Completed Construction Not-Classified --Electric																					-
2055	Construction WIP Electric																					-
2060	Electric Plant Adjustment																					-
2065	Other Electric Plant Adjustment																					-
2070	Other Utility Plant																					-
2075	Non-Utility Property Owned or Under Captial Lease																					-
Grand Total			280,178	26,500	62,939	22,800	71,500	103,000	89,440	66,375	41,900	33,845	14,700	41,801	433,832	-	-	-	-	-	-	1,288,810

Year : 2010 Actual

USoA Account	Description	CCA Class	Rotted Poles	Pad. Trans. Paris	Pad. Trans. St. George	Mile Hill Rd.	Rest Acres Rd	Mt. Pleasant	Report Oak Park	Oak Park & Paris Rd	Misc. Projects	smart meters	UG Services	Non-Project Capital	13	14	15	16	17	18	19	Total
			Project																			
1805	Land																					-
1806	Land Rights																					-
1808	Buildings & Fixtures	1																				-
1810	Leasehold Improvements																					-
1815	TS Equipment	1																				-
1820	DS Equipment	8																				-
1825	Storage Battery Equipment																					-
1830	Poles, Towers & Fixtures	47	164,473	-	-	14,089	64,220	57,221	20,614	10,662	94,336	-	-									425,615
1835	OH Conductors & Devices	47	106,173	-	-	13,561	96,427	64,898	8,531	6,854	72,515	-	-									368,960
1840	UG - Conduit	47	-	10,415	21,844	-	-	-	-	-	31,339	-	-									63,598
1845	UG - Conductors & Devices	47	-	10,107	19,762	-	-	-	-	-	41,289	-	-									71,158
1850	Line Transformers	47	38,760	13,288	28,476	8,035	-	29,790	-	-	77,080	-	-									195,428
1855	Services	47	23,417	251	181	-	-	-	-	-	24,885	-	-									48,734
1860	Meters	47										35,926	1,461,350									1,497,276
1865	Other Installations on Customer Premises																					-
1870	Leased Property on Customer Premises																					-
1875	Street Lighting & Signal Systems																					-
1905	Land																					-
1906	Land Rights																					-
1908	Buildings & Fixtures	1												$ 10,000.00								10,000
1910	Leasehold Improvements																					-
1915	Office Furniture & Equipment	8												$ 500.00								500
1920	Compter Hardware	50												$ 162,300.00								162,300
1925	Computer Software	50																				-
1930	Transportation Equipment	10												325000								325,000
1935	Stores Equipment	8																				-
1940	Tools, Shop & Garage Equipment	8												$ 13,000.00								13,000
1945	Measurement & Testing Equipment	8												$ 15,000.00								15,000
1950	Power Operated Equipment	8																				-
1955	Communication Equipment	8																				-
1960	Misc. Equipment	8																				-
1970	Load Management Controls - Customer Premises																					-
1975	Load Management Controls - Utility Premises																					-
1980	System Supervisory Equipment																					-
1985	Sentinel Light Rental Units																					-
1990	Other Tangible Property																					-
1995	Contributions & Grants - Credit										- 10,000											- 10,000
2005	Property Under Capital Lease																					-
2010	Electric Plant Purchased or Sold	47																				-
2020	Experimental Electric Plant Unclassified																					-
2030	Electric Plant and Equipment Leased to Others																					-
2040	Electric Plant Held for Future Use																					-
2050	Completed Construction Not-Classified --Electric																					-
2055	Construction WIP Electric																					-
2060	Electric Plant Adjustment																					-
2065	Other Electric Plant Adjustment																					-
2070	Other Utility Plant																					-
2075	Non-Utility Property Owned or Under Captial Lease																					-
Grand Total		553	332,822	34,061	70,263	35,685	160,648	151,910	29,145	17,516	331,444	35,926	1,461,350	525,800	-	-	-	-	-	-	-	3,186,569

Year : 2011 Actual

			Project																			
USoA Account	Description	CCA Class	Rotted Poles	Rest Acres - new circuit	Misc. Project	Smart Meters	UG Services	River Crossing	Automatic Switching	Rst Acres Rd. Conver.	Broadway St	Riverview Terrace	St. Patrick Conv.	Hiram St	Horace Dr	PM6	Oak Park to River	Microfit Install	Non-Project Capital			Total
1805	Land																					-
1806	Land Rights																					-
1808	Buildings & Fixtures	1																				-
1810	Leasehold Improvements																					-
1815	TS Equipment	1																				-
1820	DS Equipment	8																				-
1825	Storage Battery Equipment																					-
1830	Poles, Towers & Fixtures	47	114,155	166,880	67,005	-	-	825,000	-	3,604	2,691	15,139	11,985	6,751	4,567	10,341	29,719	-				1,257,837
1835	OH Conductors & Devices	47	73,691	234,478	70,075	-	-	-	-	949	737	-	-	-	-	-	-	-				379,930
1840	UG - Conduit	47	-	-	66,059	-	-	-	-	-	-	-	-	-	-	-	-	-				66,059
1845	UG - Conductors & Devices	47	-	-	43,717	-	-	-	120,000	9,265	6,975	30,805	24,387	13,736	9,292	21,042	23,736	-				302,954
1850	Line Transformers	47	26,902	-	81,612	-	-	-	-	5,454	4,106	18,133	14,355	8,085	5,470	12,386	21,097	-				197,600
1855	Services	47	16,253	-	33,052	-	38,004	-	-	-	-	-	-	-	-	-	-	-				87,309
1860	Meters	47				130,963																130,963
1865	Other Installations on Customer Premises																					-
1870	Leased Property on Customer Premises																					-
1875	Street Lighting & Signal Systems																					-
1905	Land																					-
1906	Land Rights																					-
1908	Buildings & Fixtures	1																60,000				60,000
1910	Leasehold Improvements																					-
1915	Office Furniture & Equipment	8																500				500
1920	Compter Hardware	50																165,000				165,000
1925	Computer Software	50																15,000				15,000
1930	Transportation Equipment	10																130,000				130,000
1935	Stores Equipment	8																				-
1940	Tools, Shop & Garage Equipment	8																10,000				10,000
1945	Measurement & Testing Equipment	8																				-
1950	Power Operated Equipment	8																				-
1955	Communication Equipment	8																				-
1960	Misc. Equipment	8																100,000				100,000
1970	Load Management Controls - Customer Premises																					-
1975	Load Management Controls - Utility Premises																					-
1980	System Supervisory Equipment																					-
1985	Sentinel Light Rental Units																					-
1990	Other Tangible Property																					-
1995	Contributions & Grants - Credit				- 10,000																	- 10,000
2005	Property Under Capital Lease																					-
2010	Electric Plant Purchased or Sold	47																				-
2020	Experimental Electric Plant Unclassified																					-
2030	Electric Plant and Equipment Leased to Others																					-
2040	Electric Plant Held for Future Use																					-
2050	Completed Construction Not-Classified --Electric																					-
2055	Construction WIP Electric																					-
2060	Electric Plant Adjustment																					-
2065	Other Electric Plant Adjustment																					-
2070	Other Utility Plant																					-
2075	Non-Utility Property Owned or Under Captial Lease																					-
Grand Total			231,000	401,358	351,521	130,963	38,004	825,000	120,000	19,272	14,508	64,078	50,727	28,572	19,329	43,769	74,553	480,500	-	-	-	2,893,151

Brant County Power

Review of Capital Projects

(2006 – 2009)

2006 Projects

Ball Street

Ball Street was fed from stepdown transformers that reduced the voltage from 16,000 volts to 2400 volts. The infrastructure was at end of life and this project allowed us to eliminate two stepdown transformers which will result in lower line loss and greater system reliability. Old copper conductors were eliminated as well. This was phase 1 with Phase 2 completed in 2009.

Ball Street area was converted in March and April of 2006.

Brant Road and Gun Club

The Brant Rod and Gun Club was fed from Hydro One lines. We felt that due to excessive outages, poor service response and future growth it would be advantageous to build a section of line which would allow us to feed it from our system. Work took place in September of 2006.

Alexander Street

The line was extended on Alexander Street in Burford to allow us to take load off of Hydro One's Burford DS, which was overloaded. Project dates: March, April and early May.

Colborne Street West

A primary metering unit between Brant County and the City of Brantford which measures the amount of power that we take from the city on the 64 M25 feeder was replaced. This metering unit needed to be replaced in order for us to comply with the IESO standards and compliance issues. At the same time the section of line from our boundary to Pleasant Ridge Road was rebuilt because the poles were identified during our pole testing project as being due for replacement.

A new pole was installed as well as the new metering costs. Project was completed in May of 2006.

Colborne St. E.

A forty five year old substation (MS#9) that was incurring high maintenance costs was eliminated by converting the lines fed from the station to 27.6 kV and then installing stepdown transformers to feed the outlying areas. This allowed us to eliminate the substation, reducing our line loss and saving us from investing some significant capital in old technology.

This project utilized the same conductors but required some new poles, many insulator changes and several stepdown transformers. Work was done throughout the summer of 2006.

Grand River Street South (1 & 2)

A new 27.6 kV feeder was constructed on Grand River Street South after road widening placed the poles on the travelled portion of the road. It was felt that moving the poles was required to protect our infrastructure as well as public safety. Work took place during March, April and May.

McBay Road conversion

As a part of the Corporation's strategy to eliminate our MS#9 substation McBay Road was converted as well. This road had a significant number of new lots being created and the old 4800 volt line was already heavily loaded. The conversion to 16,000/27,600 volts made sense as it dealt with the loading issue on the road and helped with the elimination of the substation.

Some conductor was retained. Some portions of the line were off road and new sections were built on road allowance. 4800 volt transformers were replaced with 16000 volt ones. This project went hand in hand with the above project and work was completed in the summer of 2006.

Mud Road line conversion

Additionally in our objective of eliminating MS#9, Mud Road, which was the last remaining stretch of 8320 volt line west from the substation, was converted as well. This conversion reduced load off of the 8 kV system. It also aided with our system reliability improvement strategy and reduces line loss.

New poles and conductor were required. This project went hand in hand with the above project and work was completed in the September of 2006.

Lightning Arresters

Due to the high number of outages due to lightning we have installed a number of lightning arresters every year. Project started in January and completed in December.

Paris Rd Conversion

At the end of 2005 a new 27.6 kV line was built, from the new transformer station that was constructed in conjunction with Brantford Power, to the town of Paris. In 2006 all of the customers that had been fed from the old 8 kV infrastructure along the route were converted to the new 16000/27,600 volt lines.

New transformers made up the bulk of the cost of this project. Project dates were March to May, 2006.

Rotted Pole Replacements

Brant County Power takes a very proactive approach to rotted pole replacements. All poles have been tested by an independent testing company and an annual pole replacement program is underway. Poles are targeted based on remaining residual strength with the least residual strength poles done first. Through our rotted pole replacements and our capital projects the goal is to replace approximately 200 poles per year. Of the approximately 7500 poles in the service area, 6800 are wood with the majority of the rest being steel and a small number of concrete.

When Hydro One informed us that they were replacing all of the poles on Colborne Street between Rest Acres Road and Cleaver Road the decision was made to convert all Brant County Power load on this line from the 8320 volt system to the 27.6 kV system. The nature of this load was mainly tobacco farms so the choice to convert the load not only helped reduce potential outages and reduce our line losses but also reduced the loading on our aging 8 kV infrastructure.

This project required new 16000 volt primary transformers to replace the 4800 volt ones. Some road crossing poles were replaced as well. Work was completed in September of 2007.

Reclosures

We purchased a new reclosure for our system to try to reduce outages in the Mount Pleasant area. The reclosure allows temporary outages an opportunity to clear and then re-energize the line rather than have the power remain out until a crew responds. Installed in December 2006.

Rest Acres Road

A section of aging infrastructure on Rest Acres Road was rebuilt to 27.6 kV standards and all load converted to the higher voltage. This not only eliminated the aging portion of our line but improved our line loss and reduced outages. Project was started in July and completed in August.

River Crossing

A single circuit river crossing existed in the town of Paris. The supporting structures consisted of two poles each, with a three hundred and twenty five foot span across the river. One of the supporting poles had been identified as being due for replacement due to rotting. We replaced the structures on both sides of the river with new higher, stronger poles and added an additional feeder across the river. This helped to meet the load growth which was being experienced in the town and hugely increased our system reliability for the town.

This project consisted of setting 4 new 70' class 1 poles. This project was contracted out to K-Line and was completed in November of 2006.

Shaver Road

This was a small conversion which was done to alleviate the loading on the 8 kV lines. Project took place in November of 2006.

St George Conversion

A small conversion was done in St George to allow some new growth to be connected to our 27.6 kV system in May of 2006.

Miscellaneous Projects

Every year brings a variety of small Capital Projects. These projects may include a single new pole for a new service, or re-insulating sections of line for future conversions or a variety of other projects. Work can occur at any time during the year.

2007 Projects

Colborne Street West

A section of line on Colborne Street West was converted from 8320 volts to 27.6 kV. This project eliminated a number of rotted poles, eliminated old copper conductors and improved reliability as well as reducing line loss. Project took place in April and May of 2007.

McBay Road

New growth on this road required additional pole work and servicing in June of 2007.

St George - Victor Blvd (2007)

There were two primary metering units at the St George boundary that did not meet IESO regulations the decision was made to eliminate the 8 kV metering unit by converting some of the load to 27.6 kV and installing stepdown transformers to feed the rest. This eliminated the $25,000 expense of a new metering unit, improved our system reliability and worked into our line loss program as well.

This project required new poles, transformers and a new 27.6 kV metering unit. This project was performed during the summer and fall of 2007.

Powerline Road PME's

Four primary metering units had to be replaced at Powerline TS as the existing ones belonged to Hydro One and no longer met IESO requirements. Work was done in August and September of 2007.

Oak Park Road

New growth prompted us to convert a section of Oak park Road and extend it to Paris Road to create a potential loop for reliability. Work was performed in June and July of 2007.

Misc Engineering

As we do not have an engineer on staff we sometimes need to contract out drawings to enable us to comply with ESA Regulations.

Rest Acres Rd (12M22 extension)

The 12M22 was extended on Rest Acres Road to allow an optional feed into a new substation being built for reliability reasons.

Miscellaneous Projects

Every year brings a variety of small Capital Projects. These projects may include a single new pole for a new service, or re-insulating sections of line for future conversions or a variety of other projects.

Work can occur at any time during the year.

2008 Projects

Highland Estates

As new lots were developed in Highland Estates subdivision we undertook some cable replacements and added some switching capability to create a secure loop feed for the subdivision. Project completed during the summer months.

Papple Rd Conv

Papple Road was converted from 8320 volts to 27,600 volts to establish a potential back up to our MS#2 substation on Powerline Road. By extending this line from Colborne Street East to Johnson Road we have now created a spot where step down transformers could be installed in the event of a failure at MS#2.

Most of Papple Road was unopened road allowance and required new poles and conductor. This project was completed during July, and August, 2008.

Mount Pleasant Rd – conversion

A section of Mt Pleasant Rd was converted from 8320 to 27.6 kV to increase line capacity and improve line loss. This project was done in October and November of 2007.

St George – Victor Boulevard

This conversion was part of our strategy to get all load in St George converted to the 27.6 kV system to increase our reliability and reduce our line losses. This work was done in July, 2008.

Line Transformers

As part of our strategy to eliminate all PCB's from our system we changed out and eliminated any transformer that tested out at greater than 50 ppm of PCB's. Work was done throughout the year.

Rotted Pole Replacements

Brant County Power takes a very proactive approach to rotted pole replacements. All poles have been tested by an independent testing company and an annual pole replacement program is underway. Poles are targeted based on remaining residual strength with the least residual strength poles done first. Through our rotted pole replacements and our capital projects the goal is to replace approximately 200 poles per year. Of the approximately 7500 poles in the service area, 6800 are wood with the majority of the rest being steel and a small number of concrete. Work on rotted poles was done throughout the year.

Capital/Road Work

Municipal road work required some relocation of our plant. This work was done on a shared cost basis at various times throughout the year.

Miscellaneous Small Projects

Small Capital Projects occur at various times throughout the year.

Lines for Long Term Load Transfers (included in Misc. projects)

Several new sections of line were built to feed customers that had historically been load transfer customers (our customers fed from Hydro One lines). Each section of line was appraised on an individual basis and where it made sense, we constructed new lines to pick up the customers. The end result was that 43 customers have more secure, reliable feeds and are now fed from Brant County Power lines.

These projects took place over the spring, summer and fall of 2008.

2009 Projects

Rotted Pole Replacements (including Colbourne St. W)

Brant County Power takes a very proactive approach to rotted pole replacements. All poles have been tested by an independent testing company and an annual pole replacement program is underway. Poles are targeted based on remaining residual strength with the least residual strength poles done first. Through our rotted pole replacements and our capital projects the goal is to replace approximately 200 poles per year. Of the approximately 7500 poles in the service area, 6800 are wood with the majority of the rest being steel and a small number of concrete.

Jane, Alexander and Jury Streets (2009)

This conversion took place in the north end of Paris and allowed us to eliminate a step down transformer, and replace a large number of old poles and old copper conductors. System reliability and line loss improvements were both realized by this project.

This project was done during September, October and November of 2009

Padmount Transformers and Pads in Paris and St George

We found a number of padmount transformer pads were crumbling in older underground fed areas of our system. These were dangerous for our employees to work on and as dirt kept washing in it was creating a hazard to the public as well. New transformer pads were installed as well as new wet well transformers were purchased as these are safer to operate than the old dry well type. Work was done in July and August.

Switch Vaults in St George

It was discovered that several of the underground switching vaults in St George were crumbling and filling with dirt. New larger sealed vaults were installed to eliminate this problem. All elbows are being upgraded to Posi break elbows as well to allow for safe operation if emergency switching is required. In some areas above ground switching units have been installed which are much safer and convenient for our staff to operate and can result in shorter power outages when cable failures occur.

The first stage of this project took place in July and August, 2009 and the second set of vaults were changed out in May to August, 2010.

Oakhill Dr Complete Loop Phase 1 (2009)

New poles and conductor were installed on Oakhill Drive for system reliability and also to eliminate some 8 kV loading. It allowed the area to be converted from 8320 volts to 27,600 volts, it gave us a loop feed where previously we only had a radial feed and it resulted in 17 poles that were nearing end of life to be replaced.

This project was done during the summer months in 2009.

Ball St Conversion

Ball Street was fed from stepdown transformers that reduced the voltage from 16,000 volts to 2400 volts. The infrastructure was at end of life and this project allowed us to eliminate two stepdown transformers which will result in lower line loss and greater system reliability. Old copper conductors were eliminated as well.

Ball Street area was converted in May , June and July of 2009.

Re-pole Old Onondaga Rd

When this section of line was converted in the 1980's the construction standards were very different than today. Pole heights were not adequate to meet today's standards so we undertook a project to replace the poles with higher ones. This project was done in April and May of 2009.

Convert Load off Robinson Rd

Feeder enhancements were made to allow some of the load on Robinson road to be fed from another feeder for system security reasons. This project was completed in September of 2009.

Shaver Road

A small amount of work was done on Shaver Road to allow the road to be fed from either end. This allows power to be restored much faster in the event of a problem on the line. Work was done in December, 2009.

King Edward Street Feeder Change

On King Edward Street we undertook to install several poles and re-route the 12M22 and PM4 feeders for a variety of reasons. Some of these reasons were to allow for future growth, put the existing load on our PM4 feeder to reduce network and connection charges, and to create a network that could be paralleled in the event of a feeder issue(see project below). This project also ties in with our future smart grid plans. This project was completed in May, June, and July of 2009.

Miscellaneous Projects

Every year brings a variety of small Capital Projects. These projects may include a single new pole for a new service, or re-insulating sections of line for future conversions or a variety of other projects.

Work can occur at any time during the year.

Asset Management Plan

Brant County Power has produced two documents entitled:

- Asset Management Plan
- Brant County Power - 5 Year Strategic Technical Plan"

which are both attached below for reference. This is our approach to the Asset Management Plan requirements in the 2011 filing guidelines.

BRANT County Power inc
your local energy provider

Asset Management Plan

Version 10-5

BRANT COUNTY POWER INC.

ASSET MANAGEMENT

1.0 Philosophy

Brant County Power will maintain (repair, replace or enhance) all assets such that they deliver the appropriate level of safety and reliability, while performing their intended function under reasonably expected conditions.

2.0 Criteria

When planning changes to the assets (repairs, replacements, or enhancements), the following criteria will be used (as appropriate):

- Age (relative to expected life)
- Physical condition
- Performance history
- Maintenance records (repair frequency and cost)
- Maintainability (availability of parts, comparison to new technology)
- Safety impacts (worker and public)
- Future use (local and regional planning)
- External demands (customer driven, road relocations)
- Efficiency opportunities (voltage conversions, new technology, cost reduction)

Many of these have been derived from Brant County Power Inc.'s Vision, Mission and Health and Safety Policy Statements (Appendix 1), Workplace, Discrimation, Harassment & Violence Prevention Policy (Appendix 2) and incorporated into policies such as, the Maintenance Policy (Appendix 3), and the Tree Trimming Policy (Appendix 4).

3.0 Categories

The assets are divided into the following main categories: computer hardware and software, vehicles and related equipment, tools, automated equipment, buildings and fixtures, revenue metering, and distribution equipment.

3.1 Computer Hardware and Software

Computer hardware and related devices (printers, plotters, telecom equipment, etc.) have a typical useful life of five years. The decision to maintain, replace or upgrade these assets is primarily driven by performance history, maintainability and efficiency opportunities.

Computer software generally requires upgrades that are part of maintenance agreements (for example AS400 software) or on an as needed basis, but typically every five years. These expenses are relatively minor and upgrades are based on maintainability and efficiency opportunities.

Computer hardware and software upgrades or replacements are considered annually as part of the overall Annual Capital Budget preparation. Annual maintenance on computer hardware is minimal and is usually driven by a component failure. The Annual Maintenance Budget for this category is normally based on prior year's experience.

3.2 Vehicles and Related Equipment

The fleet assets consist of the large construction vehicles (such as bucket trucks), pickup trucks and trailers. The upgrading or replacement of these assets is based on the physical condition, performance history, maintenance records and maintainability. The physical condition is monitored by employees (workers and contract service providers) and annual independent testing and inspections. The performance history and maintenance records are tracked by asset and the status is reviewed annually to set priorities and a five year replacement schedule. Each asset has a set maintenance schedule based on either manufacturer recommendations or good utility practice. During the Annual Capital Budget preparation, all the criteria are reviewed to set priorities and determine the replacement schedule. This review is summarized in Appendix 6 with supporting information from inspections. Due to the long lead time required for the larger vehicles, replacements are ordered approximately 12 months before they are expected to be required. A vehicle is scheduled for replacement when the physical condition is rated as "fair" or "poor", the performance history indicates two failures of "significance" in the past 12 months, or the maintenance records show a trend to excessive repair costs (above the average for that type of asset). The Annual Maintenance Budget for this category is based on the average of prior years plus any known major repairs that are expected.

3.3 Tools

Tools and miscellaneous equipment includes devices used to assist in various aspects of the operation. Purchases that exceed $1000 are generally capitalized, with the remainder being charged to maintenance. During the Annual Capital Budget preparation, tools and other equipment are identified for replacement or purchase, primarily based on physical condition. Typically, these tend to be several relatively low cost items that are replacing existing units that have reached the end of their useful life. Most of these items are formally inspected annually as well as being inspected prior to use by the worker. When the item requires a significant repair that approaches half the cost of replacement, the item is then replaced. Due to the unpredictable nature of these types of equipment failures, specific items are not always identified in the Budget, but may be grouped into categories such as replacement of safety equipment, replacement of operations tools, etc. The Annual Maintenance Budget for this category is normally based on prior year's experience.

3.4 Automated Equipment

Brant County Power Inc. intends to begin investment in automated switches for the distribution system in 2011. These switches will assist in distribution fault determination, and reconfigure the system to minimize the number of affected customers as well as outage duration and therefore help provide a level of revenue protection not currently realized.

A plan has been created for switches to be installed during the next 6 years (as part of a larger service enhancement strategy within the operating territory). The location and quantity of switches will be finalized during the Annual Capital Budget preparation, and is based on performance history (feeder reliability statistics – targeting the worst performing feeders) and future use (load growth considerations). (Reference; Brant County Power 2010 Five Year Strategic Technical Plan)

3.5 Buildings and Fixtures

Our sole service center (located at 65 Dundas Street East, Paris) houses both administration and operations. The building was constructed in 1984 and is maintained regularly. Maintenance inspections are performed by staff and external contractors. Key components, such as our HVAC have annual inspections performed by certified contractors. Major upgrades such as HVAC replacements and roof replacements are included as part of the Annual Capital Budget submission. In most cases, replacements or upgrades are determined based on physical condition, maintainability, and safety impacts, where possible, upgrades that improve energy efficiency (such as occupancy sensors) and security enhancements are also considered. Repairs or replacements that do not meet the capitalization policy are included in the Annual Maintenance Budget for this category (which also includes tasks such as snow removal, lawn care, etc).

3.6 Revenue Metering

This category includes wholesale meter points, interval meters, and non-interval meters but excludes smart meters. Replacement or upgrades are primarily based on age (when meters reach their seal expiry date and require re-verification or replacement) or external demands (new customers or customer upgrades). The estimated number of meters to be replaced is completed as part of the Annual Capital Budget. The Annual Maintenance Budget for this category is based on prior year's experience and consists primarily of routine inspections, repairs, and trouble calls.

3.6.1 Smart Meters

Smart meters are currently being installed on all residential and general service <50 kW accounts. With time of use pricing scheduled for September 2011 deployment.

3.7 Distribution Equipment

This category contains the majority of the assets (poles, wires, transformers, etc.) and represents the largest portion of the maintenance and capital budgets. There are three main drivers for the annual capital and maintenance plans for the distribution plant; the physical condition of the system, the performance (reliability) of the system, and the expected future use of the system (customer demand and load forecast). An internal investment weighting tool is utilized in the determination of both short and long term investment, components of this tool include weightings for safety, future growth, network reliability, 3rd party demand, and other (Appendix 5). When an area of the system is identified for upgrade or replacement, further analysis is conducted to review options available (replace poles only, upgrade conductor size, replace insulators, convert to underground, right-size transformers, etc.) and opportunities for network betterment (such as voltage conversions to reduce losses or relocating rear yard distribution to front yard to improve access or extending a line to create a feeder tie).

3.7.1 Physical Condition

The physical condition of the system is assessed by scheduled inspections, planned maintenance, and unplanned inspections and repairs. Data from all three processes is accumulated and reviewed when setting priorities for capital replacements. Historically this data was kept in paper form but it is now in the process of being migrated to a newly acquired geographical interface system (GIS) which will ensure enhanced asset management among other significant benefits into the future.

3.7.1.1 Scheduled Inspections

Substations and critical river crossings are inspected monthly by qualified staff, and every 2 to 5 years by an external contractor. The entire overhead primary system and all three phase padmounted equipment (transformers and switchgear) are verified for safety and reliability via infrared scanning every two years. During this inspection, an overall visual inspection is also performed. Additionally, all single phase padmounted transformers are visually inspected annually. All below grade vaults are inspected every six months. All complex metering installations are inspected every six years or when changes are needed. Other metering installations are currently visually inspected monthly by meter readers.

Problems or potential concerns are identified, documented, and scheduled for repair or replacement dependant on severity.

3.7.1.2 Planned Maintenance

Historically vegetation control takes place on a four year cycle, with inspections completed both before and after trimming thereby ensuring best value for investment. Determinations for area selection include, but are not limited to: unusual safety concerns, vegetative growth, customer report rate related to vegetative growth, or upcoming construction activity. These projects are tendered annually and awarded to the lowest qualified bidder.

Overhead three phase switchgear is maintained every 3 to 5 years, depending on frequency of operation. Before the maintenance process begins, the overall physical condition of the asset is assessed. In some cases, the condition of the asset may be determined to be in such a state that replacement or refurbishment is preferred to maintenance (Appendix 6 Vehicles & Related Equipment).

3.7.1.3 Unplanned Inspections and Repairs

After severe weather activity, automatic reclosing of breakers, or motor vehicle accidents, the affected area is inspected for damage. During this inspection, repairs will be made as needed or noted for follow-up. The information obtained from these ad hoc inspections is also used to determine the overall condition of an area (e.g. if there are numerous repairs required to one area after a storm, it may indicate the infrastructure in that area is approaching the end of service life).

3.7.2 System Reliability

The outage frequency and duration by area and feeder is tracked monthly and reported annually (Appendix 7 most recent Annual Reliability Report). The annual report identifies trends, and highlights the worst performing feeders. At a minimum, the overall system reliability is expected to be at the three year average level. The target for each feeder is set at the best of the past five years, excluding Loss of Supply and Planned outages. An in depth analysis of each feeder that does not meet the reliability target is conducted to determine if the deviation is the result of an anomaly (such as one severe storm or one motor vehicle accident), or if a trend is developing. The report creates recommendations for either improved maintenance (such as additional vegetative control) or capital upgrades (such as a line rebuild).

3.7.3 Future Planning

The expected usage of the distribution system is completed in two stages – short term plans (this year and next year), and long term plans (the next 5 to 15 years). Regular meetings with various representatives within the municipal government of the County of Brant ensures Brant County Power Inc. is proactively apprised of development projects such as new subdivisions, road widening projects, etc. that are expected to come on stream in the next 6 to 18 months. This information, along with input from sources such as builders and developers, is used to form the projected upgrades and expansions needed in the short term. Information from the municipal development department is also used to project the amount of customer driven activity (such as community upgrades or new commercial construction) that can be expected in the next 12 to 24 months. Most of these customer driven projects are accommodated with minimal changes to the distribution system. Those projects fit into the Annual Capital Budget directly, and are used to allocate the customer driven portion of the 5 year capital budget. Overarching this short term plan is the longer term plan that is focused on what the system needs to look like in 5 years and beyond.

A substantial portion of our older lines are built to operate at 4800/8320 volts. Significant efforts are planned to modernize these lines to allow for operation at 16,000/27600 volts, eliminating the need for existing 8kV stations thereby reducing outages while positively impacting our line loss. (Reference: Brant County Power 2010 Five Year Strategic Technical Plan).

4.0 Assessment

Overall, Brant County Power Inc. assets have been assessed as "sustainable", meaning that for the foreseeable future, the assets can be maintained and replaced with similar financial contributions as prior years. The two exceptions to this are the smart meter project which will require over $1 million in new capital investment by the end of 2010, and the addition of a river crossing which is scheduled for construction in 2011. The river crossing is required to meet forcasted growth and needed reliability improvements within our service area. The river crossing is a key component in plans to provide alternate feeds into the town of Paris and also to address forecasted growth in southwest Paris and the Brantford airport area. In the longer term additional monies will be invested for another river crossing to provide for an additional feeder into the north end of Paris to assist with system reliability and future load growth.

4.1 Overhead System

The overhead distribution system consists of approximately 262 km of line. All poles were tested by an independent testing company and an annual pole replacement program is underway. Of the approximately 7,500 poles in our service area; 6,800 are wood and the remaining poles are steel and concrete. Our maintenance and construction program recommends that 200 poles per year be replaced.

Over the past five years, there have been no pole failures that were not caused by either motor vehicle accidents, lightning strikes, or trees falling into lines. Visual inspections have not identified any areas of immediate concern regarding the condition of poles. There are several sections of the distribution system where all components (poles, insulators, transformers and conductors) are approaching end of life and these have been scheduled for complete rebuilds in coming years.

4.1.2 Insulators

The system has a mix of older, porcelain insulators and newer polymer insulators. Over the past 10 years, most of the porcelain insulators have been replaced as the system has been upgraded, and in a proactive manner based on field failure warnings from suppliers. The remaining porcelain insulators have been inspected and continue to be replaced, many in conjunction with pole replacements and line upgrades. The polymer insulators are expected to last up to 50 years, and experience to date has confirmed their reliability.

4.1.3 Primary Conductors

Bare overhead primary conductors have a life expectancy that exceeds 50 years. Failures tend to occur at connections and attachment points, and are detectable in advance of failure through infrared thermography. There are currently no plans in the foreseeable future to replace any primary overhead conductors except in the case of an overall line rebuild. When an area is targeted for a rebuild, the conductor size is evaluated to make sure that it will be adequate for future load growth demands.

Our experience has indicated that primary overhead conductor failures have been limited to splices and tree contacts with the majority of these being eliminated through the use of the infrared inspections and our tree trimming program. Therefore, a financial forecast has not been prepared for primary conductor replacements.

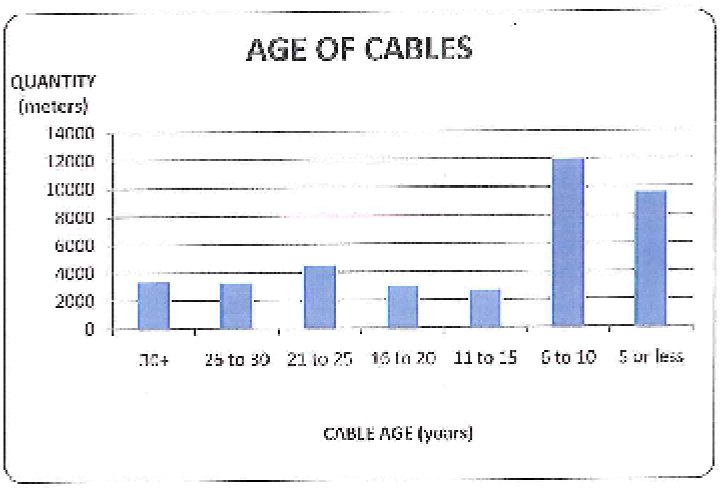
4.1.4 Secondary Conductors

Insulated secondary conductors have a life expectancy of 30 years, however many will last longer if lightly loaded and undamaged by trees and weather. Since the failure of a secondary conductor is a low risk occurrence (minimal customers affected), Brant County Power Inc. does not anticipate proactively replacing secondary conductors. When failures do occur, the first step is to make a repair using a splice, and if multiple failures occur in a single section or area, the conductor will be replaced. Generally, these costs are captured in the overhead line maintenance section of the general ledger. Therefore, a financial forecast hasn't been prepared for secondary conductor replacements.

4.2 Underground System

The underground system consists of approximately 40 km of line, primarily in newer subdivisions and the downtown core of Paris. The downtown core of Paris also contains equipment in below grade vaults, and both areas have padmounted switchgear.

Of the 40 km of cable, 65% is less than 20 years old, and only 13% is 30 years and older. The chart below shows the quantities of cable by year.



We have several areas that are fed from underground cables which are over 30 years in age. As these cables are nearing the end of their service life replacement plans are being developed. The north end of Paris contains our oldest cables which are 35 kV in nature. These cables are holding up very well on our 16 kV system but continue to be carefully monitored. Plans for replacement will be undertaken when problems begin to occur. Hillside Avenue, Paris and Victor Boulevard, St George will have underground primary cables replaced as part of the voltage conversions in these areas.

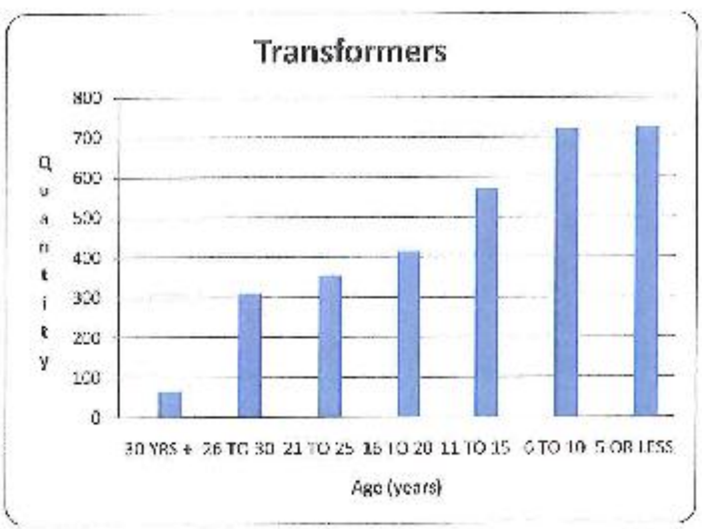
While the generally accepted life expectancy of underground primary cable is 30 years, it has been Brant County Power Inc.'s experience that this is a conservative number. There have been a small amount of cable failures that were not attributed to manufacturing defects, poor workmanship (at splices and terminators), or physical damage (due to dig ins). Over 90% of the underground primary system is a loop feed, therefore a cable fault would create a relatively short outage until the power is re-routed, at which time the section of the damaged cable would be repaired or replaced the following day. The majority of the underground system is lightly loaded (relative to cable ampacity rating) and is expected to last longer than the typical 30 years. Based on these factors, Brant County Power Inc. does not anticipate proactively replacing underground primary cable due to age alone at this time. Each section of cable will be replaced after it has been determined that it has reached its practical end of service life.

Brant County Power Inc. has investigated a method of extending the life of some of the older 27.6 kV cables through a process of "cable injection". Cable injection is a process where a dielectric liquid is forced through the cable under pressure, removing any traces of water and filling in the small gaps that are created as the cable deteriorates. Based on the cost of this process and expected improvement in life expectancy, Brant County Power Inc. does not plan to use this technology except for sections of cable that are direct buried and not readily replaceable.

To provide a future projection of cable replacement costs, it has been assumed that cables will be replaced by age 40. Currently, the oldest cables are only 32 years old, and therefore the anticipated start of replacement is still some years off.

4.3 Transformers

There are approximately 3200 distribution transformers in service or in stock. Of these, about 70% are less than 16 years old. The chart below shows the quantities of transformers by age, in groups of 5 years:



While the typical life expectancy of a transformer is 30 years, Brant County Power Inc.'s experience has been that many will surpass this age, especially those that are lightly loaded and see relatively few downstream faults. Inspections of the system will identify transformers that have external damage (chipped insulators, oil leaks, or surface rust) and these are either repaired in the field or replaced with new. The old unit is then sent for refurbishment.
Most of the transformers that are older than 30 years have historically been replaced as part of a voltage conversion.

Brant County Power Inc. does not replace transformers solely based on age. Unless the physical condition is poor, the infrared inspection identifies unusual heating, or that other work is taking place in the area (such as the transformer pole being replaced or relocated), transformers are kept in service indefinitely. However, assuming the majority of transformers are replaced by the time they are 40 years old, a long range projection of replacement costs has been created. Our current level of transformer replacements is approximately $220,000 per year, which should be adequate for the upcoming period.

4.4 Substations

There are only 3 distribution substations remaining in the system. Over the past ten years, voltage conversions have resulted in the decommissioning of 3 other municipal substations and this trend is expected to continue. As each substation and associated distribution assets approach end of life, the area is reviewed to determine if the station and lower voltage distribution should be replaced, or if an upgrade to a higher voltage is warranted. In many cases, a higher voltage circuit (27.6 kV) is readily available above the lower voltage circuit, and the conversion will require the replacement of distribution transformers. At that time, the condition of the poles and insulators are assessed to determine if they should be replaced at the same time as the voltage upgrade to minimize future costs and service disruptions. Depending on existing and future loading of the system, the conductors may be upgraded as well.

The remaining substations are listed in the table below, with comments regarding the assessed condition and future plans. The costs associated with decommissioning a substation are relatively minor.

kV			concerns	
MS#2	Outdoor Switchgear	35 years	Fair condition	Decommission in 2015*
MS#4	Outdoor Switchgear	40 years	Poor condition	Decommission in 2012*
MS#6	Outdoor Switchgear	16 years	Good condition	Decommission in 2020*

* These substations and 8 kV distribution area will be re-assessed regularly and the decommission date may be adjusted based on physical condition and reliability issues.

4.5 Vehicles and Equipment

The fleet consists of 6 large vehicles used for the construction and maintenance of the distribution system, and 8 small trucks used for light construction and general use. There are also 8 trailers of various types (pole trailers, reel trailers, stringing trailers, equipment trailers, etc). The inventory and assessment is summarized in Appendix 6.

When Brant County Power was formed in 1999 with the amalgamation of the six smaller utilities, the fleet acquisitions were generally older vehicles (typically early 1990s) but with limited usage. Since 2000, the fleet quantity has been reduced from 18 to 14 by retiring many of the older vehicles and replacing them with new vehicles that are more suited for use across the system.

While the replacement of vehicles and trailers is based on a combination of factors (Reference Section 3.2 and Appendix 8), a long range forecast would require the replacement of one large vehicle every second year (average age would be 12 years), and two small vehicles every 3 to 4 years (average age would be 10 years). This will require average spending on new vehicles of $200,000 per year for the foreseeable future. The actual amount each year will depend on the final selection of vehicles to be replaced in the coming year.

4.6 Buildings and Fixtures

Brant County Power Inc. maintains our service center and administration office in Paris and shares ownership of our Municipal Transformer Station with the City of Brantford. These buildings are not expected to require any significant capital improvements in the foreseeable future.

The service centre was constructed in 1984 and has undergone several changes since that time. The steel roof of the garage was painted in 2010 to help offset the need for replacement and the administration building will require some routine maintenance during the next two years as well as some more significant investment to address ergonomic and environmental issues as well as concerns identified as a result of a proactive review based on Bill 168. The HVAC units were replaced within the last 5 years, and should last another 10 to 15 years. No other deficiencies have been identified that would require significant financial investments in the next 5 years.

5.0 Five Year Plan

Brant County Power Inc. maintains a Five Year Capital Plan that is updated annually and reviewed by the Board of Directors. It provides a high level forecast of the financial investment required in capital to keep the assets sustainable. The estimates for each year are based on the Asset Management Plan projections that have been refined using specific project estimates for the next two years, and high level estimates for the subsequent three years. The amounts for Customer Driven Projects and New/Upgraded Services are based on historical information combined with forecasts from Economic Development departments across the service area. The latest version is follows:

	2010	2011	2012	2013	2014
Lands and Buildings	$10,500	$80,000	$20,000	$20,000	$20,000
Overhead Distribution Projects	$794,578	$818,860	$739,265	$792,344	$816,114
Underground Distribution Projects	$134,758	$249,633	$133,521	$137,528	$141,653
Distribution Transformers	$195,428	$197,915	$203,852	$209,968	$216,267
Services	$84,660	$87,093	$90,323	$93,034	$95,024
Distribution Meters (smart meters)	$1,461,250	$132,002	$65,962	$57,300	$31,500
Vehicles and Trailers	$325,000	$100,000		$100,000	$280,000
Computer Equipment	$162,300	$180,000	$100,000	$100,000	$100,000
Automated Switches		$120,000	$123,600	$127,308	$131,127
Tools & Misc. Equipment	$28,000	$10,500	$20,600	$21,218	$21,855
River Crossing		$750,000			
Contributed capital	($10,000)	($10,000)	($10,300)	($10,600)	($11,000)
Total Budgeted Amount	$3,185,570	$2,694,603	$1,516,823	$1,648,100	$1,853,340

Details	2010	2011	2012	2013	2014
Overhead Distribution Projects					
Voltage Conversions	$169,459	$240,155	$154,700	$216,370	$281,114
Rebuilds	$339,987	$175,187	$165,300	$225,974	$85,000
Extensions	$266,130	$1,151,539	$449,265	$350,000	$450,000
Underground Distribution Projects					
Voltage Conversions			$10,000	$14,653	$16,653
Rebuilds	$134,758	$162,633	$123,521	$122,875	$125,000
Extensions		$87,000			
Meters (Distribution & Wholesale)					
Retail Meters	$1,461,350	$132,002	$65,862	$57,300	$31,500
Vehicles and Trailers					
Replace Pickups or dump box		$100,000		$100,000	
Replace Panel Van					
Replace RBD					$280,000
Replace Double Bucket MHAD	$325,000				

Appendix 1	Vision, Mission and Health and Safety Policy Statements
Appendix 2	Workplace, Discrimination, Harassment & Violence Prevention Policy
Appendix 3	Maintenance Policy
Appendix 4	Line Clearing/Tree Trimming Policy
Appendix 5	Reliability Indices
Appendix 6	Vehicles & Related Equipment
Appendix 7	Annual Reliability Report
Appendix 8	Vehicle Inventory

APPENDIX 1 Vision, Mission and Health and Safety Policy Statements

BRANT County Power Inc.
your local energy provider

Our Vision,

Brant County Power's goal is to be an industry leader in safety, service, fiscal and environmental responsibility. We will achieve our goal by creating and sustaining a commitment to continual improvement in everything we do. We shall reward common sense, encourage ingenuity, and recognize that the hard work of individuals leads to the success of our team.

Health and Safety Policy Statement

Brant County Power Inc. recognizes that effective environmental, health and safety management is the responsibility of all our employees and is integral in ensuring the continual success of our business.

We are committed to protecting our workforce, customers, the public and the environment. In addition to achieving compliance with applicable laws, we will strive for excellence in our environmental, health and safety performance through adopting good management practices and setting clear objectives and targets for achieving continual improvement. To achieve this, we will ensure that environmental, health and safety management accountabilities and responsibilities are clearly defined and understood, that our employees are competent and adequately trained, and that appropriate resources are made available.

We will audit our performance to measure compliance with our policy and take the necessary corrective action when needed.

In order to fulfill this policy we aim to:

- Assess the environmental, health and safety risks associated with our business activities to manage our environmental impacts and the health and safety hazards to which people and property are exposed.
- Seek to develop and modify our activities and services so that adverse effects on health, safety and the environment are minimized.
- Design, construct, operate and maintain our facilities and equipment to ensure high standards of health and safety are maintained.
- Handle, store, transport, use and dispose of all hazardous materials associated with our activities in a manner that meets or exceeds regulatory requirements.
- Work with our customers to help ensure that they adhere to all applicable regulatory requirements.
- Be open in the exchange of environmental, health and safety information and knowledge with customers and the public.
- Report regularly on our performance to the Board of Directors.

Chief Executive Officer	Health & Safety Representative
Health & Safety Management Representative	Health & Safety Representative

August 17, 2009

APPENDIX 2 Workplace, Discrimination, Harassment & Violence Prevention Policy

BRANT County Power Inc.
your local energy provider

WORKPLACE DISCRIMINATION, HARASSMENT & VIOLENCE PREVENTION POLICY

Brant County Power Inc. is committed to the prevention of discrimination, harassment and violence in the workplace. We will take all reasonable precautions to protect our staff from discrimination, harassment and violence. Discriminatory, harassing, or violent behaviours on the part of anyone in the workplace, are unacceptable. This policy applies to all work locations and all work activities. It also applies to all staff, contractors, sub-contractors, visitors and volunteers. Discriminatory, harassing, or violent behaviours among our clients or customers will be effectively dealt with, in order to provide for optimum health and safety protection for our staff. All affected individuals covered by this policy are responsible for upholding the goals and principles of the policy.

This policy is implemented through a program that includes the identification of hazards, control strategies, measures and procedures to prevent and respond to incidents of discrimination, harassment or violence. Prompt reporting, investigating, and response to, incidents form an integral part of protecting everyone from the hazards of discrimination, harassment, and violence. Every reasonable attempt will be made to respect the privacy and confidentiality of everyone involved in incidents of discrimination, harassment, and violence. Elements of the program include the provision of training and information to workers, supervisors, managers, and volunteers.

Brant County Power Inc., as the employer, will ensure that this policy, program, measures and procedures are implemented and maintained. Managers and supervisors are responsible for ensuring that the program, measures and procedures are followed in their respective work areas. Workers are responsible for working in conformance to the program, measures, and procedures, and for promptly reporting all events or incidents of discrimination, harassment and violence.

APPENDIX 3 Maintenance Policy

MAINTENANCE POLICY

Brant County Power will provide a safe, reliable, and cost-effective electrical system for our customers while retaining and enhancing shareholder value.

All Brant County Power assets will be maintained in accordance with applicable legislation, manufacturers' recommendations, and good utility practice.

The overall goal of maintenance is to prevent problems and damage from occurring. Regular inspections and testing are necessary to determine the condition of the assets. The frequency of maintenance and inspection cycles will depend on the expected life of the asset, actual use of the asset, physical conditions, risk of failure, consequences of failure, and the health and safety of the public and workers.

Inspection and maintenance cycles will be planned, whenever possible, to take place during winter months, when fewer capital projects are in progress. Also, schedules and spending will be balanced, as much as possible, so that an equivalent amount is spent each year.

For the distribution system, the following specific schedules will be used:

Tree trimming – four year cycle (amount to be trimmed as per ESA guidelines)
Infra-red Inspection – two year cycle
Substation Inspections – monthly
River Crossing Inspection - monthly
Substation Maintenance – five year cycle
Padmount Transformer Inspections – five year cycle

Records of the above will be retained in the Operations Department. Replacement of distribution assets will be based on age, physical condition, reliability, and safety. Generally, distribution assets are expected to have a useful life of 30 years. Most planned replacements will take place as capital projects, budgeted annually.

For vehicles, equipment, and buildings, maintenance will follow manufacturers' recommendations. Any items in those categories that require excessive maintenance will be reviewed by Senior Management to determine if it should be replaced. Vehicle replacements will be tentatively planned 5 years in advance, as part of the Five Year Capital Plan, but not finalized until the annual budget is prepared.

APPENDIX 4 Line Clearing/Tree Trimming Policy

OPS-01 Line Clearing/Tree Trimming Policy

Page: 1 of 1
Issued: Dec 2008
Replaces: June 2006

Purpose: It is the Boards goal to distribute hydroelectric power to the businesses, industries, farms and residences, safely, reliably, efficiently, economically, and with due regard to the environment.

In our efforts to ensure a reliable and safe delivery of this service it will become necessary, from time to time, to address the conflicts this system may encounter with tree growth. Any installations of power lines along the rights-of -ways will be done so by first attempting to avoid any potential conflicts with tree growth. However, in some cases this may only be possible at the expense of efficiencies and economics and therefore may not be practical. Only after feasible alternate options have been exhausted will trees be trimmed back or removed from the aerial corridors to accommodate hydro servicing. It will not normally be our policy to totally remove trees otherwise directed by the road authority or unless it is absolutely necessary in order to install the electrical distribution system.

In situations where existing power lines experience tree growth conflicts, it will be necessary to trim the branches back from the lines in order to maintain a safe clearance and hopefully enhance the system's reliability. Whenever tree trimming or line clearing is required it will be done in a safe, professional manner with due regard to the tree's health and appearance and be limited to the sufficient length and clearance required, relative to line voltages and the individual tree growth rate.

The road authority will be notified of the intent of the tree-trimming project and in all cases the customer in the immediate or adjacent area will be notified of the intent of the tree-trimming project and any concerns can be addressed.

Any plans for tree trimming or line clearing will make all reasonable attempts to have the work done during the non-growth season in order to avoid the disruption of nesting birds/animals. These are very rare cases, but if nesting birds/animals are encountered and the tree trimming or line clearing threatens the security of the nest than temporary measures will be employed to mutually satisfy the environmental aspect and the reliability /safety aspect of the situation. After the nesting season has passed then a permanent remedy to the line-clearing problem will be employed. Tree trimming or line clearing will be limited to all Board owned equipment. There will be a charge for any work performed on private property as per Brant County Power Inc. Schedule of Rates "A".

If a customer is removing a tree on private property and the falling of the tree or its' branches encroaches on Board owned hydro lines and poses a threat to the security of the system, or perhaps the safety of the general public and if the situation has been brought to our attention, then our work forces will assist in the operation, and only to the point where the hydro related security safety risk is eliminated. If the customer is performing tree trimming on private property and requests the power lines to be disconnected from Board owned equipment during the project, we will provide this service free of charge once annually. This is conditional on the ability of our work crew to return to the work center by 3:30 pm, otherwise additional charges may apply, at the discretion of management.

APPENDIX 5 Reliability Indices

BRANT County Power inc
your local energy provider

Project Validation Matrix

Project Name:

Project Purpose/description:

Estimated Cost:

Process/Service	Description of Modification/Automation	Weightings (Note 2)	Comments
Safety (Note 1)	Presents a risk to public and or employee		
Possible Future Growth (demand)	Augmentation to planned projects to accommodate future growth		
Network Stability and Reliability	Projects designed for Service Assurance		
3rd Party Demand/Influence	Developer, Customer or County Driven		
Cost Justification	Intuitive benefits – these benefits "make sense" Direct benefits – these benefits are quantification of the intuitive benefits Indirect and Strategic – these benefits tend to have the greatest impact		

Note 1: Projects weighted greater than 3 for safety demand action, and as such will be given high priority in the capital budget

Note 2: Ranking of 0-5 per process. Maximum rating of a project is 25, no projects weighted less than 12 will be considered except where "cost justification" can be rationalized.

V 2011.1

APPENDIX 6 Vehicles & Related Equipment

COMMERCIAL EQUIPMENT CORP.
1006 Pattullo Avenue, R.R. 8
Woodstock, ON Canada N4S 7W3

MURRAY BOUGHNER
Cell: (519) 535-4488
Tel: (519) 421-4488
Fax: (519) 431-2155
Email: mboughner@commercialequipment.ca

MECHANICAL , HYDRAULIC , STRUCTURAL INSPECTION
(AERIAL DEVICE)

Customer:	Brant County Power	Make:	Hi-ranger
Contact:	Paul Barber	Model #:	50 OM
Phone #:	(519) 442-2215	Serial #:	50 OM-1383GBB
Mileage:	78242.5 Km.	Hour Meter:	PTO= 6561
L/P #:	Cy7 425	Unit #:	BCP-08
Work Order #:	512796	Date:	NOV.06 /09

SUGGESTED REPAIR'S :

(1) REPLACE TREE OUT OF FOUR OUTRIGGER STORAGE (RUSTED OUT).
(2) REPAINT STALIZER MARKS AT OUTRIGGERS (YELLOW PAINT).
(3) ADD MON. PROTECTION CAP AT DIELECTRIC TEST AERA.

COMMERCIAL EQUIPMENT 24 HR.
FIELD SERVICE.
Murray Boughner
Murray Boughner

COMMERCIAL EQUIPMENT CORP.
1005 Pattullo Avenue, R.R. 8
Woodstock, ON Canada N4S 7W3

MURRAY BOUGHNER
Cell: (519) 535-4498
Tel: (519) 421-4498
Fax: (519) 431-2156
Email: mboughner@commercialequipment.ca

MECHANICAL , HYDRAULIC , STRUCTURAL INSPECTION
(AERIAL DEVICE)

Customer:	Brant County Power	Make:	TELELECT
Contact:	Paul Barber	Model #:	C-5048
Phone #:	(519) 442-2215	Serial #:	2040223796
Mileage:	33656 Km.	Hour Meter:	PTO- 519 ENG-1028
L/P #:	677 9NB	Unit #:	BCP-21
Work Order #:	512781	Date:	NOV. /09

CERTIFIED REPAIR'S :
(1) REPLACE DAMAGED AUGER ROPE (ROPE REPLACED OK.).

SUGGESTED REPAIR'S :
(1) REPLACE BENT 2 SP. TELE-TUBE IN BOOM.
(2) REPAIR DAMAGED REAR STEP.
(3) REPAIR OIL LEAK AT ROTATION MOTOR.
(4) CURBSIDE BEACON SECTION NOT REVOLVING (REPAIR) BEACON MODEL = GROTE 22 INCH LIGHT BAR # 7715
(5) REPLACE LOOSE HINGE BOLTS (BOTH SIDES) AT POLE-CLAW, RETORQUE BOLTS WITH LOCTITE.
(6) RECHRCK DIGGER GEARBOX OIL LEVEL (NEED ADAPTOR.
(7) REPLACE DAMAGED NON-CONDUCTION 1\4 INCH LINE AT TURRET SIDE INSPECTION OPENING.

COMMERCIAL EQUIPMENT 24 HR. FIELD SERVICE.
Murray Boughner

Murray Boughner

COMMERCIAL EQUIPMENT CORP.
1005 Pattullo Avenue, R.R. 8
Woodstock, ON Canada N4S 7W3

MURRAY BOUGHNER
Cell: (519) 535-4480
Tel: (519) 421-4480
Fax: (519) 431-2155
Email: mboughner@commercialequipment.ca

MECHANICAL , HYDRAULIC , STRUCTURAL INSPECTION
(AERIAL DEVICE)

Customer:	Brant County Power	Make:	POSI-PLUS
Contact:	Paul Barber	Model #:	500-55 AMT
Phone #:	(519) 442-2215	Serial #:	08-08-592 2528
Mileage:	4618 Km.	Hour Meter:	PTO 245.5 ENG=403
L/P #:	980 4xh	Unit #:	BCP-33
Work Order #:	512782	Date:	NOV.05 /09

SUGGESTED REPAIR'S :

(1) Push in grease fitting at boomelbow shaftmissing,tap and replace with new grease fitting.
(2) Reposition bent grounding lug at rear bumper, turn it sideways for clearance and easer excess.

COMMERCIAL EQUIPMENT 24 HR.
FIELD SERVICE.
Murray Boughner

Murray Boughner

COMMERCIAL

DIELECTRIC INSPECTION REPORT

Customer: Brant County Power Location: Paris Ont.	Contact: Paul Barber Phone #: (519) 442-2215
Make/Model : Simon Telelect 92-47	W/O#: 512
Serial : 92-47 606 LBB	Unit #: BCP-11

INSPECTED TO CSA 225-M

	VOLTAGE (KVDC)	LEAKAGE (uA)	COMMENTS
LEAKAGE MONITORING	30	NA.	
LEAKAGE MONITORING	50	NA.	
LEAKAGE MONITORING	70	NA.	
LEAKAGE MONITORING	100	NA.	
LEAKAGE MONITORING	140	NA.	
UPPER BOOM	140	48.5	
LOWER INSERT	70	NA.	
JIB	100	NA.	
BUCKET (OPERATOR)	70	NA.	
BUCKET (PASSENGER)	70	NA.	
LINER (OPERATOR)	70	NA.	
LINER (PASSENGER)	70	NA.	

INSPECTED BY: MURRAY BOUGHNER
DATE: NOV.04/09

1005 Pattullo Ave, R. R. 8 Woodstock, ON N4S 7W3
Tel: 519-421-4488 Fax: 519-421-2155

COMMERCIAL

DIELECTRIC INSPECTION REPORT

Customer: Brant County Power	Contact: Paul Barber
Location: Paris Ont.	Phone #: (519) 442-2215
Make/Model : Posi-Plus 500-55 AMT	W/O#: 512786
Serial : 09-09-592 2528	Unit #: BCP-33

INSPECTED TO CSA 225-M

	VOLTAGE (KVDC)	LEAKAGE (uA)	COMMENTS
LEAKAGE MONITORING	30	NA.	
LEAKAGE MONITORING	50	NA.	
LEAKAGE MONITORING	70	.25.	
LEAKAGE MONITORING	100	.25	
LEAKAGE MONITORING	140	.50	
UPPER BOOM	140	15	
LOWER INSERT	70	22.	
JIB	100	33	
BUCKET (OPERATOR)	70	.24	
BUCKET (PASSENGER)	70	10	
LINER (OPERATOR)	70	OK.	
LINER (PASSENGER)	70	OK.	

INSPECTED BY:_MURRAY BOUGHNER_
DATE:____Nov.05/09

1005 Pattullo Ave. R. R. 8 Woodstock, ON N4S 7W3

Tel: 519-421-4488 Fax: 519-421-2155

COMMERCIAL

DIELECTRIC INSPECTION REPORT

Customer: Brant County Power	Contact: Paul Barber
Location: Paris Ont.	Phone #: (519) 442-
Make/Model ; Telelect C-5048	W/O#: 512781
Serial :	Unit #: BCP-21

INSPECTED TO CSA 225-M

	VOLTAGE (KVDC)	LEAKAGE (uA)	COMMENTS
LEAKAGE MONITORING	30	NA.	
LEAKAGE MONITORING	50	NA.	
LEAKAGE MONITORING	70	NA.	
LEAKAGE MONITORING	100	.NA.	
LEAKAGE MONITORING	140	.NA.	
UPPER BOOM	140	22.5	
LOWER INSERT	70	NA.	
JIB	100	NA.	
BUCKET (OPERATOR)	70	.NA.	
BUCKET (PASSENGER)	70	NA.	
LINER (OPERATOR)	70	NA.	
LINER (PASSENGER)	70	NA.	

INSPECTED BY: MURRAY BOUGHNER

DATE: Nov.04/09

1005 Pattullo Ave. R. R. 8 Woodstock, ON N4S 7W3

Tel: 519-421-4488 Fax: 519-421-2155

COMMERCIAL

DIELECTRIC INSPECTION REPORT

Customer: BRANT COUNTY POWER	Contact: PAUL BARBER
Location: PARIS ON.	Phone #: (519) 442-2215
Make/Model ; HI-RANGER 50 OM	W/O#: 512796
Serial : 5O OM-1383GBB	Unit #: BCP-08

INSPECTED TO CSA 225-M

	VOLTAGE (KVDC)	LEAKAGE (uA)	COMMENTS
LEAKAGE MONITORING	30	NIL.	
LEAKAGE MONITORING	50	NIL.	
LEAKAGE MONITORING	70	NIL	
LEAKAGE MONITORING	100	..25	
LEAKAGE MONITORING	140	.25	
UPPER BOOM	140	128	
LOWER INSERT	70	6.5	
JIB	100	40	
BUCKET (OPERATOR)	70	.FAILED	REPAIR (DONE)
BUCKET (PASSENGER)	70	24	
LINER (OPERATOR)	70	OK.	
LINER (PASSENGER)	70	FAILED	REPLACE (DONE)

INSPECTED BY: MURRAY BOUGHNER
DATE: NOV.06/09

1005 Pattullo Ave. R. R. 8 Woodstock, ON N4S 7W3

Tel: 519-421-4406 Fax: 519-421-2155

COMMERCIAL

CUSTOMER:	BRANT COUNTY POWER		
MAKE :	TELELECT	DATE	NOV 6 09
MODEL:	92 47	MILEAGE:	50147KM
SERIAL #:	92 47 606	CHASSIS:	
UNIT #:	BCP11	W/O #:	512782

ANNUAL INSPECTION REPORT

REQUIRED REPAIRS:

1. NONE

RECOMMENDED REPAIRS

2. WASH OUT TOWER AND REPAIR LEAK
3. REPLACE BACK MOUNT 3000PSI PRESSURE GUAGE
4. REPLACE PLUG IN THE ROTATION BOX, STRIPPED AND SIEZED SO YOU CAN NOT CHECK THE LEVEL.
5. SEAL THE OPEN GLASS ON THE TIP OF 3[RD]
6. UNIT WILL NOT LIFT RATED LOAD

NOTE BEARING DEFLECTION .061

DAVE CLAYTON
COMMERCIAL FIELD SERVICE
519 535 2326

COMMERCIAL

CUSTOMER:	BRANT COUNTY POWER		
MAKE:	TEREX	DATE	NOV 11 09
MODEL:	TPL40	MILEAGE:	7269KM
SERIAL #:	2061032043	CHASSIS:	
UNIT #:	BCP24	W/O #:	512858

ANNUAL INSPECTION REPORT

REQUIRED REPAIRS:

1. LOWER EMERGENCY STOP SIEZED AND NEEDS A NEW $50 RED KNOB
2. REPLACE UPPER CONTROL HANDLE MAST ASSEMBLY
3. LOWER LEVELING CYLINDER TRUNNION MOUNTING BOLTS LOOSE(REPAIRED)
4. REPLACE BOOM SAFETY DECALS

RECOMMENDED REPAIRS

5. REAR POSSUM BELLY DOOR WILL NOT LATCH
6. REPLACE GROTE 5252 DECK LIGHT OVER STEP
7. LUBE OUTRIGGER/UNIT SELECTER END CAP
8. LUBE LEFT SIDE OUTRIGGER VALVE END CAP
9. REPLACE FILTER(NEED A FILTER WRENCH THAT WILL BEND OR REMOVE HOSES)
10. REPLACE LEAKING FILTER GUAGE
11. ADJUST BACK LASH IN ROTATION
12. ROTATION BOX VENT PLUGGED
13. REPLACE PARALLEOGRAM LINK BUSHING AT KNUCKLE END
14. REPLACE ALL COVERS AT THE TIP BUT THE UPPER CONTROL COVER
15. REPLACE WORN HOSE SOCK FROM BOOM TO BUCKET

2005 Pattullo Ave. R. R. 8 Woodstock, ON N4S 7W3
Tel: 519-421-4488 Fax: 519-421-2885

COMMERCIAL

DIELECTRIC INSPECTION REPORT

Customer: BRANT COUNTY POWER	Contact:
Location:	Phone #:
Make/Model: TPL 40	W/O#:512858
Serial#: 2061032043	Unit #: BCP24

INSPECTED TO CSA 225-M

	VOLTAGE (KVDC)	LEAKAGE (uA)	COMMENTS
LEAKAGE MONITORING	30	NA	
LEAKAGE MONITORING	50	NA	
LEAKAGE MONITORING	70	NA	
LEAKAGE MONITORING	100	NA	
LEAKAGE MONITORING	140	NA	
UPPER BOOM	140	25	
LOWER INSERT	70	7	
JIB	100	NA	
BUCKET (OPERATOR)	70	15	
BUCKET (PASSENGER)	70	NA	
LINER (OPERATOR)	70	PASS	
LINER (PASSENGER)	70	NA	

Inspected By: D CLAYTON	Date: NOV 11 09

[illegible] Pattullo Ave. R. R. 8 Woodstock, ON [illegible]

Tel: [illegible] Fax: [illegible]

COMMERCIAL

DIELECTRIC INSPECTION REPORT

Customer: BRANT COUNTY POWER	Contact:
Location:	Phone #:
Make/Model: 200 42 A	W/O#:512832
Serial#: 09 02 725 2568	Unit #: BCP33

INSPECTED TO CSA 225-M

	VOLTAGE (KVDC)	LEAKAGE (uA)	COMMENTS
LEAKAGE MONITORING	30	0	
LEAKAGE MONITORING	50	0	
LEAKAGE MONITORING	70	0	
LEAKAGE MONITORING	100	0	
LEAKAGE MONITORING	140	.01	
UPPER BOOM	140	2	
LOWER INSERT	70	4	
JIB	100	NA	
BUCKET (OPERATOR)	70	11	
BUCKET (PASSENGER)	70	NA	
LINER (OPERATOR)	70	PASS	
LINER (PASSENGER)	70	NA	

Inspected By: D CLAYTON	Date: NOV 10 09

1005 Pattullo Ave, R. R. 8 Woodstock, ON N4S 7W3

Tel: 519-421-4401 Fax: 519-421-2155

COMMERCIAL

CUSTOMER:	BRANT COUNTY POWER		
MAKE:	POSI +	DATE	NOV 10 09
MODEL:	200 42 A	MILEAGE:	7269KM
SERIAL #:	09 02 725 2560	CHASSIS:	
UNIT #:	BCP33	W/O #:	512832

ANNUAL INSPECTION REPORT

REQUIRED REPAIRS:

1. INSERT BOLTS LOOSE(REPAIRED BY INSPECTOR)

RECOMMENDED REPAIRS

2. REPLACE FILTER (PART NUMBER 100 093 049)
3. REPAIR BUCKET GEL COAT
4. REPLACE LEVEL INDICATOR BRACKET
5. SPOT LIGHTS DO NOT WORK CHECK THE WIRING , IT IS NOT FUSED IN THE POSI SYSTEM SO IS A WILCOX INSTALL
6. REAR GROUND LUG TOO CLOSE TO THE STEP
7. PLATFORM ROTATE VALVE HANDLE LOOSE(REPAIRED BY INSPECTOR)

NOTE BEARING DEFLECTION .054

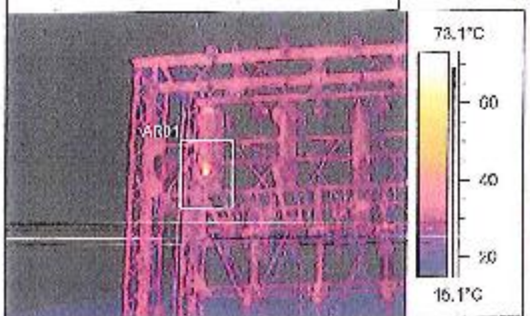
DAVE CLAYTON
COMMERCIAL FIELD SERVICE
519 535 2326

3005 Pattullo Ave. R. R. 8 Woodstock, ON N4S 7W3
Tel: 519-421-4100 Fax: 519-421-2555

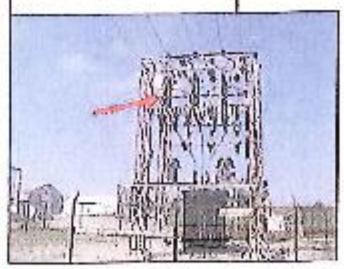
Identification:	DATE
MS4, Pleasant Ridge Road	12/08/2010

Description: Fuse

INFRARED IMAGE



PHOTO



Temperature rise: 76.89 °C
(over ambient)

IR information	Value
Date of creation	12/08/2010
Time of creation	11:18:33 AM
Object parameter	Value
Ambient temperature	24.0°C
Label	Value
AR01 : max	100.9°C

Status:

Repaired Date:

Notes:

INFORMATION:

Infrared image of the structure at MS4.
Located at 277 Pleasant Ridge Road in Mount Pleasant.
Heating noted at the bottom connection of the indicated fuse.
At arrow in photo.
See IR information chart above for maximum temperature inside area box (AR01).

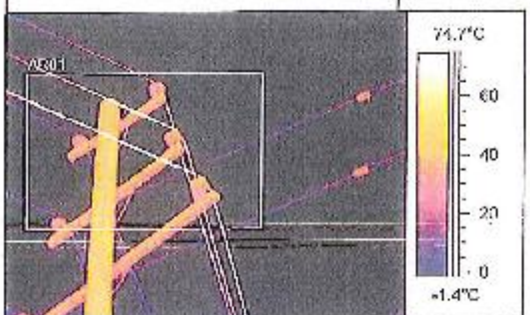
PRIORITY: High Medium Low

ANOMALY:	Heating fuse connection

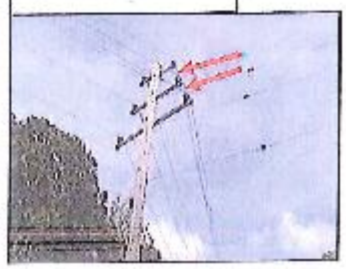
Identification:	DATE
Hydro Pole # AN7RUH: Pole 112	11/08/2010

Description: Primary Cables

INFRARED IMAGE



PHOTO



Temperature rise: (over ambient) *186.96 °C

IR information	Value
Date of creation	11/08/2010
Time of creation	3:02:03 PM
Object parameter	**Value**
Ambient temperature	24.0°C
Label	**Value**
AR01 : max	>211.0°C

Status:

Repaired Date:

Notes:

INFORMATION:

Infrared image of the wire on Hydro One Pole # AN7RUH.
Located on Powerline Road west of the Grand River. Pole 112 (shared pole).
Heating noted at the road side wires on the middle and bottom phases.
At arrows in photo.
See IR information chart above for maximum temperature inside area box (AR01).

PRIORITY: High | Medium | Low

ANOMALY: Heating wires

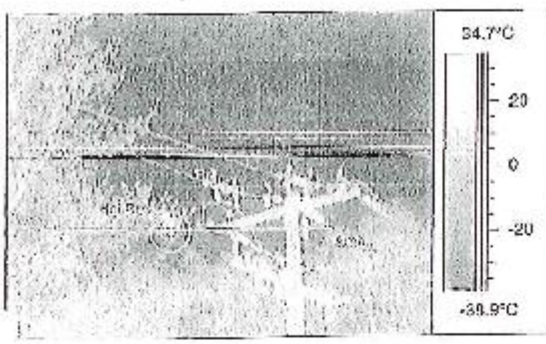
Heat Seekers Infrared Inspection Services

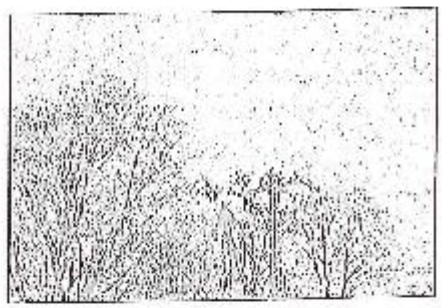
Brant County Power Paris, ON File No.: 9900 0096

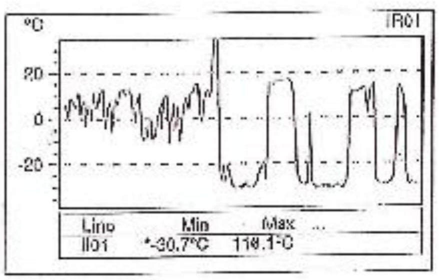
Temp Rise: 82°C Severity: ****

FINDING NO. 12 ROUTE NO. 6

LOCATION: Brant County Power Line Distribution
EQUIPMENT: Burford town lines, 27.7 Kv. 104 King St. Switch # S104, East West Main Line
SPECIFIC ITEM: North phase east side, Switch fuse barrel to catch. (all associated connections)







Date:	
Time:	10:15:48 AM
Max Area Temperature = Hot Spot	94.6°C
Reference Temperature = Ref	12.4°C
Ambient Reference Temp. = Amb.	9.6°C
Line Max. Temp.	118.1°C

PROBABLE CAUSE: Loose/deteriorated fused safety switch component(s).

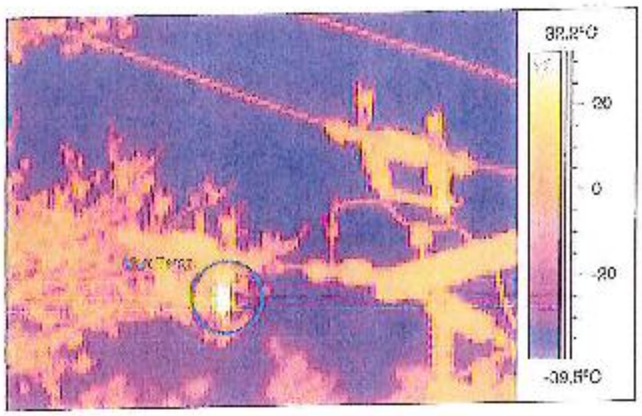
RECOMMENDATION: Clean, align and tighten all connecting points of switch assembly.

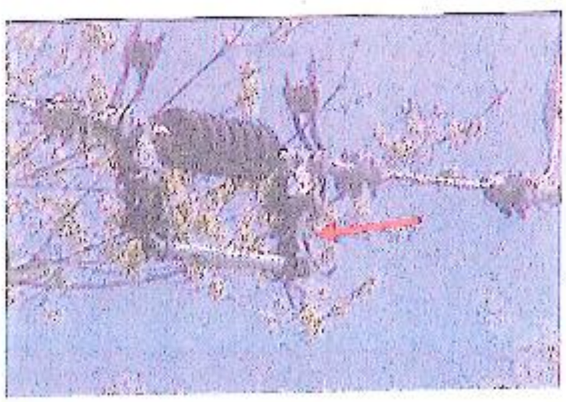
COMMENTS:

Repair Notes: Completed
Changed Switch. Scott Loran

Heat Seekers Infrared Inspection Services

Hot spot temperature= 94.6°C

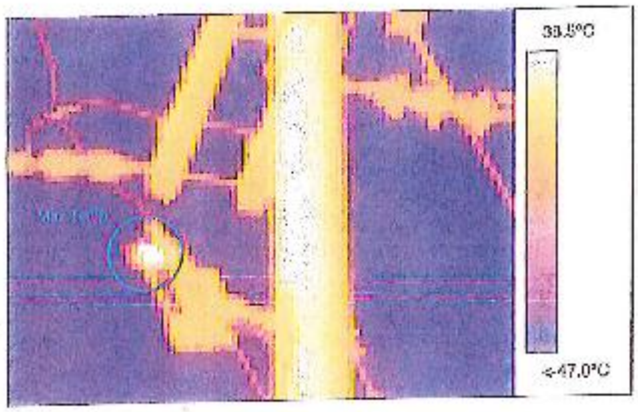


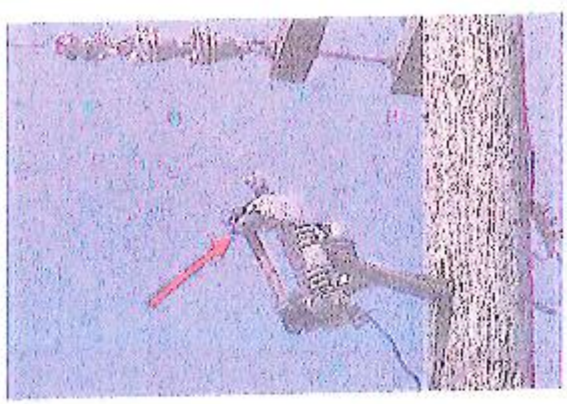


This thermal image was taken with a high definition non-digital 3X telescopic lens and solar reflectant LW detector from a mobile 360 degree full tilt - multiple screen IR/Visual viewing system.

Heat Seekers Infrared Inspection Services

Hot spot temperature= 72.6°C

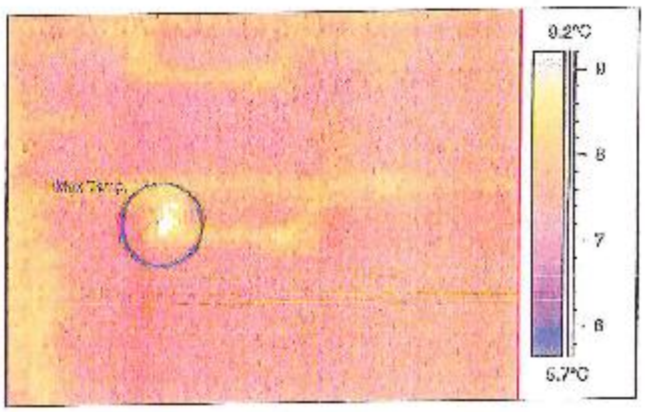


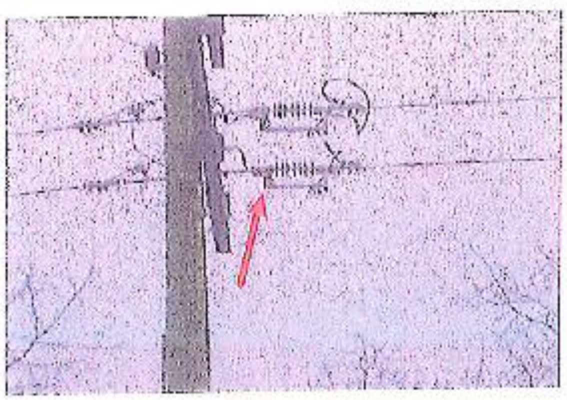


This thermal image was taken with a high definition non-digital 3X telescopic lens and color reflectant LW detector from a mobile 360 degree full tilt – multiple screen IR/Visual viewing system.

Heat Seekers Infrared Inspection Services

Hot spot temperature= 10.0°C

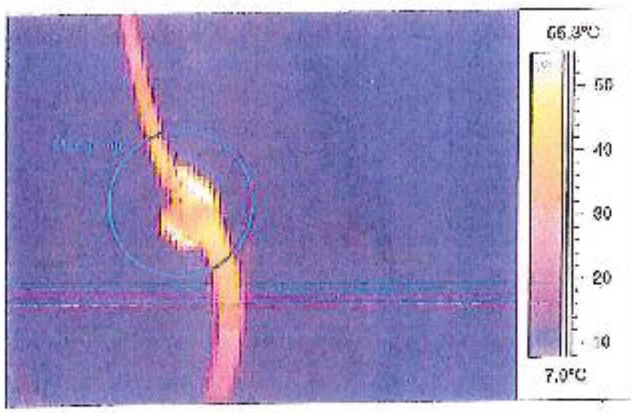


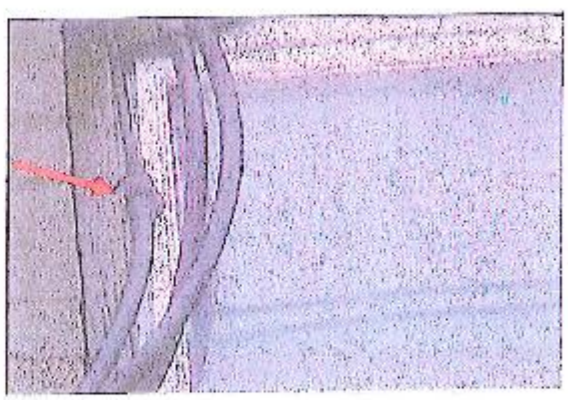


This thermal image was taken with a high definition non-digital 3X telescopic lens and solar reflectant LW detector from a mobile 360 degree full tilt - multiple screen IR/Visual viewing system.

Heat Seekers Infrared Inspection Services

Hot spot temperature= 60.1°C





This thermal image was taken with a high definition non digital 3X telescopic lens and solar reflectant LW detector from a mobile 360 degree full tilt - multiple screen IR/Visual viewing system.

APPENDIX 7 Annual Reliability Report

Annual Reliability Indices

2009

	Total customer hours of Interruptions	total customer Interuptions	total number of customers	SAIDI	SAIFI	CAIDI
Jan	198.27	62.00	9300	0.02	0.01	3.20
Feb	128.25	79.00	9300	0.01	0.01	1.62
Mar	57.42	57	9300	0.0062	0.0061	1.0074
Apr	5734.00	2102.00	9300	0.62	0.23	2.73
May	184.92	155.00	9300	0.02	0.02	1.19
Jun	4795.00	2217.00	9300	0.52	0.24	2.16
Jul	516.78	2411.00	9300	0.06	0.26	0.21
Aug	167.50	97.00	9300	0.02	0.01	1.73
Sep	5.02	6.00	9300	0.00	0.00	0.84
Oct	1250.58	3351.00	9300	0.13	0.36	0.37
Nov	144.00	123.00	9300	0.02	0.01	1.17
Dec	51.58	23.00	9300	0.01	0.00	2.24
Annual Total	13234.32	10683.00	9300.00	1.4230	1.1487	1.2388

APPENDIX 8 Vehicle Inventory

Vehicle replacement schedule

Unit #	Make	Type	Year	Anticipated replacement date	Estimated Cost
3	Chevrolet	½ ton	2005	2013	$25,000.00
4	Chevrolet	½ ton	2005	2013	$25,000.00
6	GMC	½ ton	2003	2011	$30,000.00
20	GMC	½ ton	2004	2011	$30,000.00
25	Chevrolet	½ ton	2007	2015	$21,000.00
23	Chevrolet	1-Ton dump	2005	2013	$50,000.00
27	GM	Van	2007	2015	$25,000.00
28	GM	Van	2007	2015	$25,000.00
	Ford	Hybrid	2011	2016	$35,000.00
11	International	Radial Boom Derrick	1991	2013	$260,000.00
8	International	Double Bucket Material Handler	1995	2010	$310,000.00
21	International	Radial Boom Derrick	2004	2014	$260,000.00
24	International	Single Bucket	2006	2016	$200,000.00
13	International	Single Bucket	2009	2019	$210,000.00
33	International	Double Bucket Material Handler	2008	2018	$320,000.00

Brant County Power Five Year Strategic Technical Plan

Table of Contents

1. Introduction

This is the first five year technical strategic plan developed by Brant County Power Inc. Input to this document has been received from a variety of stakeholders including; customers, municipal partners, service providers and shareholder representatives.

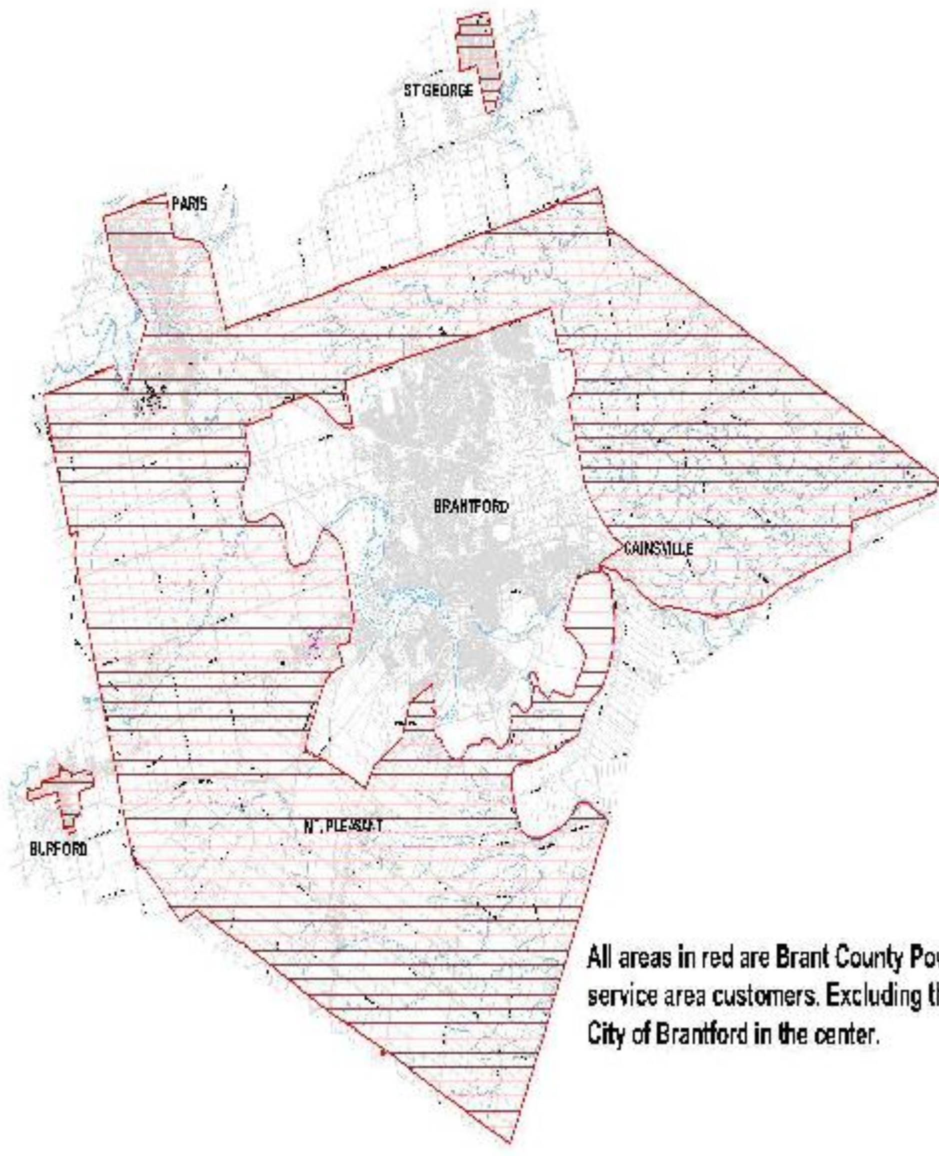
The service territory for Brant County Power extends over two hundred and eighty two square kilometers and includes the villages of Burford and St. George, and the town of Paris. We currently provide service to nine thousand five hundred and ninety three customers. The breakdown is as follows, eight thousand one hundred and seventy residential customers, one thousand three hundred and fourteen small commercial customers and one hundred and nine large commercial users.

Future growth is forecasted across all market segments and has been considered in all aspects of this plan. Included in the proposed five year plan are appropriate strategies to address future demand and ongoing network reliability improvements.

The majority of this forecasted growth is expected in and around the Paris area as well as strong industrial growth in the area of the Brantford Airport. The official plan for the municipality identifies significant future development will occur in the Southwest Paris area. Additionally Municipally owned land is being developed in the area of Rest Acres Road at Highway 403 for a large industrial park.

By utilizing new technologies such as Scada-mate with Intelli-Team, Trip Saver devices, MCA Software and building additional feeders in key locations our objective is to strengthen reliability within our existing infrastructure.

In developing and strengthening our network we intend to shorten our outage duration times, enhance customer service and increase revenue while ensuring adequate supply for new customers.



All areas in red are Brant County Power service area customers. Excluding the City of Brantford in the center.

2. Existing Condition and Data

2.1 Load Growth

New Developments are planned in South-West Paris which will require significant changes on the loading of the system. These developments will be mainly residential however a large industrial development will result in additional significant loading also. A large residential development in the north end of Paris is also expected to begin during the next few years as delays associated with water supply are resolved.

Near the airport area, which already has a strong industrial customer presence, we will see noteworthy load growth requiring additional energy supplies. A large brick manufacturer has recently acquired the recently closed Canadian Bluebird property, with other interested parties currently pursuing other properties which would also add demand in this area.

The St. George area could see 2000 more homes added during this five year period while proposals from First Urban for development in the Cainsville area of our service territory could have a very positive residential and commercial impact there.

2.2 Supply Availability

Brant County Power has previously invested in a transformer station on Powerline Road (in partnership with the Brantford Power) to ensure adequate energy is available well into the future. Our challenge now is to build the feeders to deliver this energy to the areas seeing growth. The north east portion of our service area and the village of St George are most at risk in our service area. The community of St George is fed from the 12M14 feeder which additionally serves a large Hydro One area. Residents there have suffered through numerous outages due to problems on the Hydro One portion of the line. Challenges to meet any additional growth in the Northeast portion of our service area are caused by the current limited feeders in that area also. Further, rudimentary discussions with Brantford Power regarding a second jointly owned transformer station to be built east of the City of Brantford have begun. This undertaking would permit us to reinforce our infrastructure in the northeast part of our service area and would assist in further developing a backup feed to the village of St. George.

2.3 Transformer Station Loading

Presently we have load on three separate transformer stations, thereby permitting us some opportunity to provide feeder backup to our customers. This also results in additional challenges as we need to be sensitive of peak demand on each station and the associated affordability of short term shifting. One of the key elements of our plan is to design our feeder system to ensure that most load transfers occur between feeders fed from the same transformer station. This ensures feeder or station overloads do not occur. (Two of these existing stations are owned by Hydro One and we are aware that they are near capacity.) As a direct result of these changes, our customers will experience shorter outage durations as the load transfer would permit us to switch customers who currently may be completely without hydro over to a different feeder.

2.4 Transformer Backup

Both Brant Transformer Station and Powerline Transformer Station are fully redundant stations. They have two transformers in each station and either transformer is capable of supporting the entire load of the station. This means that even in the event of a transformer failure we will still be able to ensure a reliable supply of electrical energy to our customers. Brant Transformer Station is owned by Hydro One, while Powerline Municipal Transformer Station is owned by both Brantford Power and ourselves; Brant County Power. These stations are expected to support the load growth in both the north and western part of our territory throughout the study period and beyond. The east end of our service area is fed from a Municipal Substation located at 391 Powerline Road. The station is rated at 5000 kVA and the primary voltage is 27,600 volts and 4800/4160 volt secondary.

2.5 Feeder Loading

All of Brant County Power Feeders are designed for a Nominal 600 Amps while our loading is kept at not more than fifty percent thereby permitting the entire load to be shifted in the event of a significant feeder failure. We attempt to maximize our use of our feeders by ensuring that our loads are balanced equally across all three phases. This also helps to keep our line loss as low as possible.
For the main feeder conductors we use 336 AL or 556 AL and some 3/0. U/G cables main feeders are 500 Cu.

The chart below shows our current feeder loading.

Peak Amps	12M24 (Brant Transformer Station)	PM4 (Powerline Municipal Transformer Station)	12M21(Brant Transformer Station)	12M11(Brant Transformer Station)	12M22(Brant Transformer Station)	64M25 (Brantford Transformer Station)	64M27 (Brantford Transformer Station
May-09	204	173	171	23	63	58	159
June-09	248	153	246	22	76	74	182
July-09	232	203	204	24	67	65	153
August-09	268	147	308	24	96	81	180
September-09	224	141	225	25	76	64	162
October-09	221	180	208	24	70	59	171
November-09	216	183	218	24	44	61	169
December-09	220	193	253	24	50	66	198
January-10	230	168	253	15	65	64	209
February-10	220	145	226	16	66	57	216
March-10	203	161	207	16	58	63	168
April-10	204	160	183	17	46	51	156
Peak	268	203	308	25	96	74	216

In addition to these feeders we have our Municipal Substation #2 embedded on the PM1 feeder (out of Powerline TS) and the village of ST. George which is embedded on the 12M13 feeder out of Brant TS.

2.6 Losses, Phase Balancing, Peak Management Load Transfer Capability.

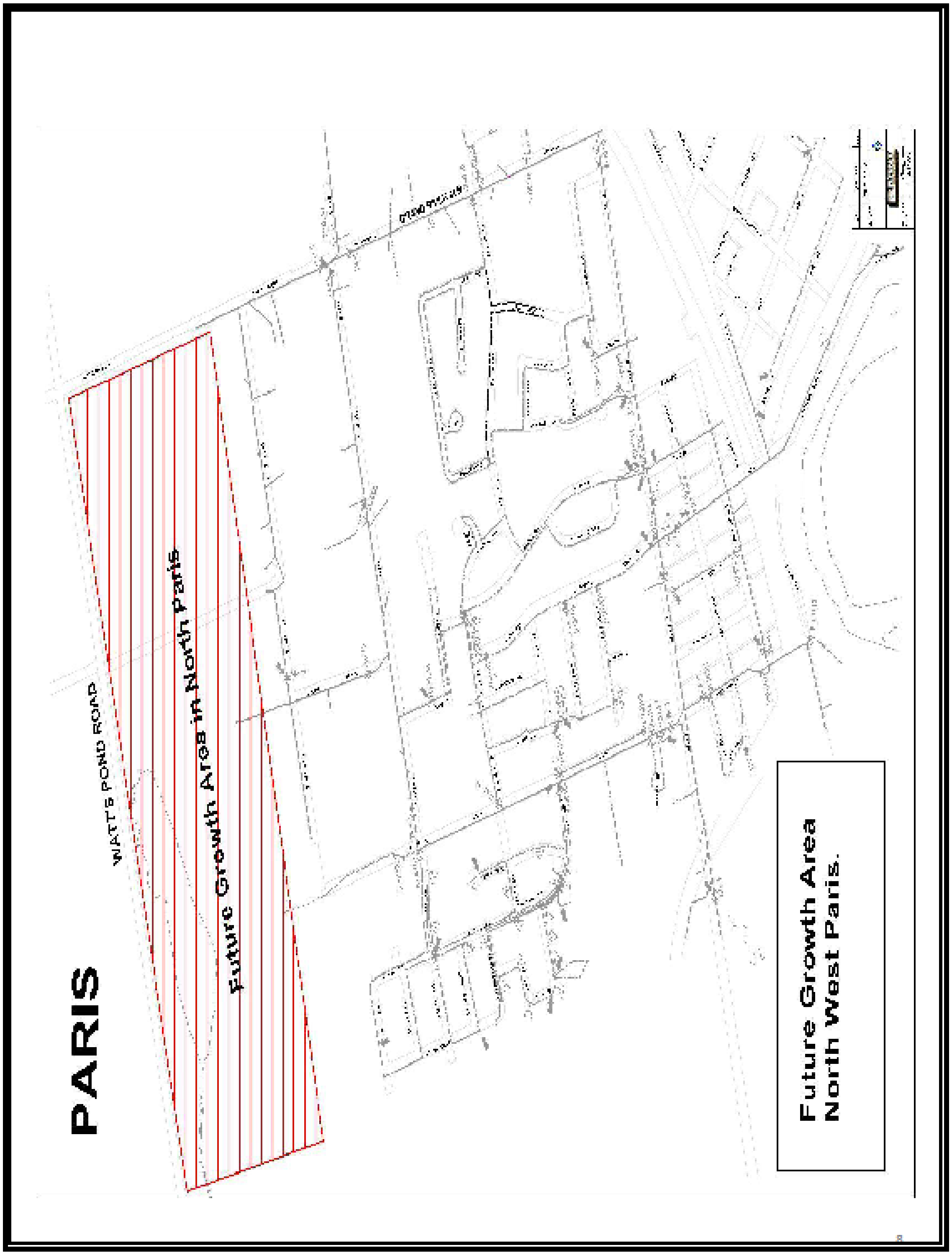
Our desire is to continue to minimize loss to ensure that we keep our loads balanced. We are very aware of the sensitivity of our customers to outages, particularly in the north-Paris Industrial area and the downtown core. We recognize the need for smart grid development to support these areas, and where possible, the rest of our service area. Some concerns will be addressed with smart switches.

2.7 Feeder Level Reliability and Sensitive Customers

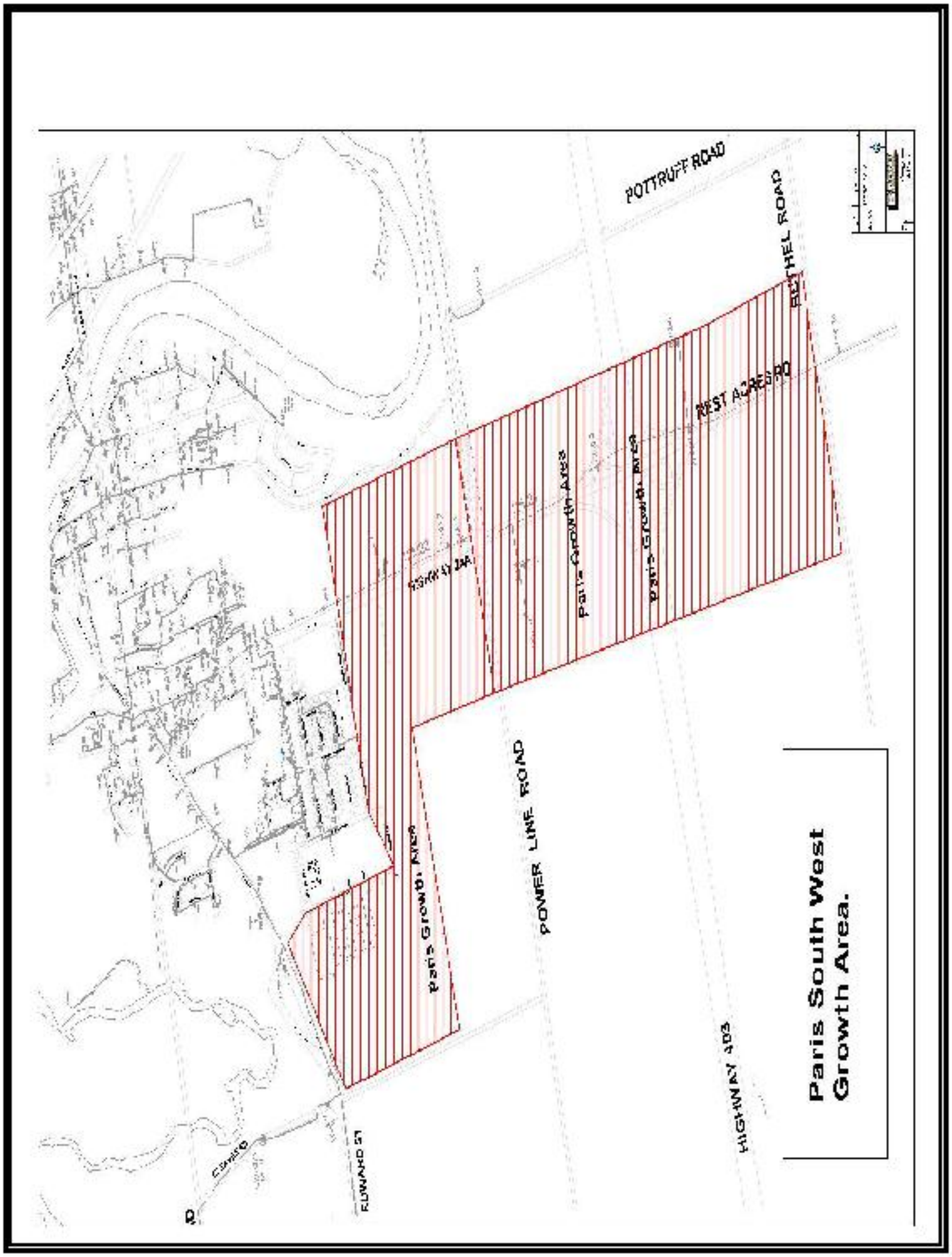
A substantial number of customer minutes and customer outages have been caused by loss of supply at Brant TS. Part of our strategy will be to reroute our feeders to allow the majority of Paris to be fed from Powerline Municipal Transformer Station. By rerouting these feeders we will be in a position to switch our loads between feeders, thus improving customer service while minimizing our exposure to significant peaking and the associated expense.

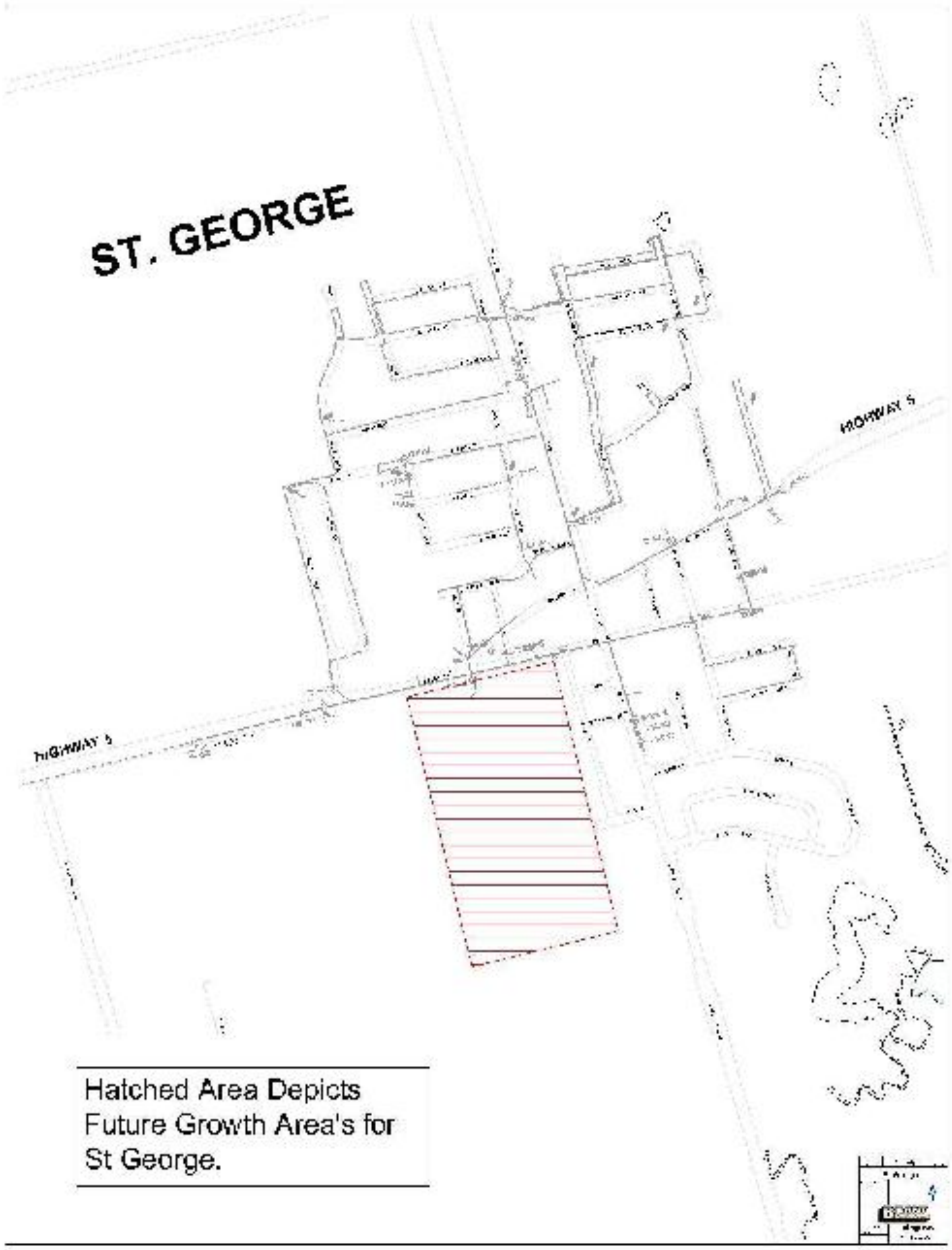
2.8 Indentified Growth

As identified in the introduction, our strong industrial growth will be realized in the area of Rest Acres Road with residential growth spreading south from Paris and Industrial growth occurring south of Highway 403. In south west Paris a new sewer line is being installed which encourages growth in the Dundas Street East and Paris Road area. As our main feeder lines into Paris are located here, we don't anticipate any additional infrastructure being required in this area during this five year period. We also expect growth to continue in the village of St George (residential) and around the Brantford Airport (industrial).


PARIS
WATT'S POND ROAD
Future Growth Area in North Paris
Future Growth Area
North West Paris.

EB-2010-0125
Filed on: November 5, 2010





Hatched Area Depicts Future Growth Area's for St George.

2.9 Paris area Feeder Review

Brant 12M24

The 12M24 Feeder runs along a corridor from Brant Transformer Station to Paris and then winds through the downtown core ending up in the north end of Paris. The feeder mainly consists of 556 mcm conductor but has a short section of 3/0 in the parking lot downtown.

The 12M24 is presently capable of carrying the entire load of Paris.

Powerline PM4

The PM4 Feeder runs from Powerline Municipal Transformer Station, along Paris Road at the east of the town then crosses the river on the same structure as the 12M24. This feeder supplies the south and west areas of Paris and approximately one half of the industrial park at the north of the town. The PM4 is also currently capable of carrying the entire load of the town.

Brant 12M22

The 12M22 feeder runs from Brant Transformer Station, along Powerline Road to Rest Acres Road and then north to Paris Road. We try to avoid placing load on this feeder as it feeds into Hydro One's service area. Due to its significant length (38 km) it carries a high exposure to outages.

See chart below depicting outages for 2009

Cause	Number of customers affected	Outage duration in minutes
Unknown/Other	1,101	43,721
Scheduled Outage	414	144,734
Loss of Supply	4,492	875,424
Tree Contacts	47	2,095
Lightning	3,307	418,553
Equipment Related	5,720	125,385
Adverse Weather	102	4,770
Foreign Interference	1,311	223,531
Total	16,494	1,838,233

As shown in the above chart loss of supply is our largest cause of loss of service to our customers.

Meetings with Hydro One have occurred in an effort to both better the network and gain access to their switches. This ultimately provides us with a smaller number of outages therefore reducing outage duration.

2.10 System Improvement Initiatives

Wood Pole Replacement Program

We currently have approximately seven thousand five hundred poles in our service area. Of these, around six thousand eight hundred are made from wood. As the life expectancy of wood poles is only fourty years, we proactively started to both test and replace aging poles. All poles are tested by an independent testing company that determines the poles that require immediate replacement. This program has been underway for six years and will continue going forward. Our current maintenance and construction program allows for approximately two hundred poles per year to be replaced.

Lightning Arresters

Analysis of our outages shows that lightning is another high outage cause affecting a significant number of customers. This fluctuates based on different weather conditions yearly and consequently can be unpredictable, however by adding a combination of arresters and very low impedance grounding placed in strategic locations, we significantly lessen the impact of lightning strikes. This program is now an ongoing initiative with additional protection being added throughout our most susceptible areas each and every year.

Animal Protection

Although we cannot anticipate the number of outages caused by animal contacts, we initiated a program designed to aid in reducing these outages. By installing bushing protectors on all our overhead transformers we expect to reduce these outages by twenty five percent once fully implemented and currently an overall reduction of over fifty percent is being realized; however it is understood that this quick significant gain could be simply reflective of other environmental issues.

3. Smart Grid Development

3.1 System Reinforcement solutions being undertaken in 2011

Sectionalize Auto-Transfer Industrial Park in North.

In 2011 the intention is to install two Scada-mates with Intelli-team technology in the north end of Paris. One of these will be placed on the PM4 feeder and the other on the 12M24 feeder. This will allow us to close the open point in the industrial park and open the new Scada-mate on the PM4. If a fault occurs before the 12M24 Scada-mate, it opens, the PM4 Scada-mate will close and the industrial load will be restored within a minute. If the fault is on the load side of 12M24 Scada-mate the switch will open and the Downtown core is restored by closing the Hydro One 12M24 breaker as quickly as communication allows.

We are also creating a new tie between the 12M24 feeder and the PM4 feeder in the downtown core. This will allow us to work towards seamless switching of the commercial area for the town of Paris between the two feeders automatically if the normal feeder is lost.

Coordination Study and Trip Saver Devices

We are currently undergoing a coordination study to be followed by the selection of a proper sectionalizing device. This will be utilized for the rural supply along King Edward Street to the west of Paris and the rural area around the Brantford Airport. A sectionalizing device such as a Trip Saver will automatically reclose and clear temporary faults with no effect on the rest of the feeder. No line crew field visit would be required to restore power thus reducing outage durations and associated labour costs.

3.2 System Reinforcement solutions being undertaken in 2012

Split Industrial Load back to PM4 and 12M24

A third Scada-mate switch will be installed at the current open point in the north Paris industrial area. The Industrial load will be shared by both feeders as per current layout. If a fault occurs on either PM4 or 12M24, on the supply side of the switches, only half the Industrial load will see a momentary outage and will be restored within a minute. If the fault occurs in the industrial area, the Scada-mate will isolate the fault, and only half the Industrial park will be left without power until restoration is achieved.

Further, additional smart switches will be installed in the downtown core to allow automatic load transfers in the event of a lost feeder.

3.4 System Reinforcement solutions being undertaken in 2013

A fourth Scada-mate with Intelli-team technology will be located on Broadway Street. This will allow the downtown core to be protected from faults on the supply side up to and including the feeder breaker. When teamed with the previously installed Scada-mates, the downtown core will be fully restored within a minute.

Further automation will occur in other areas of our service territory, particularly in the area around the airport and Cainsville. Our intention is to perform co-ordination studies to determine where we may deploy Trip Saver devices as we believe that this technology can reduce both the number and the length of outages to our customers.

3.3 System Reinforcement solutions being undertaken in 2014

In 2014 we plan to install a series of Scada-mate switches on Rest Acres Road to extend our smart grid to the industrial area located at Bethel Road. We will be able to put load switching in place that will automatically react to system faults providing an extremely high level of service reliability to this area.

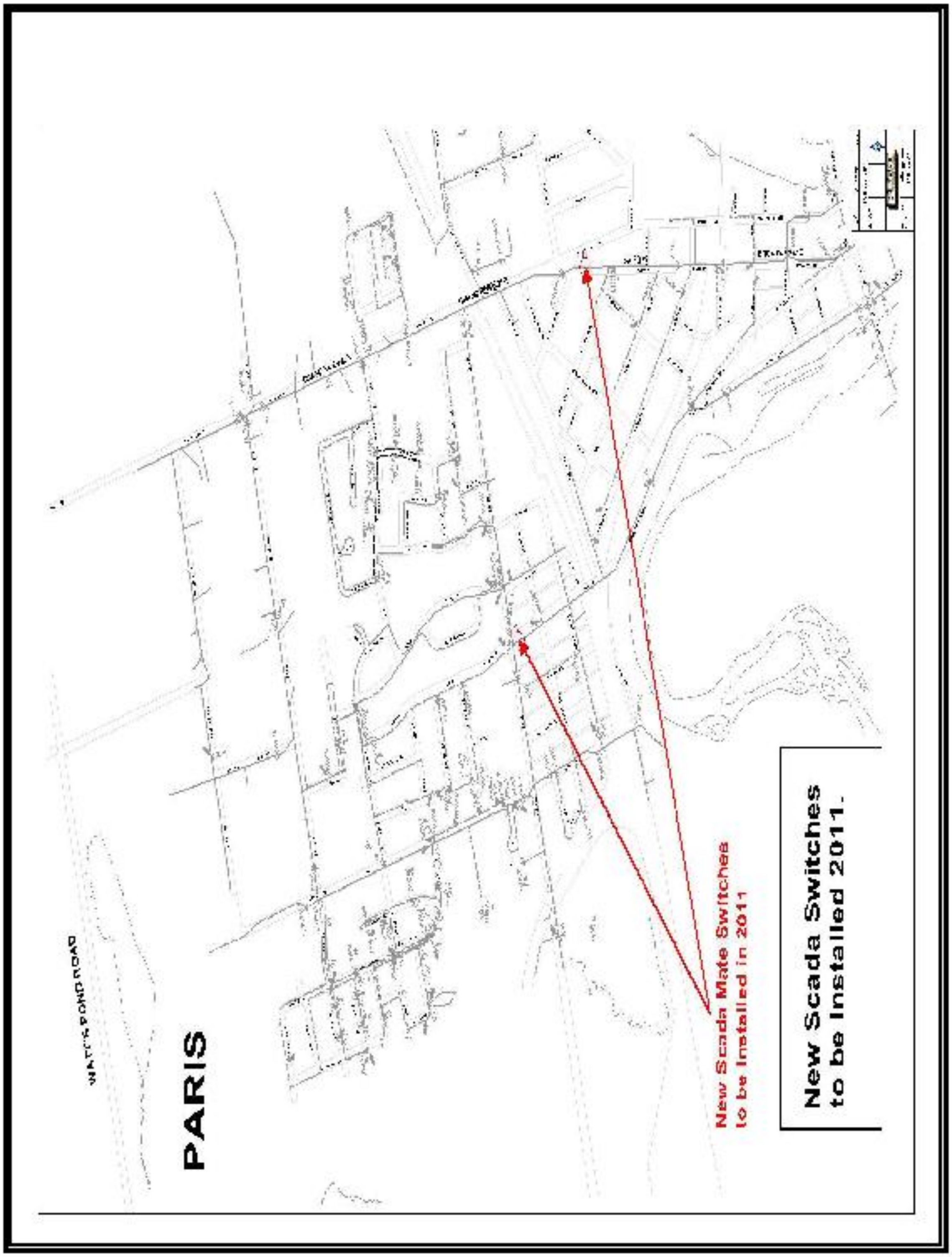
3.5 System Reinforcement solutions being undertaken in 2015

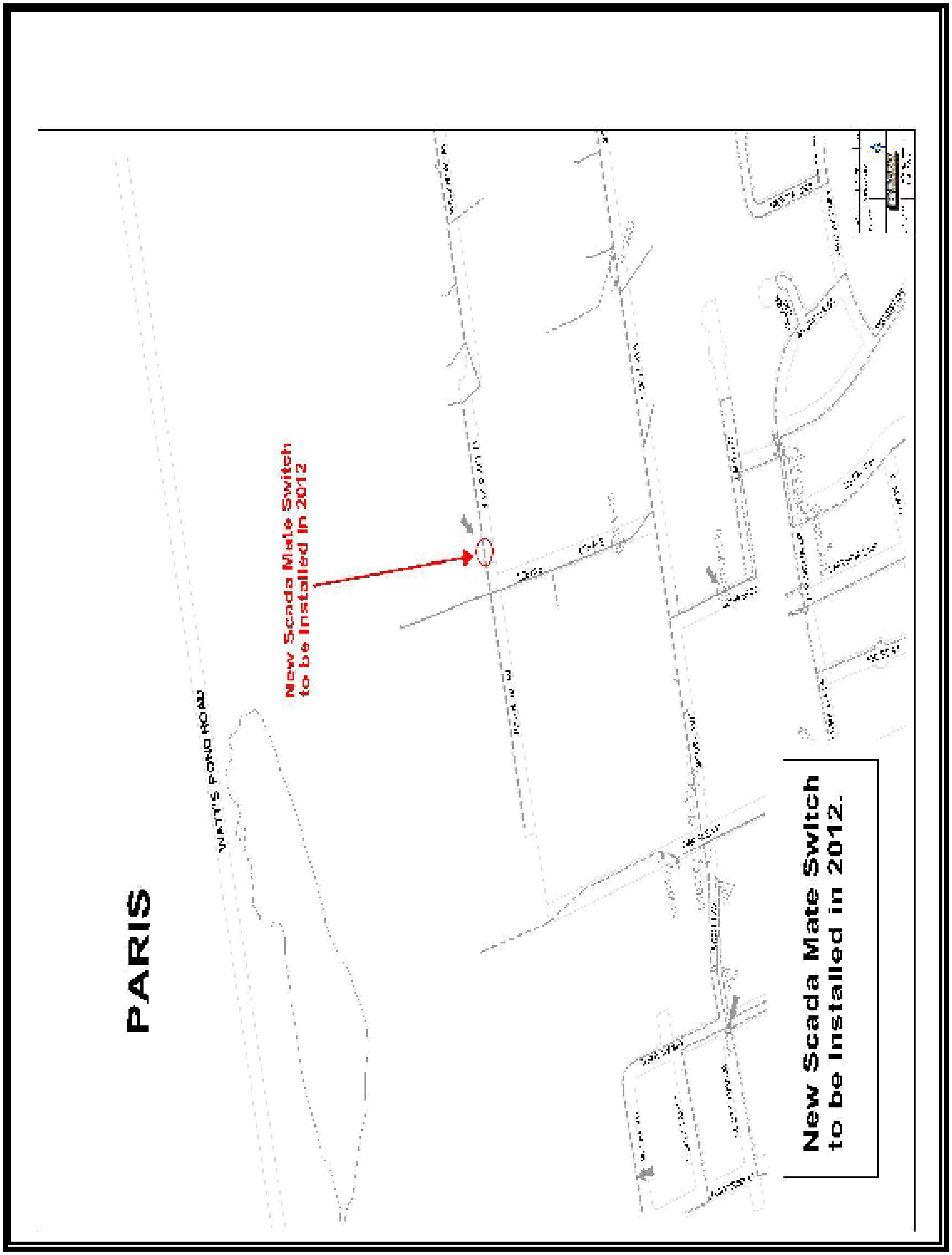
In 2015 additional Scada-mate switches will be installed to further enhance our smart grid. As we expect a new feeder to be built into north Paris, switches will be required to permit automatic switching when system failures occur.

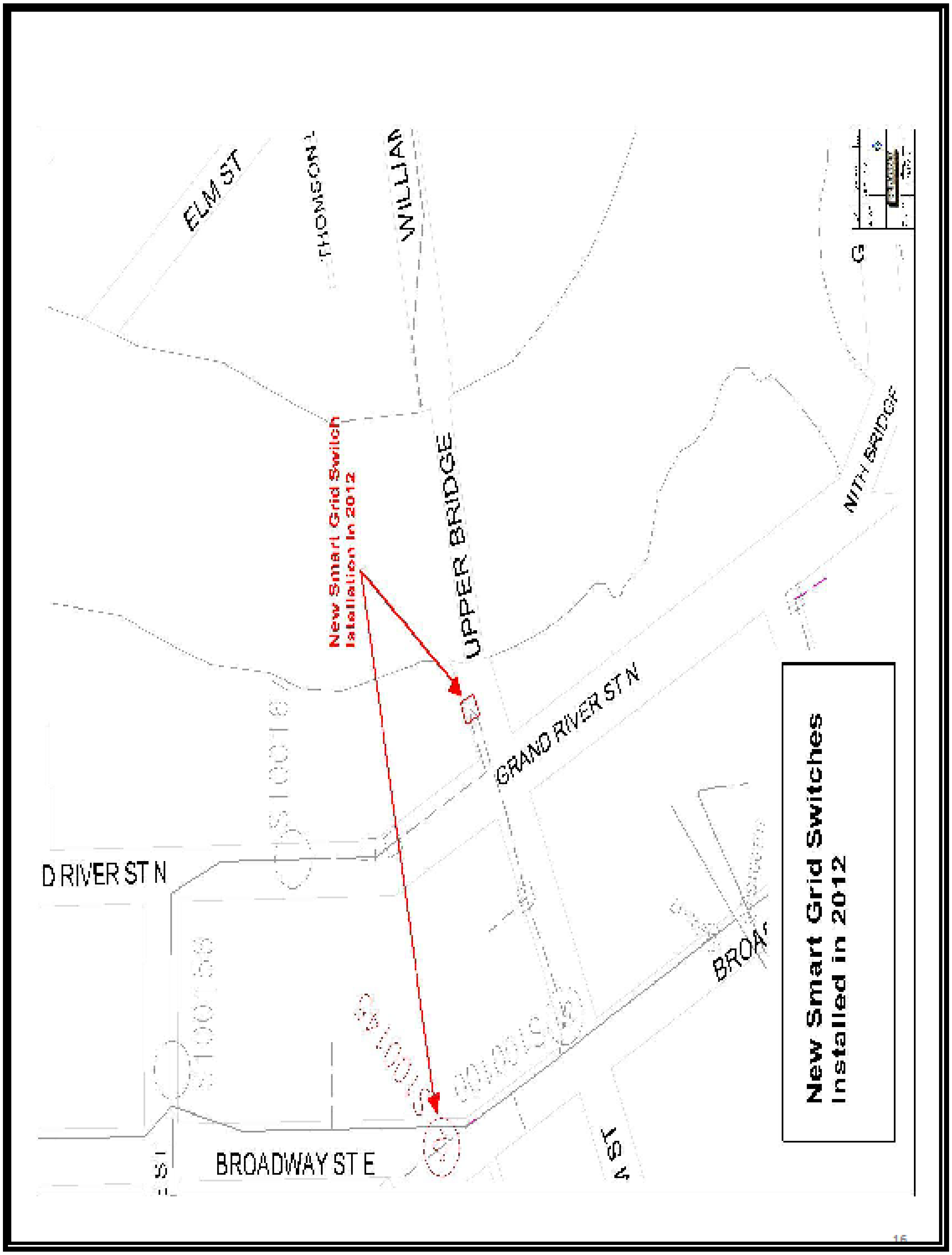
3.6 Automation Options Planned for 2013

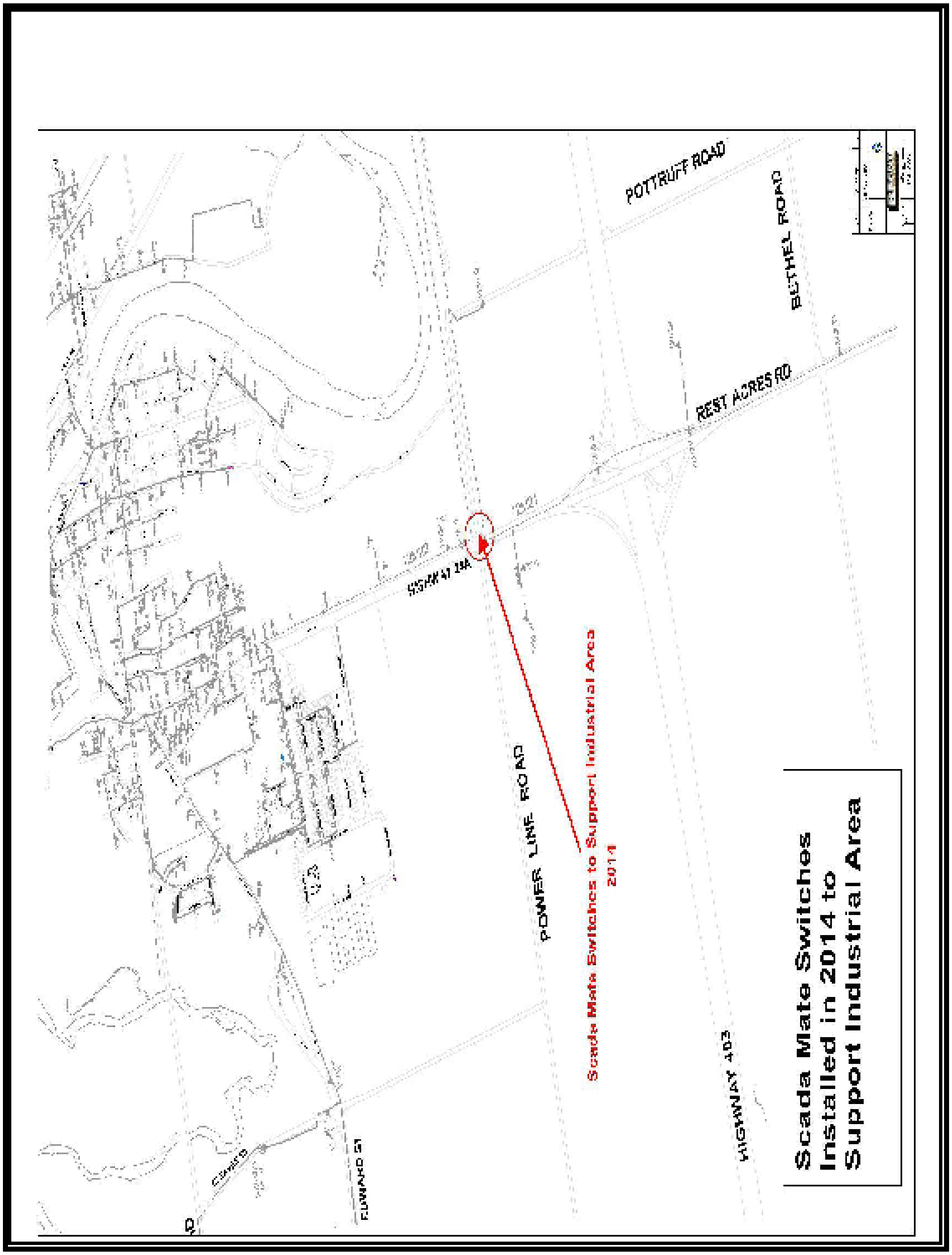
Monitoring and Control of Scada Switches

The S&C MCA software is a monitoring and control application that will put system status on secure Internet sites for access by on-call line technicians and utility management. Features will include tools such as paging, email status information and opening and closing of controlled devices. These features shall permit us to be quickly aware of changes in our systems thereby reducing response time and ultimately shortening the duration time.
We expect that real time automation and any associated technician involvement for these initiatives will come as a subset to our 2010 GIS project.


PARIS
WATTS POND ROAD
New Scada Mate Switches
to be Installed in 2011
New Scada Switches
to be Installed 2011.


PARIS
WATT'S POND ROAD
New Scada Mate Switch
to be Installed in 2012
New Scada Mate Switch
to be Installed in 2012.


New Smart Grid Switches
Installed in 2012
New Smart Grid Switch
Istallation in 2012
ELM ST
UPPER BRIDGE
GRAND RIVER ST N
NITH BRIDGE
D RIVER ST N
BROADWAY ST E


POTTRUFF ROAD
BETHEL ROAD
REST ACRES RD
POWER LINE ROAD
HIGHWAY 403
Scada Mate Switches to Support Industrial Area
2014
Scada Mate Switches
Installed in 2014 to
Support Industrial Area

4. New Feeder Plans

New PM6 Feeder along Powerline Road

2011

In 2011 a new river crossing and 1.5km extension of a feeder along Powerline Road will be built to provide a back-up supply to the south west of the town and to provide necessary supply to the new Industrial Park. This will be an additional feeder (PM6) fed out of Powerline MTS. In addition the 12M11 feeder will be extended across the river and brought out to Powerline Road. This strengthens our back-up supply to the Industrial Park in the south and west of the town and will service new development in the area around the Brantford Municipal airport.

2012

We will lengthen the 12M11 to extend towards the municipal industrial park located at Rest Acres Road and Bethel Road. By extending the existing feeder we ensure service will be provided to the expected business development in the area.

2013

The next extension on the 12M11 will go to Colborne Street West. The PM6 feeder will be used to feed the growth in south west Paris and support the other two feeders in the Paris area.

An important footnote is our intention to do some additional work which will permit us to transfer the load on the 12M24 permanently onto the PM6 feeder and the PM6 load will move to the 12M24. This will allow us to transfer loads in the downtown core, the industrial area and southwest Paris without the risk of double peaking on transformer stations, therefore not incurring any additional costs.

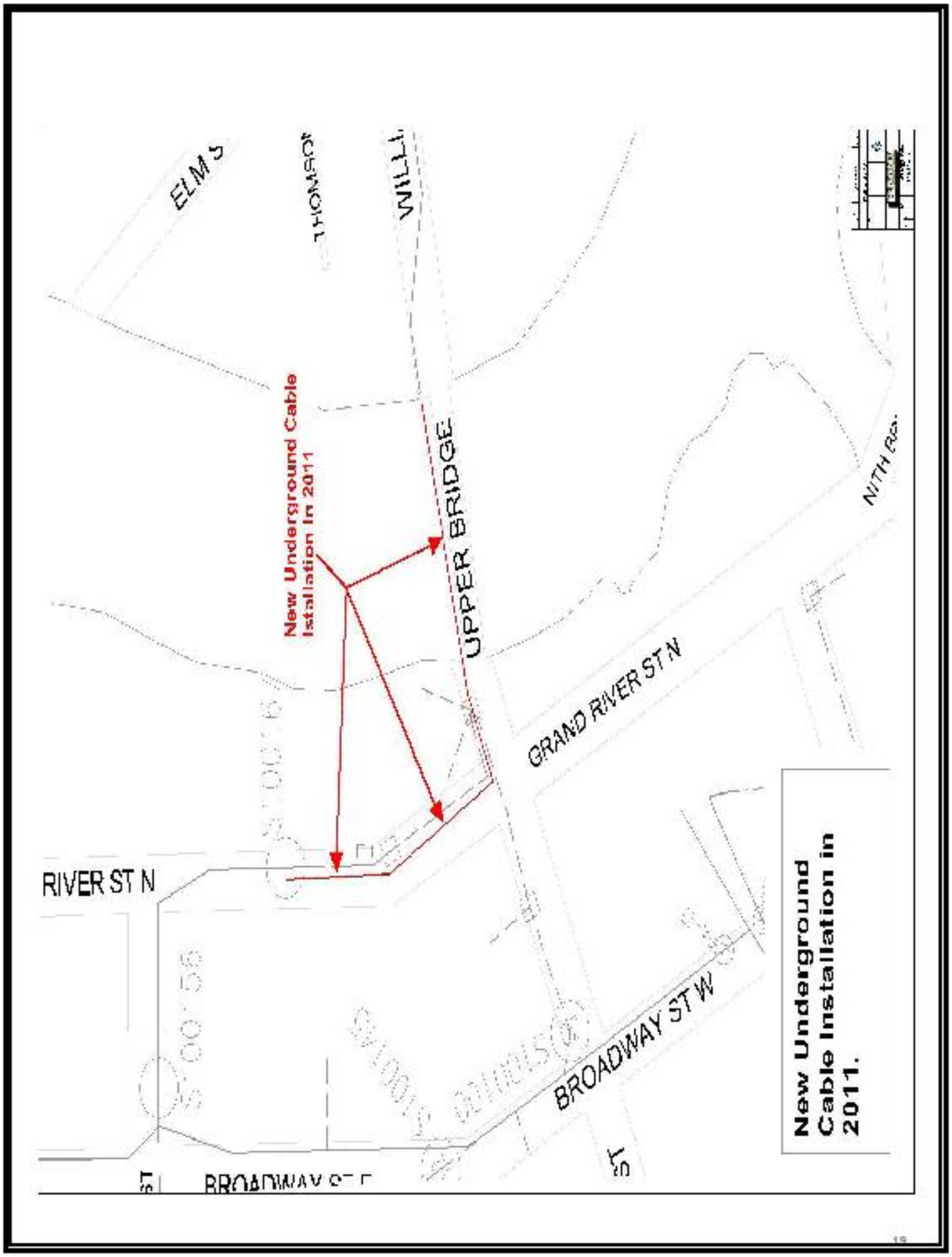
2014

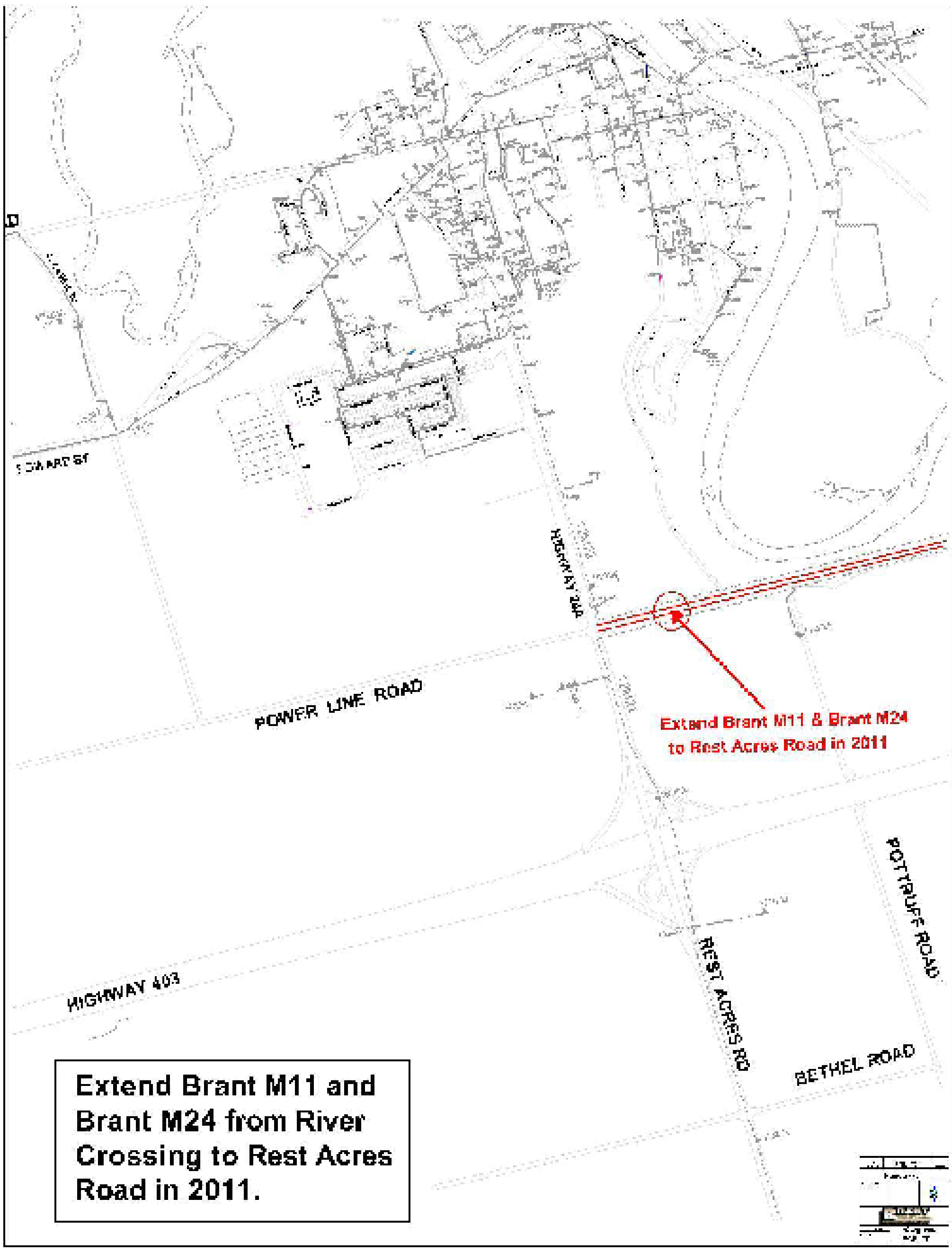
The 12M11 will next be extended along Colborne Street West to Airport Road. All load along the route will be converted to 16 kv and the 8320kv will be eliminated. This feeder will also provide a backup feed for the MS#6 substation. In the event that the substation fails, we will still remain in a position to provide supply to our customers.

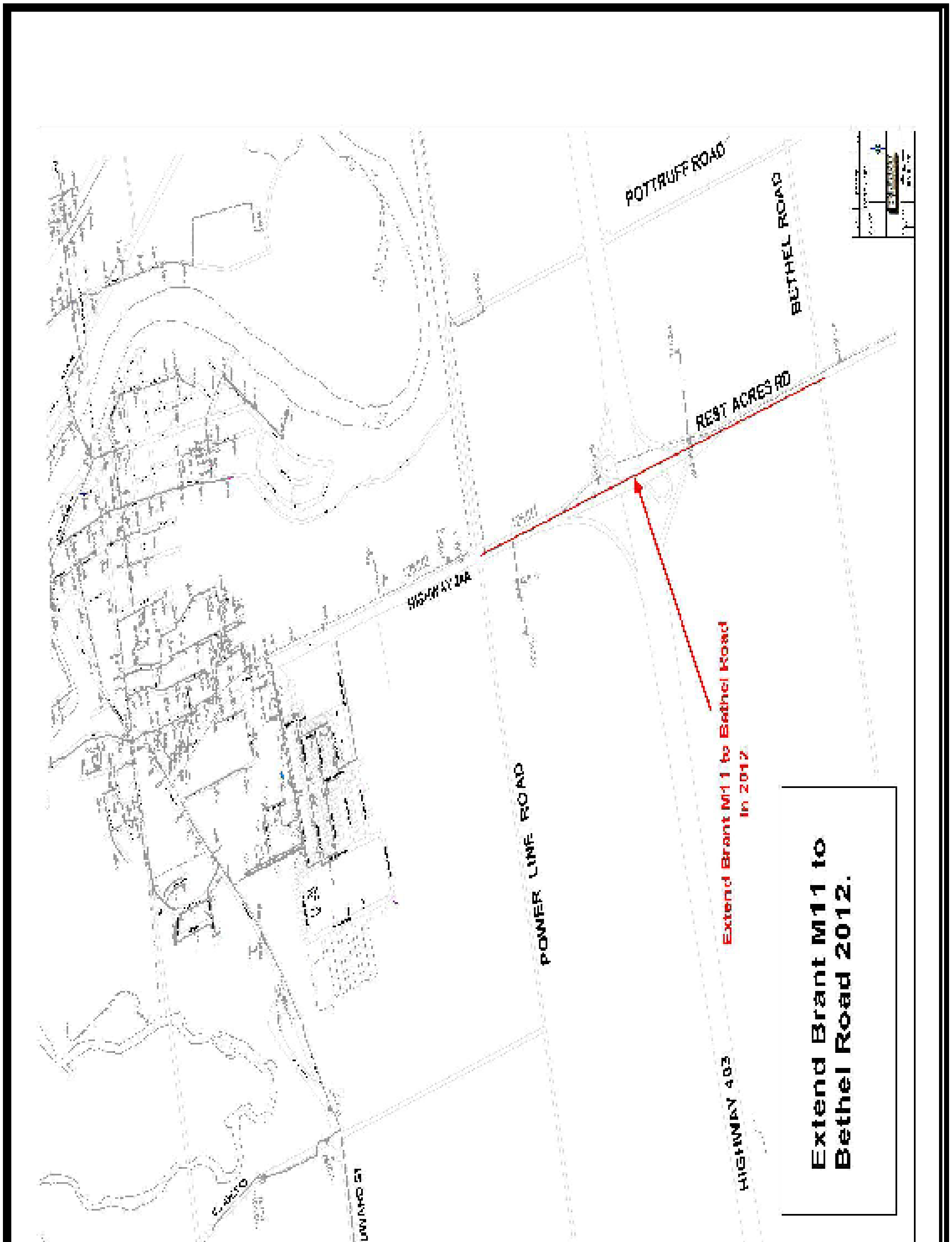
2015

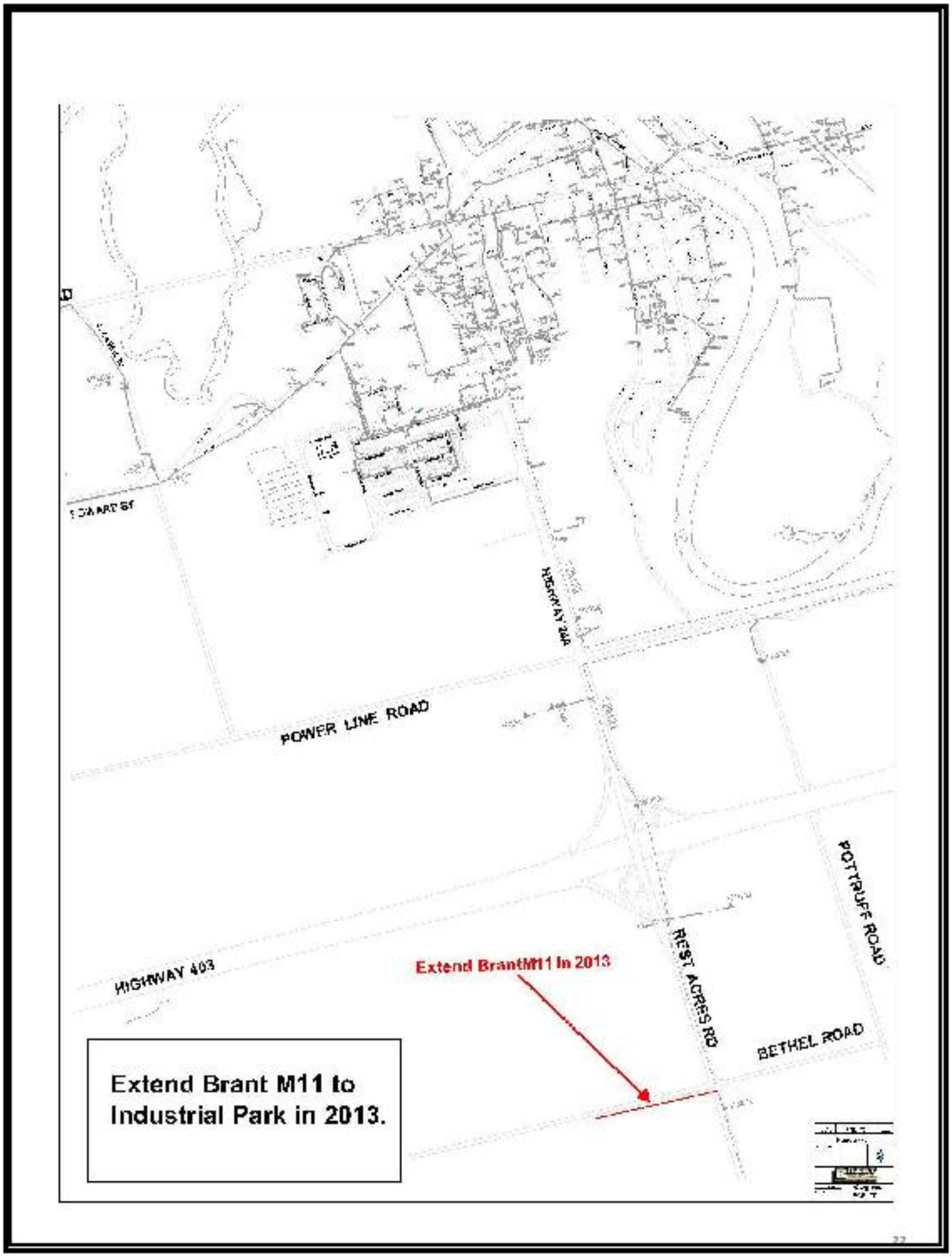
We anticipate that an additional feeder will be required in the Paris area. A new river crossing is proposed from Green Lane to Paris Links Road. This feeder (PM5) will provide additional load support for the north end of Paris and provide additional back up to the industrial area and downtown Paris.

We have had some discussions with Brantford Power concerning an additional transformer station to be built along Powerline Road, east of Brantford. This station will allow us to feed future load growth in the Cainsville area and ultimately provide us with an opportunity to build a feeder to St George. This would result in better reliability to these areas and further reduce our line loss.


New Underground Cable
Istallation In 2011
UPPER BRIDGE
GRAND RIVER ST N
RIVER ST N
BROADWAY ST W
New Underground Cable Installation in 2011.


HIGHWAY 24A
POWER LINE ROAD
Extend Brant M11 & Brant M24
to Rest Acres Road in 2011
POTTRUFF ROAD
HIGHWAY 403
REST ACRES RD
BETHEL ROAD
Extend Brant M11 and
Brant M24 from River
Crossing to Rest Acres
Road in 2011.


POTTRUFF ROAD
BETHEL ROAD
REST ACRES RD
POWER LINE ROAD
Extend Brant M11 to Bethel Road
In 2012
HIGHWAY 403
Extend Brant M11 to
Bethel Road 2012.


HIGHWAY 24A
POWER LINE ROAD
POTTRUFF ROAD
HIGHWAY 403
Extend BrantM11 In 2013
REST ACRES RD
BETHEL ROAD
Extend Brant M11 to Industrial Park in 2013.

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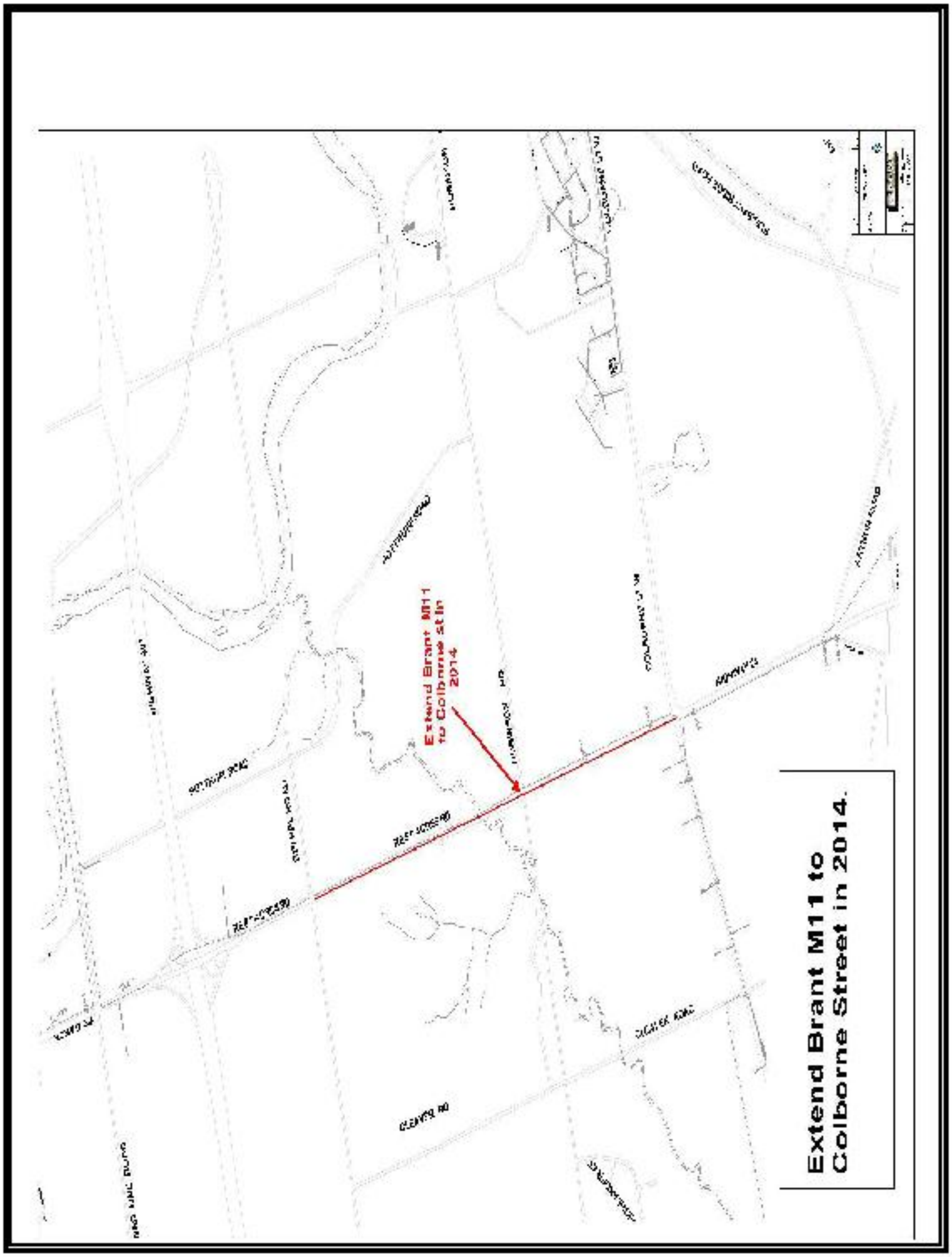
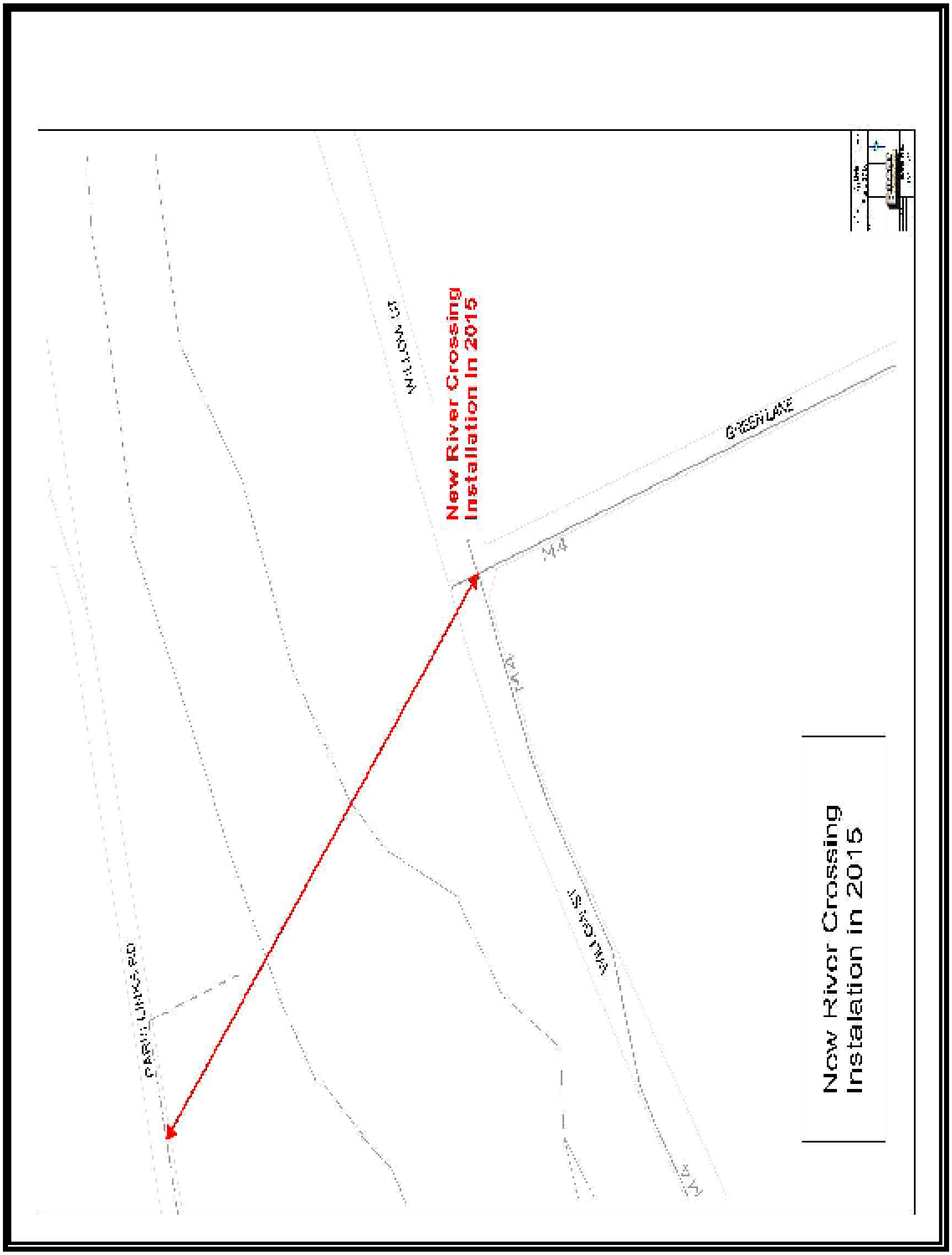
Filed on: November 5, 2010
Exhibit: 2
Tab: 6
Schedule: 1
Page: 71




New River Crossing
Installation In 2015
WILLOW ST
GREEN LANE
New River Crossing
Instalation in 2015

Service Quality and Reliability Performance

Brant County Power has summarized the SQI and reliability indices below. In 2009, all statistics met or within the Board's target range. In 2008, CAIDI was the only measure that was not within the Board's target range. In 2007, all measures were within the Board's target range.

SQI	Target	2009 Result	2008 Result	2007 Result
New Connection – Low Voltage	90%	100%	100%	100%
New Connection – High Voltage	90%	N/A	N/A	N/A
Appointments Schedule	90%	100%	N/A	N/A
Appointments Met	90%	100%	99.9%	100%
Appointments Rescheduled	100%	N/A	N/A	N/A
Telephone Accessibility	65%	91.8%	89.7%	90.3%
Telephone Call Abandon Rate	10%	0%	N/A	N/A
Written Responses to Enquiries	80%	100%	100%	N/A
Emergency Response – Urban	80%	N/A	100%	N/A
Emergency Response – Rural	80%	100%	100%	100%
Service Reliability Indices – All Outages				
SAIDI	1.40 – 2.95	1.40	1.81	2.95
SAIFI	1.15 – 2.64	1.15	1.34	2.64
CAIDI	1.11 – 1.24	1.24	1.35	1.11
MIAFI	N/A	N/A	N/A	N/A
Service Reliability Indices – Excluding Loss of Supply				
SAIDI	1.27 – 3.6	3.6	1.27	2.90
SAIFI	0.92 – 2.57	1.85	0.92	2.57
CAIDI	1.13 – 1.95	1.95	1.37	1.13
MAIFI	N/A	N/A	N/A	

Note: N/A – means no records for the year (i.e. no requests), or
– not applicable to BCP operations

Ex.	Tab	Schedule	Contents of Schedule

3 - Operating Revenue

OVERVIEW OF OPERATING REVENUE

This exhibit provides the details on Brant County Power's 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. In particular, delivery rates are based on the Rate Order EB-2009-0258, dated April, 1, 2010.

Distribution revenue does not include Regulatory Asset Recovery and Deferred Revenue Recovery Rate Rider revenues, Low Voltage Wheeling revenues. Distribution revenues do, however, include PILS Revenue Recovery amounts. A summary of normalized operating revenues is presented in Exhibit 3, Tab 1, Schedule 2.

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

<u>Other Revenue</u>
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.

SUMMARY OF OPERATING REVENUE TABLE

SUMMARY OF OPERATING REVENUE	2006 Board Approved	2006 Actual	Variance from 2006 Board Approved	2006 Actual	2007 Actual	Variance from 2006 Actual	2007 Actual	2008 Actual	Variance from 2007 Actual	2008 Actual	2009 Actual	Variance from 2008 Actual	2009 Actual	2010 Bridge	Variance from 2009 Actual	2010 Bridge	2011 Test	Variance from 2010 Bridge
	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)
Distribution Revenues																		
Residential	$2,565,169	$2,534,358	-$30,811	$2,534,358	$2,869,873	$335,515	$2,869,873	$3,145,523	$275,650	$3,145,523	$2,846,853	-$298,670	$2,846,853	$2,825,767	-$21,086	$2,825,767	$3,521,261	$695,493
GS<50	$855,358	$833,345	-$22,013	$833,345	$971,028	$137,683	$971,028	$896,126	-$74,902	$896,126	$895,321	-$805	$895,321	$986,584	$91,263	$986,584	$1,068,037	$81,454
GS>50 to 499	$1,355,978	$1,566,872	$210,893	$1,566,872	$1,889,661	$322,790	$1,889,661	$1,710,954	-$178,708	$1,710,954	$1,826,477	$115,523	$1,826,477	$2,294,821	$468,345	$2,294,821	$1,031,310	-$1,263,512
Large Use	$153,803	$40,609	-$113,194	$40,609	$0	-$40,609	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Unmetered Scattered Load	$12,472	$16,677	$4,205	$16,677	$18,137	$1,460	$18,137	$15,473	-$2,664	$15,473	$13,677	-$1,796	$13,677	$14,850	$1,173	$14,850	$11,534	-$3,317
Sentinel Lighting	$12,326	$10,996	-$1,330	$10,996	$12,213	$1,217	$12,213	$11,869	-$344	$11,869	$11,493	-$376	$11,493	$11,713	$220	$11,713	$17,768	$6,056
Street Light	$40,034	$47,093	$7,059	$47,093	$51,307	$4,214	$51,307	$35,586	-$15,721	$35,586	$46,800	$11,214	$46,800	$46,859	$59	$46,859	$258,893	$212,034
	$4,995,139	**$5,049,949**	**$54,810**	**$5,049,949**	**$5,812,219**	**$762,270**	**$5,812,219**	**$5,815,531**	**$3,312**	**$5,815,531**	**$5,640,621**	**-$174,910**	**$5,640,621**	**$6,180,594**	**$539,973**	**$6,180,594**	**$5,908,802**	**-$271,792**
Other Distribution Revenue																		
Late Payment Charges	$85,606	$69,205	-$16,401	$69,205	$78,169	$8,964	$78,169	$86,045	$7,876	$86,045	$96,584	$10,539	$96,584	$102,000	$5,416	$102,000	$102,000	$0
Specific Service Charges	$218,186	$101,564	-$116,622	$101,564	$129,254	$27,690	$129,254	$138,484	$9,230	$138,484	$108,459	-$30,025	$108,459	$117,920	$9,461	$117,920	$117,920	$0
Other Utility Operation Income	$0	$56,504	$56,504	$56,504	$161,618	$105,114	$161,618	$67,850	-$93,768	$67,850	$37,649	-$30,201	$37,649	$45,408	$7,759	$45,408	$135,000	$89,592
Other Electric Revenue	$31,691	$288,768	$257,078	$288,768	$210,930	-$77,838	$210,930	$197,173	-$13,757	$197,173	$199,910	$2,737	$199,910	$208,574	$8,664	$208,574	$251,574	$43,000
RCVA Revenue	$10,233	$0	-$10,233	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$345,716	**$516,041**	**$170,325**	**$516,041**	**$579,971**	**$63,930**	**$579,971**	**$489,552**	**-$90,419**	**$489,552**	**$442,602**	**-$46,950**	**$442,602**	**$473,902**	**$31,300**	**$473,902**	**$606,494**	**$132,592**
Total Operating revenue	**$5,340,855**	**$5,565,990**	**$225,135**	**$5,565,990**	**$6,392,190**	**$826,200**	**$6,392,190**	**$6,305,083**	**-$87,107**	**$6,305,083**	**$6,083,223**	**-$221,860**	**$6,083,223**	**$6,654,496**	**$571,273**	**$6,654,496**	**$6,515,296**	**-$139,200**

VARIANCE ANALYSIS ON OPERATING REVENUE

Brant County Power distribution revenue has been calculated using the most recently approved rates. In particular, delivery rates are based on the EB-2009-0258 Rate Order, dated April 1, 2010. Distribution revenue does not include commodity related revenue.

2011 Test Year

BCP operating revenue is forecast to be $6,515,296 in Fiscal 2011, as shown in Exhibit 3, Tab 1, and Schedule 2. Distribution revenue totals $5,908,802 or 90.7% of total revenues. Other operating revenue (net) accounts for the remaining revenue difference of $606,494 (includes transformer allowance of $49,168).

Comparison to 2010 Bridge Year

As shown in Exhibit 3, Tab 1, Schedule 2, the total operating revenue is expected to be $382,006 above the bridge year level in fiscal 2010. The 2010 fiscal revenue is based on current rates * projected consumption while 2011 is based on rebased revenue.

These increases are discussed in detail in Exhibit 4.

The Other Revenue contributes a difference of $132,592 which represents an increase to other revenue of $135,000 relating to Green Energy Act initiatives and a reduction in other interest income of $2,408.

2010 Bridge Year

Comparison to Fiscal 2009 Actual

As shown in Exhibit 3, Tab 1, Schedule 2, the total operating revenue is expected to be $571,273 above the 2009 Actual level in fiscal 2010. This is a result from IRM increase and changes in the consumption profile.

2009 Actual

Comparison to 2008 Actual

As shown in Exhibit 3, Tab 1, Schedule 2, the total operating revenue was $221,860 lower in 2009 vs. 2008 Actual.

2008 Actual

Comparison to 2007 Actual

As shown in Exhibit 3, Tab 1, Schedule 2, the total operating revenue was $87,107 lower in 2008 vs. 2007 Actual.

<u>2007 Actual</u>

<u>Comparison to 2006 Actual</u>

As shown in Exhibit 3, Tab 1, Schedule 2, the total operating revenue was $826,200 higher in 2007 vs. 2006 Actual and results from the application of approved rates.

<u>2006 Actual</u>

<u>Comparison to 2006 Approved</u>

As shown in Exhibit 3, Tab 1, Schedule 2, the total operating revenue was $225,135 higher in 2006 vs. 2006 approved. This amount is arrived at from applying approved 2006 rates against actual 2006 consumption. The difference can be attributed to differences between 2006 actual and projected consumption profiles.

Customer, Consumption and Load Forecast

Brant County Power utilized the customer counts, consumption and load forecasts as provided by Burman Energy Consultants Group Inc. We are including the final report of the load and customer forecast as provided by Burman Energy Consultants.

Customer Forecast										
	2002	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
RESIDENTIAL	**7,008**	**7,211**	**7,471**	7,580	7689	7822	7920	8033	8170	8290
GENERAL SERVICE										
Less than 50 kW	1,275	1,253	1,286	1,267	1247	1200	1203	1249	1314	1315
Greater than 50 to 4,999 kW	172	159	121	118	114	111	108	104	109	106
Unmetered Scattered Load	42	41	43	50	57	56	55	52	52	51
Sentinel Lighting	242	247	238	215	191	142	139	179	221	218
Street Lighting	2,469	2,536	2,576	2,611	2,646	2653	2640	2640	2640	2630
TOTALS	**11,208**	**11,447**	**11,735**	**11,840**	**11,944**	**11,984**	**12,065**	**12,257**	**12,506**	**12,610**
Load Forecast										
Normalized Average Consumption kWh										
	2002	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
RESIDENTIAL	68,659,239	72,712,385	73,977,688	81,427,289	79,560,842	80,124,626	79,456,965	79,540,610	77,571,849	80,122,583
GENERAL SERVICE										
Less than 50 kW	32,010,516	31,414,184	33,999,045	36,179,422	34,406,201	33,769,287	35,036,376	36,124,082	37,411,381	39,095,551
Greater than 50 to 4,999 kW	96,037,314	98,159,714	93,388,024	101,120,635	105,111,506	171,480,226	164,540,705	153,259,553	157,033,123	151,750,742
Unmetered Scattered Load	376,828	464,888	468,188	532,055	524,636	521,085	502,476	496,256	499,482	493,370
Sentinel Lighting	245,304	228,491	220,029	210,113	208,256	196,420	187,414	180,387	220,415	215,167
Street Lighting	1,348,551	1,551,177	1,464,366	1,632,853	1,694,400	1699400	1702146	1696627	1711505	1707054
TOTALS	**198,677,752**	**204,530,839**	**203,517,340**	**221,102,367**	**221,505,841**	**287,791,044**	**281,426,082**	**271,297,515**	**274,447,755**	**273,384,467**
Normalized Average Consumption kW										
	2002	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
Greater than 50 to 4,999 kW	303,425	318,143	299,165	321664	332145	356488	353530	342040	402016	388493
Sentinel Lighting	681	634	611	560	555	523	499	481	588	574
Street Lighting	2,528	4,135	4,202	4,685	4,779	4779	4770	4770	4795	4783
TOTALS	**306,634**	**322,912**	**303,978**	**326,909**	**337,479**	**361,790**	**358,799**	**347,291**	**407,399**	**393,850**

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Brant County Power Inc.
Load Forecasting Methodology

Summary

The purpose of this report is to present the process used by Burman Energy Consultants Group to prepare the normalized load forecast used for the purpose of rate application for Brant County Power. Burman Energy reviewed various processes used by the 2008 and 2009 cost of service applicants on the OEB database and is proposing to adopt weather normalization forecasting (WNF). This method is the one approved by the Ontario Energy Board for Toronto Hydro Electric System Ltd in its 2008, 2009 and 2010 rate application (EB-2007-0680).

Burman Energy has used a widely accepted multivariate regression analysis methodology which is used by various distributors in Ontario. The regression analysis establishes purchased kWh as the independent variable against a number of dependent variables. The dependant variables are considered contributors to the determination of load and energy. There is a very high correlation between the historical and forecasted model data which demonstrates the effectiveness of this tool.

Load Forecast and Methodology

- Burman Energy's weather normalized load forecast is developed in a multi-step process.
  - First, the total system weather normalized purchased energy forecast is developed based on a multivariate regression model that incorporates weather, historical load and economic data.
  - Next, the purchased energy forecast is adjusted by a historical loss factor to produce a weather normalized billed energy forecast.
  - Then using the billed energy forecast, the rate class billed energy (kWh) is developed based on a forecast of customer numbers and historical usage patterns per customer.
  - The billed energy forecast for classes that are weather sensitive, is adjusted to ensure that the total billed energy forecast by class correlates to the total weather normalized billed energy forecast.

- Finally a geometric analysis is conducted in order to forecast the customers from the different classes. For classes that use kW for the distribution volumetric billing determinant, an adjustment factor is applied to class energy forecast based on the historical relationship between kW and kWh.

Regression Analysis Model Equation:

BECGI has developed coefficients for the following dependant variables used in the regression model:

- weather (heating and cooling degree days)
- Ontario economic output (GDP)
- Conservation and Demand Management (CDM) activity
- Calendar variables (days in month)
- A 'Constant' used for change in purchased kWh in 2006

Dependant Variables:

- **Weather** impacts on load are apparent in both the winter heating season, and in the summer cooling season. For that reason, both **Heating Degree Days** ("**HDD**" i.e. a measure of coldness in winter) and **Cooling Degree Days** ("**CDD**" i.e. a measure of summer heat) are modeled.
    - Due to the recent global activity surrounding climate change historical weather data is showing that there is a warming of the global climate system.
        - In this regard, Burman Energy has reviewed the impact of weather on the energy usage starting from January 1990 to July 2010. This is done to determine weather-normalized forecast. A sensitivity analysis was done showing the impact on the 2010 and 2011 purchased kWh weather normalized forecast based on 10-year and a 20-year weather trend data.
- **Economic** output – which encompasses customer trends in the Brant County Power service area as well as general economic conditions; this is captured in the model using the Ontario Real Gross Domestic Product (GDP) as an index of economic output.
- **CDM** activity is another driver which impacts the load forecast and thus, historical CDM activity reported by the OPA as well as the Minister's Directive for CDM activity for 2011-2014 target numbers for Brant County Power have been used in the regression analysis model as part of the equation.

- **Calendar variable** is another factor in determining energy use in the monthly model. For example, the number of days in a particular month will impact energy use.

- A '**Constant**' was used for the purchased kWh in 2006 due to higher kWh consumption towards the end of 2006 onwards.

Determination of coefficients:

- Monthly **Purchased kWh** and values of the dependant variables from January 2005 to December 2009 resulted in 60 data points.. This is done in order to obtain the coefficients of the regression model equation.

Purchased kWh Prediction Model Equation:

The following outlines the equation of the predication model used to predict weather normal kWh purchases.

$$\begin{aligned} Purchased\ kWh_{Predicted} &= (HDD_{coefficient} * HDD) + (CDD_{coefficient} * CDD) \\ &+ (GS > 50kW\ Flag_{Coefficient} * 'Constant') \\ &+ (Number\ of\ Days\ in\ a\ Month_{Coefficient} * Number\ of\ days\ in\ a\ month) \\ &+ (Ontario\ real\ GDP_{Coefficient} * GDP) + (CDM\ Activity_{coefficient} \\ &* CDM\ activity) \end{aligned}$$

A table at the end of the report illustrate the resulting outcome of the predicted kWh and is compared to the actual kWh.

The sources of data for the various data points are:

1. Environment Canada website for monthly heating degree day and cooling degree information. Data for the Brantford/Brant County weather station was used.
2. The 2003, 2008 and 2009 Ontario Economic Outlooks from the Ontario Ministry of Finance provided the Ontario real GDP index.
3. The calendar provided information related to number of days in the month.

Billed energy (kWh) Forecast:

To determine the total weather normalized energy billed forecast, the total system weather normalized purchased forecast is adjusted by a historical loss factor. As outlined in the table below, historically the Brant County Power loss factor on average has been 6.80%. This loss factor was used in load forecast for the prediction of billed kWh.

Year	Purchased kWh Actual	Billed kWh Actual	Loss Factor
2005	236,756,080	221,102,367	7.080%
2006	244,309,195	221,505,841	10.288%
2007	306,747,610	287,791,044	6.587%
2008	297,492,850	281,426,082	5.709%
2009	285,044,124	271,297,515	5.067%
		Average	6.945%

With this average loss factor the total weather normalized billed energy (kWh) will be:

$$\left(\text{Purchased } kWh_{Predicted} \middle/ \text{Loss } Factor_{Average} \right)$$

Billed Demand Usage (kW) Forecast:

As Brant County has classes which are not weather sensitive and the cost of power is based on kW (demand) use, the energy forecast for these classes needs to be converted to a kW basis. The forecast of kW for these classes is based on a review of the historical ratio of kW to kWh and applying the average ratio to the forecasted kWh to produce the required kW. This approach was done for the GS>50 kW, Streetlights and Sentinel lights classes.

The following is the historical billed kW and predicted kW for 2010 and 2011.

Annual Ratio of kW to kWh

Year	GS>50 kW	Street Lights	Sentinel Lights
2005	0.31810%	0.28689%	0.26667%
2006	0.31599%	0.28202%	0.26667%
2007	0.20789%	0.28119%	0.26667%
2008	0.21486%	0.28026%	0.26667%
2009	0.22320%	0.28117%	0.26667%
Average	0.25601%	0.28231%	0.26667%

Annual Billed kW

Year	GS>50 kW	Street Lights	Sentinel Lights	Total
2005	321,664	4,685	560	326,909
2006	332,145	4,779	555	337,479
2007	356,488	4,779	524	361,790
2008	353,530	4,770	500	358,800
2009	342,070	4,770	481	347,322
2010	425,205	4,792	459	430,455
2011	451,104	4,794	437	456,335

Results of Prediction Model:

The prediction formula form the regression analysis has the following statistical result which generally indicates the formula has a very good fit to the actual data set.

Regression Statistics	
Multiple R	0.95
R Square	0.91
Adjusted R Square	0.90
Observations	60

	t Stat
Intercept	-1
Heating Degree Days	9
Cooling Degree Days	10
GS>50kW Flag for 2006	9
Number of Days in Month	3
Ontario Real GDP Monthly %	2
CDM Activity	-1.8

Prediction Results and Actual Data Comparison:

The annual results of the above prediction formula compared to the actual annual purchases from 2005 to 2009 are shown in the table below.

Brant County Power-Weather Normalized Load Forecast

	2005	2006	2007	2008	2009	2010	2011
Actual kWh Purchases	236,756,080	242,722,450	306,747,610	297,492,850	285,044,124		
Predicted kWh Purchases	237,105,183	241,529,155	303,227,205	298,065,175	288,836,397	293,500,326	292,363,223
% Difference	0.147%	-0.492%	-1.148%	0.1924%	1.330%		
Billed kWh	221,115,207	221,518,681	287,802,804	281,438,922	271,310,355	274,447,754	273,384,466

The weather normalized forecast amount for 2010 and 2011 is determined by using dependant variables in the prediction formula on a monthly basis.

(yellow)	Actual
(green)	Predicted

Brant County Power-Weather Normalized Load Forecast

	2005	2006	2007	2008	2009	2010	2011
Actual kWh Purchases	236,756,080	242,722,450	306,747,610	297,492,850	285,044,124		
Predicted kWh Purchases	237,105,183	241,529,155	303,227,205	298,065,175	288,836,397	293,500,326	292,363,223
% Difference	0.147%	-0.492%	-1.148%	0.1924%	1.330%		
Billed kWh	221,115,207	221,518,681	287,802,804	281,438,922	271,310,355	274,447,754	273,384,466
By Class							
Residential							
Customers		7,689	7,822	7,920	8,033	8,170	8,290
kWh	81,427,289	79,560,842	80,124,626	79,456,965	79,540,610	77,571,849	80,122,583
General Service (GS) < 50 kW							
Customers		1,247	1,200	1,203	1,249	1,314	1,315
kWh	36,179,422	34,406,201	33,769,287	35,036,376	36,124,082	37,411,381	39,095,551
General Service (GS) > 50 kW							
Customers		114	111	108	104	109	106
kWh	101,120,635	105,111,506	171,480,226	164,540,705	153,259,553	157,033,123	151,750,742
kW	321,664	332,145	356,488	353,530	342,070	402,016	388,493
Streetlights							
Customers		2,646	2,653	2,640	2,640	2,640	2,630
kWh	1,645,693	1,707,240	1,712,240	1,714,986	1,709,467	1,711,505	1,707,054
kW	4,685	4,779	4,779	4,770	4,770	4,795	4,783
Sentinel Lights							
Connections		242	240	231	225	221	218
kWh	210,113	208,256	196,420	187,414	180,387	220,415	215,167
kW	560.301	555.349	523.787	499.771	481.032	587.772	573.779
Unmetered Scattered Load (USL)							
Connections		58	57	55	52	52	51
kWh	532,055	524,636	520,005	502,476	496,256	499,482	493,370
Total							
Customer Connections		11,995	12,081	12,156	12,302	12,507	12,611
kWh from all classes	221,115,207	221,518,681	287,802,804	281,438,922	271,310,355	274,447,754	273,384,466
kW from applicable classes	326,348	336,924	361,266	358,301	346,841	406,811	393,276

Variance Analysis

Customer Count

The customer count forecast varies depending upon customer classification. The residential class has shown relatively steady growth over the last several years. The average customer additions for 2006, 2007 and 2008 are 114 customers. For 2010 the projected additions were 137 customers and the actual year to date additions are 161 customers. BCP has forecasted 120 additional residential customers for the Test Year which is slightly higher than the average for 2006, 2007 and 2008 and relatively close to the average over the past 4 years. The addition of 120 residential customers would be the largest second largest number of customers added increase since 2004. Residential customer growth is forecasted at approximately 1.5% residential customers per year for both the Bridge and Test Years. The annualized average growth per year between 2002 and 2009 has been 146 residential customers or 1.9%. The new customer additions for 2005 and beyond are less than 50% of the growth in 2003 and 2004. Brant County Power is forecasting lower customer growth (compared to long-term historical occurrences) due to economic factors and Brant County Power's forecast is consistent with the previous 5 year horizon.

The GS<50kW classification is more difficult to predict. From 2002 through 2009 the number of customers, on average, showed a slight decline. In 2010, the number of customers forecasted was 1,314 which represents the addition of 65 customers. The year to date additions is 99 customers. Brant County is forecasting insignificant growth which is consistent with the historical trend which saw customer reductions in four of the previous 9 years and modest growth, 0.4%, overall since 2002.

The GS>50kW classification has shown a small decline since 2006 from 114 customers to 104 in 2009. Brant County Power experienced a small increase in 2010, likely due to stimulus spending (i.e. the Brant Twin Pad Arena scheduled to open in 2011). For 2010, Brant County is predicting a reduction of 3 customers (2.9%) resulting from the economic factors. Historically, the large customers in Brant County Power's service area are agricultural which has been impacted by the downturn in the economy. Prior to 2006, there was a significant reduction in GS>50kW customers, approximately 38%, from the 2002 customer count of 176. Brant County Power anticipates that the customer count in the GS>50kW classification will remain flat for the 2011 Test Year.

The number of connections for the remaining customer classifications, Unmetered Scattered, Sentinel and Streetlighting, shows small reductions which are mainly attributable to economic factors.

Customer Class	2006 Actual	2007 Actual	Variance	2007 Actual	2008 Actual	Variance	2008 Actual	2009 Actual	Variance	2009 Actual	2010 Projected	Variance	2010 Projected	2011 Projected	Variance
RESIDENTIAL	7,689	7,822	133	7,822	7,920	98	7,920	8,033	113	8,033	8,170	137	8,170	8,290	120
GENERAL SERVICE															
Less than 50 kW	1,247	1,200	-47	1,200	1,203	3	1,203	1,249	46	1,249	1,314	65	1,314	1,315	1
Greater than 50 to 4,999 kW	114	111	-3	111	108	-3	108	104	-4	104	109	5	109	106	-3
Unmetered Scattered Load	57	56	-1	56	55	-1	55	52	-3	52	52	0	52	51	-1
Sentinel Lighting	191	142	-49	142	139	-3	139	179	40	179	221	42	221	218	-3
Street Lighting	2,646	2,653	7	2,653	2,640	-13	2,640	2,640	0	2,640	2,640	0	2,640	2,630	-10
TOTALS	11,944	11,984	40	11,984	12,065	81	12,065	12,257	192	12,257	12,506	249	12,506	12,610	104

Note: customer counts shown in year-end format

Consumption Forecast - kWh

Customer Class	2006 Actual	2007 Actual	Variance	2007 Actual	2008 Actual	Variance	2008 Actual	2009 Actual	Variance	2009 Actual	2010 Projected	Variance	2010 Projected	2011 Projected	Variance
RESIDENTIAL	79,560,842	80,124,626	563,784	80,124,626	79,456,965	-667,661	79,456,965	79,540,610	83,645	79,540,610	77,571,849	-1,968,761	77,571,849	80,122,583	2,550,734
GENERAL SERVICE															
Less than 50 kW	34,406,201	33,769,287	-636,914	33,769,287	35,036,376	1,267,089	35,036,376	36,124,082	1,087,706	36,124,082	37,411,381	1,287,299	37,411,381	39,095,551	1,684,170
Greater than 50 to 4,999 kW	105,111,506	171,480,226	66,368,720	171,480,226	164,540,705	-6,939,521	164,540,705	153,259,553	-11,281,152	153,259,553	157,033,123	3,773,570	157,033,123	151,750,742	-5,282,381
Unmetered Scattered Load	524,636	521,085	-3,551	521,085	502,476	-18,609	502,476	496,256	-6,220	496,256	499,482	3,226	499,482	493,370	-6,112
Sentinel Lighting	208,256	196,420	-11,836	196,420	187,414	-9,006	187,414	180,387	-7,027	180,387	220,415	40,028	220,415	215,167	-5,248
Street Lighting	1,694,400	1,699,400	5,000	1,699,400	1,702,146	2,746	1,702,146	1,696,627	-5,519	1,696,627	1,711,505	14,878	1,711,505	1,707,054	-4,451
TOTALS	221,505,841	287,791,044	66,285,203	287,791,044	281,426,082	-6,364,962	281,426,082	271,297,515	-10,128,567	271,297,515	274,447,755	3,150,240	274,447,755	273,384,467	-1,063,288

Average Usage (kWh)

Customer Class	2006	2007	2008	2009	2010	2011
RESIDENTIAL	10,347	10,243	10,032	9,902	9,495	9,665
GENERAL SERVICE						
Less than 50 kW	27,591	28,141	29,124	28,922	28,471	29,730
Greater than 50 to 4,999 kW	922,031	1,544,867	1,523,525	1,473,650	1,440,671	1,431,611
Unmetered Scattered Load	9,204	9,305	9,136	9,543	9,605	9,674
Sentinel Lighting	1,090	1,383	1,348	1,008	997	987
Street Lighting	640	641	645	643	648	649

Load Forecast - kW

Customer Class	2006 Actual	2007 Actual	Variance	2007 Actual	2008 Actual	Variance	2008 Actual	2009 Actual	Variance	2009 Actual	2010 Projected	Variance	2010 Projected	2011 Projected	Variance
Greater than 50 to 4,999 kW	332,145	356,488	24,343	356,488	353,530	-2,958	353,530	342,040	-11,490	342,040	402,016	59,976	402,016	388,493	-13,523
Sentinel Lighting	555	523	-32	523	499	-24	499	481	-18	481	588	107	588	574	-14
Street Lighting	4,779	4,779	0	4,779	4,770	-9	4,770	4,770	0	4,770	4,795	25	4,795	4,783	-12
Totals	337,479	361,790	24,311	361,790	358,799	-2,991	358,799	347,291	-11,508	347,291	407,399	60,108	407,399	393,850	-13,549

Other Revenue

Appendix 2-C
Other Operating Revenue

USoA	Description	2006	2007	2008	2009	2010 - Bridge	2011 - Test
4235	Misc. Service Revenues	101,564	129,254	138,484	108,459	117,920	117,920
4225	Late Payment Charges	69,205	78,169	86,045	96,584	97,000	97,000
4082	Retail Services Revenue						
4084	Service Transaction Requests Revenues						
4090	Electric Service Incidental to Energy Sales						
4205	Interdepartmenal Rents						
4210	Rent from Electric Property	32,884	43,162	37,315	34,748	37,574	37,574
4215	Other Utility Operating Income						135,000
4220	Other Electric Revenues	255,884	167,768	159,858	165,162	168,000	168,000
4240	Provision for Rate Refunds						
4245	Government Assistance Directly Credit to Income						
Total Other Distribution Revenues		**288,768**	**210,930**	**197,173**	**199,910**	**205,574**	**340,574**
4305	Regulatory Debits						
4310	Regulatory Credits						
4315	Revenues from Electric Plant Leased to Others						
4320	Expenses of Electric Plant Leased to Others						
4325	Revenues from Merchandise, Jobbing, Etc.			2,000			
4330	Costs and Expenses of Merchandising, Jobbing, Etc						
4335	Profits and Losses from Financial Instruments Hedges						
4340	Profits and Losses form Financial Instrument Investments						
4345	Gains from Disposition of Future Use Utility Plant						
4350	Losses from Disposition of Future Use Utility Plant						
4355	Gains from Disposition Utility and Other Plant		44,822	- 9,578			
4360	Losses from Disposition of Utility and Other Plant						
4365	Gains from Disposition of Allowance for Emission						
4370	Losses from Disposition of Allowance for Emission						
4375	Revenues from Non-Utility Operations	24,385	39,622	26,477	41,311	-	-
4380	Expenses of Non-Utility Operations	- 21,163	- 20,360	- 23,911	- 40,286		
4385	Non-Utility Rental Income						
4390	Misc. Non-Operating Income	17,041	21,951	23,839	10,973	8,000	8,000
4395	Rate-Payer Benefit Including Interest						
4398	Foreign Exchange Gains and Losses, Inc. Amortization						
4405	Interest and Dividend Income	36,241	75,583	49,023	25,651	45,408	43,000
4415	Equity in Earnings of Subsidiary Companies						
Total Other Distribution Expenses		**56,504**	**161,618**	**67,850**	**37,649**	**53,408**	**51,000**
Specific Service Charges		101,564	129,254	138,484	108,459	117,920	117,920
Late Payment Charges		69,205	78,169	86,045	96,584	97,000	97,000
Other Distribution Revenues		288,768	210,930	197,173	199,910	205,574	340,574
Other Income and Expenses		56,504	161,618	67,850	37,649	53,408	51,000
Total		**516,041**	**579,971**	**489,552**	**442,602**	**473,902**	**606,494**

Comparison of Other Revenue

Brant County Power's Specific Service Charges revenue has not been stable over the re-regulated energy market. 2010 and 2011 projected specific service charge revenue has been increased over the 2009 actual occurrences. There was a different management regime in the 2007 & 2008 periods and specifics on the specific service charge revenue is not available. Management has reviewed the 2009 occurrences and expects an approximate 10% increase into 2010 and consistency in the 2011 test year projections.

Late Payment Charges have been projected at the 2009 actual occurrences.

Other Utility operating income represents a new energy generation project (under Green Energy Act) projected at $135,000 per year commencing in the test year 2011 and revenue from MicroFit generators.

Ex.	Tab	Schedule	Contents of Schedule
4 - Operating Costs			
	1	1	Managers Summary
	2	1	Summary and Cost Driver Tables
	3	1	Variance Analysis
	4	1	Employee Compensation Breakdown
	5	1	Shared Services / Corporate Cost Allocation
	6	1	Purchase of Non-Affiliate Services
	7	1	Depreciation / Amortization / Depletion
	8	1	Taxes
	9	1	Green Energy Act
	10	1	CDM Costs

Manager's Summary

This Exhibit is intended to provide a summary of Brant County Power's operating, maintenance and administration ("**OM&A**") costs. Brant County Power would note that spending in individual accounts may vary significantly from year to year depending upon work undertaken and events during the year. The last cost of service hearing for Brant County Power was 2006, based upon 2004 financial data, and as such, Brant County Power has used this as comparator along with annual expenditures in the intervening years to explain material variances.

In 2008 Brant County Power hired a new (the current) Chief Executive Officer and in 2009 a new Chief Financial Officer was hired. In 2009, the number of full-time equivalents ("FTEs") was 25 and Brant County Power has made 2 hires in 2010 and is proposing the inclusion of five (5) full-time equivalent additional staff in the OM&A. The new additions to staff are to ensure Brant County Power is appropriately staffed for safely and efficiently distributing electricity and for Green Energy Act initiatives, CDM, changing billing and collections policies and proper succession planning. A summary of the additional staff positions is provided below:

<u>2010</u>

- Smart Meter Analyst – required as a result of the mandated smart meter implementation. This person is responsible for oversight on the implementation of the project itself as well as all reconciliation and other integration processes necessary to advance the billing process to TOU billing in 2011.
- CDM/Green Energy Coordinator – required to assist the company with compliance of all OEB mandated CDM requirements. It should be noted that the Smart Meter Data Analyst is a change from a capital expenditure in 2010 to an OM&An expense during the 2011 Test Year. Brant County Power has included Other Revenue of $135,000 related to this position

<u>2011</u>

- Sales Manager - The Company has started a renewable energy division in late 2010. This person is tasked with the growing this business and further developing the business model/plan. It is anticipated that there will be offsetting revenue against this expected cost.
- Office Manager – The Company has created this position to better align business processes across the inside staff. This will allow for more cross training, staff coverage, more efficient processes and consistency across this department, allowing for better and more enhanced service to our customers.

- GIS/GPS implementation Manager – BCP has begun the implementation of a GIS/GPS software program which allows for better mapping of our service territory and amongst other things will allow for a faster pinpointing of outage causes, thereby allowing for quick restoration of power in the event of an outage. This person will be responsible for the implementation and ongoing maintenance of the new GIS/GPS system.

- Engineering Manager – The Company does not currently have a P. Eng. on staff. The Company expects to lose both the current Operations Manager and Operations Superintendent over the next 2-3 years because of retirement. The Company felt it prudent to plan for this retirement through succession planning along with the desire to bring some of this function back in house – as opposed to being outsourced.

- Jr. Collector – As a result of recent OEB collection guidelines, the company has decided to repatriate the collections function from the current outsourced model with the hiring of an additional staff member to handle collections. It is anticipated that this will allow for better "control" of this function by being able to monitor it on a daily basis. We expect that this cost will be offset by savings in our outsourced collections cost.

Brant County Power has assumed a 2.5% labour increase based upon the collective bargaining obligations. For non-labour costs Brant County Power has generally assumed costs will be in line with costs in 2009 and 2010 except where specifically identified.

Brant County Power is aware of the Board's recent direction regarding LEAP funding. Further to recent OEB guidance as outlined in the LEAP report, LDCs are required to commit to 0.12% of its revenue requirement as emergency financial assistance to eligible low-income customers. For BCP, this approximates $7,800. BCP has traditionally supported these types of financial assistance programs (i.e. Share the Warmth, Winter Warmth etc.) and has already included $5,000 in its 2011 budget to support such programs (included in USoA 5410). BCP is therefore committed to these programs and will increase its spending slightly to meet the LEAP requirement.

Operations

2009 operations costs are slightly below the 2004 actual cost level. Cost increases in 2010 and 2011 relative to 2009 are driven by the following factors:

- Increase in labour effort due to program changes over the period;
- Labour escalation;
- Increase in associated costs such as supervision and vehicles driven by the increased effort
- Higher vehicle and equipment rates resulting from fleet replacements over the period at higher costs
- Increase in staff

Maintenance

2009 maintenance costs are approximately $190,000 below the 2004 actual cost level. Cost increases in 2010 are primarily due to an increase in contracted tree trimming services. Cost increases in 2011 are primarily due to an increase in supervision costs (new P. Eng hire in 2011) and vehicle costs driven by higher vehicle and equipment rates resulting from fleet replacements.

Billing and Collecting

2009 billing and collecting costs are approximately $170,000 below the 2004 actual cost level. Further cost reductions in 2010 are primarily due to anticipated reductions in contracted meter reading costs and postage. The 2011 cost increase relates to an additional staff member hired in late 2009. (Smart Meter Data Analyst) The additional costs were capitalized in 2010 as part of the smart meter installation but are being expensed in 2011 as part of the smart meter operational process.

Community Relations

2009 cost levels are higher than 2004 due to the cumulative increase in energy conservation programs and community projects over the intervening period. Cost increases in 2010 are due to the full year impact of a CDM Coordinator hired part way through 2009 and an increase in Health and Safety programs

Administrative and General

2009 reported administrative and general expenses total $2,402,408. These reported expenses include the total amount of employee pension and benefit costs (USOA 5645 - $856,850) that were already allocated to O&M and capital accounts. Normalizing for this amount reduces actual expenses to $1,545,558.

2010 costs are significantly lower (approximately $472,000) than 2009 costs due to non-recurring costs in 2009:

- Severance costs
- Collective agreement negotiations consulting expense
- Share of Toronto Hydro late payment litigation
- Correction of regulatory accounting balances based on an independent review

Cost increases in 2011 as compared to 2010 are due to:

- the addition of 3 new staff members:
  - CDM/Green Energy Coordinator whose costs are more than offset via a $135,000 Miscellaneous Revenue offset
  - Collections Clerk – repatriate collections from outsourced collection service to better address needs based on recent OEB direction
  - Replacement of Smart Meter Data Analyst who was promoted to an Office Manager role
- Increased anticipated contracted services costs in the areas of audit, tax, and financial services
- Advertising expenses related to launch of new Renewable Energy Division
- Regulatory costs arising from the 2011 cost of service rate application

General Assumptions

Brant County Power applied 2.5% labour escalation factors in both 2010 and 2011. These reflect the actual negotiated collective agreement increases. These increases have been applied to non-union staff costs as well. Pension and benefit costs that are related to base compensation have also risen by the 2.5 % escalation factors.

Very little non labour escalation was applied as part of the 2010 and 2011 budgeting process.

Summary and Cost Drivers Tables

OM&A Expenses by Category

Appendix 2-E below summarizes OM&A expenses by category for the years 2006 to 2011.

Appendix 2-E
Summary of OM&A Expenses

Table # 1

	2006 Board Approved	2006 Actual	Variance $	Variance %	2006 Actual	2007 Actual	Variance $	Variance %	2007 Actual	2008 Actual	Variance $	Variance %	2008 Actual	2009 Actual	Variance $	Variance %	2009 Actual	2010 Bridge	Variance $	Variance %	2010 Bridge	2011 Test	Variance $	Variance %
OM&A expenses																								
Operation (Working Capital)	$523,299	$587,104	$63,805	12.2%	$587,104	$636,856	$49,752	8.5%	$636,856	$536,058	-$100,799	-15.8%	$536,058	$503,294	-$32,764	-6.1%	$503,294	$651,704	$148,410	29.5%	$651,704	$863,472	$211,768	32.5%
Maintenance (Working Capital)	$768,774	$610,177	-$158,597	-20.6%	$610,177	$751,012	$140,835	23.1%	$751,012	$771,756	$20,744	2.8%	$771,756	$577,892	-$193,864	-25.1%	$577,892	$628,644	$50,752	8.8%	$628,644	$649,837	$21,193	3.4%
Billing and Collections	$889,242	$862,851	-$26,392	-3.0%	$862,851	$870,899	$8,049	0.9%	$870,899	$778,857	-$92,043	-10.6%	$778,857	$720,924	-$57,933	-7.4%	$720,924	$700,602	-$20,322	-2.8%	$700,602	$766,275	$65,673	9.4%
Community Relations	$50,511	$59,848	$9,337	18.5%	$59,848	$104,500	$44,652	74.6%	$104,500	$119,225	$14,725	14.1%	$119,225	$123,948	$4,723	4.0%	$123,948	$165,529	$41,581	33.5%	$165,529	$178,019	$12,490	7.5%
Administrative and General Expenses	$1,057,255	$1,312,249	$254,994	24.1%	$1,312,249	-$646,875	-$1,959,124	-149.3%	-$646,875	$1,201,538	$1,848,413	-285.7%	$1,201,538	$2,402,408	$1,200,870	99.9%	$2,402,408	$1,083,453	-$1,318,955	-54.9%	$1,083,453	$1,387,435	$303,982	28.1%
Total OM&A Expenses	$3,289,081	$3,432,229	$143,148	4.4%	$3,432,229	$1,716,394	-$1,715,835	-50.0%	$1,716,394	$3,407,433	$1,691,040	98.5%	$3,407,433	$4,328,466	$921,033	27.0%	$4,328,466	$3,229,932	-$1,098,534	-25.4%	$3,229,932	$3,845,038	$615,106	19.0%
Inflation Rate				2.1%				-33.3%				33.0%				11.9%				-14.5%				8.7%

Table # 2

	%
Required Total OM&A Comparision	%
2011 Year vs. 2009 Actual	-11.17%
2011 vs. 2006 Approved	16.90%
Simple Avg. of Variance % (2006 - 2009)	25.19%
Compound Annual Growth Rate (2006-2009)	9%

OM&A USOA Account Details

Appendix 2-F below provides the detailed account by account OM&A values filed with the Board.

	2006 Actual			2007 Actual			2008 Actul			2009 Actual			2010 Bridge			2011 Test		
WORKING CAPITAL ALLOWANCE CALCULATION BY ACCOUNT	**Expense**	**15%**	**Allowance for Working Capital**	**Expense**	**15%**	**Allowance for Working Capital**	**Expense**	**15%**	**Allowance for Working Capital**	**Expense**	**15%**	**Allowance for Working Capital**	**Expense**	**15%**	**Allowance for Working Capital**	**Expense**	**15%**	**Allowance for Working Capital**
Operation (Working Capital)																		
5005-Operation Supervision and Engineering	$45,441.24	15%	$6,816.19	$47,208.69	15%	$7,081.30	$48,487.43	15%	$7,273.11	$30,131.00	15%	$4,519.65	$30,049.00	15%	$4,507.35	$29,509.00	15%	$4,426.35
5010-Load Dispatching	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
5012-Station Buildings and Fixtures Expense	$40,172.96	15%	$6,025.94	$56,515.31	15%	$8,477.30	$67,078.81	15%	$10,061.82	$74,737.00	15%	$11,210.55	$90,067.00	15%	$13,510.05	$93,806.00	15%	$14,070.90
5014-Transformer Station Equipment - Operation Labour	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
5015-Transformer Station Equipment - Operation Supplies and Expenses	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
5016-Distribution Station Equipment - Operation Labour	$2,442.67	15%	$366.40	$1,663.32	15%	$249.50	$1,886.69	15%	$283.00	$8,534.00	15%	$1,280.10	$4,491.00	15%	$673.65	$4,751.00	15%	$712.65
5017-Distribution Station Equipment - Operation Supplies and Expenses	$41,762.28	15%	$6,264.34	$19,616.16	15%	$2,942.42	$45,919.10	15%	$6,887.87	$54,678.00	15%	$8,201.70	$53,500.00	15%	$8,025.00	$53,500.00	15%	$8,025.00
5020-Overhead Distribution Lines and Feeders - Operation Labour	$39,477.67	15%	$5,921.65	$23,147.25	15%	$3,472.09	$23,899.67	15%	$3,584.95	$27,126.00	15%	$4,068.90	$35,168.00	15%	$5,275.20	$37,079.00	15%	$5,561.85
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$769.21	15%	$115.38	$8,461.18	15%	$1,269.18	$1,200.96	15%	$180.14	$7.00	15%	$1.05	$5,000.00	15%	$750.00	$5,000.00	15%	$750.00
5030-Overhead Sub transmission Feeders - Operation	$4,430.48	15%	$664.57	$45,447.66	15%	$6,817.15	-$413.77	15%	-$62.07	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
5035-Overhead Distribution Transformers- Operation	$43,293.47	15%	$6,494.02	$54,605.99	15%	$8,190.90	$10,538.93	15%	$1,580.84	$1,241.00	15%	$186.15	$18,710.00	15%	$2,806.50	$19,767.00	15%	$2,965.05
5040-Underground Distribution Lines and Feeders - Operation Labour	$6,622.42	15%	$993.36	$3,495.92	15%	$524.39	$2,605.32	15%	$390.80	$2,514.00	15%	$377.10	$5,237.00	15%	$785.55	$5,516.00	15%	$827.40
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$905.37	15%	$135.81	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
5050-Underground Sub transmission Feeders - Operation	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
5055-Underground Distribution Transformers - Operation	$7,566.70	15%	$1,135.01	$3,625.84	15%	$543.88	$12,999.79	15%	$1,949.97	$2,252.00	15%	$337.80	$9,479.00	15%	$1,421.85	$10,011.00	15%	$1,501.65
5060-Street Lighting and Signal System Expense	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
5065-Meter Expense	$28,963.41	15%	$4,344.51	$27,296.48	15%	$4,094.47	$17,205.30	15%	$2,580.80	$5,824.00	15%	$873.60	$17,582.00	15%	$2,637.30	$18,443.00	15%	$2,766.45
5070-Customer Premises - Operation Labour	$88,965.24	15%	$13,344.79	$112,906.05	15%	$16,935.91	$106,501.15	15%	$15,975.17	$112,588.00	15%	$16,888.20	$140,145.00	15%	$21,021.75	$148,229.00	15%	$22,234.35
5075-Customer Premises - Materials and Expenses	$937.36	15%	$140.60	$1,245.91	15%	$186.89	$493.95	15%	$74.09	$894.00	15%	$134.10	$0.00	15%	$0.00	$0.00	15%	$0.00
5085-Miscellaneous Distribution Expense	$219,811.46	15%	$32,971.72	$221,307.12	15%	$33,196.07	$197,654.18	15%	$29,648.13	$164,704.00	15%	$24,705.60	$222,276.00	15%	$33,341.40	$417,861.00	15%	$62,679.15
5090-Underground Distribution Lines and Feeders - Rental Paid	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
5095-Overhead Distribution Lines and Feeders - Rental Paid	$15,512.36	15%	$2,326.85	$10,013.50	15%	$1,502.03	$0.00	15%	$0.00	$18,064.00	15%	$2,709.60	$20,000.00	15%	$3,000.00	$20,000.00	15%	$3,000.00
5096-Other Rent	$30.00	15%	$4.50	$300.00	15%	$45.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
Sub-Total	$587,104.30		$88,065.65	$636,856.38		$95,528.46	$536,057.51		$80,408.63	$503,294.00		$75,494.10	$651,704.00		$97,755.60	$863,472.00		$129,520.80
Maintenance (Working Capital)																		
5105-Maintenance Supervision and Engineering	$45,352.88	15%	$6,802.93	$47,525.82	15%	$7,128.87	$48,306.21	15%	$7,245.93	$48,630.00	15%	$7,294.50	$30,049.00	15%	$4,507.35	$29,509.00	15%	$4,426.35
5110-Maintenance of Buildings and Fixtures - Distribution Stations	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$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	$45,120.92	15%	$6,768.14	$40,801.00	15%	$6,120.15	$37,000.00	15%	$5,550.00	$37,000.00	15%	$5,550.00
5114-Maintenance of Distribution Station Equipment	$766.07	15%	$114.91	$459.60	15%	$68.94	$8,956.46	15%	$1,343.47	$7,773.00	15%	$1,165.95	$0.00	15%	$0.00	$0.00	15%	$0.00
5120-Maintenance of Poles, Tow ers and Fixtures	$16,154.99	15%	$2,423.25	$40,736.73	15%	$6,110.51	$37,117.42	15%	$5,567.61	$31,104.00	15%	$4,665.60	$75,868.00	15%	$11,380.20	$79,307.00	15%	$11,896.05
5125-Maintenance of Overhead Conductors and Devices	$79,617.65	15%	$11,942.65	$97,354.19	15%	$14,603.13	$66,986.35	15%	$10,047.95	$113,326.00	15%	$16,998.90	$148,106.00	15%	$22,215.90	$155,272.00	15%	$23,290.80
5130-Maintenance of Overhead Services	$105,140.86	15%	$15,771.13	$97,803.89	15%	$14,670.58	$97,425.26	15%	$14,613.79	$95,972.00	15%	$14,395.80	$77,763.00	15%	$11,664.45	$81,996.00	15%	$12,299.40
5135-Overhead Distribution Lines and Feeders - Right of Way	$204,579.69	15%	$30,686.95	$218,287.04	15%	$32,743.06	$185,399.43	15%	$27,809.91	$71,620.00	15%	$10,743.00	$133,741.00	15%	$20,061.15	$134,195.00	15%	$20,129.25
5145-Maintenance of Underground Conduit	$623.11	15%	$93.47	$0.00	15%	$0.00	$3,518.74	15%	$527.81	$1,746.00	15%	$261.90	$898.00	15%	$134.70	$950.00	15%	$142.50
5150-Maintenance of Underground Conductors and Devices	$6,701.46	15%	$1,005.22	$4,206.20	15%	$630.93	$6,280.73	15%	$942.11	$9,348.00	15%	$1,402.20	$10,477.00	15%	$1,571.55	$11,021.00	15%	$1,653.15
5155-Maintenance of Underground Services	$11,192.88	15%	$1,678.93	$20,681.18	15%	$3,102.18	$20,900.37	15%	$3,135.06	$13,528.00	15%	$2,029.20	$21,452.00	15%	$3,217.80	$22,553.00	15%	$3,382.95
5160-Maintenance of Line Transformers	$36,084.98	15%	$5,412.75	$31,251.02	15%	$4,687.65	$20,006.87	15%	$3,001.03	$30,021.00	15%	$4,503.15	$38,787.00	15%	$5,818.05	$40,817.00	15%	$6,122.55
5165-Maintenance of Street Lighting and Signal Systems	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
5170-Sentinel Lights - Labour	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$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	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
5175-Maintenance of Meters	$28,943.65	15%	$4,341.55	$96,348.85	15%	$14,452.33	$163,552.12	15%	$24,532.82	$116,611.00	15%	$17,491.65	$48,503.00	15%	$7,275.45	$51,217.00	15%	$7,682.55
5178-Customer Installations Expenses- Leased Property	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$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	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
5186-Water Heater Rentals - Materials and Expenses	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
5190-Water Heater Controls - Labour	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
5192-Water Heater Controls - Materials and Expenses	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
5195-Maintenance of Other Installations on Customer Premises	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
Sub-Total	$535,158.22		$80,273.73	$654,654.52		$98,198.18	$703,570.88		$105,535.63	$580,480.00		$87,072.00	$622,644.00		$93,396.60	$643,837.00		$96,575.55
Billing and Collections																		
5305-Supervision	$13,396.29	15%	$2,009.44	$82,318.22	15%	$12,347.73	$57,090.78	15%	$8,563.62	$8.00	15%	$1.20	$0.00	15%	$0.00	$0.00	15%	$0.00
5310-Meter Reading Expense	$214,297.79	15%	$32,144.67	$215,994.70	15%	$32,399.21	$214,213.89	15%	$32,132.08	$162,510.00	15%	$24,376.50	$139,536.00	15%	$20,930.40	$144,362.00	15%	$21,654.30
5315-Customer Billing	$279,106.98	15%	$41,866.05	$268,137.88	15%	$40,220.68	$275,358.14	15%	$41,303.72	$278,614.00	15%	$41,792.10	$286,833.00	15%	$43,024.95	$347,894.00	15%	$52,184.10
5320-Collecting	$262,674.56	15%	$39,401.18	$215,638.11	15%	$32,345.72	$144,610.12	15%	$21,691.52	$151,318.00	15%	$22,697.70	$152,723.00	15%	$22,908.45	$153,216.00	15%	$22,982.40
5325-Collecting- Cash Over and Short	$139.26	15%	$20.89	-$244.09	15%	-$36.61	$580.79	15%	$87.12	-$377.00	15%	-$56.55	$120.00	15%	$18.00	$120.00	15%	$18.00
5330-Collection Charges	$530.34	15%	$79.55	$3,097.66	15%	$464.65	$737.40	15%	$110.61	$2,176.00	15%	$326.40	$1,500.00	15%	$225.00	$1,500.00	15%	$225.00
5335-Bad Debt Expense	$48,556.78	15%	$7,283.52	$48,356.14	15%	$7,253.42	$54,869.23	15%	$8,230.38	$79,500.00	15%	$11,925.00	$75,000.00	15%	$11,250.00	$75,000.00	15%	$11,250.00
5340-Miscellaneous Customer Accounts Expenses	$44,148.76	15%	$6,622.31	$37,600.87	15%	$5,640.13	$31,396.23	15%	$4,709.43	$47,175.00	15%	$7,076.25	$44,890.00	15%	$6,733.50	$44,183.00	15%	$6,627.45
Sub-Total	$862,850.76		$129,427.61	$870,899.49		$130,634.92	$778,856.58		$116,828.49	$720,924.00		$108,138.60	$700,602.00		$105,090.30	$766,275.00		$114,941.25

Exhibit: 1
Tab: 2
Schedule: 1
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	2006 Actual			2007 Actual			2008 Actul			2009 Actual			2010 Bridge			2011 Test		
WORKING CAPITAL ALLOWANCE CALCULATION BY ACCOUNT	Expense	15%	Allowance for Working Capital	Expense	15%	Allowance for Working Capital	Expense	15%	Allowance for Working Capital	Expense	15%	Allowance for Working Capital	Expense	15%	Allowance for Working Capital	Expense	15%	Allowance for Working Capital
Community Relations																		
5405-Supervision	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$30,543.00	15%	$4,581.45	$0.00	15%	$0.00	$0.00	15%	$0.00
5410-Community Relations - Sundry	$3,957.80	15%	$593.67	$11,244.44	15%	$1,686.67	$39,606.10	15%	$5,940.92	$0.00	15%	$0.00	$30,000.00	15%	$4,500.00	$35,000.00	15%	$5,250.00
5415-Energy Conservation	$34,849.54	15%	$5,227.43	$83,754.82	15%	$12,563.22	$67,671.54	15%	$10,150.73	$80,445.00	15%	$12,066.75	$109,529.00	15%	$16,429.35	$117,019.00	15%	$17,552.85
5420-Community Safety Program	$17,067.66	15%	$2,560.15	$7,750.05	15%	$1,162.51	$11,947.37	15%	$1,792.11	$8,960.00	15%	$1,344.00	$20,000.00	15%	$3,000.00	$20,000.00	15%	$3,000.00
5425-Miscellaneous Customer Service and Informational Expenses	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
5505-Supervision	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$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	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
5515-Advertising Expense	$3,972.70	15%	$595.91	$1,750.74	15%	$262.61	$0.00	15%	$0.00	$4,000.00	15%	$600.00	$6,000.00	15%	$900.00	$6,000.00	15%	$900.00
5520-Miscellaneous Sales Expense	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
Sub-Total	$59,847.70		$8,977.16	$104,500.05		$15,675.01	$119,225.01		$17,883.75	$123,948.00		$18,592.20	$165,529.00		$24,829.35	$178,019.00		$26,702.85
Administrative and General Expenses																		
5605-Executive Salaries and Expenses	$295,258.53	15%	$44,288.78	$316,534.81	15%	$47,480.22	$445,083.13	15%	$66,762.47	$411,959.00	15%	$61,793.85	$332,855.00	15%	$49,928.25	$332,929.00	15%	$49,939.35
5610-Management Salaries and Expenses	$68,895.19	15%	$10,334.28	$66,876.58	15%	$10,031.49	$72,573.31	15%	$10,886.00	$76,600.00	15%	$11,490.00	$76,989.00	15%	$11,548.35	$77,709.00	15%	$11,656.35
5615-General Administrative Salaries and Expenses	$104,684.96	15%	$15,702.74	$122,401.28	15%	$18,360.19	$182,115.00	15%	$27,317.25	$148,455.00	15%	$22,268.25	$141,026.00	15%	$21,153.90	$316,586.00	15%	$47,487.90
5620-Office Supplies and Expenses	$28,068.62	15%	$4,210.29	$14,337.92	15%	$2,150.69	$17,684.09	15%	$2,652.61	$16,703.00	15%	$2,505.45	$19,400.00	15%	$2,910.00	$20,400.00	15%	$3,060.00
5625-Administrative Expense Transferred Credit	-$4,928.10	15%	-$739.22	-$47,790.09	15%	-$7,168.51	-$66,455.95	15%	-$9,968.39	-$51,192.00	15%	-$7,678.80	-$48,400.00	15%	-$7,260.00	-$48,400.00	15%	-$7,260.00
5630-Outside Services Employed	$119,905.11	15%	$17,985.77	$120,698.35	15%	$18,104.75	$156,764.39	15%	$23,514.66	$122,185.00	15%	$18,327.75	$86,500.00	15%	$12,975.00	$129,000.00	15%	$19,350.00
5635-Property Insurance	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
5640-Injuries and Damages	$53,962.24	15%	$8,094.34	$53,220.43	15%	$7,983.06	$32,632.40	15%	$4,894.86	$31,525.00	15%	$4,728.75	$33,000.00	15%	$4,950.00	$45,000.00	15%	$6,750.00
5645-Employee Pensions and Benefits	$299,000.00	15%	$44,850.00	-$1,711,140.00	15%	-$256,671.00	$28,640.00	15%	$4,296.00	$856,850.00	15%	$128,527.50	$0.00	15%	$0.00	$0.00	15%	$0.00
5650-Franchise Requirements	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
5655-Regulatory Expenses	$65,876.14	15%	$9,881.42	$96,979.78	15%	$14,546.97	$42,657.99	15%	$6,398.70	$115,770.00	15%	$17,365.50	$120,875.00	15%	$18,131.25	$150,000.00	15%	$22,500.00
5660-General Advertising Expenses	$3,279.10	15%	$491.87	$2,334.35	15%	$350.15	$0.00	15%	$0.00	$1,622.00	15%	$243.30	$0.00	15%	$0.00	$0.00	15%	$0.00
5665-Miscellaneous General Expenses	$195,036.59	15%	$29,255.49	$208,888.12	15%	$31,333.22	$219,910.05	15%	$32,986.51	$622,460.00	15%	$93,369.00	$277,908.00	15%	$41,686.20	$320,911.00	15%	$48,136.65
5670-Rent	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
5675-Maintenance of General Plant	$76,740.31	15%	$11,511.05	$88,736.47	15%	$13,310.47	$64,161.52	15%	$9,624.23	$47,936.00	15%	$7,190.40	$43,300.00	15%	$6,495.00	$43,300.00	15%	$6,495.00
5680-Electrical Safety Authority Fees	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$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	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
Sub-Total	$1,305,778.69		$195,866.80	-$667,922.00		-$100,188.30	$1,195,765.93		$179,364.89	$2,400,873.00		$360,130.95	$1,083,453.00		$162,517.95	$1,387,435.00		$208,115.25
Cost of Power																		
4705-Power Purchased	$13,206,104.11	15%	$1,980,915.62	$16,089,184.93	15%	$2,413,377.74	$15,654,293.50	15%	$2,348,144.03	$12,535,062.00	15%	$1,880,259.30	$18,937,733.42	15%	$2,840,660.01	$18,863,907.20	15%	$2,829,586.08
4708-Charges-WMS	$1,214,971.31	15%	$182,245.70	$1,538,296.60	15%	$230,744.49	$1,697,949.03	15%	$254,692.35	$1,761,282.00	15%	$264,192.30	$1,419,374.66	15%	$212,906.20	$1,413,841.42	15%	$212,076.21
4710-Cost of Power Adjustments	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
4712-Charges-One-Time	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
4714-Charges-NW	$1,519,028.55	15%	$227,854.28	$1,062,252.24	15%	$159,337.84	$679,953.77	15%	$101,993.07	$798,847.00	15%	$119,827.05	$1,364,528.57	15%	$204,679.29	$1,359,861.40	15%	$203,979.21
4715-System Control & Load Dispatching	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
4716-Charges-CN	$1,161,169.66	15%	$174,175.45	$824,773.61	15%	$123,716.04	$530,010.67	15%	$79,501.60	$589,901.00	15%	$88,485.15	$1,004,556.96	15%	$150,683.54	$1,001,100.59	15%	$150,165.09
4720-Other Expenses	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
4725-Competition Transition Expense	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
4730-Rural Rate Assistance Expense	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
4750-LV charges	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$303,455.00	15%	$45,518.25	$686,372.47	15%	$102,955.87	$682,064.84	15%	$102,309.73
5205-Purchase of Transmission and System Services	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
5210-Transmission Charges	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
5215-Transmission Charges Recovered	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$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	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00	$0.00	15%	$0.00
Sub-Total	$17,101,273.63		$2,565,191.04	$19,514,507.38		$2,927,176.11	$18,562,206.97		$2,784,331.05	$15,988,547.00		$2,398,282.05	$23,412,566.08		$3,511,884.91	$23,320,775.45		$3,498,116.32
WORKING CAPITAL ALLOWANCE TOTAL			**$3,067,802.00**			**$3,167,024.37**			**$3,284,352.43**	**$21,333,949.00**		**$3,047,709.90**	**$27,520,779.21**		**$3,995,474.71**	**$28,056,027.45**		**$4,073,972.02**

OM&A Cost Drivers

The following Appendix 2–G identifies and describes the key cost drivers impacting OM&A costs over the period from the 2006 EDR to the 2011 test year. Overall cost increases since 2006 Board Approved are approximately 3.4% per year, or in-line with inflationary increases. Given the additional regulatory expenses and additional responsibilities Brant County Power feels the increase is reasonable.

Appendix 2 - G
Brant County Power
OM&A Cost Drivers

	Year 1 Actual (last Board Approved Rebasing Year) 2006	Year 2 Actual 2007	Year 3 Actual 2008	Year 4 Actual 2009	Bridge Year 2010	Test Year 2011
Opening Balance	3,289,080	3,432,229	1,716,394	3,407,433	4,328,463	3,229,932
Labour	-42,358	225,552	17,044	-70,016	110,586	372,171
Vehicles	-27,121	45,055	-4,936	-94,591	50,677	81,807
Materials	-79,132			48,196	33,659	
Contracted Services						
Consultants	-31,116	14,892	-23,591		-25,053	
Tree trimming	26,000		-44,000	-107,000	62,000	
IT Support	19,919	10,638		27,250	-14,005	13,500
Legal	25,173	-24,100	39,845	-41,168		
Other	17,721		-44,226	65,089	-29,439	
Meter Reading	35,042				-9,673	
Pay Equity			22,989	19,120	-37,109	
Settlement				-34,362	-13,439	
Audit, Tax, Financial					33,220	40,000
Advertising						20,000
CFO Overlap				34,000	-34,000	
Regulatory	39,902	31,104	-54,322	73,112		40,000
Employee Pension and Benefits	48,997	-2,010,140	1,739,780	828,210	-856,850	
Administrative Expense Transferred	139,959	-13,760	-16,147	26,268		
Postage	24,108			21,323	-10,546	5,000
Community / Energy Conservation Projects			65,664	-46,842	51,707	10,000
One Time Costs				263,305	-263,305	
Staff Training and Education					-24,980	26,000
Directors Costs					18,658	
Miscellaneous	-53,945	4,924	-7,061	-90,864	-140,639	6,628
Closing Balance	3,432,229	1,716,394	3,407,433	4,328,463	3,229,932	3,845,038
OEB Filed Value	3,432,229	1,716,394	3,407,433	4,328,463	3,229,932	3,845,038

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Labour

Labour costs fluctuate over the period and are driven by the following factors:

- change in work effort between operations, maintenance, and capital programs (programs are not linear from year to year)
- labour escalation due to collective agreement changes and non-union compensation increases
- job progression through pay grades
- staff additions
- increased costs of pensions and benefits

Vehicles

Similar to above vehicle usage changes over the period based on the labour effort required. In addition, the nature of the work determines which equipment will be needed to support the job resulting in a different utilization mix. The costs for vehicles and equipment increase over the period due to fleet replacements, additions, and variable cost escalation. (insurance, fuel, repairs etc.)

Materials

Similar to above materials usage will change based on the nature of the work. The unit costs for materials also increase over the period due to material price escalation.

Contracted Services

Contract Services which are primarily ongoing in nature are used to support LDC program delivery but are used in varying degrees over the period driven by need. As a result there are both increases and decreases in the provision and cost of these services.

Regulatory

The ongoing portion of regulatory costs increase over the period due to the increase in OEB assessment fees.

Specific one-time costs relate to the following:

- 2006 - Filing of 2006 EDR
- 2007 - Preliminary work on a 2008 COS rate application that was subsequently deferred
- 2009 - Independent Regulatory Accounting Review, Brantford Motion to Rehear,
- 2010 - IRM application, Conclusion of Brantford Motion to Rehear
- 2011 - 2011 COS rate application

Employee Pension and Benefits

Brant County Power utilized different approaches to filing values for USOA 5645 - Employee Pensions and Benefits.

BCP follows an accounting process whereby all pension and employee benefit costs are collected in USOA 5645. Costs are charged out to projects as labour is utilized with the offset going to a 5905 Contra account. BCP does not clear out any over or under recovered balances at year-end (difference goes to P&L)

In 2004, 2006 and 2008 the balance filed represents the net difference charged to P&L between total costs and costs allocated to projects.

In 2007 the amount recorded reflects an actuarial re-valuation of the employee benefit liability.

In 2009 the amount recorded reflects the total amount of the expense (revenue offset recorded in revenue section of filing)

No amounts are included in 2010 or 2011.

Administrative Expense Transferred

These amounts reflect the charge to BCP's affiliate for the provision of Management services.

Postage

Cost changes reflect postal rate changes and volume changes over the period.

<u>Community / Energy Conservation Projects</u>

These costs reflect the change in community and energy conservation projects over the period. With the exception of 2009 costs the costs in 2010 and 2011 are close to 2008 actual levels.

<u>One Time Costs</u>

The one-time cost increases in 2009 are primarily driven by accounting adjustments required as a result of an independent regulatory accounting review and BCP's share of costs related to the Toronto Hydro late payment litigation case.

<u>Staff Training and Education</u>

Staff training costs are set to return to 2008 actual levels in 2011.

<u>Director's Costs</u>

The 2010 increase reflects a provision for training and education related expenses for Board members.

<u>Miscellaneous</u>

These cost changes reflect the net impact of an assortment of smaller dollar value cost increases and decreases. BCP utilizes approximately 50 different elements of costs to categorize its expenditures.

Regulatory Costs

The following Appendix 2 – H provides details regarding regulatory costs. BCP intends to amortize the one-time costs related to the 2011 cost of service rate application over the 4 year cost of service + IRM term. Brant County Power has assumed the rate application will be dealt with in writing and that an oral hearing will not be required. OEB Assessment costs, legal costs and consultant costs are forecasted at the 2010 level and approximately $5,105 more than 2009.

Appendix 2-H
Regulatory Cost Schedule

Regulatory Cost Category	USoA	Balance	On-Going / One-Time	2006	2009	2010	Delta	2011	Delta
1. OEB Annual Assessment	5655		on-going	31,954	45,901	45,901	0.00%	45,901	0.00%
2. OEB Hearing Assessments									
3. OEB Section 30 Costs									
4. Expert Witness Cost for Regulatory Matters									
5. Legal Costs for Regulatory Matters	5655		on-going	16,842	33,401	29,974	-10.26%	29,474	-1.67%
6. Consultants for Regulatory Matters	5655		on-going	5,339	36,468	45,000	23.40%	45,000	0.00%
7. Operating Expenses associated with Staff Resources Allocated to Regulatory Matters									
8. Operating Expenss associated with Other Resources Allocaed to Regulatory Matters									
9. Other Regulatgory Agency Fees or Assessments									
10. Other (Define) CoS onetime	5655		One time					25,875	
11. Intervenor Costs	5655		one time	10,327				3,750	
12. Subtotal - On-Going Costs									
13. Subtotal - One-Time Costs									
14. Total		0		64,462	115,770	120,875	13.14%	150,000	-1.67%
Note: 10 - Other CoS Onetime costs include									
	- $8,500 load forecast								
	- $70,000 consulting for application / interrogatories								
	- $25,000 legal for application / interrogatories								
	103,500	Total							
		4 years							
	25,875	per year							
Note: 11 Intervenor costs for 2011									
	15000	total							
		4 years							
	3750	per year							

OM&A Cost per Customer and per FTE

The following Appendix 2 – I provides details regarding BCPs average costs per customer and per employee. OM&A costs per FTEE are decreasing. Costs are in line with the historical averages. The 2007 numbers in Brant County Power's view are anomalous as there was a $1.7 million reduction in OM&A expenses due to an actuarial revaluation of the employee pension and benefit liability.

Appendix 2-I
OM&A Cost Per Customer and FTEE

	2006	2007	2008	2009	2010	2011
Customers	11,944	11,984	12,257	12,506	12,506	12,610
Total OM&A (from 2-G)	3,432,229	1,716,394	3,407,433	4,328,466	3,229,932	3,845,038
OM&A Cost per Customer	287	143	278	346	258	305
Number FTEEs	28	28	25	25	27	32
FTEEs/Customer	0.002	0.002	0.002	0.002	0.002	0.003
Customer / FTEEs	427	428	490	500	463	394
OM&A Cost per FTEE	122,580	61,300	136,297	173,139	119,627	120,157

Charitable Donations

The only donation made by BCP was a $400 contribution in 2004.

Variance Analysis

Brant County Power does not use the following USOA accounts:

Operations

- 5010 - Load Dispatching
- 5014 - Transformer Station Equipment - Operation Labour
- 5015 - Transformer Station Equipment - Operation Supplies and Expense
- 5050 - Underground Sub-transmission Feeders - Operation
- 5060 - Street Lighting and Signal System Expense
- 5090 - Underground Distribution Lines and Feeders - Rental Paid

Maintenance

- 5110 - Maintenance of Buildings and Fixtures - Distribution Stations
- 5165 - Maintenance of Street Lighting and Signal Systems
- 5170 - Sentinel Lights - Labour
- 5172 - Sentinel Lights - Materials and Expenses
- 5178 - Customer Installations Expenses - Leased Property
- 5195 - Maintenance of Other Installations on Customer Premises

Community Relations

- 5425 - Miscellaneous Customer Service and Informational Expenses
- 5505 - Supervision
- 5510 - Demonstrating and Selling Expense
- 5520 - Miscellaneous Sales Expense

Administrative and General Expenses

- 5635 - Property Insurance
- 5650 - Franchise Requirements
- 5670 - Rent
- 5680 - Electrical Safety Authority Fees
- 5685 - IESO Fees and Penalties

Comparisons for Operations, Maintenance, Billing and Collecting, Community Relations, and Administration & General accounts are provided below for the following years:

- 2006 EDR vs. 2006 Actual
- 2006 vs. 2007 (Actual)
- 2008 vs. 2007 (Actual)
- 2009 vs. 2008 (Actual)
- 2010 (Bridge) vs. 2009 Actual
- 2011 (Test) vs. 2010 (Bridge)
- 2011 (Test) vs. 2006 Actual
- 2011 (Test) vs. 2009 Actual

USOA cost increases or decreases greater than $25,000 are addressed in the variance analysis.

2006 Actual VS 2006 EDR

Account Description	2006 Actual	2006 EDR	Difference
5017-Distribution Station Equipment - Operation Supplies and Expenses	**41,762**	**8,715**	**33,047**

2006 actual expenses included incremental MSP, settlement, and metering costs above the 2006 EDR (2004 actual) charges

5020 - Overhead Distribution Lines and Feeders - Operation Labour	**39,478**	**65,733**	**-26,255**

Work effort associated with this activity decreased from 2004 to 2006. In addition the related resources required to perform the work such as supervision and vehicle costs decreased.

5035-Overhead Distribution Transformers- Operation	**43,293**	**9,554**	**33,739**

Work effort associated with this activity increased from 2004 to 2006. The labour costs increased due to wage increases as well. In addition the related resources required to perform the work such as supervision and vehicle costs increased.

5065 - Meter Expense	**28,963**	**85,735**	**-56,772**

Work effort associated with this activity decreased from 2004 to 2006. In addition the related resources required to perform the work such as supervision and vehicle costs decreased.

5070 - Customer Premises - Operation Labour	**88,965**	**63,534**	**25,431**

Work effort associated with this activity increased from 2004 to 2006. The labour costs increased due to wage increases as well. In addition the related resources required to perform the work such as supervision and vehicle costs increased.

5085 - Miscellaneous Distribution Expense	**219,811**	**169,456**	**50,355**

2006 expenditures were higher primarily due to incremental contracted transformer maintenance expenses not incurred in 2004

5120 - Maintenance of Poles Towers and Fixtures	**16,155**	**88,632**	**-72,477**

Work effort associated with this activity decreased from 2004 to 2006. In addition the related resources required to perform the work such as supervision and vehicle costs decreased.

5125 - Maintenance of Overhead Conductors and Devices	**79,618**	**235,819**	**-156,201**

Work effort associated with this activity decreased from 2004 to 2006. In addition the related resources required to perform the work such as supervision and vehicle costs decreased.

5305 - Supervision	**13,396**	**71,518**	**-58,122**

The reduction of costs in 2006 reflects the reduction in a Customer Care/ IT Manager position

5405 - Supervision	**0**	**27,727**	**-27,727**

5415 - Energy Conservation	**34,850**	**9,023**	**25,827**

Post 2004 BCP re-allocated the labour portion of effort from 5405 to 5415

5605 - Executive Salaries and Expense	**295,259**	**0**	**295,259**

Prior to 2006 all Executive labour costs were charged to USOA 5610

5610 - Management Salaries and Expenses	**68,895**	**312,757**	**-243,862**

In 2006 Executive costs were charged to 5605. The reduction in expenses due to the re-categorization was reduced by a one- time severance payment and contracted CFO services. In addition Executive Assistant.

5615 - General Administrative Salaries and Expenses	**104,685**	**219,502**	**-114,817**

The primary reason for the reduction in expenses was due to the re-categorization of executive Assistant compensation to USOA 5610

5625 - Administrative Expense Transferred Credit	**-4,928**	**-187,511**	**182,583**

In 2004 an entry was made to credit 5625 due to over-charging of employee pension and benefit costs which did not occur in 2006

5640 - Injuries and Damages	**53,962**	**17,187**	**36,775**

Insurance expenses in 2004 were allocated over OM&A accounts but consolidated in 5640 in 2006

5645 - Employee Pensions and Benefits	**299,000**	**250,003**	**48,997**

The 2006 and 2004 values reflect the net amount of total employee pension and benefit remaining after costs were allocated to USOA accounts via the 5905 contra account.

5655 - Regulatory Expenses	**65,876**	**25,974**	**39,902**

2006 expenses are higher due to costs related to filing the 2006 rate application.

5665 - Miscellaneous General Expenses	**195,037**	**158,754**	**36,283**

The cost increase was primarily driven by an increase in IT support costs.

5675 - Maintenance of General Plant	**76,740**	**106,616**	**-29,876**

The reduction in costs was driven by a reduction in office equipment, hardware, and software maintenance

2007 Actual VS 2006 Actual

Account Description	2007 Actual	2006 Actual	2007 vs. 2006
5030- Overhead Sub transmission Feeders - Operation	**45,448**	**4,430**	**41,018**

Work effort associated with this activity increased from year to year. The labour costs increased due to wage increases as well. In addition the related resources required to perform the work such as supervision and vehicle costs increased.

Account Description	2007 Actual	2006 Actual	2007 vs. 2006
5175 - Maintenance of Meters	**96,349**	**28,944**	**67,405**

Work effort associated with this activity increased from year to year. The labour costs increased due to wage increases as well. In addition the related resources required to perform the work such as supervision and vehicle costs increased.

Account Description	2007 Actual	2006 Actual	2007 vs. 2006
6105 - Taxes Other than Income Taxes	**96,358**	**75,019**	**21,339**

The 2007 and 2006 charges reflect incorrect income tax adjustments as well as the property taxes.

The total property taxes are approximately $35,000 to $40,000 broken down between admin building of approx $6,000 and distribution assets for the balance. They have been correctly split in the 2011 test year.

Account Description	2007 Actual	2006 Actual	2007 vs. 2006
5305 - Supervision	**82,318**	**13,396**	**68,922**

The reduction of costs in 2006 reflects the reduction in a Customer Care/ IT Manager position

5415 - Energy Conservation	**83,755**	**34,850**	**48,905**

The expenditure difference represents differential annual spending patterns against the 2005 CDM expenditure targets

5625 - Administrative Expense - Transferred Credit	**-47,790**	**-4,928**	**-42,862**

The difference reflects the value of senior management services charged to its affiliate

5645 - Employee Pension and Benefits	**-1,711,140**	**299,000**	**-2,010,140**

The 2007 value reflects the impact of an actuarial evaluation re: pension benefit liabilities as of December 31, 2007.

The 2006 value reflects the net amount of total employee pension and benefit remaining after costs were allocated to USOA accounts via the 5905 contra account.

5655 - Regulatory Expenses	**96,980**	**65,876**	**31,104**

2007 expenses were higher related to the preliminary development of a Cost of Service rate application which was subsequently deferred.

2008 Actual VS 2007 Actual

Account Description	2008 Actual	2007 Actual	2008 vs. 2007
5017-Distribution Station Equipment - Operation Supplies and Expenses	**45,919**	**19,916**	**26,303**

The difference is due to the higher level of services provided by BCP's MSP provider

Account Description	2008 Actual	2007 Actual	2008 vs. 2007
5030 - Overhead Sub transmission Feeders - Operation	**-414**	**45,448**	**-45,862**

Work effort associated with this activity decreased from year to year. In addition the related resources required to perform the work such as supervision and vehicle costs decreased.

Account Description	2008 Actual	2007 Actual	2008 vs. 2007
5035-Overhead Distribution Transformers- Operation	**10,539**	**54,606**	**-44,067**

Work effort associated with this activity decreased from year to year. In addition the related resources required to perform the work such as supervision and vehicle costs decreased.

Account Description	2008 Actual	2007 Actual	2008 vs. 2007
5112 - Maintenance of Transformer Station Equipment	**45,121**	**0**	**45,121**

Work effort associated with this activity decreased from year to year. In addition the related resources required to perform the work such as supervision and vehicle costs decreased.

BCP acquired a 3/8 interest in a TS in association with Brantford Power in 2008. These costs represent BCP's share of maintenance costs (provided by Brantford Power)

5125-Maintenance of Overhead Conductors and Devices	**66,986**	**97,354**	**-30,368**

The reduction in cost is due to an inventory write-up adjustment credited to this account in 2008. This cost reduction was partially offset by increased work effort resulting in labour and associated costs.

5135-Overhead Distribution Lines and Feeders - Right of Way	**185,399**	**218,287**	**-32,888**

The 2089 program reflects a decrease in the contracted tree trimming program from the 2007 level

5175-Maintenance of Meters	**163,552**	**96,349**	**67,203**

Work effort associated with this activity increased from year to year. The labour costs increased due to wage increases as well. In addition the related resources required to perform the work such as supervision and vehicle costs increased.

6105 - Taxes Other than Income Taxes	**68,185**	**96,358**	**-28,173**

The 2008 and 2007 charges reflect incorrect income tax adjustments as well as the property taxes.

The total property taxes are approximately $35,000 to $40,000 broken down between admin building of approx $6,000 and distribution assets for the balance. They have been correctly split in the 2011 test year.

5305 - Supervision	**57,091**	**82,318**	**-25,227**

The billing supervisor position was eliminated in 2008 with the responsibility transferred to the Finance Department. The reduction of costs in 2008 reflects this.

5320 - Collecting	**144,610**	**215,638**	**-71,028**

The majority of the reduction is due to the elimination of a collections assistant position in 2008.

5410 - Community Relations - Sundry	**39,606**	**11,244**	**28,362**

The increase is due to the cost of a 1 time LED street lighting project in 2008 and an allocation of internal staff costs.

5605 - Executive Salaries and Expense	**445,083**	**316,535**	**128,548**

The increase is primarily due to one- time severance costs and salary adjustments in 2008.

5615 - General Administrative Salaries and Expenses	**182,115**	**122,401**	**59,714**

The difference is due to a one time severance package expensed in 2008.

5630 - Outside Services Employed	**156,764**	**120,698**	**36,066**

Cost increases are due to legal costs related to severances and pay equity studies partially offset by reductions in consulting expenses relating to metering and settlement.

5645 - Employee Pensions and Benefits	**28,640**	**-1,711,140**	**1,739,780**

The 2008 value reflects the net amount of total employee pension and benefit remaining after costs were allocated to USOA accounts via the 5905 contra account.

The 2007 value reflects the impact of an actuarial evaluation re: pension benefit liabilities as of December 31, 2007

5655 - Regulatory Expenses	**42,658**	**96,980**	**-54,322**

2007 expenses were higher related to the preliminary development of a Cost of Service rate application which was subsequently deferred.

6105 - Taxes Other than Income Taxes	**68,185**	**96,358**	**-28,173**

The 2008 and 2007 charges reflect an incorrect income tax adjustment as well as the property taxes for 2008.

The total property taxes are approximately $35,000 to $40,000 broken down between admin building of approx $6,000 and distribution assets for the balance. They have been correctly split in the 2011 test year.

2009 Actual VS 2008 Actual

Account Description	2009 Actual	2008 Actual	2009 vs. 2008
5085 - Miscellaneous Distribution Expense	**164,704**	**197,654**	**-32,950**

Work effort associated with this activity decreased from year to year. In addition the related resources required to perform the work such as supervision and vehicle costs decreased.

5125 - Maintenance of Overhead Conductors and Devices	**113,326**	**66,986**	**46,340**

The increase in cost is due to an inventory write-up adjustment credited to this account in 2008

5135 - Overhead distribution Lines and Feeders - Right of Way	**71,620**	**185,399**	**-113,779**

The 2009 program reflects a decrease in the contracted tree trimming program from the 2008 level

5175 - Maintenance of Meters	**116,611**	**163,552**	**-46,941**

Work effort associated with this activity decreased from year to year. In addition the related resources required to perform the work such as supervision and vehicle costs decreased.

6105 - Taxes Other than Income Taxes	**-2,588**	**68,185**	**-70,773**

The amount charged to this account in 2009 incorrectly captured an income tax adjustment. Property taxes for 2009 were charged to operations accounts

The 2008 charges again reflected an incorrect income tax adjustment as well as the property taxes for 2008.

The total property taxes are approximately $35,000 to $40,000 broken down between admin building of approx $6,000 and distribution assets for the balance. They have been correctly split in the 2011 test year.

5305 - Supervision	**8**	**57,091**	**-57,083**

The billing supervisor position was eliminated in 2008 with the responsibility transferred to the Finance Department. As a result no costs were charged from 2009 on.

5310 - Meter Reading Expense	**162,510**	**214,214**	**-51,704**

The major portion of the cost reduction was caused by a change to a more cost effective settlement provider.

5405 - Supervision	**30,543**	**0**	**30,543**

5410 - Community Relations - Sundry	**0**	**39,606**	**-39,606**

In reality there is not a material variance related to both these accounts. The trial balance for 2009 filed with the Board incorrectly reflected the 2009 expenditure in USOA 5405 whereas the GL shows it as a 5410 expense.

5605 - Executive Salaries and Expenses	**411,959**	**445,083**	**-33,124**

2008 included higher severance costs than the portion incurred in 2009. Partially offsetting these increased costs were the one time overlap costs related to the CFO position only charged in 2009.

5615 - General Administrative Salaries and Expenses	**148,455**	**182,115**	**-33,660**

The difference is due to a one time severance package expensed in 2008.

5630 - Outside Services Employed	**122,185**	**156,764**	**-34,579**

The difference is primarily due to one-time legal services related to employee severances expensed in 2008

5645 - Employee Pensions and Benefits	**856,850**	**28,640**	**828,210**

The 2009 expenditure reflected in the actual accounts captures the cumulative employee pension and benefit costs incurred by BCP.

These costs were charged out to OM&A and Capital accounts with a recovery through the use of a 5905 Contra Account

The 2008 value reflects the net amount remaining after costs were allocated to USOA accounts via the 5905 contra account.

5655 - Regulatory Expenses	**115,770**	**42,658**	**73,112**

2009 costs were higher due to the following one time activities involving external consulting and legal support:

- Regulatory Accounting Review
- Brantford Motion to Rehear Rate Case (EB-2009-0063)
- 2010 IRM Rate Application

5665 - Miscellaneous General Expense	**622,460**	**219,910**	**402,550**

2009 costs contain 1 time non-recurring costs related to:

- BCP share of Toronto Hydro interest litigation court case
- Correction of Regulatory Accounting balances as per independent review

In addition 2009 costs include higher IT support and staff training costs.

2010 Bridge VS 2009 Actual

Account Description	2010 Bridge	2009 Actual	2010 vs. 2009
5070 - Customer Premises - Operation Labour	**140,145**	**112,588**	**27,557**

Work effort associated with this activity increased from year to year. The labour costs increased due to wage increases as well. In addition the related resources required to perform the work such as supervision and vehicle costs increased. Vehicle costs have also increased due to higher V&E rates related to new vehicle acquisitions in 2010.

5085 - Miscellaneous Distribution Expense	**222,276**	**164,704**	**57,572**

The difference is caused by accounting process errors in 2009 which undercharged the 5085 USOA account for both supervision and V&E costs. These costs were distributed over other accounts. The process has been corrected for both 2010 and 2011.

5120 - Maintenance of Poles, Towers, and Fixtures	**75,868**	**31,104**	**44,764**

Work effort associated with this activity increased from year to year. The labour costs increased due to wage increases as well. In addition the related resources required to perform the work such as supervision and vehicle costs increased. Vehicle costs have also increased due to higher V&E rates related to new vehicle acquisitions in 2010.

5125 - Maintenance of Overhead Conductors and Devices	**148,106**	**113,326**	**34,780**

Work effort associated with this activity increased from year to year. The labour costs increased due to wage increases as well. In addition the related resources required to perform the work such as supervision and vehicle costs increased. Vehicle costs have also increased due to higher V&E rates related to new vehicle acquisitions in 2010.

5135 -Overhead Distribution Lines & Feeders - Right of Way	**133,741**	**71,620**	**62,121**

The 2011 program reflects an increase in the contracted tree trimming program from the 2010 level

5175 - Maintenance of Meters	**48,503**	**116,611**	**-68,108**

Work effort associated with this activity decreased from year to year. In addition the related resources required to perform the work such as supervision and vehicle costs decreased.

The reduction in work effort is related to the implementation of the smart meter program resulting in a newer meter population

5405 - Supervision	**0**	**30,543**	**-30,543**

5410 - Community Relations - Sundry	**30,000**	**0**	**30,000**

In reality there is not a material variance related to both these accounts. The trial balance for 2009 filed with the Board incorrectly reflected the 2009 expenditure in USOA 5405 whereas the GL shows it as a 5410 expense.

5415 - Energy Conservation	**109,529**	**80,445**	**29,084**

BCP hired a CDM coordinator in late 2009 to further CDM initiatives. The 2011 cost increase reflects the full year impact of this hire.

5605 - Executive Salaries and Expenses	**332,855**	**411,959**	**-79,104**

2009 costs included severance costs that were not repeated in 2010. In addition there overlap costs associated with the replacement of the CFO in 2009.

5630 - Outside Services Employed	**86,500**	**122,185**	**-35,685**

One time consulting costs related to collective agreement negotiations and pay equity studies were incurred in 2009. Partially offsetting these one-time cost reductions is an increase in anticipated audit fees for 2010.

5645 - Employee Pensions and Benefits	**0**	**856,850**	**-856,850**

2010 costs are zero as the budget process included labour burdens directly in the respective labour components of the OM&A and capital USOA accounts.

The 2009 expenditure reflected in the actual accounts captures the cumulative employee pension and benefit costs incurred by BCP.

These costs were charged out to OM&A and Capital accounts with a recovery through the use of a 5905 Contra Account

5665 - Miscellaneous General Expenses	**277,908**	**622,460**	**-344,552**

2009 costs contain 1 time non-recurring costs related to:

- BCP share of Toronto Hydro interest litigation court case
- Correction of Regulatory Accounting balances as per independent review

In addition 2010 costs include lower IT support and staff training costs.

2011 Test VS 2010 Bridge

Account Description	2011 Test	2010 Bridge	2011 vs. 2010
5085 - Miscellaneous Distribution Expense	**417,861**	**222,276**	**195,585**

Work effort associated with this activity increased from year to year. The labour costs increased due to wage increases as well. In addition the related resources required to perform the work such as supervision and vehicle costs increased. Supervisory costs have also increased due to the addition of a new P eng position in 2011. Vehicle costs have also increased due to higher V&E rates related to new vehicle acquisitions in 2011.

5315 - Customer Billing	**347,894**	**286,833**	**61,061**

The cost increase relates to an additional staff member hired in late 2009. (Smart Meter Data Analyst) The additional costs were capitalized in 2010 as part of the smart meter installation but are being expensed in 2011 as part of the smart meter operational process.

5615 - General Administrative Salaries and Expenses	**316,586**	**141,026**	**175,560**

2011 costs reflect 3 additional staff members

- Renewable Energy Coordinator whose costs are more than offset via a $135,000 Miscellaneous Revenue offset
- Collections Clerk – move collections back in house
- Replacement of Smart Meter Data Analyst who was promoted to an Office Manager role

5630 - Outside Services Employed	**129,000**	**86,500**	**42,500**

2011 costs include additional expenses related to increased audit, tax, and external financial services

5655 - Regulatory Expense	**150,000**	**120,875**	**29,125**

The increase in costs is due to the costs related to the 2011 Cost of Service application. The COS rate application costs have been amortized over 4 years

5665 - Miscellaneous General Expense	**320,911**	**277,908**	**43,003**

Incremental expenses in 2011 are due to:

- advertising related to solar energy initiatives (revenue offset in Miscellaneous Revenue)
- Increase IT costs to support a Daffron software upgrade
- Provision for staff training (no provision in 2010)

2011 Test VS 2006 Actual

Account Description	2011 Test	2006 Actual	2011 vs. 2006
5012 - Station Buildings and Fixtures Expense	93,806	40,173	53,633

Work effort associated with this activity increased over the period. The labour costs increased due to wage increases as well. In addition the related resources required to perform the work such as supervision and vehicle costs increased. Supervisory costs have also increased due to the addition of a new P eng position in 2011. Vehicle costs have also increased due to higher V&E rates related to new vehicle acquisitions over the period.

5070 - Customer Premises - Operation Labour	148,229	88,965	59,264

Work effort associated with this activity increased over the period. The labour costs increased due to wage increases as well. In addition the related resources required to perform the work such as supervision and vehicle costs increased. Supervisory costs have also increased due to the addition of a new P eng position in 2011. Vehicle costs have also increased due to higher V&E rates related to new vehicle acquisitions over the period.

5085 - Miscellaneous Distribution Expense	417,861	219,811	198,050

Work effort associated with this activity increased over the period. The labour costs increased due to wage increases as well. In addition the related resources required to perform the work such as supervision and vehicle costs increased. Supervisory costs have also increased due to the addition of a new P eng position in 2011. Vehicle costs have also increased due to higher V&E rates related to new vehicle acquisitions over the period.

5112 - Maintenance of Transformer Station Equipment	37,000	0	37,000

BCP acquired a 3/8 interest in a TS in association with Brantford Power in 2008. These costs represent BCP’s share of maintenance costs (provided by Brantford Power).

5120 - Maintenance of Poles, Towers, and Fixtures	**79,307**	**16,155**	**63,152**

Work effort associated with this activity increased over the period. The labour costs increased due to wage increases as well. In addition the related resources required to perform the work such as supervision and vehicle costs increased. Supervisory costs have also increased due to the addition of a new P eng position in 2011. Vehicle costs have also increased due to higher V&E rates related to new vehicle acquisitions over the period.

5125 - Maintenance of Overhead Conductors and Devices	**155,272**	**79,618**	**75,654**

Work effort associated with this activity increased over the period. The labour costs increased due to wage increases as well. In addition the related resources required to perform the work such as supervision and vehicle costs increased. Supervisory costs have also increased due to the addition of a new P eng position in 2011. Vehicle costs have also increased due to higher V&E rates related to new vehicle acquisitions over the period.

5135 - Overhead Distribution Lines and Feeders - Right of Way	**134,195**	**204,580**	**-70,385**

The 2011 program reflects a decrease in the contracted tree trimming program from the 2006 level

6105 - Taxes other than Income Taxes	**6,000**	**75,019**	**-69,019**

2006 costs incorrectly include income tax adjustments. 2011 costs reflect only property taxes related to the administration building

5310 - Meter Reading Expense	**144,362**	**214,298**	**-69,936**

The major portion of the cost reduction was caused by a change to a more cost effective settlement provider. In addition labour effort was lower with associated cost reductions.

5315 - Customer Billing	**347,894**	**279,107**	**68,787**

The cost increase is driven by the addition of 2 staff members from the 2006 level. Postage costs are also higher. There was a partial cost reduction due to a decrease in support costs from the 2006 level.

5320 - Collecting	**153,216**	**262,675**	**-109,459**

Lower costs result from the outsourcing of collections

5335 - Bad Debt Expense	**75,000**	**48,557**	**26,443**

The increase is due to a larger customer base with a higher accounts receivable risk.

5410 - Community Relations - Sundry	**35,000**	**3,958**	**31,042**

BCP has incorporated the following community projects in its 2011 test year (school programs including electrical safety and share the warmth program (assist low income families to heat homes),

5415 - Energy Conservation	**117,019**	**34,850**	**82,169**

The majority of the cost increase is due to the addition of a CDM Coordinator.

5605 - Executive Salaries and Expenses	**332,929**	**295,259**	**37,670**

The difference primarily reflects 5 years of escalation.

5615 - General Administrative Salaries and Expenses	**316,586**	**104,685**	**211,901**

The increase is driven by the addition of 3 staff members; Renewable Energy Coordinator, Smart Meter Dada Analyst, Collections Assistant

5625 - Administrative Expense - Transferred Credit	**-48,400**	**-4,928**	**-43,472**

This reflects an increase in the charge for Senior Management time charged to the LDC affiliate

5645 - Employee Pensions and Benefits	**0**	**299,000**	**-299,000**

2011 costs are zero as the budget process included labour burdens directly in the respective labour components of the OM&A and capital USOA accounts.

The 2006 expenditure reflected in the actual accounts captures the net difference between cumulative employee pension and benefit costs incurred by BCP and the costs that were charged out to OM&A and Capital accounts with a recovery through the use of a 5905 Contra Account

5655 - Regulatory Expenses	**150,000**	**65,876**	**84,124**

The increase is due to the following factors:

- increase in OEB assessment costs
- increase in ongoing legal and consultant costs for regulatory matters
- increase in one time 2011 COS costs (costs amortized over 4 years) vs. the costs related to the 2006 rate application

5665 - Miscellaneous General Expenses	**320,911**	**195,037**	**125,874**

Incremental expenses in 2011 are due to:

- Advertising related to solar energy initiatives (revenue offset in Miscellaneous Revenue)
- Increase in IT costs to support a Daffron software upgrade
- Increase in directors costs – escalation + payment for 2 municipal directors that were not previously paid

5675 - Maintenance of General Plant	**43,300**	**76,740**	**-33,440**

The decrease in costs was caused by a reduction in stuffing machine and hardware maintenance partially offset by an increase in janitorial costs.

2011 Test VS 2009 Actual

Account Description	2011 Test	2009 Actual	2011 vs. 2009
5070 - Customer Premises - Operation Labour	**148,229**	**112,588**	**35,641**

Work effort associated with this activity increased from year to year. The labour costs increased due to wage increases as well. In addition the related resources required to perform the work such as supervision and vehicle costs increased. Supervisory costs have also increased due to the addition of a new P eng position in 2011. Vehicle costs have also increased due to higher V&E rates related to new vehicle acquisitions in 2010 and 2011.

5085 - Miscellaneous Distribution Expense	**417,861**	**164,704**	**253,157**

Work effort associated with this activity increased from year to year. The labour costs increased due to wage increases as well. In addition the related resources required to perform the work such as supervision and vehicle costs increased. Supervisory costs have also increased due to the addition of a new P eng position in 2011. Vehicle costs have also increased due to higher V&E rates related to new vehicle acquisitions in 2010 and 2011.

5120 - Maintenance of Poles, Towers, and Fixtures	**79,307**	**31,104**	**48,203**

Work effort associated with this activity increased from year to year. The labour costs increased due to wage increases as well. In addition the related resources required to perform the work such as supervision and vehicle costs increased. Supervisory costs have also increased due to the addition of a new P eng position in 2011. Vehicle costs have also increased due to higher V&E rates related to new vehicle acquisitions in 2010 and 2011.

5125 - Maintenance of Overhead Conductors and Devices	**155,272**	**113,326**	**41,946**

Work effort associated with this activity increased from year to year. The labour costs increased due to wage increases as well. In addition the related resources required to perform the work such as supervision and vehicle costs increased. Supervisory costs have also increased due to the addition of a new P eng position in 2011. Vehicle costs have also increased due to higher V&E rates related to new vehicle acquisitions in 2010 and 2011.

5135 - Overhead Distribution Lines & Feeders - Right of Way	**134,195**	**71,620**	**62,575**

The 2011 program reflects an increase in the contracted tree trimming program from the 2009 level

5175 - Maintenance of Meters	**51,217**	**116,611**	**-65,394**

Work effort associated with this activity decreased from year to year. In addition the related resources required to perform the work such as supervision and vehicle costs decreased.

The reduction in work effort is related to the implementation of the smart meter program resulting in a newer meter population

5315 - Customer Billing	**347,894**	**278,614**	**69,280**

The cost increase relates to an additional staff member hired in late 2009. (Smart Meter Data Analyst) The additional costs were capitalized in 2010 as part of the smart meter installation but are being expensed in 2011 as part of the smart meter operational process.

5405 - Supervision	**0**	**30,543**	**-30,543**

5410 - Community Relations - Sundry	**35,000**	**0**	**35,000**

In reality there is not a material variance related to both these accounts. The trial balance for 2009 filed with the Board incorrectly reflected the 2009 expenditure in USOA 5405 whereas the GL shows it as a 5410 expense.

5415 - Energy Conservation	**117,019**	**80,445**	**36,574**

BCP hired a CDM coordinator in late 2009 to further CDM initiatives. The 2011 cost increase reflects the full year impact of this hire.

5605 - Executive Salaries and Expenses	**332,929**	**411,959**	**-79,030**

2009 costs included severance costs that were not repeated in 2011. In addition there overlap costs associated with the replacement of the CFO in 2009.

5615 - General Administrative Salaries and Expenses	**316,586**	**148,455**	**168,131**

2011 costs reflect 3 additional staff members

- Renewable Energy Coordinator whose costs are more than offset via a $135,000 Miscellaneous Revenue offset
- Collections Clerk – move collections back in house
- Replacement of Smart Meter Data Analyst who was promoted to an Office Manager role

5645 - Employee Pensions and Benefits	**0**	**856,850**	**-856,850**

2011 costs are zero as the budget process included labour burdens directly in the respective labour components of the OM&A and capital USOA accounts.

The 2009 expenditure reflected in the actual accounts captures the cumulative employee pension and benefit costs incurred by BCP.

These costs were charged out to OM&A and Capital accounts with a recovery through the use of a 5905 Contra Account

5665 - Miscellaneous General Expenses	**320,911**	**622,460**	**-301,549**

2009 costs contain 1 time non-recurring costs related to:

- BCP share of Toronto Hydro interest litigation court case
- Correction of Regulatory Accounting balances as per independent review

Employee Compensation

The following appendix 2- K provides details regarding employee compensation. The Executive and Management categories have been merged as the Executive category covers 2 individuals.

The most recent postretirement benefit actuarial assessment is 3 years old and is attached. BCP will be obtaining a revised assessment as part of the 2010 year-end closing process.

Brant County Power applied 2.5% labour escalation factors in both 2010 and 2011. These reflect the actual negotiated collective agreement increases. These increases have been applied to non-union staff costs as well. Pension and benefit costs that are related to base compensation have also risen by the 2.5 % escalation factors.

New hires in both 2010 and 2011 have been budgeted for the full fiscal year. (assumed a January 1 start date) to ensure full cost recovery for the remainder of the COS + IRM term.

Appendix 2-K

Employee Costs

	Last Rebasing Year	Historical Year - 2009	Bridge Year - 2010	Test Year - 2011
Number of Employees (FTEs including Part-Time)				
Executive	-			
Management	6	5	6	7
Non-Union	9	9	10	12
Union	11.9	11	11	13
Total	26.9	25	27	32
Number of Part-Time Employees				
Executive	-	-	-	-
Management	-	-	-	-
Non-Union	-	-	-	-
Union	-	-	-	-
Total	-	-	-	-
Total Salary and Wages				
Executive				
Management	$ 424,944	$ 492,305	$ 525,222	$ 588,235
Non-Union	$ 348,732	$ 365,303	$ 423,351	$ 511,806
Union	$ 634,734	$ 801,717	$ 822,274	$ 945,659
Total	$ 1,408,410	$ 1,659,325	$ 1,770,847	$ 2,045,700
Current Benefits				
Executive		$ 96,519	$ -	$ -
Management	$ 115,848	$ 96,624	$ 199,149	$ 194,493
Non-Union	$ 95,580	$ 143,317	$ 160,523	$ 169,223
Union	$ 174,442	$ 314,532	$ 311,783	$ 312,672
Total	$ 385,870	$ 650,992	$ 671,454	$ 676,388
Accrued Pension and Post-Retirement Benefits				
Executive				
Management				
Non-Union				
Union				
Total				
Total Benefits (Current + Accrued)				
Executive	$ -			
Management	$ 115,848	$ 193,143	$ 199,149	$ 194,493
Non-Union	$ 95,580	$ 143,317	$ 180,656	$ 187,793
Union	$ 174,442	$ 314,532	$ 350,888	$ 346,983
Total	$ 385,870	$ 650,992	$ 671,454	$ 676,388
Total Compensation (Salary, Wages, & Benefits)				
Executive	$ -			
Management	$ 540,792	$ 342,910	$ 440,994	$ 508,642
Non-Union	$ 444,312	$ 508,620	$ 604,007	$ 699,599
Union	$ 809,176	$ 1,116,249	$ 1,173,162	$ 1,292,642
Total	$ 1,794,280	$ 2,310,317	$ 2,442,301	$ 2,722,088
Compensation - Average Yearly Base Wages				
Executive				
Management	$ 70,824	$ 98,461	$ 87,537	$ 84,034
Non-Union	$ 38,748	$ 40,589	$ 42,335	$ 42,651
Union	$ 53,339	$ 72,883	$ 74,752	$ 72,743
Total				
Compensation - Average Yearly Overtime				
Executive	$ -	$ -	$ -	$ -
Management	$ 237	$ -	$ -	$ -
Non-Union	$ 574	$ -	$ -	$ -
Union	$ 4,238	$ 4,028	$ 5,424	$ 4,727
Total				
Compensation - Average Yearly Incentive Pay				
Executive	$ -	$ -	$ -	$ -
Management	$ -	$ -	$ -	$ -
Non-Union	$ -	$ -	$ -	$ -
Union	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	$ -
Compensation - Average Yearly Benefits				
Executive	$ -			
Management	$ 19,308	$ 38,629	$ 33,191	$ 27,785
Non-Union	$ 10,620	$ 15,924	$ 18,066	$ 15,649
Union	$ 14,659	$ 28,594	$ 31,899	$ 26,691
Total	$ -	$ -	$ -	$ -
Total Compensation	$ 1,851,300	$ 2,354,628	$ 2,501,964	$ 2,783,542
Total Compensation Charged to OM&A	$ 1,483,884	$ 1,614,106	$ 1,724,692	$ 2,096,863
Total Compensation Capitalized	$ 367,416	$ 740,522	$ 777,272	$ 686,679

Post-Retirement Benefits

As part of its statutory audit obligations, BCP is required to complete a post benefit retirement assessment every three years to support the accrued benefit liability on the Company's audited financial statements. The last assessment was completed in early calendar 2008 for the fiscal year ended December 31, 2007. A copy of the last report is attached as Tab 4 Schedule 1 Page 4 of this exhibit.

The company is required to complete a further assessment for the year ended December 31, 2010 and is currently in the process of engaging an actuarial advisor to complete this assessment.

BRANT COUNTY POWER INC.

Report on the
Actuarial Valuation of
Post-Retirement Benefits
(Other than Pensions)

As at January 1, 2007

DRAFT

March 11, 2008

TABLE OF CONTENTS

EXECUTIVE SUMMARY

PURPOSE

MBARIB Actuarial Services and Dion, Durrell + Associates Inc. were engaged by Brant County Power Inc. (the "Utility") to perform an actuarial valuation of the post-retirement non-pension benefits sponsored by the Utility and to determine the accounting results for those benefits for the fiscal period starting January 1, 2007 and ending December 31, 2007. The nature of these benefits is defined benefit.

This report is prepared in accordance with The Canadian Institute of Chartered Accountants (the "CICA") guidelines outlined in Employee Future Benefits, Section 3461 of the CICA Handbook – Accounting. CICA 3461 was first applied with effect from January 1, 2007.

The purpose of this valuation is threefold:

i) to determine the Employer's liabilities in respect of post-retirement non-pension benefits;

ii) to determine the benefit expense for fiscal year 2007; and

iii) to provide all other pertinent information necessary for compliance with CICA Section 3461.

The intended users of this report include the Utility and their auditors. This report is not intended for use by the plan beneficiaries or for use in determining any funding of the benefit obligations.

SUMMARY OF KEY RESULTS

The key results of this actuarial valuation as at January 1, 2007 are shown below (all figures are in thousands):

		January 1, 2007 (000's)
ACCRUED BENEFIT OBLIGATION (ABO)		
a)	People in receipt of benefits	$ 301
b)	Fully eligible actives	$ 10
c)	Non fully eligible actives	$ 255
TOTAL		$ 566
CURRENT SERVICE COST		$ 22
BENEFIT EXPENSE		$ 51

ACTUARIAL CERTIFICATION

An actuarial valuation has been performed on the post-retirement non-pension benefit plans sponsored by the Utility as at January 1, 2007, for the purposes described in this report.

In accordance with the Canadian Institute of Actuaries Consolidated Standards of Practice General Standards, we hereby certify that, in our opinion, for the purposes stated in the Executive Summary:

1. The data on which the valuation is based is sufficient and reliable;

2. The assumptions employed, as outlined in this report, have been selected by the Utility as best estimate assumptions (no provision for adverse deviations) and are in accordance with accepted actuarial practice;

3. The actuarial methods employed, as outlined in Section C, are appropriate for the purpose and consistent with sound actuarial principles;

4. All known substantive commitments with respect to the post-retirement, non-pension benefits sponsored by and identified by the Utility are included in the calculations; and

5. The valuation conforms to the standards set out in the Canadian Institute of Chartered Accountants Accounting Handbook Section 3461.

The latest date on which the next actuarial valuation should be performed is January 1, 2010. If any supplemental advice or explanation is required, please advise the undersigned.

Respectfully submitted,

DION, DURRELL + ASSOCIATES INC.

Karen G. Long
Fellow, Canadian Institute of Actuaries

Connie Cheung
Actuarial Analyst

Toronto, Ontario
March 11, 2008

SECTION A
VALUATION RESULTS

Table A - 1 shows the key valuation results for the prior valuation and the current valuation.

Table A - 2 shows the sensitivity of the valuation results to certain changes in assumptions. We have shown a change to the assumed retirement age from age 60 to 57, and an increase/decrease in the health, dental, vision and orthodontics claims cost trend rate by 1% per annum.

TABLE A - 1
VALUATION RESULTS

(IN THOUSANDS OF DOLLARS)

			January 1, 2007 (000's)
1.	ACCRUED BENEFIT OBLIGATION		
	a)	People in receipt of benefits	$ 301
	b)	Fully eligible actives	$ 10
	c)	Not fully eligible actives	$ 255
	TOTAL ABO		**$ 566**
2.	BENEFIT EXPENSE		
	a)	Current Service Cost	$ 22
	b)	Interest Cost	$ 29
	c)	Expected Return on Assets	$ -
	TOTAL BENEFIT EXPENSE		**$ 51**
3.	BENEFIT PAYMENTS*		$ 27

*Annualized actual payments based on year to date payments at November 30, 2007

TABLE A - 2
SENSITIVITY ANALYSIS

(IN THOUSANDS OF DOLLARS)

	January 1, 2007			
	Valuation Results (000's)	*Retirement Age 57* (000's)	1% *Higher Trend* (000's)	1% *Lower Trend* (000's)
1. ABO				
a) People in receipt of benefits	$ 301	$ 301	$ 301	$ 300
b) Fully eligible actives	$ 10	$ 10	$ 11	$ 10
c) Not fully eligible actives	$ 255	$ 353	$ 281	$ 211
TOTAL	$ 566	$ 664	$ 593	$ 541
2. CURRENT SERVICE COST	$ 22	$ 29	$ 25	$ 20
3. INTEREST COST	$ 29	$ 34	$ 30	$ 27
4. BENEFIT PAYMENTS	$ 27	$ 24	$ 24	$ 24

SECTION B
PLAN PARTICIPANTS

PARTICIPANT DATA

Membership data as at January 1, 2007 was received from the Employer via e-mail and included information such as name, sex, date of birth, date of hire, current salary, benefit amounts and other applicable details for all active employees and people in receipt of benefits.

We have reviewed the data and compared it to the data used in the prior valuation for consistency and reliability for use in this valuation. The main tests of sufficiency and reliability that were conducted on the membership data are as follows:

- Date of birth prior to date of hire
- Salaries less than $20,000 per year, or greater than $250,000 per year
- Ages under 18 or over 100
- Abnormal levels of benefits and/or premiums
- Duplicate records

ACTIVE EMPLOYEES

As of January 1	2007		
	Male	Female	Total
NUMBER OF EMPLOYEES	15	11	26
AVERAGE LENGTH OF SERVICE	13.10	8.01	10.95

As of January 1, 2007 — **NUMBER OF LIVES**

Current Age Band	Active Lives – not fully eligible Count			Active Lives – fully eligible Count		
	Male	Female	Total	Male	Female	Total
Less than 30	2	2	4	-	-	-
30-35	2	-	2	-	-	-
36-40	-	-	-	-	-	-
41-45	3	3	6	-	-	-
46-50	6	4	10	-	-	-
51-55	1	2	3	-	-	-
56-60	-	-	-	-	-	1
61-65	-	-	-	-	-	-
66-70	-	-	-	-	-	-
71-75	-	-	-	-	-	-
Greater than 75	-	-	-	-	-	-
TOTAL	14	11	25	1	-	1

As of January 1, 2007

AVERAGE SERVICE

Age Band	Active Lives – not fully eligible Service			Active Lives – fully eligible Service		
	Male	Female	Total	Male	Female	Total
Less than 30	1.96	3.42	2.60	-	-	-
30-35	4.08	-	4.08	-	-	-
36-40	-	-	-	-	-	-
41-45	14.22	8.39	11.31	-	-	-
46-50	18.07	8.13	14.09	-	-	-
51-55	15.75	11.79	13.11	-	-	-
56-60	-	-	-	-	-	-
61-65	-	-	-	17.58	-	17.58
66-70	-	-	-	-	-	-
71-75	-	-	-	-	-	-
Greater than 75	-	-	-	-	-	-
TOTAL	12.78	8.01	10.68	17.58	-	17.58

PEOPLE IN RECEIPT OF BENEFITS

As of January 1	2007		
	Male	Female	Total
NUMBER OF MEMBERS	14	2	16

As of January 1, 2007

EXPECTED ANNUAL BENEFIT PAYMENTS

Age Band	Male	Female	Total
Less than 30	-	-	-
30-35	-	-	-
36-40	-	-	-
41-45	-	-	-
46-50	-	-	-
51-55	-	-	-
56-60	6,453	-	6,452
61-65	2,885	-	2,885
66-70	374	-	374
71-75	1,269	243	1,511
Greater than 75	10,765	654	11,419
TOTAL	21,745	896	22,642

SECTION C
SUMMARY OF ACTUARIAL METHOD AND ASSUMPTIONS

ACTUARIAL METHOD

The aim of an actuarial valuation of post-retirement non-pension benefits is to provide a reasonable and systematic allocation of the cost of these future benefits to the years in which the related employees' services are rendered. In order to value the liabilities of the post-employment benefits, it is necessary to:

- make assumptions as to the discount rates, salary increase rates, mortality and other decrements;
- use these assumptions to calculate the present value of the expected future benefits; and
- adopt an actuarial cost method to allocate the present value of expected future benefit to the specific years of employment.

The Accrued Benefit Obligation and Current Service Cost were determined using the projected benefit method, pro-rated on service. This is the method stipulated by the Accounting Recommendations when future salary levels or cost escalation affect the amount of the employee's future benefits. Under this method, the projected post-retirement benefits are deemed to be earned on a pro-rata basis over the years of service in the attribution period. The CICA Section 3461 stipulates that the attribution period commences at the employee's hire date and ends at the earliest age at which the employee could retire and qualify for full benefits.

For each active employee, the Accrued Benefit Obligation is equal to the present value of expected future benefit multiplied by the ratio of the years of service to the valuation date to the total years of service in the attribution period. The Current Service Cost is equal to the present value of expected future benefits multiplied by the ratio of the year (or part) of service in the fiscal year to total years of service in the attribution period.

For health and dental benefits, we have used the premium rates charged by Equitable Life with respect to the retirees as an estimate of the claims to be incurred. For vision and orthodontics benefits, we have used the deemed premium rates as provided by Brant County Power. The monthly rates used are as follows:

Equitable Life				In-house	
Health		Dental		Vision	Orthodontics
Single	Family	Single	Family		
$87.03	$214.92	$37.67	$106.35	$9.33	$14.58

ECONOMIC ASSUMPTIONS

CONSUMER PRICE INDEX
The consumer price index is assumed to be 2.00% per annum.

DISCOUNT RATE
The rate used to discount future benefits is assumed to be 5.00% per annum. This rate reflects the assumed long term yield on high quality bonds as at September 30, 2007.

SALARY INCREASE RATE
The rate used to increase salaries is assumed to be 3.30% per annum. This rate reflects the expected Consumer Price Index adjusted for productivity, merit and promotion, as at September 30, 2007.

CLAIMS COST TREND RATE
The rates used to project benefits costs into the future are as follows:

	Current Valuation			
Jan 1, Year	***Health***	***Dental***	***Vision***	***Orthodontics***
2007	10.0%	5.0%	2.0%	2.0%
2008	9.0%	5.0%	2.0%	2.0%
2009	8.0%	5.0%	2.0%	2.0%
2010	7.0%	5.0%	2.0%	2.0%
2011	6.0%	5.0%	2.0%	2.0%
2012 →	5.0%	5.0%	2.0%	2.0%

DEMOGRAPHIC ASSUMPTIONS

MORTALITY TABLE
Mortality is assumed to be in accordance with the 1994 Uninsured Pensioner Mortality (UP-94) table, with a projection of mortality improvements to the year 2015 based upon Projection Scale AA. This is the mortality table to be used in accordance with the Canadian Institute of Actuaries' Standard of Practice for Determining Pension Commuted Values, effective February 1, 2005.

Mortality rates are applied on a sex-distinct basis.

RATES OF WITHDRAWAL
Termination of employment prior to retirement was assumed to be equal to 2.0% per annum.

RETIREMENT AGE
All active employees are assumed to retire at age 60, or immediately if currently over age 60.

DISABLITY

No provision was made for future disability. It is assumed that individuals currently receiving long-term disability benefits will remain disabled until retirement age.

FAMILY/SINGLE COVERAGE

It is assumed that the current coverage type will remain into retirement.

EXPENSES AND TAXES

We have assumed 10% of benefits is required for taxes and the cost of sponsoring the program for life insurance.

We have assumed taxes and expenses are included in the premium rates for health and dental benefits.

SECTION D
SUMMARY OF POST-RETIREMENT BENEFITS

The following is a summary of the plan provisions that are pertinent to this valuation.

EFFECTIVE DATE OF THE PROGRAM

The program is governed by the collective agreements expiring on March 31, 2009.

LENGTH OF SERVICE

Length of service is defined as continuous service from the date of hire to the valuation date, measured in years and months.

SUMMARY OF BENEFITS

Life Insurance/AD&D

All employees who retire from the Brant County Power are eligible for lifetime post-retirement life insurance as per the MEARIE plan, administered by Great West Life, based upon the following table:

Plan Option	Amount of Coverage	Eligibility
1	Flat $2,000.	If employee retires with less than 10 years of service in the Plan.
2	50% of final annual earnings reducing by 2.5% of final annual earnings each year thereafter for 10 years, to a final benefit equal to 25.0% of final annual earnings. Reduction occurs on anniversary date of retirement.	If employee was ever insured under Employee Plan options 2, 3 or 4, or if employee retires with 10 or more years of service in Plan but was never in superseded plan.
3	50% of final annual earnings.	If employee was insured under superseded plan and was hired on or after May 1, 1967 and elected coverage under Option 1 only.
4	70% of the final amount insured for under the life plan immediately prior to retirement.	If employee was insured under the superseded plan and was hired before May 1, 1967 and elected coverage under Option 1 only.
5	Amount of retirement insurance coverage in force under superseded plan grandfathered.	Frozen group of insured whose retirement occurred under superseded plan prior to transfer to Sun Life.

Health/Dental/Vision/Orthodontics Benefits

Employees hired before August 1, 2003

All employees who were hired before August 1, 2003 with 20 years of service at retirement are eligible for post-retirement benefits to age 65 at retirement, 100% payable by the company.

Those employees who retire with less than 20 years of service are eligible for post-retirement benefits to age 65, 50% payable by the company.

Employees hired after August 1, 2003

All employees who were hired after August 1, 2003 are eligible for post-retirement benefits to age 65 at retirement, 50% payable by the company.

Coverage for post-retirement benefits continues to the eligible dependents of a deceased employee or pensioner for 2 years or when the retiree should have turned 65 years old.

SECTION E
EMPLOYER CERTIFICATION

Post-Retirement Non-Pension Benefit Plan
of Brant County Power Inc.
Actuarial Valuation as at January 1, 2007

I hereby confirm as an authorized signing officer of the administrator of the Post-Retirement Non-Pension Benefit Plan of Brant County Power Inc. that, to the best of my knowledge and belief, for the purposes of the valuation:

i) the assumptions upon which this report is based are management best estimate assumptions and are adequate and appropriate for the purposes of this valuation;

ii) the membership data is accurate and complete; and

iii) the summary of Plan Provisions is an accurate and complete summary of the terms of the Plan in effect on January 1, 2007.

BRANT COUNTY POWER INC.

March 17/08
Date

Signature

Deborah Sleeth
Name

CEO
Title

Brant County Power Inc.

ESTIMATED BENEFIT EXPENSE (CICA 3461)

Draft

	Calendar Year 2007	Projected Calendar Year 2008	Projected Calendar Year 2009
Discount Rate	5.00%	5.00%	5.00%
A. Determination of Benefit Expense			
Current Service Cost	21,859	22,952	24 069
Interest on Benefits	26,693	29,983	31 463
Expected Interest on Assets	-	-	-
Transitional Obligation/(Asset)	-	-	-
Actuarial (Gain)/Loss	-	-	-
Benefit Expense	50,552	52,935	55,552
B. Reconciliation of Prepaid Benefit Asset (Liability)			
Accrued Benefit Obligation (ABO) as at December 31	588,860	617,500	648,384
Assets as at December 31	-	-	-
Unfunded ABO	(588,860)	(617,500)	(648,384)
Unrecognized Loss/(Gain)	-	-	-
Unrecognized Transition	-	-	-
Prepaid Benefit Asset (Liability)	(588,860)	(617,500)	(648,384)
Prepaid Benefit/(Liability) as at January 1	(565,700)	(588,860)	(617,500)
Benefit Income/(Expense)	(50,552)	(52,935)	(55,552)
Contributions/Benefit Payments by the Employer	27,398	24,295	24,678
Prepaid Benefit Asset (Liability)	(588,860)	(617,500)	(648,384)

1/6/2006

Brant County Power Inc.
ESTIMATED BENEFIT EXPENSE (CICA 3461)
Draft

	Calendar Year 2007	Projected Calendar Year 2008	Projected Calendar Year 2009
C. Calculation of Component Items			
Calculation of the Service Cost			
- Current service cost	21,859	22,952	24,099
Interest on Benefits			
- ABO at January 1	565,703	588,860	617,500
- Current service cost	21,859	22,952	24,069
- Benefit payments	(13,698)	(12,148)	(12,339)
- Accrued benefits	575,854	599,564	629,260
- Interest	26,893	29,983	31,463
Expected Interest on Assets			
- Assets at January 1	-	-	-
- Funding	13,698	12,146	12,339
- Benefit payments	(13,698)	(12,146)	(12,339)
- Expected assets	-	-	-
- Interest	-	-	-
Expected ABO as at December 31			
- ABO at January 1	565,703	588,860	617,500
- Current service cost	21,859	22,952	24,099
- Interest on benefits	28,693.22	29,983	31,463
- Benefit payments	(27,395)	(24,295)	(24,678)
- Expected ABO at December 31	588,860	617,600	648,384
Expected Assets as at December 31			
- Assets at January 1	-	-	-
- Funding	27,395	24,295	24,679
- Interest on assets	-	-	-
- Benefit payments	(27,395)	(24,295)	(24,678)
- Expected Assets at December 31	-	-	-

Brant County Power Inc.
ESTIMATED BENEFIT EXPENSE (CICA 3461)
Draft

	Calendar Year 2007	Projected Calendar Year 2008	Projected Calendar Year 2009
D. Actuarial (Gain)/Loss			
(Gain)/Loss on ABO as at January 1			
- Prepaid Benefit Liability	565,703		
- Unrecognized Actuarial Gains/Losses			
- Expected ABO	565,703	588,880	617,500
- Actual ABO	565,703	588,880	617,500
- (Gain)/Loss on ABO	-	-	-
(Gain)/Loss on assets as at January 1			
- Expected assets	-	-	-
- Actual assets	-	-	-
- (Gain)/Loss on assets	-	-	-
Total (Gain)/Loss as at January 1	-	-	-
10% of ABO as at January 1	56,570	58,888	61,750
Total (Gain)/Loss in excess of 10%	-	-	-
Expected average remaining service life (years)	0	9	7
Minimum Amortization for current year	-	-	-
Actual Amortization for current year	-	-	-
Unamortized (Gain)/Loss	-	-	-

1/8/2008

Shared Services / Corporate Cost Allocation

Brant County Power Inc. has an affiliate – Brant County Power Services Inc. (”BCPS”). BCPS provides a number of services including: water billing services for the County of Brant, water heater and water softener rental services for customers in Brant County and Woodstock as well as fibre optic cable services for various Brant County residents.

BCP provides the following services to BCPS:

- Management oversight
- Financial
- Customer Service

The costs charged to the affiliate represent management’s best estimates of time spent and a reasonable share of other expenses.

The company has recently implemented a “time sheet” system to better track the labour effort spent assisting the affiliate. The majority of costs are labour based. BCP is also taking steps to more clearly define the distinction between BCP and BCPS by separating both the billing and mailing systems, and expects to have this in place by the end of calendar 2010. Other systems including contact telephone numbers, website, and other advertising is already clearly distinct.

The charges for these services are collected in USOA 5625 – Administrative Expense Transferred Credit.

Purchase of Non Affiliate Services

The following provides details regarding purchases by year from non-affiliated companies that exceed the materiality level of $50,000 per vendor per year.

2004

- Oakhill Tree Service - $174,092 (tree trimming service, this is tendered out to at least five vendors – generally lowest cost vendor with capability wins bid)

- RDS Utility Services – $60,175 (meter reading service – not many providers – this vendor had most competitive pricing).

- Brantford Power Inc. - $60,000 (market settlement services).

2006

- Oakhill Tree Service - $200,750 (tree trimming service, this is tendered out to at least five vendors – generally lowest cost vendor with capability wins bid)

- RDS Utility Services – $95,217 (meter reading service – not many providers – this vendor had most competitive pricing).

2007

- Oakhill Tree Service - $214,052 (tree trimming service, this is tendered out to at least five vendors – generally lowest cost vendor with capability wins bid)

- RDS Utility Services – $88,283 (meter reading service – not many providers – this vendor had most competitive pricing).

2008

- Oakhill Tree Service - $170,448 (tree trimming service, this is tendered out to at least five vendors – generally lowest cost vendor with capability wins bid)

- RDS Utility Services – $99,392 (meter reading service – not many providers – this vendor had most competitive pricing).

<u>2009</u>

- Beswick Tree Service - $58,475 (tree trimming service, this is tendered out to at least five vendors – generally lowest cost vendor with capability wins bid)

- RDS Utility Services – $99,351 (meter reading service – not many providers – this vendor had most competitive pricing).

<u>2010</u>

- Beswick Tree Service - $125,000 (tree trimming service, this is tendered out to at least five vendors – generally lowest cost vendor with capability wins bid)

- RDS Utility Services – $90,000 (meter reading service – not many providers – this vendor had most competitive pricing).

- Ian McKenzie Business Services Inc. - $115,000 (rate application - $70,000, variance account rebuild, rate consulting – specialized service)

- Aird & Berlis LLP - $54,000 (legal services including $25,000 for rate application).

<u>2011</u>

- Beswick Tree Service - $125,000 (tree trimming service, this is tendered out to at least five vendors – generally lowest cost vendor with capability wins bid). This tender is currently underway

- RDS Utility Services – $90,000 (meter reading service – not many providers – this vendor does cheaper than competitors). BCP is still evaluating based on smart meter and TOU pricing which will come into effect in late 2011.

Depreciation / Amortization

The following appendix 2- M provides details regarding depreciation and amortization.

For actual accounting purposes BCP starts depreciation in the month following the in-service date of the asset. As additions are distributed over the course of the year this practice approximates the half year rule.

For 2010 and 2011 the depreciation values (determined on a budget basis) included in the application reflect the full ½ year rule.

Additional information regarding BCPs asset accounting practices is contained in the notes to the audited financial statements.

Note 1 – for 2006, 2007, 2008 and 2009 the calculated depreciation value in Appendix 2-M does not equal the values utilized for rate based identification purposes. This arises from a fair market assessment that was performed in 2000 on both Gross Assets and Accumulated Depreciation. This adjustment was done by BCP auditors upon the creation of BCP (from former municipalities). This value impacted the fixed assets and accumulated depreciation for rate base purposes, however, should have only impacted tax calculations. Unfortunately the history to provide a full appendix M does not exist.

Essentially on accumulated depreciation for BCP in 2000 was re-set to a $0 value and the financial statements do not account for distribution assets that are depreciated over more than 10 years properly.

BCP is confident that the projected depreciation values for 2010 and 2011 are accurate and reasonable.

Appendix 2-M
Depreciation and Amortization Expense

2006

Account	Description	Opening Balance A	Less Fully Depreciated B	Net for Depreciation C = A - B	Additions D	Total for Depreciation E = C + D	Years F	Depreciation Rate G = 1/F	Depreciation Expense H = E / F	Application Utilized Values	Variance	
1805	Land	94,643	-	94,643	-	94,643		0%	-	-	-	
1808	Buildings	753,038	-	753,038	39,251	792,289	25 / 30	4% / 3.33%	31,847	31,847	-	
1810	Leasehold Improvements	-		-	-	-	50	2%	-	-	-	
1815	Transformer Station Equipment > 50kV	2,440,513	-	2,440,513	67,054	2,507,567	40	2.5%	62,689	62,689	0	
1820	Substation Equipment	116,080	-	116,080	-	116,080	25	4%	4,643	6,201	1,558	Issue re: note # 1
1825	Storage Battery Equipment	-		-	-	-		0%	-	-	-	
1830	Poles, Towers & Fixtures	3,132,819	87,789	3,045,029	456,927	3,501,957	25	4%	140,078	184,866	44,788	Issue re: note # 1
1835	OH Conductor & Devices	2,611,586	100,209	2,511,378	254,506	2,765,884	25	4%	110,635.36	146,935	36,300	Issue re: note # 1
1840	UG Conduit	444,358	-	444,358	33,622	477,981	25	4%	19,119	23,059	3,940	Issue re: note # 1
1845	UG Conductor & Devices	1,914,076	-	1,914,076	47,084	1,961,160	25	4%	78,446.40	103,996	25,550	Issue re: note # 1
1850	Line Transformer	3,345,152	-	3,345,152	378,354	3,723,506	25	4%	148,940	186,222	37,282	Issue re: note # 1
1855	Services (OH & UG)	2,178,522	57,262	2,121,260	91,904	2,213,164	25	4%	88,527	119,295	30,769	Issue re: note # 1
1860	Meters	1,048,552	-	1,048,552	90,639	1,139,191	25	4%	45,568	56,213	10,645	Issue re: note # 1
1861	Smart Meters			-		-			-		-	
1861	Smart Meters/Communication System			-		-			-		-	
1905	Land	72,665	-	72,665	-	72,665		0%	-	-	-	
1906	Land Rights	-		-	-	-		0%	-	-	-	
1908	Buildings & Fixtures	227,733	-	227,733	-	227,733	25 / 30	4% / 3.33%	6,714	6,714	-	Issue re: note # 1
1910	Leasehold Improvements	-		-	-	-		0%	-	-	-	
1915	Office Furniture & Equipment (10 years)	84,613	-	84,613	7,349	91,962	10	10%	9,196	9,235	39	Issue re: note # 1
1915	Furniture & Equipment (5 years)			-		-			-		-	
1920	Computer - Hardware	431,641	79,601	352,040	9,130	361,170	5	20%	72,234	72,234	0	
1925	Computer -Software	249,459	144,211	105,248	20,869	126,117	5	20%	25,223.40	25,224	0	
1930	Transportation Equipment	1,019,409	68,099	951,310	202,832	1,154,142	4 / 5 / 8	25% / 20% / 12.5%	165,144	165,144	-	
1935	Stores Equipment	1,149	1,149	-	-	-		0%	-	-	-	
1940	Tools, Shop & Garage Equipment	99,263	99,288	- 24	12,724	12,700	10	10%	1,270	9,837	8,567	Issue re: note # 1
1945	Measurement & Testing equipment	41,177	4,660	36,517	-	36,517	10	10%	3,652	3,891	239	immaterial
1950	Power operated Equipment	2,675	710	1,965	-	1,965	10	10%	196	196	- 0	
1955	Communications Equipment	39,996	1,108	38,888	-	38,888	10	10%	3,889	3,887	- 2	immaterial
1960	Graphics Equipment	22,123	730	21,393	-	21,393	10	10%	2,139	2,139	- 0	
1965	Water Heater Rental Units	-		-	-	-		0%	-	-	-	
1970	Load Management Controls	-		-	-	-		0%	-	-	-	
1975	Load Management Controls Utility Premises	-		-	-	-		0%	-	-	-	
1980	System Supervisor Equipment	-		-	-	-		0%	-	-	-	
1985	Misc. Fixed Assets	-		-	-	-		0%	-	-	-	
1995	Contributions & Grants	- 1,628,129	-	- 1,628,129	- 10,767	- 1,638,896		misc.	- 65,556	- 65,556	-	
Total		18,743,113	644,815	18,098,298	1,701,477	19,799,775			954,594	1,154,268	199,674	

Appendix 2-M

Depreciation and Amortization Expense

2007												
Account	Description	Opening Balance	Less Fully Depreciated	Net for Depreciation	Additions	Total for Depreciation	Years	Depreciation Rate	Depreciation Expense			
		A	B	C = A - B	D	E = C + D	F	G = 1/F	H = E / F	Bal Check		
1805	Land	94,643	-	94,643	-	94,643	0	0%	-	-	-	
1808	Buildings	792,289	-	792,289	7,067	799,355	25 / 30	4% / 3.33%	32,082	32,082	-	
1810	Leasehold Improvements	-		-	-	-	50	2%	-	-	-	
1815	Transformer Station Equipment > 50kV	2,507,567	-	2,507,567	-	2,507,567	40	3%	62,689	62,689	0	
1820	Substation Equipment	116,080	-	116,080	-	116,080	25	4%	4,643	6,201	1,558	Issue re: note # 1
1825	Storage Battery Equipment	-		-	-	-	0	0%	-	-	-	
1830	Poles, Towers & Fixtures	3,589,746	160,765	3,428,981	437,857	3,866,838	25	4%	154,674	196,602	41,929	Issue re: note # 1
1835	OH Conductor & Devices	2,866,093	156,968	2,709,125	158,780	2,867,905	25	4%	114,716	150,068	35,352	Issue re: note # 1
1840	UG Conduit	477,981	-	477,981	26,002	503,983	25	4%	20,159	25,499	5,340	Issue re: note # 1
1845	UG Conductor & Devices	1,961,160	-	1,961,160	19,743	1,980,903	25	4%	79,236	103,226	23,990	Issue re: note # 1
1850	Line Transformer	3,723,506	-	3,723,506	313,220	4,036,726	25	4%	161,469	198,751	37,282	Issue re: note # 1
1855	Services (OH & UG)	2,270,426	86,696	2,183,730	89,532	2,273,262	25	4%	90,930	120,438	29,507	Issue re: note # 1
1860	Meters	1,139,191	-	1,139,191	84,060	1,223,251	25	4%	48,930	59,576	10,645	Issue re: note # 1
1861	Smart Meters			-		-	0	0%	-		-	
1861	Smart Meters/Communication System			-		-	0	0%	-		-	
1905	Land	72,665	-	72,665	-	72,665	0	0%	-	-	-	
1906	Land Rights	-		-	-	-	0	0%	-	-	-	
1908	Buildings & Fixtures	227,733	-	227,733	17,272	245,005	25 / 30	4% / 3.33%	7,290	7,290	-	
1910	Leasehold Improvements	-		-	-	-	0	0%	-	-	-	
1915	Office Furniture & Equipment (10 years)	91,962	-	91,962	2,306	94,268	10	10%	9,427	9,466	39	Issue re: note # 1
1915	Furniture & Equipment (5 years)			-		-	0	0%	-		-	
1920	Computer - Hardware	440,771	88,180	352,591	76,211	428,801	5	20%	85,760	78,139	- 7,621	
1925	Computer -Software	270,328	157,611	112,717	16,377	129,094	5	20%	25,819	24,181	- 1,638	
1930	Transportation Equipment	1,222,241	68,099	1,154,142	147,261	1,301,403	4 / 5 / 8	25% / 20% / 12.5%	194,372	194,372	-	
1935	Stores Equipment	1,149	1,149	-	-	-	0	0%	-	-	-	
1940	Tools, Shop & Garage Equipment	111,987	107,724	4,263	15,726	19,989	10	10%	1,999	10,709	8,710	Issue re: note # 1
1945	Measurement & Testing equipment	41,177	4,660	36,517	6,958	43,475	10	10%	4,348	4,024	- 324	immaterial
1950	Power operated Equipment	2,675	710	1,965	33	1,998	10	10%	200	200	- 0	immaterial
1955	Communications Equipment	39,996	1,108	38,888	-	38,888	10	10%	3,889	3,887	- 2	immaterial
1960	Graphics Equipment	22,123	730	21,393	-	21,393	10	10%	2,139	2,139	- 0	
1965	Water Heater Rental Units	-		-	-	-	0	0%	-	-	-	
1970	Load Management Controls	-		-	-	-	0	0%	-	-	-	
1975	Load Management Controls Utility Premises	-		-	-	-	0	0%	-	-	-	
1980	System Supervisor Equipment	-		-	-	-	0	0%	-	-	-	
1985	Misc. Fixed Assets	-		-	-	-	0	0%	-	-	-	
1995	Contributions & Grants	- 1,638,896	-	- 1,638,896	- 60,603	- 1,699,499	0	misc.	- 67,980	- 67,980	-	
Total		20,444,590	834,400	19,610,190	1,357,802	20,967,992			1,036,791	1,221,558	184,767	

Appendix 2-M
Depreciation and Amortization Expense

2008

Account	Description	Opening Balance A	Less Fully Depreciated B	Net for Depreciation C = A - B	Additions D	Total for Depreciation E = C + D	Years F	Depreciation Rate G = 1/F	Depreciation Expense H = E / F	Bal Check		
1805	Land	94,643	-	94,643	-	94,643	0	0%	-	-	-	
1808	Buildings	799,355	-	799,355	3,640	802,995	25 / 30	4% / 3.33%	32,204	32,204	-	
1810	Leasehold Improvements	-		-	-	-	50	2%	-	-	-	
1815	Transformer Station Equipment > 50kV	2,507,567	-	2,507,567	2,543	2,510,109	40	2.50%	62,753	63,198	445	immaterial
1820	Substation Equipment	116,080	-	116,080	-	116,080	25	4%	4,643	6,201	1,558	Issue re: note # 1
1825	Storage Battery Equipment	-		-	-	-	0	0%	-	-	-	
1830	Poles, Towers & Fixtures	4,027,603	215,612	3,811,992	378,246	4,190,238	25	4%	167,610	209,106	41,497	Issue re: note # 1
1835	OH Conductor & Devices	3,024,873	199,626	2,825,247	207,302	3,032,549	25	4%	121,302	155,042	33,740	Issue re: note # 1
1840	UG Conduit	503,983	-	503,983	32,980	536,963	25	4%	21,479	25,178	3,700	Issue re: note # 1
1845	UG Conductor & Devices	1,980,903	-	1,980,903	72,417	2,053,320	25	4%	82,133	106,123	23,990	Issue re: note # 1
1850	Line Transformer	4,036,726	-	4,036,726	177,597	4,214,322	25	4%	168,573	205,855	37,282	Issue re: note # 1
1855	Services (OH & UG)	2,359,958	114,072	2,245,886	37,099	2,282,985	25	4%	91,319	120,026	28,706	Issue re: note # 1
1860	Meters	1,223,251	-	1,223,251	25,155	1,248,406	25	4%	49,936	60,582	10,645	Issue re: note # 1
1861	Smart Meters			-		-	0	0%	-		-	
1861	Smart Meters/Communication System			-		-	0	0%	-		-	
1905	Land	72,665	-	72,665	-	72,665	0	0%	-	-	-	
1906	Land Rights	-		-	-	-	0	0%	-	-	-	
1908	Buildings & Fixtures	245,005	-	245,005	112,874	357,879	25 / 30	4% / 3.33%	11,052	11,052	-	
1910	Leasehold Improvements	-		-	-	-	0	0%	-	-	-	
1915	Office Furniture & Equipment (10 years)	94,268	37,337	56,931	-	56,931	10	10%	5,693	9,465	3,772	Issue re: note # 1
1915	Furniture & Equipment (5 years)			-		-	0	0%	-		-	
1920	Computer - Hardware	516,981	147,523	369,458	38,347	407,805	5	20%	81,561	81,561	0	
1925	Computer -Software	286,705	169,957	116,748	22,377	139,125	5	20%	27,825	27,825	0	
1930	Transportation Equipment	1,003,785	120,643	883,142	313,663	1,196,805	4 / 5 / 8	25% / 20% / 12.5%	162,705	162,705	-	
1935	Stores Equipment	1,149	1,149	-	-	-	0	0%	-	-	-	
1940	Tools, Shop & Garage Equipment	127,713	112,789	14,925	14,950	29,875	10	10%	2,987	11,360	8,373	Issue re: note # 1
1945	Measurement & Testing equipment	48,135	8,272	39,863	2,137	42,000	10	10%	4,200	4,237	37	immaterial
1950	Power operated Equipment	2,708	710	1,998	-	1,998	10	10%	200	200	- 0	
1955	Communications Equipment	39,996	4,510	35,485	584	36,069	10	10%	3,607	3,945	338	immaterial
1960	Graphics Equipment	22,123	730	21,393	-	21,393	10	10%	2,139	2,139	- 0	
1965	Water Heater Rental Units	-		-	-	-	0	0%	-	-	-	
1970	Load Management Controls	-		-	-	-	0	0%	-	-	-	
1975	Load Management Controls Utility Premises	-		-	-	-	0	0%	-	-	-	
1980	System Supervisor Equipment	-		-	-	-	0	0%	-	-	-	
1985	Misc. Fixed Assets	-		-	-	-	0	0%	-	-	-	
1995	Contributions & Grants	- 1,699,499	-	- 1,699,499	- 90,610	- 1,790,109	0	misc.	- 71,604	- 71,604	-	
Total		21,436,674	1,132,929	20,303,745	1,351,300	21,655,045			1,032,316	1,226,400	194,083	

Appendix 2-M
Depreciation and Amortization Expense

2009												
Account	Description	Opening Balance	Less Fully Depreciated	Net for Depreciation	Additions	Total for Depreciation	Years	Depreciation Rate	Depreciation Expense			
		A	B	C = A - B	D	E = C + D	F	G = 1/F	H = E / F	Bal Check		
1805	Land	94,643	-	94,643	6,380	101,023	0	0%	-	-	-	
1808	Buildings	802,995	-	802,995	-	802,995	25 / 30	4% / 3.33%	32,204	32,204	-	
1810	Leasehold Improvements			-		-	50	2%	-		-	
1815	Transformer Station Equipment > 50kV	2,510,109	-	2,510,109	-	2,510,109	40	3%	62,753	63,198	445	immaterial
1820	Substation Equipment	116,080	-	116,080	-	116,080	25	4%	4,643	6,201	1,558	Issue re: note # 1
1825	Storage Battery Equipment	-		-	-	-	0	0%	-	-	-	
1830	Poles, Towers & Fixtures	4,405,849	269,839	4,136,011	428,137	4,564,148	25	4%	182,566	219,998	37,432	Issue re: note # 1
1835	OH Conductor & Devices	3,232,175	241,803	2,990,372	300,481	3,290,853	25	4%	131,634	152,320	20,686	Issue re: note # 1
1840	UG Conduit	536,963	-	536,963	72,833	609,796	25	4%	24,392	25,564	1,172	Issue re: note # 1
1845	UG Conductor & Devices	2,053,320	-	2,053,320	55,349	2,108,669	25	4%	84,347	108,337	23,990	Issue re: note # 1
1850	Line Transformer	4,214,322	733,507	3,480,816	250,877	3,731,693	25	4%	149,268	215,890	66,622	Issue re: note # 1
1855	Services (OH & UG)	2,397,057	138,173	2,258,884	47,836	2,306,720	25	4%	92,269	120,384	28,115	Issue re: note # 1
1860	Meters	1,248,406	-	1,248,406	141,958	1,390,364	25	4%	55,615	62,970	7,355	Issue re: note # 1
1861	Smart Meters			-		-	0	0%	-		-	
1861	Smart Meters/Communication System			-		-	0	0%	-		-	
1905	Land	72,665	-	72,665	-	72,665	0	0%	-	-	-	
1906	Land Rights	-		-	-	-	0	0%	-	-	-	
1908	Buildings & Fixtures	357,879	-	357,879	21,907	379,786	25 / 30	4% / 3.33%	11,382	11,382	-	
1910	Leasehold Improvements	-		-	-	-	0	0%	-	-	-	
1915	Office Furniture & Equipment (10 years)	94,268	38,050	56,218	25,000	81,218	10	10%	8,122	8,199	77	Issue re: note # 1
1915	Furniture & Equipment (5 years)			-		-	0	0%	-		-	
1920	Computer - Hardware	555,328	388,035	167,293	26,990	194,283	5	20%	38,857	38,857	0	
1925	Computer -Software	309,082	205,180	103,902	7,752	111,654	5	20%	22,331	22,331	0	
1930	Transportation Equipment	833,100	130,255	702,845	218,906	921,751	4 / 5 / 8	25% / 20% / 12.5%	179,562	179,560	- 2	immaterial
1935	Stores Equipment	1,149	1,149	-	-	-	0	0%	-	-	-	
1940	Tools, Shop & Garage Equipment	142,663	114,713	27,950	12,346	40,296	10	10%	4,030	12,088	8,058	Issue re: note # 1
1945	Measurement & Testing equipment	50,272	14,621	35,651	824	36,475	10	10%	3,647	3,958	311	immaterial
1950	Power operated Equipment	2,708	710	1,998	-	1,998	10	10%	200	200	0	
1955	Communications Equipment	40,580	24,951	15,629	-	15,629	10	10%	1,563	3,606	2,043	immaterial
1960	Graphics Equipment	22,123	730	21,393	-	21,393	10	10%	2,139	2,139	- 0	
1965	Water Heater Rental Units	-		-	-	-	0	0%	-	-	-	
1970	Load Management Controls	-		-	-	-	0	0%	-	-	-	
1975	Load Management Controls Utility Premises	-		-	-	-	0	0%	-	-	-	
1980	System Supervisor Equipment	-		-	-	-	0	0%	-	-	-	
1985	Misc. Fixed Assets	-		-	-	-	0	0%	-	-	-	
1995	Contributions & Grants	- 1,790,109	-	- 1,790,109	- 8,661	- 1,798,770	0	misc.	- 71,951	- 71,951	-	
Total		22,303,627	2,301,714	20,001,912	1,608,915	21,610,827			1,019,571	1,217,435	197,864	

Appendix 2-M

Depreciation and Amortization Expense

2010 - Bridge

Account	Description	Opening Balance A	Less Fully Depreciated B	Net for Depreciation C = A - B	Additions D	Total for Depreciation E = C + D	Years F	Depreciation Rate G = 1/F	Depreciation Expense H = E / F	Bal Check	
1805	Land	101,023	-	101,023	-	101,023	0	0%	-	-	-
1808	Buildings	802,995	-	802,995	-	802,995	25 / 30	4% / 3.33%	28,114	28,114	-
1810	Leasehold Improvements	-		-	-	-	50	2%	-	-	-
1815	Transformer Station Equipment > 50kV	2,510,109	-	2,510,109	-	2,510,109	40	3%	62,753	62,753	0
1820	Substation Equipment	116,080	-	116,080	-	116,080	25	4%	4,643	4,643	-
1825	Storage Battery Equipment	-		-	-	-	0	0%	-	-	-
1830	Poles, Towers & Fixtures	4,833,986	339,524	4,494,463	425,616	4,920,079	25	4%	186,010	186,010	-
1835	OH Conductor & Devices	3,532,656	296,002	3,236,654	368,960	3,605,614	25	4%	134,552	134,552	-
1840	UG Conduit	609,796	-	609,796	63,598	673,394	25	4%	26,936	26,936	-
1845	UG Conductor & Devices	2,108,669	-	2,108,669	71,158	2,179,827	25	4%	87,193	87,193	-
1850	Line Transformer	4,465,199	720,887	3,744,312	195,428	3,939,740	25	4%	128,249	128,249	-
1855	Services (OH & UG)	2,444,893	169,144	2,275,749	84,660	2,360,409	25	4%	88,889	88,889	-
1860	Meters	1,390,364	-	1,390,364	1,461,350	2,851,714	25	4%	114,069	114,069	-
1861	Smart Meters			-		-	0	0%	-		-
1861	Smart Meters/Communication System			-		-	0	0%	-		-
1905	Land	72,665	-	72,665	-	72,665	0	0%	-	-	-
1906	Land Rights	-		-	-	-	0	0%	-	-	-
1908	Buildings & Fixtures	379,786	-	379,786	10,000	389,786	25 / 30	4% / 3.33%	13,032	13,032	-
1910	Leasehold Improvements	-		-	-	-	0	0%	-	-	-
1915	Office Furniture & Equipment (10 years)	119,268	46,398	72,869	500	73,369	10	10%	7,337	7,337	-
1915	Furniture & Equipment (5 years)			-		-	0	0%	-		-
1920	Computer - Hardware	582,318	458,441	123,876	162,300	286,176	5	20%	57,235	57,235	-
1925	Computer -Software	316,834	229,470	87,364	-	87,364	5	20%	17,473	17,473	-
1930	Transportation Equipment	1,052,006	130,255	921,751	325,000	1,246,751	4 / 5 / 8	25% / 20% / 12.5%	220,187	220,187	-
1935	Stores Equipment	1,149	1,149	-	-	-	0	0%	-	-	-
1940	Tools, Shop & Garage Equipment	155,009	116,191	38,818	13,000	51,818	10	10%	5,182	5,182	-
1945	Measurement & Testing equipment	51,096	15,171	35,925	15,000	50,925	10	10%	5,093	5,093	-
1950	Power operated Equipment	2,708	762	1,946	-	1,946	10	10%	195	195	-
1955	Communications Equipment	40,580	26,174	14,406	-	14,406	10	10%	1,441	1,441	-
1960	Graphics Equipment	22,123	730	21,393	-	21,393	10	10%	2,139	2,139	-
1965	Water Heater Rental Units	-		-	-	-	0	0%	-	-	-
1970	Load Management Controls	-		-	-	-	0	0%	-	-	-
1975	Load Management Controls Utility Premises	-		-	-	-	0	0%	-	-	-
1980	System Supervisor Equipment	-		-	-	-	0	0%	-	-	-
1985	Misc. Fixed Assets	-		-	-	-	0	0%	-	-	-
1995	Contributions & Grants	- 1,798,770	-	- 1,798,770	- 10,000	- 1,808,770	0	misc.	- 72,204	- 72,204	-
Total		23,912,542	2,550,299	21,362,243	3,186,570	24,548,813			1,118,517	1,118,517	0

Appendix 2-M
Depreciation and Amortization Expense

2011 - Test

Account	Description	Opening Balance	Less Fully Depreciated	Net for Depreciation	Additions	Total for Depreciation	Years	Depreciation Rate	Depreciation Expense		
		A	B	C = A - B	D	E = C + D	F	G = 1/F	H = E / F	Bal Check	
1805	Land	101,023	-	101,023	-	101,023	0	0%	-	-	-
1808	Buildings	802,995	-	802,995	-	802,995	25 / 30	4% / 3.33%	26,516	26,516	-
1810	Leasehold Improvements	-		-	-	-	50	2%	-	-	-
1815	Transformer Station Equipment > 50kV	2,510,109	-	2,510,109	-	2,510,109	40	2.50%	62,753	62,753	0
1820	Substation Equipment	116,080	-	116,080	-	116,080	25	4%	4,643	4,643	-
1825	Storage Battery Equipment	-		-	-	-	0	0%	-	-	-
1830	Poles, Towers & Fixtures	5,259,602	759,780	4,499,822	1,257,839	5,757,661	25	4%	205,932	205,932	-
1835	OH Conductor & Devices	3,901,616	622,868	3,278,748	379,930	3,658,678	25	4%	124,835	124,835	-
1840	UG Conduit	673,394	-	673,394	66,059	739,453	25	4%	29,578	29,578	-
1845	UG Conductor & Devices	2,179,827	-	2,179,827	302,955	2,482,782	25	4%	99,311	99,311	-
1850	Line Transformer	4,660,627	760,353	3,900,275	197,599	4,097,874	25	4%	105,739	105,739	-
1855	Services (OH & UG)	2,529,553	355,925	2,173,628	87,309	2,260,937	25	4%	78,145	78,145	-
1860	Meters	2,851,714	46,517	2,805,197	130,963	2,936,160	25	4%	117,446	117,446	-
1861	Smart Meters			-		-	0	0%	-		-
1861	Smart Meters/Communication System			-		-	0	0%	-		-
1905	Land	72,665	-	72,665	-	72,665	0	0%	-	-	-
1906	Land Rights	-		-	-	-	0	0%	-	-	-
1908	Buildings & Fixtures	389,786	-	389,786	60,000	449,786	25 / 30	4% / 3.33%	14,243	14,243	-
1910	Leasehold Improvements	-		-	-	-	0	0%	-	-	-
1915	Office Furniture & Equipment (10 years)	119,768	61,200	58,568	500	59,068	10	10%	5,907	5,907	-
1915	Furniture & Equipment (5 years)			-		-	0	0%	-		-
1920	Computer - Hardware	744,618	530,675	213,942	165,000	378,942	5	20%	75,788	75,788	-
1925	Computer -Software	316,834	254,694	62,140	15,000	77,140	5	20%	15,428	15,428	-
1930	Transportation Equipment	1,377,006	209,580	1,167,426	130,000	1,297,426	4 / 5 / 8	25% / 20% / 12.5%	236,271	236,271	-
1935	Stores Equipment	1,149	1,149	-	-	-	0	0%	-	-	-
1940	Tools, Shop & Garage Equipment	168,009	124,389	43,620	10,000	53,620	10	10%	5,362	5,362	-
1945	Measurement & Testing equipment	66,096	18,053	48,043	-	48,043	10	10%	4,804	4,804	-
1950	Power operated Equipment	2,708	1,075	1,633	-	1,633	10	10%	163	163	-
1955	Communications Equipment	40,580	29,461	11,119	-	11,119	10	10%	1,112	1,112	-
1960	Graphics Equipment	22,123	730	21,393	-	21,393	10	10%	2,139	2,139	-
1965	Water Heater Rental Units	-		-	-	-	0	0%	-	-	-
1970	Load Management Controls	-		-	-	-	0	0%	-	-	-
1975	Load Management Controls Utility Premises	-		-	-	-	0	0%	-	-	-
1980	System Supervisor Equipment	-		-	-	-	0	0%	-	-	-
1985	Misc. Fixed Assets	-		-	100,000	100,000	40	3%	2,500	2,500	-
1995	Contributions & Grants	- 1,808,770	-	- 1,808,770	- 10,000	- 1,818,770	0	misc.	- 72,551	- 72,551	-
Total		27,099,112	3,776,448	23,322,664	2,893,154	26,215,818			1,146,066	1,146,066	0

Taxes (PILS and Capital Taxes)

The attached tables detail the determination of income and capital taxes for 2010 and 2011.

The actual 2009 combined federal and provincial income tax return is also included.

CCA continuity schedules are also provided for 2010 and 2011.

Brant County Power
PILS Determination

	2010 Bridge		2011 Test
Determination of Taxable Income			
Regulatory Net Income (before tax)	$1,040,540		$888,212
Book to Tax Adjustments			
Additions to Accounting Income:			
Depreciation and amortization	$884,281		$896,214
Other Additions			
Total Additions	$884,281		$896,214
Deductions from Accounting Income:			
Capital Cost Allowance	$1,294,410		$1,496,414
Cumulative eligible capital deductions	$103,597		$96,345
Other Deductions			
Total Deductions	$1,398,007		$1,592,759
Regulatory Taxable Income	$526,814		$191,666
Corporate Income Tax Rate	32.00%		28.50%
Regulatory Income Tax	$168,581		$54,625
Calculation of Utility Income Taxes			
Income Taxes (prior to gross-up)	$168,581		$54,625
Ontario Capital Tax	$22,498		$24,718
Large Corporation Tax	$0		$0
Total Taxes	$191,078		$79,343
Gross UP factor (1-tax rate)	0.00%		71.50%
Taxes after Gross-up			
Income Taxes	$168,581		$76,399
Ontario Capital Tax	$22,498		$24,718
Large Corporation Tax	$0		$0
Total taxes with Gross up	$191,078		$101,117

Brant County Power

Cumulative Eligible Capital Deduction

Balance December 31, 2009 per tax return	1,479,958
2010 Deduction - 7%	-103,597
Balance December 31, 2010	1,376,361
2011 Deduction - 7%	-96,345
Balance December 31, 2011	1,280,016

Brant County Power Inc.
Ontario Capital Tax

Determination of Taxable Capital

	2010	**2011**	
Capital Stock	9,512,193	9,512,193	
Retained Earnings - beginning of year	4,250,196	5,122,155	
Net income after tax for the year	871,959	888,212	before capital tax
Other surpluses	2,738,065	2,738,065	
Loans and Advances	7,224,286	7,224,286	per 2009 tax return + $2,000,000 increase in 2010
Other indebtedness	646,300	646,300	per 2009 tax return
Subtotal	25,242,999	26,131,211	
Less: Deferred tax balance - end of year	-661,022	-661,022	per 2009 tax return
Less: Loans to other corporations	-582,850	-582,850	per 2009 tax return
Taxable Capital	23,999,127	24,887,339	
Ontario Deduction	-15,000,000	-15,000,000	
Amount subject to tax	8,999,127	9,887,339	
Capital tax @.00225	22,498	24,718	

Canada Revenue Agency / Agence du revenu du Canada

T2 CORPORATION INCOME TAX RETURN

200

055 Do not use this area

CLIENT'S COPY

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Ontario (for tax years ending before 2009), Quebec, or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

Parts, sections, subsections, paragraphs, and subparagraphs mentioned on this return refer to the federal *Income Tax Act*. This return may contain changes that had not yet become law at the time of printing.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see www.cra.gc.ca or Guide T4012, *T2 Corporation – Income Tax Guide*.

Identification

Business Number (BN) 001 89113 2011 RC0001

Corporation's name
002 BRANT COUNTY POWER INC.

Address of head office
Has this address changed since the last time you filed your T2 return? 010 1 Yes [ ] 2 No [X]
(If yes, complete lines 011 to 018.)
011 65 DUNDAS STREET EAST
012
City 015 PARIS — Province, territory, or state 016 ON
Country (other than Canada) 017 — Postal code/Zip code 018 N3L 3H1

Mailing address (if different from head office address)
Has this address changed since the last time you filed your T2 return? 020 1 Yes [ ] 2 No [X]
(If yes, complete lines 021 to 028.)
021 c/o
022
023
City 025 — Province, territory, or state 026
Country (other than Canada) 027 — Postal code/Zip code 028

Location of books and records
Has the location of books and records changed since the last time you filed your T2 return? 030 1 Yes [ ] 2 No [X]
(If yes, complete lines 031 to 038.)
031 65 DUNDAS STREET EAST
032
City 035 PARIS — Province, territory, or state 036 ON
Country (other than Canada) 037 — Postal code/Zip code 038 N3L 3H1

040 **Type of corporation at the end of the tax year**
1 [X] Canadian-controlled private corporation (CCPC)
2 [ ] Other private corporation
3 [ ] Public corporation
4 [ ] Corporation controlled by a public corporation
5 [ ] Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change. 043 YYYY MM DD

To which tax year does this return apply?
Tax year start 060 2009-01-01 (YYYY MM DD) — Tax year end 061 2009-12-31 (YYYY MM DD)

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? 063 1 Yes [ ] 2 No [X]

If yes, provide the date control was acquired 065 YYYY MM DD

Is the date on line 061 a deemed tax year-end in accordance with subsection 249(3.1)? 066 1 Yes [ ] 2 No [X]

Is the corporation a professional corporation that is a member of a partnership? 067 1 Yes [ ] 2 No [X]

Is this the first year of filing after:
Incorporation? 070 1 Yes [ ] 2 No [X]
Amalgamation? 071 1 Yes [ ] 2 No [X]
If yes, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? 072 1 Yes [ ] 2 No [X]
If yes, complete and attach Schedule 24.

Is this the final tax year before amalgamation? 076 1 Yes [ ] 2 No [X]

Is this the final return up to dissolution? 078 1 Yes [ ] 2 No [X]

If an election was made under section 261, state the functional currency used 079

Is the corporation a resident of Canada? 080 1 Yes [X] 2 No [ ] If no, give the country of residence on line 081 and complete and attach Schedule 97.
081

Is the non-resident corporation claiming an exemption under an income tax treaty? 082 1 Yes [ ] 2 No [X]
If yes, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:
085
1 [ ] Exempt under paragraph 149(1)(e) or (l)
2 [ ] Exempt under paragraph 149(1)(j)
3 [ ] Exempt under paragraph 149(1)(t)
4 [ ] Exempt under other paragraphs of section 149

Do not use this area
091 092 093 094 095 096
100

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.

Schedules – Answer the following questions. For each Yes response, attach to the T2 return the schedule that applies.

Question	Line	Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160	X	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered yes to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165		15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166		T5004
Is the corporation a member of a partnership for which a partnership identification number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202		2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203	X	3
Is the corporation claiming any type of losses?	204	X	4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205	X	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) is the corporation claiming the refundable portion of Part I tax?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210	X	10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming reserves of any kind?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231		31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232		T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	
Is the corporation claiming a surtax credit?	237		37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II – Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

Attachments – continued from page 2

		Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	256		T1134-A
Did the corporation have any controlled foreign affiliates?	258		T1134-B
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265	X	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268	X	53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54

Additional information

Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270	1 Yes	2 No X
Is the corporation inactive?	280	1 Yes	2 No X
Has the major business activity changed since the last return was filed? (enter yes for first-time filers)	281	1 Yes	2 No X

What is the corporation's major business activity? **282** ____
(Only complete if yes was entered at line 281)

If the major business activity involves the resale of goods, show whether it is wholesale or retail **283** 1 Wholesale ☐ 2 Retail ☐

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.				
	284	UTILITY	285	100.000 %
	286		287	%
	288		289	%

Did the corporation immigrate to Canada during the tax year?	291	1 Yes	2 No X
Did the corporation emigrate from Canada during the tax year?	292	1 Yes	2 No X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293	1 Yes	2 No
If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible	294	YYYY MM DD	
If the corporation's major business activity is construction, did you have any subcontractors during the tax year?	295	1 Yes	2 No

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI **300** -199,007 A

Deduct:			
	Charitable donations from Schedule 2	311	
	Gifts to Canada, a province, or a territory from Schedule 2	312	
	Cultural gifts from Schedule 2	313	
	Ecological gifts from Schedule 2	314	
	Gifts of medicine from Schedule 2	315	
	Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320	
	Part VI.1 tax deduction *	325	
	Non-capital losses of previous tax years from Schedule 4	331	
	Net capital losses of previous tax years from Schedule 4	332	
	Restricted farm losses of previous tax years from Schedule 4	333	
	Farm losses of previous tax years from Schedule 4	334	
	Limited partnership losses of previous tax years from Schedule 4	335	
	Taxable capital gains or taxable dividends allocated from a central credit union	340	
	Prospector's and grubstaker's shares	350	

Subtotal ____ ► ____ B

Subtotal (amount A minus amount B) (if negative, enter "0") ____ C

Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355		D
Taxable income (amount C plus amount D)	360		
Income exempt under paragraph 149(1)(t)	370		
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 minus line 370)			Z

* This amount is equal to 3 times the Part VI.1 tax payable at line 724.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360			A
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27	B		
Amount QQ from Part 13 of Schedule 27	C		
Amount used to calculate the credit union deduction from Schedule 17	D		
Amount from line 400, 405, 410, or 425, whichever is the least	E		
Aggregate investment income from line 440	F		
Total of amounts B to F		►	G
Amount A minus amount G (if negative, enter "0")			H

Amount H × (Number of days in the tax year before January 1, 2008 / Number of days in the tax year 365) × 7 % = I

Amount H × (Number of days in the tax year after December 31, 2007, and before January 1, 2009 / Number of days in the tax year 365) × 8.5 % = J

Amount H × (Number of days in the tax year after December 31, 2008, and before January 1, 2010 365 / Number of days in the tax year 365) × 9 % = K

Amount H × (Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year 365) × 10 % = L

Amount H × (Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year 365) × 11.5 % = L1

Amount H × (Number of days in the tax year after 2011 / Number of days in the tax year 365) × 13 % = L2

General tax reduction for Canadian-controlled private corporations – Total of amounts I to L2 M

Enter amount M on line 638.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from page 3 (line 360 or amount Z, whichever applies)			N
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27	O		
Amount QQ from Part 13 of Schedule 27	P		
Amount used to calculate the credit union deduction from Schedule 17	Q		
Total of amounts O to Q		►	R
Amount N minus amount R (if negative, enter "0")			S

Amount S × (Number of days in the tax year before January 1, 2008 / Number of days in the tax year 365) × 7 % = T

Amount S × (Number of days in the tax year after December 31, 2007, and before January 1, 2009 / Number of days in the tax year 365) × 8.5 % = U

Amount S × (Number of days in the tax year after December 31, 2008, and before January 1, 2010 365 / Number of days in the tax year 365) × 9 % = V

Amount S × (Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year 365) × 10 % = W

Amount S × (Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year 365) × 11.5 % = W1

Amount S × (Number of days in the tax year after 2011 / Number of days in the tax year 365) × 13 % = W2

General tax reduction – Total of amounts T to W2 X

Enter amount X on line 639.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7	440	× 26 2 / 3 % =		A
Foreign non-business income tax credit from line 632				
Deduct: Foreign investment income from Schedule 7	445	× 9 1 / 3 % =		
		(if negative, enter "0")	►	B
Amount A **minus** amount B (if negative, enter "0")				C
Taxable income from line 360				
Deduct: Amount from line 400, 405, 410, or 425, whichever is the least				
Foreign non-business income tax credit from line 632		× 25 / 9 =		
Foreign business income tax credit from line 636		× 3 =		
			►	
		× 26 2 / 3 % =		D
Part I tax payable minus investment tax credit refund (line 700 **minus** line 780)				
Deduct: Corporate surtax from line 600				
Net amount			►	E
Refundable portion of Part I tax – Amount C, D, or E, whichever is the least	450			F

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year	460			
Deduct: Dividend refund for the previous tax year	465		►	G
Add the total of:				
Refundable portion of Part I tax from line 450 above				
Total Part IV tax payable from Schedule 3				
Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation	480			
			►	H
Refundable dividend tax on hand at the end of the tax year – Amount G **plus** amount H	485			

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 of Schedule 3	445,000 × 1 / 3	148,667	I
Refundable dividend tax on hand at the end of the tax year from line 485 above			J
Dividend refund – Amount I or J, whichever is less (enter this amount on line 784)			

Part I tax

Base amount of Part I tax – Taxable income (line 360 or amount Z, whichever applies) multiplied by 38.00 % . . . . **550** ______ A

Corporate surtax calculation

Base amount from line A above . . . . ______ 1

Deduct:

10 % of taxable income (line 360 or amount Z, whichever applies) 2
Investment corporation deduction from line 620 below 3
Federal logging tax credit from line 640 below 4
Federal qualifying environmental trust tax credit from line 648 below 5

For a mutual fund corporation or an investment corporation throughout the tax year, enter amount a, b, or c below on line 6, whichever is the least:

28.00 % of taxable income from line 360 . . . . . . ______ a
28.00 % of taxed capital gains . . . . . . ______ b
Part I tax otherwise payable . . . . . . ______ c
(line A plus lines C and D minus line F)

______ 6

Total of lines 2 to 6 . . . . ______ 7

Net amount (line 1 minus line 7) . . . . ______ 8

Corporate surtax*

Line 8 × Number of days in the tax year before January 1, 2008 / Number of days in the tax year 365 × 4 % = **600** ______ B

* The corporate surtax is zero effective January 1, 2008.

Recapture of investment tax credit from Schedule 31 . . . . **602** ______ C

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 . . . . ______ i
Taxable income from line 360 . . . . . . ______
Deduct:
Amount from line 400, 405, 410, or 425, whichever is the least . . . . . . ______
Net amount . . . . . . ______ ► ______ ii

Refundable tax on CCPC's investment income – 6 2 / 3 % of whichever is less: amount i or ii . . . . . . **604** ______ D

Subtotal (add lines A to D) ______ E

Deduct:

Small business deduction from line 430 . . . . ______ 9
Federal tax abatement . . . . **608** ______
Manufacturing and processing profits deduction from Schedule 27 . . . . **616** ______
Investment corporation deduction . . . . **620** ______
Taxed capital gains **624** ______
Additional deduction – credit unions from Schedule 17 . . . . **628** ______
Federal foreign non-business income tax credit from Schedule 21 . . . . **632** ______
Federal foreign business income tax credit from Schedule 21 . . . . **636** ______
General tax reduction for CCPCs from amount M . . . . **638** ______
General tax reduction from amount X . . . . **639** ______
Federal logging tax credit from Schedule 21 . . . . **640** ______
Federal qualifying environmental trust tax credit . . . . **648** ______
Investment tax credit from Schedule 31 . . . . **652** ______

Subtotal ______ ► ______ F

Part I tax payable – line E minus line F . . . . ______ G

Enter amount G on line 700

Summary of tax and credits

Federal tax

Part I tax payable	700	
Part I surtax payable from Schedule 46	708	
Part II.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		

Add provincial or territorial tax:

Provincial or territorial jurisdiction 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Ontario [for tax years ending before 2009], Quebec, and Alberta)	760	56,486	
Provincial tax on large corporations (New Brunswick* and Nova Scotia)	765		
		56,486 ▶	56,486
Total tax payable	770		56,486 A

* The New Brunswick tax on large corporations is eliminated effective January 1, 2009.

Deduct other credits:

Investment tax credit refund from Schedule 31	780		
Dividend refund	784		
Federal capital gains refund from Schedule 18	788		
Federal qualifying environmental trust tax credit refund	792		
Canadian film or video production tax credit refund (Form T1131)	796		
Film or video production services tax credit refund (Form T1177)	797		
Tax withheld at source	800		
Total payments on which tax has been withheld 801			
Provincial and territorial capital gains refund from Schedule 18	808		
Provincial and territorial refundable tax credits from Schedule 5	812		
Tax instalments paid	840	823,374	
Total credits	890	823,374 ▶	823,374 B

Refund code 894 ______ Overpayment 766,888 ◀ Balance (line A minus line B) -766,888

If the result is negative, you have an **overpayment**.
If the result is positive, you have a **balance unpaid**.
Enter the amount on whichever line applies.

Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid

Enclosed payment 898

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information 910 Branch number

914 Institution number 918 Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? 896 1 Yes ☐ 2 No ☒

Certification

I, 950 ED 951 GLASBERGEN 954 CFO
Last name in block letters / First name in block letters / Position, office, or rank

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I further certify that the method of calculating income for this tax year is consistent with that of the previous year except as specifically disclosed in a statement attached to this return.

955 2010-05-31 Date (yyyy/mm/dd) — Signature of the authorized signing officer of the corporation — 956 (519) 442-2215 Telephone number

Is the contact person the same as the authorized signing officer? If no, complete the information below 957 1 Yes ☒ 2 No ☐

958 Name in block letters 959 Telephone number

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français. 990 1

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2009 12 31

GRANT COUNTY POWER INC.
89113 2011 RC0001

Canada Revenue Agency | Agence du revenu du Canada

SCHEDULE 100

Form identifier 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
BRANT COUNTY POWER INC.	89113 2011 RC0001	2009-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
Assets					
	Total current assets	1599	+	8,694,214	7,430,062
	Total tangible capital assets	2008	+	23,912,541	22,303,627
	Total accumulated amortization of tangible capital assets	2009	–	8,345,414	7,127,980
	Total intangible capital assets	2178	+		
	Total accumulated amortization of intangible capital assets	2179	–		
	Total long-term assets	2589	+	4,617,830	4,134,835
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	28,879,171	26,740,544
Liabilities					
	Total current liabilities	3139	+	5,560,095	3,534,912
	Total long-term liabilities	3450	+	6,818,622	8,026,840
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	12,378,717	11,561,752
Shareholder equity					
	Total shareholder equity (mandatory field)	3620	+	16,500,454	15,178,792
	Total liabilities and shareholder equity	3640	=	28,879,171	26,740,544
Retained earnings					
	Retained earnings/deficit – end (mandatory field)	3849	=	4,250,196	2,928,534

* Generic item

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Current Assets

SCHEDULE 100

Form identifier 100

Account	Description	GIFI		Current year	Prior year
Cash and deposits					
	*Cash and deposits	1000		2,356,414	1,816,242
	Cash and deposits		+	2,356,414	1,816,242
Accounts receivable					
	*Accounts receivable	1060		5,125,403	4,964,181
	Taxes receivable	1066		823,374	206,811
	Accounts receivable		+	5,948,777	5,170,992
Inventories					
	*Inventories	1120		234,314	293,097
	Inventories		+	234,314	293,097
Loans and notes receivable					
	*Loans and notes receivable	1240		44,681	73,679
	Loans and notes receivable		+	44,681	73,679
Other current assets					
	*Other current assets	1480		110,028	76,052
	Other current assets		+	110,028	76,052
	Total current assets	1599	=	8,694,214	7,430,062

* Generic item

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Tangible Capital Assets and Accumulated Amortization

SCHEDULE 100

Form identifier 2008/2009

Account	Description	GIFI	Tangible capital assets	Accumulated amortization	Prior year
Land					
	*Land	1600 +	173,688		167,308
	Total		173,688		
Buildings					
	*Buildings	1680 +	1,182,781		1,160,874
	*Accumulated amortization of buildings	1681		246,473	202,887
	Total		1,182,781	246,473	
Machinery, equipment, furniture and fixtures					
	*Machinery, equipment, furniture, and fixtures	1740 +	508,015		469,843
	*Accumulated amortization of machinery, equipment, furniture, and fixtures	1741		308,636	272,446
	Motor vehicles	1742 +	1,052,006		833,300
	Accumulated amortization of motor vehicles	1743 −		359,122	179,552
	Computer equipment/software	1774 +	899,152		864,410
	Accumulated amortization of computer equipment/software	1775 −		791,889	730,701
	Total		2,459,173	1,459,849	
Other tangible capital assets					
	*Other tangible capital assets	1900 +	20,096,899		18,808,092
	*Accumulated amortization of other tangible capital assets	1901 −		6,639,092	5,742,384
	Total		20,096,899	6,639,092	
	Total tangible capital assets	2008 =	23,912,541		22,303,827
	Total accumulated amortization of tangible capital assets	2009 =		8,345,414	7,127,980

* Generic item

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SCHEDULE 100

Long-term Assets

Form identifier 2559

Account	Description	GIFI		Current year	Prior year
Long-term loans					
	*Long-term loans	2300		538,169	546,835
	Long-term loans		+	538,169	546,835
Other long-term assets					
	*Other long-term assets	2420		3,588,000	3,588,000
	Future (deferred) income taxes	2421		491,661	
	Other long-term assets		+	4,079,661	3,588,000
	Total long-term assets	2589	=	4,617,830	4,134,835

* Generic item

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2009-12-31

BRANT COUNTY POWER INC
[illegible]113 2011 RC0001

Current Liabilities

SCHEDULE 100

Form identifier 3139

Account	Description	GIFI		Current year	Prior year
Amounts payable and accrued liabilities					
	*Amounts payable and accrued liabilities	2620		5,069,695	3,065,512
	Amounts payable and accrued liabilities		+	5,069,695	3,065,512
	*Current portion of long-term liability	2920	+	11,100	11,100
Other current liabilities					
	Dividends payable	2962		416,000	425,000
	Other current liabilities		+	416,000	425,000
	Total current liabilities	3139	=	5,560,095	3,534,912

*Generic item

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 125

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
BRANT COUNTY POWER INC.	89113 2011 RC0001	2009 12 31

Income statement information

Description	GIFI	
Operating name	0001	
Description of the operation	0002	
Sequence Number	0003	01

Account	Description	GIFI		Current year	Prior year
	Income statement information				
	Total sales of goods and services	8089	+	21,325,713	24,377,738
	Cost of sales	8518	–	15,685,092	18,562,207
	Gross profit/loss	8519	=	5,640,621	5,815,531
	Cost of sales	8518	+	15,685,092	18,562,207
	Total operating expenses	9367	+	4,992,576	4,815,089
	Total expenses (mandatory field)	9368	=	20,677,668	23,377,296
	Total revenue (mandatory field)	8299	+	21,768,315	24,867,290
	Total expenses (mandatory field)	9368	–	20,677,668	23,377,296
	Net non-farming income	9369	=	1,090,647	1,489,994
	Farming income statement information				
	Total farm revenue (mandatory field)	9659	+		
	Total farm expenses (mandatory field)	9898	–		
	Net farm income	9899	=		
	Net income/loss before taxes and extraordinary items	9970	=	1,090,647	1,489,994
	Extraordinary items and income (linked to Schedule 140)				
	Extraordinary item(s)	9975	–		
	Legal settlements	9976	–		
	Unrealized gains/losses	9980	+		
	Unusual items	9985	–		
	Current income taxes	9990	–		698,563
	Deferred income tax provision	9995	–	342,923	
	Total – Other comprehensive income	9998	+		
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	747,724	791,431

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Revenue

SCHEDULE 125

Form identifier 8299

Account	Description	GIFI		Current year	Prior year
	* Trade sales of goods and services	8000	+	21,325,713	24,377,738
	Total sales of goods and services	8089	=	21,325,713	24,377,738
	Realized gains/losses on disposal of assets				
	* Realized gains/losses on disposal of assets	8210			-9,575
	Realized gains/losses on disposal of assets				-9,575
	Other revenue				
	* Other revenue	8230		442,602	499,130
	Other revenue		=	442,602	499,130
	Total revenue	8299	=	21,768,315	24,867,29[illegible]

* Generic item

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Canada Revenue Agency / Agence du revenu du Canada

NET INCOME (LOSS) FOR INCOME TAX PURPOSES

SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
BRANT COUNTY POWER INC.	89113 2011 RC0001	2009-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 Corporation Income Tax Guide.
- Sections, subsections, and paragraphs referred to on this schedule are from the Income Tax Act.

Amount calculated on line 9999 from Schedule 125				747,724 A
Add:				
Provision for income taxes – deferred		102	342,923	
Amortization of tangible assets		104	1,217,434	
Reserves from financial statements – balance at the end of the year		126	646,300	
Subtotal of additions			2,206,657	2,206,657
Other additions:				
Miscellaneous other additions:				
600 REG VARIANCE ACCTS - ENDING CR BALANCES 12/31/09		290	2,125,704	
602 PILS 12/31/09 BALANCE		292	1,133,652	
603 OTHER REG LIABILITIES CLOSING 12/31/09	10,332			
2009 OCL JC ADDBACK	926			
Total	11,258	293	11,258	
604				
Subtotal of other additions		199	3,270,614	3,270,614
Total additions		500	5,477,271	5,477,271
Deduct:				
Capital cost allowance from Schedule 8		403	1,185,086	
Cumulative eligible capital deduction from Schedule 10		405	111,395	
Reserves from financial statements – balance at the beginning of the year		414	617,500	
Subtotal of deductions			1,913,981	1,913,981
Other deductions:				
Miscellaneous other deductions:				
700 REGULATORY VARIANCE ACCOUNTS @ 12/31/08		390	3,338,674	
701 OTHER REG LIABILITIES OPENING @ 12/31/08		391	28,737	
702 DEFERRED PILS BAL @ 12/31/09		392	1,143,600	
704				
Total		394		
Subtotal of other deductions		499	4,511,011	4,511,011
Total deductions		510	6,424,992	6,424,992
Net income (loss) for income tax purposes – enter on line 300 of the T2 return				-199,997

* For reference purposes only

T2 SCH 1 E (09)

Canada

Canada Revenue Agency / Agence du revenu du Canada

DIVIDENDS RECEIVED, TAXABLE DIVIDENDS PAID, AND PART IV TAX CALCULATION

SCHEDULE 3

Name of corporation	Business Number	Tax year end Year Month Day
BRANT COUNTY POWER INC.	89113 2011 RC0001	2009-12-31

- This schedule is for the use of any corporation to report:
  - non-taxable dividends under section 83;
  - deductible dividends under subsection 138(6);
  - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a), (b) or (d); or
  - taxable dividends paid for purposes of a dividend refund.
- The calculations in this schedule apply only to private or subject corporations.
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the federal *Income Tax Act*.
- A recipient corporation is connected with a payer corporation at any time in a taxation year, if at that time the recipient corporation:
  - controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b); or
  - owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- For more information, see the sections about Schedule 3 in the *T2 Corporation Income Tax Guide*.
- "X" under column A if dividend received from a foreign source (connected corporation only).
- "1" under column B if the payer corporation is connected.
- Enter in column F1, the amount of dividends received reported in column 240 that are eligible.
- Under column F2, enter the code that applies to the deductible taxable dividend.

Part 1 – Dividends received during the taxation year

Do not include dividends received from foreign non-affiliates.

	Name of payer corporation (Use only one line per corporation, abbreviating its name if necessary) 200	A	B 205	C Business Number 210 (Complete if payer corporation is connected)	D Taxation year end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends were paid YYYYMMDD 220	E Non-taxable dividend under section 83 230
1			2			
					Total	

Note: If your corporation's taxation year end is different than that of the connected payer corporation, your corporation could have received dividends from more than one taxation year of the payer corporation. If so, use a separate line to provide the information for each taxation year of the payer corporation.

	F Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (b), or (d) 240	F1 Eligible dividends (included in column F)	F2	G Total taxable dividends paid by connected payer corporation 250 (If payer corporation is not connected, leave these columns blank.)	H Dividend refund of the connected payer corporation 260	I Part IV tax before deductions F x 1 / 3 * 270
1						
Total (enter amount of column F on line 320 of the T2 return)						

For dividends received from connected corporations: Part IV tax equals: $\frac{\text{Column F x Column H}}{\text{Column G}}$

* Life insurers are not subject to Part IV tax on subsection 138(6) dividends.
Public corporations (other than subject corporations) do not need to calculate Part IV tax.

Part 2 – Calculation of Part IV tax payable

Part IV tax before deductions (amount J in Part 1) . . . . ______

Deduct:
Part IV.1 tax payable on dividends subject to Part IV tax . . . . . . **320** ______

Subtotal ______

Deduct:
Current-year non-capital loss claimed to reduce Part IV tax . . . . . **330** ______
Non-capital losses from previous years claimed to reduce Part IV tax . . . . . **335** ______
Current-year farm loss claimed to reduce Part IV tax . . . . . **340** ______
Farm losses from previous years claimed to reduce Part IV tax . . . . . **345** ______
Total losses applied against Part IV tax ______ × 1 / 3 = ______

Part IV tax payable (enter amount on line 712 of the T2 return) . . . . . **360** ______

Part 3 – Taxable dividends paid in the taxation year for purposes of a dividend refund

	A	B	C	D	D1
	Name of connected recipient corporation	Business Number	Taxation year end of connected recipient corporation in which the dividends in column D were received YYYYMMDD	Taxable dividends paid to connected corporations	Eligible dividends (included in column D)
	400	**410**	**420**	**430**	
1					

Note
If your corporation's taxation year end is different than that of the connected recipient corporation, your corporation could have paid dividends in more than one taxation year of the recipient corporation. If so, use a separate line to provide the information for each taxation year of the recipient corporation.

Total ______

Total taxable dividends paid in the taxation year to other than connected corporations **450** 446,000

Eligible dividends (included in line 450) . . . . . **450a** ______

Total taxable dividends paid in the taxation year for the purposes of a dividend refund (total of column D above plus line 450) **460** 446,000

Part 4 – Total dividends paid in the taxation year

Complete this part if the total taxable dividends paid in the taxation year for purposes of a dividend refund (line 460 above) is different from the total dividends paid in the taxation year.

Total taxable dividends paid in the taxation year for the purposes of a dividend refund (from above) 446,000
Other dividends paid in the taxation year (total of 510 to 540) . . . . . ______
Total dividends paid in the taxation year **500** 446,000

Deduct:
Dividends paid out of capital dividend account . . . . . **510** ______
Capital gains dividends . . . . . **520** ______
Dividends paid on shares described in subsection 129(1.2) . . . . . **530** ______
Taxable dividends paid to a controlling corporation that was bankrupt at any time in the year . . . . . **540** ______
Subtotal ______ ► ______

Total taxable dividends paid in the taxation year for purposes of a dividend refund 446,000

Part 2 – Calculation of Part IV tax payable

Part IV tax before deductions (amount J in Part 1)			
Deduct:			
Part IV.I tax payable on dividends subject to Part IV tax	320		
		Subtotal	
Deduct:			
Current-year non capital loss claimed to reduce Part IV tax	330		
Non-capital losses from previous years claimed to reduce Part IV tax	335		
Current-year farm loss claimed to reduce Part IV tax	340		
Farm losses from previous years claimed to reduce Part IV tax	345		
Total losses applied against Part IV tax		× 1 / 3 =	
Part IV tax payable (enter amount on line 712 of the T2 return)	360		

Part 3 – Taxable dividends paid in the taxation year for purposes of a dividend refund

A	B	C	D	D1
Name of connected recipient corporation	Business Number	Taxation year end of connected recipient corporation in which the dividends in column D were received YYYYMMDD	Taxable dividends paid to connected corporations	Eligible dividends (included in column D)
400	410	420	430	
1				

Note

If your corporation's taxation year end is different than that of the connected recipient corporation, your corporation could have paid dividends in more than one taxation year of the recipient corporation. If so, use a separate line to provide the information for each taxation year of the recipient corporation.

Total

Total taxable dividends paid in the taxation year to other than connected corporations	450	446,000
Eligible dividends (included in line 450)	450a	
Total taxable dividends paid in the taxation year for the purposes of a dividend refund (total of column D above plus line 450)	460	446,000

Part 4 – Total dividends paid in the taxation year

Complete this part if the total taxable dividends paid in the taxation year for purposes of a dividend refund (line 460 above) is different from the total dividends paid in the taxation year.

Total taxable dividends paid in the taxation year for the purposes of a dividend refund (from above)			446,000
Other dividends paid in the taxation year (total of 510 to 540)			
Total dividends paid in the taxation year	500		446,000
Deduct:			
Dividends paid out of capital dividend account	510		
Capital gains dividends	520		
Dividends paid on shares described in subsection 129(1.2)	530		
Taxable dividends paid to a controlling corporation that was bankrupt at any time in the year	540		
	Subtotal		
Total taxable dividends paid in the taxation year for purposes of a dividend refund			446,000

T2 SCH 3 E (08)

Canada

Election under paragraph 88(1.1)(f)

Paragraph 88(1.1)(f) election indicator . . . . 190 Yes
Loss from a wholly owned subsidiary deemed to be a loss of the parent from its immediately previous tax year.

Part 2 - Capital losses

Continuity of capital losses and request for a carryback

Capital losses at the end of the previous tax year	200			
Capital losses transferred on the amalgamation or the wind-up of a subsidiary corporation	205			
Deduct:				
Other adjustments (includes adjustments for an acquisition of control)	250			
Section 80 – Adjustments for forgiven amounts	240			
Add:		Subtotal		
Current-year capital loss (from the calculation on Schedule 6)			210	
Unused non-capital losses that expired in the tax year*			A	
Allowable business investment losses (ABIL) that expired as non-capital losses in the tax year**			B	
Enter amount from line A or B, whichever is less	215			
ABILs expired as non-capital loss: line 215 divided by the inclusion rate*** 75.0000 %			220	
		Subtotal		

Note: If there has been an amalgamation or a wind-up of a subsidiary, do a separate calculation of the ABIL expired as non-capital loss for each predecessor or subsidiary. Add all these amounts and enter the total at line 220 above.

Deduct: Amount applied against the current year capital gain (see Note 1)			225	
			Subtotal	

Deduct – Request to carry back capital loss to (see Note 2):

	Capital gain (100%)		Amount carried back (100%)		
First previous tax year		951			
Second previous tax year		952			
Third previous tax year		953			
Capital losses – Closing balance				280	

Note 1
Enter the amount from line 225 multiplied by 50% on line 332 of the T2 return.
Note 2
On lines 225, 951, 952, or 953, whichever applies, enter the actual amount of the loss. When the loss is applied, multiply this amount by the 50% inclusion rate.

* Enter the losses from the 8th previous tax year if the losses were incurred in a tax year ending before March 23, 2004. Enter the losses from the 11th previous tax year if the losses were incurred in a tax year ending after March 22, 2004, and before 2006. Enter the losses from the 21st previous tax year if the losses were incurred in a tax year ending after 2005. Enter the part that was not used in previous years and the current year on line A.

** Enter the losses from the 8th previous tax year if the losses were incurred in a tax year ending before March 23, 2004. Enter the losses from the 11th previous tax year if the losses were incurred in a tax year ending after March 22, 2004. Enter the full amount on line B.

*** This inclusion rate is the rate used to calculate your ABIL referred to at line B. Therefore, use one of the following inclusion rates, whichever applies:

- For ABILs incurred in the 1999 and previous tax years, use 0.75.
- For ABILs incurred in the 2000 and 2001 tax years, the inclusion rate is equal to amount M on Schedule 6 - version T2SCH6(01).
- For ABILs incurred in the 2002 and later tax years, use 0.50.

Part 3 – Farm losses

Continuity of farm losses and request for a carryback

Farm losses at the end of the previous tax year			
Deduct: Farm loss expired *	300		
Farm losses at the beginning of the tax year	302		
Add: Farm losses transferred on the amalgamation or the wind-up of a subsidiary corporation	305		
Current-year farm loss	310		
Deduct:			
Other adjustments (includes adjustments for an acquisition of control)	350		
Section 80 – Adjustments for forgiven amounts	340		
Amount applied against taxable income (enter on line 334 of the T2 return)	330		
Amount applied against taxable dividends subject to Part IV tax	335		
Subtotal			
Deduct – Request to carry back farm loss to:			
First previous tax year to reduce taxable income	921		
Second previous tax year to reduce taxable income	922		
Third previous tax year to reduce taxable income	923		
First previous tax year to reduce taxable dividends subject to Part IV tax	931		
Second previous tax year to reduce taxable dividends subject to Part IV tax	932		
Third previous tax year to reduce taxable dividends subject to Part IV tax	933		
Farm losses – Closing balance		380	

* A farm loss expires as follows:
- After 10 tax years if it arose in a tax year ending before 2006; or
- After 20 tax years if it arose in a tax year ending after 2005.

Part 4 – Restricted farm losses

Current-year restricted farm loss

Total losses for the year from farming business		485	C
Minus the deductible farm loss:			
$2,500 plus D or E, whichever is less	$ 2,500		
(Amount C above ..... – $2,500) divided by 2 =	D		
	$ 6,250 E	2,500	F
Current-year restricted farm loss (amount C minus amount F) (enter this amount on line 410)			

Continuity of restricted farm losses and request for a carryback

Restricted farm losses at the end of the previous tax year			
Deduct: Restricted farm loss expired *	400		
Restricted farm losses at the beginning of the tax year	402		
Add: Restricted farm losses transferred on the amalgamation or the wind-up of a subsidiary corporation	405		
Current-year restricted farm loss (enter on line 233 of Schedule 1)	410		
Deduct:			
Amount applied against farming income (enter on line 333 of the T2 return)	430		
Section 80 – Adjustments for forgiven amounts	440		
Other adjustments	450		
Subtotal			
Deduct – Request to carry back restricted farm loss to:			
First previous tax year to reduce farming income	941		
Second previous tax year to reduce farming income	942		
Third previous tax year to reduce farming income	943		
Restricted farm losses – Closing balance		480	

Note
The total losses for the year from all farming businesses are calculated without including scientific research expenses.

* A restricted farm loss expires as follows:
- After 10 tax years if it arose in a tax year ending before 2006; or
- After 20 tax years if it arose in a tax year ending after 2005.

Part 5 – Listed personal property losses

Continuity of listed personal property loss and request for a carryback

Listed personal property losses at the end of the previous tax year				
Deduct: Listed personal property loss expired after seven tax years			500	
Listed personal property losses at the beginning of the tax year			502	
Add: Current-year listed personal property loss (from Schedule 6)			510	
			Subtotal	
Deduct:				
Amount applied against listed personal property gains (enter on line 655 of Schedule 6)	530			
Other adjustments	550			
			Subtotal	
Deduct – Request to carry back listed personal property loss to:				
First previous tax year to reduce listed personal property gains	661			
Second previous tax year to reduce listed personal property gains	662			
Third previous tax year to reduce listed personal property gains	663			
Listed personal property losses – Closing balance			580	

Part 7 – Limited partnership losses

Current-year limited partnership losses

1 Partnership identifier	2 Fiscal period ending	3 Corporation's share of limited partnership loss	4 Corporation's at-risk amount	5 Total of corporation's share of partnership investment tax credit, farming losses, and resource expenses	6 Column 4 minus column 5 (if negative, enter "0")	7 Current-year limited partnership losses (column 3 - 6)
600	602	604	606	608		620

Total (enter this amount on line 222 of Schedule 1)

Limited partnership losses from prior tax years that may be applied in the current year

1 Partnership identifier	2 Fiscal period ending	3 Limited partnership losses at the end of the previous tax year	4 Corporation's at-risk amount	5 Total of corporation's share of partnership investment tax credit, business or property losses, and resource expenses	6 Column 4 minus column 5 (if negative, enter "0")	7 Limited partnership losses that may be applied in the year (the lesser of columns 3 and 6)
630	632	634	636	638		650

Continuity of limited partnership losses that can be carried forward to future tax years

Partnership identifier	Limited partnership losses at the end of the previous tax year	Limited partnership losses transferred on an amalgamation or the wind-up of a subsidiary	Current-year limited partnership losses (from column 620)	Limited partnership losses applied (cannot exceed column 650)	Limited partnership losses closing balance (662 + 664 + 670 - 675)
660	662	664	670	675	680

Total (enter this amount on line 335 of the T2 return)

Non-Capital Loss Continuity Workchart

Part 6 – Analysis of balance of losses by year of origin

Non-capital losses – losses that can be carried forward over 20 years

Year of origin	Balance at beginning of year	Loss incurred in current year	Adjustments and transfers	Loss carried back Parts I & IV	Applied to reduce: Taxable income	Applied to reduce: Part IV tax	Balance at end of year
Current	N/A	199,997		199,997	N/A		
1st preceding taxation year 2008-12-31		N/A		N/A			
2nd preceding taxation year 2007-12-31		N/A		N/A			
3rd preceding taxation year 2006-12-31		N/A		N/A			
4th preceding taxation year 2005-12-31		N/A		N/A			
5th preceding taxation year 2004-12-31		N/A		N/A			
6th preceding taxation year 2003-12-31		N/A		N/A			
7th preceding taxation year 2002-12-31		N/A		N/A			
8th preceding taxation year 2001-12-31		N/A		N/A			
9th preceding taxation year 2001-09-30		N/A		N/A			
10th preceding taxation year 2000-09-30		N/A		N/A			
11th preceding taxation year 1999-09-30		N/A		N/A			
12th preceding taxation year 1998-09-30		N/A		N/A			
13th preceding taxation year 1997-09-30		N/A		N/A			
14th preceding taxation year 1996-09-30		N/A		N/A			
15th preceding taxation year 1995-09-30		N/A		N/A			
16th preceding taxation year 1994-09-30		N/A		N/A			
17th preceding taxation year 1993-09-30		N/A		N/A			
18th preceding taxation year 1992-09-30		N/A		N/A			
19th preceding taxation year 1991-09-30		N/A		N/A			
20th preceding taxation year 1990-09-30		N/A		N/A			
Total		199,997		199,997			

Non-capital losses – losses that can be carried forward over 10 years

Year of origin	Balance at beginning of year	Loss incurred in current year	Adjustments and transfers	Loss carried back Parts I & IV	Applied to reduce: Taxable income	Applied to reduce: Part IV tax	Balance at end of year
Current	N/A	N/A		N/A	N/A	N/A	N/A
1st preceding taxation year 2008-12-31		N/A		N/A			
2nd preceding taxation year 2007-12-31		N/A		N/A			
3rd preceding taxation year 2006-12-31		N/A		N/A			
4th preceding taxation year 2005-12-31		N/A		N/A			
5th preceding taxation year 2004-12-31		N/A		N/A			
6th preceding taxation year 2003-12-31		N/A		N/A			
7th preceding taxation year 2002-12-31		N/A		N/A			
8th preceding taxation year 2001-12-31		N/A		N/A			
9th preceding taxation year 2001-09-30		N/A		N/A			
10th preceding taxation year 2000-09-30		N/A		N/A			
Total		N/A		N/A			

Non-capital losses – losses that can be carried forward over 7 years

Year of origin	Balance at beginning of year	Loss incurred in current year	Adjustments and transfers	Loss carried back Parts I & IV	Applied to reduce: Taxable income	Applied to reduce: Part IV tax	Balance at end of year
Current	N/A	N/A		N/A	N/A	N/A	N/A
1st preceding taxation year 2008-12-31		N/A		N/A			
2nd preceding taxation year 2007-12-31		N/A		N/A			
3rd preceding taxation year 2006-12-31		N/A		N/A			
4th preceding taxation year 2005-12-31		N/A		N/A			
5th preceding taxation year 2004-12-31		N/A		N/A			
6th preceding taxation year 2003-12-31		N/A		N/A			
7th preceding taxation year 2002-12-31		N/A		N/A			
Total		N/A		N/A			

Farm losses – losses that can be carried forward over 20 years

Year of origin	Balance at beginning of year	Loss incurred in current year	Adjustments and transfers	Loss carried back Parts I & IV	Applied to reduce Taxable income	Applied to reduce Part IV tax	Balance at end of year
Current	N/A				N/A		
1st preceding taxation year 2008-12-31		N/A		N/A			
2nd preceding taxation year 2007-12-31		N/A		N/A			
3rd preceding taxation year 2006-12-31		N/A		N/A			
4th preceding taxation year 2005-12-31		N/A		N/A			
5th preceding taxation year 2004-12-31		N/A		N/A			
6th preceding taxation year 2003-12-31		N/A		N/A			
7th preceding taxation year 2002-12-31		N/A		N/A			
8th preceding taxation year 2001-12-31		N/A		N/A			
9th preceding taxation year 2001-09-30		N/A		N/A			
10th preceding taxation year 2000-09-30		N/A		N/A			
11th preceding taxation year 1999-09-30		N/A		N/A			
12th preceding taxation year 1998-09-30		N/A		N/A			
13th preceding taxation year 1997-09-30		N/A		N/A			
14th preceding taxation year 1996-09-30		N/A		N/A			
15th preceding taxation year 1995-09-30		N/A		N/A			
16th preceding taxation year 1994-09-30		N/A		N/A			
17th preceding taxation year 1993-09-30		N/A		N/A			
18th preceding taxation year 1992-09-30		N/A		N/A			
19th preceding taxation year 1991-09-30		N/A		N/A			
20th preceding taxation year 1990-09-30		N/A		N/A			
Total							

Farm losses – losses that can be carried forward over 10 years

Year of origin	Balance at beginning of year	Loss incurred in current year	Adjustments and transfers	Loss carried back Parts I & IV	Applied to reduce: Taxable income	Applied to reduce: Part IV tax	Balance at end of year
Current	N/A	N/A		N/A	N/A	N/A	N/A
1st preceding taxation year 2008-12-31		N/A		N/A			
2nd preceding taxation year 2007-12-31		N/A		N/A			
3rd preceding taxation year 2006-12-31		N/A		N/A			
4th preceding taxation year 2005-12-31		N/A		N/A			
5th preceding taxation year 2004-12-31		N/A		N/A			
6th preceding taxation year 2003-12-31		N/A		N/A			
7th preceding taxation year 2002-12-31		N/A		N/A			
8th preceding taxation year 2001-12-31		N/A		N/A			
9th preceding taxation year 2001-09-30		N/A		N/A			
10th preceding taxation year 2000-09-30		N/A		N/A			
Total		N/A		N/A			

Restricted farm losses – losses that can be carried forward over 20 years

Year of origin	Balance at beginning of year	Loss incurred in current year	Adjustments and transfers	Loss carried back Part I	Applied to reduce: Taxable income	Applied to reduce: Part IV tax	Balance at end of year
Current	N/A				N/A	N/A	
1st preceding taxation year 2008-12-31		N/A		N/A		N/A	
2nd preceding taxation year 2007-12-31		N/A		N/A		N/A	
3rd preceding taxation year 2006-12-31		N/A		N/A		N/A	
4th preceding taxation year 2005-12-31		N/A		N/A		N/A	
5th preceding taxation year 2004-12-31		N/A		N/A		N/A	
6th preceding taxation year 2003-12-31		N/A		N/A		N/A	
7th preceding taxation year 2002-12-31		N/A		N/A		N/A	
8th preceding taxation year 2001-12-31		N/A		N/A		N/A	
9th preceding taxation year 2001-09-30		N/A		N/A		N/A	
10th preceding taxation year 2000-09-30		N/A		N/A		N/A	
11th preceding taxation year 1999-09-30		N/A		N/A		N/A	
12th preceding taxation year 1998-09-30		N/A		N/A		N/A	
13th preceding taxation year 1997-09-30		N/A		N/A		N/A	
14th preceding taxation year 1996-09-30		N/A		N/A		N/A	
15th preceding taxation year 1995-09-30		N/A		N/A		N/A	
16th preceding taxation year 1994-09-30		N/A		N/A		N/A	
17th preceding taxation year 1993-09-30		N/A		N/A		N/A	
18th preceding taxation year 1992-09-30		N/A		N/A		N/A	
19th preceding taxation year 1991-09-30		N/A		N/A		N/A	
20th preceding taxation year 1990-09-30		N/A		N/A		N/A	
Total						N/A	

Restricted farm losses – losses that can be carried forward over 10 years

Year of origin	Balance at beginning of year	Loss incurred in current year	Adjustments and transfers	Loss carried back Part I	Applied to reduce: Taxable income	Applied to reduce: Part IV tax	Balance at end of year
Current	N/A	N/A		N/A	N/A	N/A	N/A
1st preceding taxation year 2008-12-31		N/A		N/A		N/A	
2nd preceding taxation year 2007-12-31		N/A		N/A		N/A	
3rd preceding taxation year 2006-12-31		N/A		N/A		N/A	
4th preceding taxation year 2005-12-31		N/A		N/A		N/A	
5th preceding taxation year 2004-12-31		N/A		N/A		N/A	
6th preceding taxation year 2003-12-31		N/A		N/A		N/A	
7th preceding taxation year 2002-12-31		N/A		N/A		N/A	
8th preceding taxation year 2001-12-31		N/A		N/A		N/A	
9th preceding taxation year 2001-09-30		N/A		N/A		N/A	
10th preceding taxation year 2000-09-30		N/A		N/A		N/A	*
Total		N/A		N/A		N/A	

* This balance expires this year and will not be available next year.

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SCHEDULE 5

TAX CALCULATION SUPPLEMENTARY – CORPORATIONS

Corporation's name	Business Number	Tax year-end Year Month Day
BRANT COUNTY POWER INC.	89113 2011 RC0001	2009-12-31

- Use this schedule if, during the tax year, the corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B and D in Part 1); or
  - is claiming provincial or territorial tax credits or rebates (see Part 2).
- Regulations mentioned in this schedule are from the *Income Tax Regulations*.
- For more information, see the *T2 Corporation – Income Tax Guide*.
- Enter the regulation number in field 100 of Part 1.

Part 1 – Allocation of taxable income

100 402 Corporations not specified — Enter the regulation that applies (402 to 413).

A Jurisdiction Tick yes if the corporation had a permanent establishment in the jurisdiction during the tax year *		B Total salaries and wages paid in jurisdiction	C (B x taxable income**) / G	D Gross revenue	E (D x taxable income**) / H	F Allocation of taxable income (C + E) x 1/2 (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	003 1 Yes	103		143		
Newfoundland and Labrador offshore	004 1 Yes	104		144		
Prince Edward Island	005 1 Yes	105		145		
Nova Scotia	007 1 Yes	107		147		
Nova Scotia offshore	008 1 Yes	108		148		
New Brunswick	009 1 Yes	109		149		
Quebec	011 1 Yes	111		151		
Ontario	013 1 Yes X	113		153		
Manitoba	015 1 Yes	115		155		
Saskatchewan	017 1 Yes	117		157		
Alberta	019 1 Yes	119		159		
British Columbia	021 1 Yes	121		161		
Yukon	023 1 Yes	123		163		
Northwest Territories	025 1 Yes	125		165		
Nunavut	026 1 Yes	126		166		
Outside Canada	027 1 Yes	127		167		
Total		129 G		169 H		

* "Permanent establishment" is defined in Regulation 400(2).

** Starting in 2009, if the corporation has income or loss from an international banking centre, the taxable income is the amount on line 360 or line Z of the T2 return plus the total amount not required to be included, or minus the total amount not allowed to be deducted, in calculating the corporation's income under section 33.1 of the federal *Income Tax Act*.

Notes:

1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see line 760 of the *T2 Corporation – Income Tax Guide*.
2. If the corporation has provincial or territorial tax payable, complete Part 2.

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits

	Line	Amount		Total
Ontario basic income tax (from Schedule 500)	270			
Deduct: Ontario small business deduction (from schedule 500)	402			
Subtotal (if negative, enter "0")			►	A6
Add:				
Surtax re Ontario small business deduction (from Schedule 500)	272			
Ontario additional tax re Crown royalties (from Schedule 504)	274			
Ontario transitional tax debits (from Schedule 506)	276			
Recapture of Ontario research and development tax credit (from Schedule 508)	277			
Subtotal			►	B6
Subtotal (amount A6 plus amount B6)				C6
Deduct:				
Ontario resource tax credit (from Schedule 504)	404			
Ontario tax credit for manufacturing and processing (from Schedule 502)	406			
Ontario foreign tax credit (from Schedule 21)	408			
Ontario credit union tax reduction (from Schedule 500)	410			
Ontario transitional tax credits (from Schedule 506)	414			
Ontario political contributions tax credit (from Schedule 525)	415			
Subtotal			►	D6
Subtotal (amount C6 minus amount D6) (if negative, enter "0")				E6
Ontario research and development tax credit (from Schedule 508)	416			
Ontario corporate income tax payable before Ontario corporate minimum tax credit (amount E6 minus amount on line 416) (if negative, enter "0")				F6
Deduct:				
Ontario corporate minimum tax credit (from schedule 510)	418			
Ontario corporate income tax payable (amount F6 minus amount on line 418) (if negative, enter "0")				G6
Add:				
Ontario corporate minimum tax (from Schedule 510)	278	43,626		
Ontario special additional tax on life insurance corporations (from Schedule 512)	280			
Ontario capital tax (from Schedule 514 or Schedule 515, whichever applies)	282	13,786		
Subtotal		57,412	►	57,412 H6
Total Ontario tax payable before refundable credits (amount G6 plus amount H6)				57,412 I6
Deduct:				
Ontario qualifying environmental trust tax credit	450			
Ontario co-operative education tax credit (from Schedule 550)	452	926		
Ontario apprenticeship training tax credit (from Schedule 552)	454			
Ontario computer animation and special effects tax credit (from Schedule 554)	456			
Ontario film and television tax credit (from Schedule 556)	458			
Ontario production services tax credit (from Schedule 558)	460			
Ontario interactive digital media tax credit (from Schedule 560)	462			
Ontario sound recording tax credit (from Schedule 562)	464			
Ontario book publishing tax credit (from Schedule 564)	466			
Ontario innovation tax credit (from Schedule 566)	468			
Ontario business-research institute tax credit (from Schedule 568)	470			
Subtotal		926	►	926 J6
Net Ontario tax payable or refundable credit (amount I6 minus amount J6) (if a credit, enter a negative amount) Include this amount on line 255.	290			56,486 K6

Summary

Enter the total net tax payable or refundable credits for all provinces and territories at line 255.

Net provincial and territorial tax payable or refundable credits **255** 56,486

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

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SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
BRANT COUNTY POWER INC.	89113 2011 RC0001	2009-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under regulation 1101(5q)? **101** 1 Yes [ ] 2 No [X]

	1 Class number (See Note)	Description	2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year)	3 Cost of acquisitions during the year (new property must be available for use)*	4 Net adjustments**	5 Proceeds of dispositions during the year (amount not to exceed the capital cost)	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)***	7 Reduced undepreciated capital cost	8 CCA rate %	9 Recapture of capital cost allowance (line 107 of Schedule 1)	10 Terminal loss (line 404 of Schedule 1)	11 Capital cost allowance (column 7 multiplied by column 8; or a lower amount) (line 403 of Schedule 1)****	12 Undepreciated capital cost at the end of the year (column 6 plus column 7 minus column 11)
	200		**201**	**203**	**205**	**207**	**211**		**212**	**213**	**215**	**217**	**220**
1.	1		9,381,099			0		9,381,099	4	0	0	375,244	9,005,855
2.	8		128,585	36,171		0	18,085	147,570	20	0	0	29,514	137,221
3.	10		499,635	218,905		0	109,453	608,093	30	0	0	182,427	535,113
4.	12		11,189			0		11,189	100	0	0	11,189	
5.	17	Generator '72	25,260			0		25,260	8	0	0	2,021	23,239
6.	45		15,533			0		15,533	45	0	0	6,990	8,543
7.	47	TS > 50 KV	5,710,314	1,283,310		0	641,655	6,351,969	8	0	0	508,158	6,485,466
8.	50	computers	49,242			0		49,242	55	0	0	27,083	22,159
9.	13	2009 building additions	113,059	21,907		0	10,954	128,972	5	0	0	7,435	127,488
10.	52			34,742		0		34,742	100	0	0	34,742	
		Total	15,533,377	1,602,535			783,897	16,752,015				1,103,608	16,352,826

Note: Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed.
Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see Regulation 1100(2) and (2.2).

** Include amounts transferred under section 85, or on amalgamation and winding-up of a subsidiary. See the *T2 Corporation Income Tax Guide* for other examples of adjustments to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) plus or minus certain adjustments from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.

**** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

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SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
BRANT COUNTY POWER INC.	89113 2011 RC0001	2009-12-31

This schedule is to be completed by a corporation having one or more of the following:
- related corporation(s)
- associated corporations(s)

	Name	Country of residence (if other than Canada)	Business Number (Canadian corporation only) (see note 1)	Relationship code (see note 2)	Number of common shares owned	% of common shares owned	Number of preferred shares owned	% of preferred shares owned	Book value of capital stock
	100	200	300	400	500	550	600	650	700
1.	CORPORATION OF THE COUNTY OF		87970 0333 RC0001	1	5,437,947	100.000			5,437,947
2.	BRANT COUNTY POWER SERVICES		86427 7357 RC0001	3					

Note 1: Enter "NR" if a corporation is not registered.
Note 2: Enter the code number of the relationship that applies from the following order: 1 – Parent 2 – Subsidiary 3 – Associated 4 – Related, but not associated.

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SCHEDULE 10

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year end Year Month Day
BRANT COUNTY POWER INC.	89113 2011 RC0001	2009-12-31

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide*.
- A separate cumulative eligible capital account must be kept for each business.

Part 1 – Calculation of current year deduction and carry-forward

Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter "0") **200** 1,591,353 A

Add: Cost of eligible capital property acquired during the taxation year **222** ______

Other adjustments **226** ______

Subtotal (line 222 plus line 226) ______ × 3 / 4 = ______ B

Non-taxable portion of a non arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002 **228** ______ × 1 / 2 = ______ C

amount B minus amount C (if negative, enter "0") ______ ► ______ D

Amount transferred on amalgamation or wind-up of subsidiary **224** ______ E

Subtotal (add amounts A, D, and E) **230** 1,591,353 F

Deduct: Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year **242** ______ G

The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7) **244** ______ H

Other adjustments **246** ______ I

(add amounts G, H, and I) ______ × 3 / 4 = **248** ______ J

Cumulative eligible capital balance (amount F minus amount J) 1,591,353 K

(If amount K is negative, enter "0" at line M and proceed to Part 2)

Cumulative eligible capital for a property no longer owned after ceasing to carry on that business **249** ______

amount K 1,591,353

less amount from line 249 ______

Current year deduction 1,591,353 × 7.00 % * = **250** 111,395 ►

(line 249 plus line 250) (enter this amount at line 405 of Schedule 1) 111,395 ► 111,395 L

Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0") **300** 1,479,958 M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

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Part 2 – Amount to be included in income arising from disposition
(complete this part only if the amount at line K is negative)

Amount from line K (show as positive amount)					N
Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988	400			1	
Total of all amounts which reduced CEC in the current or prior years under subsection 80(7)	401			2	
Total of CEC deductions claimed for taxation years beginning before July 1, 1988	402		3		
Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988	408		4		
Line 3 minus line 4 (if negative, enter "0")			►	5	
Total of lines 1, 2 and 5				6	
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400			7		
Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000			8		
Subtotal (line 7 plus line 8)	409		►	9	
Line 6 minus line 9 (if negative, enter "0")				►	O
Line N minus line O (if negative, enter "0")					P
Line 5 ______ × 1 / 2 =					Q
Line P minus line Q (if negative, enter "0")					R
Amount R ______ × 2 / 3 =					S
Amount N or amount O, whichever is less					T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)	410				

Continuity of financial statement reserves (not deductible)

Financial statement reserves (not deductible)

	Description	Balance at the beginning of the year	Transfer on amalgamation or wind-up of subsidiary	Add	Deduct	Balance at the end of the year
1	POST EMPLOYMENT BENEFITS	617,500		28,800		646,300
2						
	Reserves from Part 2 of Schedule 13					
	Totals	617,500		28,800		646,300

The total opening balance plus the total transfers should be entered on line 414 of Schedule 1 as a deduction.
The total closing balance should be entered on line 126 of Schedule 1 as an addition.

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SCHEDULE 23

AGREEMENT AMONG ASSOCIATED CANADIAN-CONTROLLED PRIVATE CORPORATIONS TO ALLOCATE THE BUSINESS LIMIT

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group. Include non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* (ITA) not to be associated for purposes of the small business deduction.

Column 2: Provide the Business Number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code that applies to each corporation:

1 – Associated for purposes of allocating the business limit (unless code 5 applies)
2 – CCPC that is a "third corporation" that has elected under subsection 256(2) not to be associated for purposes of the small business deduction
3 – Non-CCPC that is a "third corporation" as defined in subsection 256(2)
4 – Associated non-CCPC
5 – Associated CCPC to which code 1 does not apply because of a subsection 256(2) election made by a "third corporation"

Column 4: Enter the business limit for the year of each corporation in the associated group. The business limit is computed at line 4 on page 4 of each respective corporation's T2 return.

Column 5: Assign a percentage to allocate the business limit to each corporation that has an association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A. Ensure that the total at line A falls within the range for the calendar year to which the agreement applies:

Calendar year	Acceptable range	Calendar year	Acceptable range
2006	maximum $300,000	2008	maximum $400,000
2007	$300,001 to $400,000	2009	$400,001 to $500,000

If the calendar year to which this agreement applies is after 2009, ensure that the total at line A does not exceed $500,000.

Allocating the business limit

Date filed (do not use this area) . . . . . 025 Year Month Day

Enter the calendar year to which the agreement applies . . . . . 050 Year 2009

Is this an amended agreement for the above-noted calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . . 075 1 Yes [ ] 2 No [X]

	1 Names of associated corporations	2 Business Number of associated corporations	3 Association code	4 Business limit for the year (before the allocation) $	5 Percentage of the business limit %	6 Business limit allocated* $
	100	200	300		350	400
1	BRANT COUNTY POWER INC.	89113 2011 RC0001	1	500,000		
2	CORPORATION OF THE COUNTY OF BRANT	87070 0333 RC0001	1			
3	BRANT COUNTY POWER SERVICES INC.	86427 7397 RC0001	1	500,000	100.0000	500,000
				Total	100.0000	500,000 A

Business limit reduction under subsection 125(5.1) of the ITA

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "Large corporation amount" at line 415 of the T2 return. If the corporation is a member of an associated group** of corporations in the current tax year, the amount at line 415 of the T2 return is equal to 0.225% x (A - $10,000,000) where, "A" is the total of taxable capital employed in Canada*** of each corporation in the associated group for its last tax year ending in the preceding calendar year.

* Each corporation will enter on line 410 of the T2 return the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules apply if a CCPC has more than one tax year ending in a calendar year and is associated in more than one of those years with another CCPC that has a tax year ending in the same calendar year. If the tax year straddles January 1, 2009, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit that would have been determined for the first tax year ending in the calendar year if $500,000 was used in allocating the amounts among associated corporations and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year. Otherwise, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit determined for the first tax year ending in the calendar year and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year.

** The associated group includes the corporation filing this schedule and each corporation that has an "association code" of 1 or 4 in column 3.

*** "Taxable capital employed in Canada" has the meaning assigned by subsection 181.2(1) or 181.3(1) or section 181.4 of the ITA.

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Canada

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SCHEDULE 33

TAXABLE CAPITAL EMPLOYED IN CANADA – LARGE CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
BRANT COUNTY POWER INC.	89113 2011 RC0001	2009-12-31

- Use this schedule in determining if the total taxable capital employed in Canada of the corporation (other than a financial institution or an insurance corporation) and its related corporations is greater than $10,000,000.
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the federal *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 181(1) defines the terms "financial institution," "long-term debt," and "reserves."
- Subsection 181(3) provides the basis to determine the carrying value of a corporation's assets or any other amount under Part I.3 for its capital, investment allowance, taxable capital, or taxable capital employed in Canada, or for a partnership in which it has an interest.
- If you are filing a provincial capital tax return with your *T2 Corporation Income Tax Return*, also file a completed Schedule 33 with the return no later than six months from the end of the tax year.
- This schedule may contain changes that had not yet become law at the time of publishing.

If the corporation was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada, go to Part 4, "Taxable capital employed in Canada."

Part 1 – Capital

Add the following amounts at the end of the year:

	Line	Amount		
Reserves that have not been deducted in computing income for the year under Part I	101			
Capital stock (or members' contributions if incorporated without share capital)	103	9,512,193		
Retained earnings	104	4,250,196		
Contributed surplus	105			
Any other surpluses	106	2,738,065		
Deferred unrealized foreign exchange gains	107			
All loans and advances to the corporation	108	5,224,286		
All indebtedness of the corporation represented by bonds, debentures, notes, mortgages, hypothecary claims, bankers' acceptances, or similar obligations	109	646,300		
Any dividends declared but not paid by the corporation before the end of the year	110			
All other indebtedness of the corporation (other than any indebtedness for a lease) that has been outstanding for more than 365 days before the end of the year	111			
Proportion of the amount, if any, by which the total of all amounts (see note below) for the partnership of which the corporation is a member at the end of the year exceeds the amount of the partnership's deferred unrealized foreign exchange losses	112			
Subtotal		22,371,040	22,371,040	A

Deduct the following amounts:

	Line	Amount		
Deferred tax debit balance at the end of the year	121	661,022		
Any deficit deducted in computing its shareholders' equity (including, for this purpose, the amount of any provision for the redemption of preferred shares) at the end of the year	122			
Any amount deducted under subsection 135(1) in computing income under Part I for the year, as long as the amount may reasonably be regarded as being included in any of lines 101 to 112 above	123			
The amount of deferred unrealized foreign exchange losses at the end of the year	124			
Subtotal		661,022	661,022	B
Capital for the year (amount A minus amount B) (if negative, enter "0")	190		21,710,018	

Note: Lines 101, 107, 108, 109, 111, and 112 are determined as follows:

- If the partnership is a member of another partnership (tiered partnerships), include the amounts of the partnership and tiered partnerships.
- Amounts for the partnership and tiered partnerships are those that would be determined for lines 101, 107, 108, 109, 111, and 112 as if they apply in the same way that they apply to corporations.
- Do not include amounts owing to the member or to other corporations that are members of the partnership.
- Amounts are determined at the end of the last fiscal period of the partnership ending in the year of the corporation.
- The proportion of the total amounts is determined by the corporation's share of the partnership's income or loss for the fiscal period of the partnership.

Part 2 – Investment allowance

Add the carrying value at the end of the year of the following assets of the corporation:

A share of another corporation	401	
A loan or advance to another corporation (other than a financial institution)	402	582,850
A bond, debenture, note, mortgage, hypothecary claim, or similar obligation of another corporation (other than a financial institution)	403	
Long-term debt of a financial institution	404	
A dividend receivable on a share of the capital stock of another corporation	405	
A loan or advance to, or a bond, debenture, note, mortgage, hypothecary claim, or similar obligation of, a partnership all of the members of which, throughout the year, were other corporations (other than financial institutions) that were not exempt from tax under Part I.3 (other than by reason of paragraph 181.1(3)(d))	406	
An interest in a partnership (see note 1 below)	407	
Investment allowance for the year (add lines 401 to 407)	490	582,850

Notes:
1. Where the corporation has an interest in a partnership or in tiered partnerships, consider the following:
   – the investment allowance of a partnership is deemed to be the amount calculated at line 490 above, at the end of its fiscal period, as if it was a corporation;
   – the total of the carrying value of each asset of the partnership described in the above lines is for its last fiscal period ending at or before the end of the corporation's tax year; and
   – the carrying value of a partnership member's interest at the end of the year is its specified proportion (as defined in subsection 248(1)) of the partnership's investment allowance.
2. Lines 401 to 405 should not include the carrying value of a share of the capital stock of, a dividend payable by, or indebtedness of a corporation that is exempt from tax under Part I.3 (other than by reason of paragraph 181.1(3)(d)).
3. Where a trust is used as a conduit for loaning money from a corporation to another related corporation (other than a financial institution), the loan will be considered to have been made directly from the lending corporation to the borrowing corporation, according to subsection 181.2(6).

Part 3 – Taxable capital

Capital for the year (line 390)		21,710,018	C
Deduct: Investment allowance for the year (line 490)		582,850	D
Taxable capital for the year (amount C minus amount D) (if negative, enter "0")	500	21,127,168	

Part 4 – Taxable capital employed in Canada

To be completed by a corporation that was resident in Canada at any time in the year

Taxable capital for the year (line 500) 21,127,168 × (Taxable income earned in Canada **610** 1,000 / Taxable income 1,000) = Taxable capital employed in Canada **690** 21,127,168

Notes:
1. Regulation 8601 gives details on calculating the amount of taxable income earned in Canada.
2. Where a corporation's taxable income for a tax year is "0," it shall, for the purpose of the above calculation, be deemed to have a taxable income for that year of $1,000.
3. In the case of an airline corporation, Regulation 8601 should be considered when completing the above calculation.

To be completed by a corporation that was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada

Total of all amounts each of which is the carrying value at the end of the year of an asset of the corporation used in the year or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada		701	
Deduct the following amounts:			
Corporation's indebtedness at the end of the year [other than indebtedness described in any of paragraphs 181.2(3)(c) to (f)] that may reasonably be regarded as relating to a business it carried on during the year through a permanent establishment in Canada	711		
Total of all amounts each of which is the carrying value at the end of year of an asset described in subsection 181.2(4) of the corporation that it used in the year, or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada	712		
Total of all amounts each of which is the carrying value at the end of year of an asset of the corporation that is a ship or aircraft the corporation operated in international traffic, or personal or movable property used or held by the corporation in carrying on any business during the year through a permanent establishment in Canada (see note below)	713		
Total deductions (add lines 711, 712, and 713)		►	E
Taxable capital employed in Canada (line 701 minus amount E) (if negative, enter "0")		790	

Note: Complete line 713 only if the country in which the corporation is resident did not impose a capital tax for the year on similar assets, or a tax for the year on the income from the operation of a ship or aircraft in international traffic, of any corporation resident in Canada during the year.

Part 5 – Calculation for purposes of the small business deduction

This part is applicable to corporations that are not associated in the current year, but were associated in the prior year.

Taxable capital employed in Canada (line 690 or 790, whichever applies)		F
Deduct:	10,000,000	G
Excess (amount F minus amount G) (if negative, enter "0")		H
Calculation for purposes of the small business deduction (amount H x 0.00225)		I

Enter this amount at line 415 of the T2 return

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SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
BRANT COUNTY POWER INC.	89113 2011 RC0001	2009-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust)	Provide only one number per shareholder: Business Number (If a corporation is not registered, enter "NR")	Social insurance number	Trust number	Percentage common shares	Percentage preferred shares
	100	200	300	350	400	500
1	CORPORATION OF THE COUNTY OF BRANT	87070 0333 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

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SCHEDULE 53

GENERAL RATE INCOME POOL (GRIP) CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
BRANT COUNTY POWER INC.	89113 2051 RC0001	2009-12-31

On: 2009-12-31

- If you are a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC), use this schedule to determine the general rate income pool (GRIP).
- When an eligible dividend was paid in the tax year, file a completed copy of this schedule with your *T2 Corporation Income Tax Return*. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- Subsections referred to in this schedule are from the *Income Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool, and low rate income pool.

Eligibility for the various additions

Answer the following questions to determine the corporation's eligibility for the various additions:

2006 addition

1. Is this the corporation's first taxation year that includes January 1, 2006? . . . . . [ ] Yes [X] No
2. If not, what is the date of the taxation year end of the corporation's first year that includes January 1, 2006? Enter the date and go directly to question 4 2006-12-31
3. During that first year, was the corporation a CCPC or would it have been a CCPC if not for the election of subsection 89(11) ITA? . . . . . [X] Yes [ ] No
   If the answer to question 3 is yes, complete Part "GRIP addition for 2006".

Change in the type of corporation

4. Was the corporation a CCPC during its preceding taxation year? . . . . . [X] Yes [ ] No
5. Corporations that become a CCPC or a DIC . . . . . [ ] Yes [X] No
   If the answer to question 5 is yes, complete Part 4.

Amalgamation (first year of filing after amalgamation)

6. Corporations that were formed as a result of an amalgamation . . . . . [ ] Yes [X] No
   If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to question 9.
7. Was one or more of the predecessor corporations neither a CCPC nor a DIC? . . . . . [ ] Yes [ ] No
   If the answer to question 7 is yes, complete Part 4.
8. Was one or more of the predecessor corporation a CCPC or a DIC during the taxation year that ended immediately before amalgamation? . . . . . [ ] Yes [ ] No
   If the answer to question 8 is yes, complete Part 3.

Winding-up

9. Corporations that wound-up a subsidiary . . . . . [ ] Yes [X] No
   If the answer to question 9 is yes, answer questions 10 and 11. If the answer is no, go to Part 1.
10. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? . . . . . [ ] Yes [ ] No
    If the answer to question 10 is yes, complete Part 4.
11. Was the subsidiary a CCPC or a DIC during its last taxation year? . . . . . [ ] Yes [ ] No
    If the answer to question 11 is yes, complete Part 3.

Part 1 – Calculation of general rate income pool (GRIP)

GRIP at the end of the previous tax year .... **100** 4,924,983 A

Taxable income for the year (DICs enter "0") * .... **110** ______ B

Income for the credit union deduction * (amount E in Part 3 of Schedule 17) .... **120** ______

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less * .... **130** ______

For a CCPC, the lesser of aggregate investment income (line 440 of the T2 return) and taxable income * .... **140** ______

Subtotal (add lines 120, 130, and 140) ______ ► ______ C

Income taxable at the general corporate rate (line B minus line C) (if negative, enter "0") .... **150** ______

After-tax income (line 150 x general rate factor for the tax year ** 0.68) .... **190** ______ D

Eligible dividends received in the tax year .... **200** ______

Dividends deductible under section 113 received in the tax year .... **210** ______

Subtotal (add lines 200 and 210) ______ ► ______ E

GRIP addition:

Becoming a CCPC (line PP from Part 4) .... **220** ______

Post amalgamation (total of lines EE from Part 3 and lines PP from Part 4) .... **230** ______

Post-wind-up (total of lines EE from Part 3 and lines PP from Part 4) .... **240** ______

Subtotal (add lines 220, 230, and 240) ______ ► **290** ______ F

Subtotal (add lines A, D, E, and F) 4,924,983 G

Eligible dividends paid in the previous tax year .... **300** ______

Excessive eligible dividend designations made in the previous tax year .... **310** ______

Note: If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310.

Subtotal (line 300 minus line 310) ______ ► ______ H

GRIP before adjustment for specified future tax consequences (line G minus line H) (amount can be negative) **490** 4,924,983

Total GRIP adjustment for specified future tax consequences to previous tax years (amount W from Part 2) **560** 1,432,394

GRIP at the end of the tax year (line 490 minus line 560) **590** 3,492,589

Enter this amount on line 160 of Schedule 55

* For lines 110, 120, 130, and 140, the income amount is the amount before considering specified future tax consequences. This phrase is defined in subsection 248(1). It includes the deduction of a loss carryback from subsequent tax years, a reduction of Canadian exploration expenses and Canadian development expenses that were renounced in subsequent tax years (e.g., flow-through share renunciations), reversals of income inclusions where an option is exercised in subsequent tax years, and the effect of certain foreign tax credit adjustments.

** The general rate factor for a tax year is 0.68 for any portion of the tax year that falls before 2010, 0.69 for any portion of the tax year that falls in 2010, 0.70 for any portion of the tax year that falls in 2011, and 0.72 for any portion of the tax year that falls after 2011. Calculate the general rate factor in Part 5 for tax years that straddle these dates.

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560.

First previous tax year 2009-12-31

Taxable income before specified future tax consequences from the current tax year 2,117,179 J1

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) ... ______ K1

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less 15,004 L1

Aggregate investment income (line 440 of the T2 return) .... ______ M1

Subtotal (add lines K1, L1, and M1) 15,004 ► 15,004 N1

Subtotal (line J1 minus line N1) (if negative, enter "0") 2,102,175 ► 2,102,175 O1

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

	Future tax consequences that occur for the current year				
	Amount carried back from the current year to a prior year				
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences P1

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) ... Q1

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less R1

Aggregate investment income (line 440 of the T2 return) S1

Subtotal (add lines Q1, R1, and S1) ▶ T1

Subtotal (line P1 minus line T1) (if negative, enter "0") ▶ U1

Subtotal (line O1 minus line U1) (if negative, enter "0") V1

GRIP adjustment for specified future tax consequences to the first previous tax year
(line V1 multiplied by the general rate factor for the tax year 0.68) **600**

Second previous tax year 2007-12-31

Taxable income before specified future tax consequences from the current tax year 2,365,549 J2

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) ... K2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less L2

Aggregate investment income (line 440 of the T2 return) M2

Subtotal (add lines K2, L2, and M2) ▶ N2

Subtotal (line J2 minus line N2) (if negative, enter "0") 2,365,549 ▶ 2,365,549 O2

	Future tax consequences that occur for the current year				
	Amount carried back from the current year to a prior year				
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences P2

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) Q2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less R2

Aggregate investment income (line 440 of the T2 return) S2

Subtotal (add lines Q2, R2, and S2) ▶ T2

Subtotal (line P2 minus line T2) (if negative, enter "0") ▶ U2

Subtotal (line O2 minus line U2) (if negative, enter "0") V2

GRIP adjustment for specified future tax consequences to the second previous tax year
(line V2 multiplied by the general rate factor for the tax year 0.68) **620**

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Third previous tax year 2006-12-31

Taxable income before specified future tax consequences from the current tax year . . . 2,106,462 J3

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . K3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . 300,000 L3

Aggregate investment income (line 440 of the T2 return) . . . M3

Subtotal (add lines K3, L3, and M3) 300,000 ▶ 300,000 N3

Subtotal (line J3 minus line N3) (if negative, enter "0") 2,106,462 ▶ 2,106,462 O3

Future tax consequences that occur for the current year

Amount carried back from the current year to a prior year

Non-capital loss carry-back (paragraph 111(1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks
199,997					199,997

Taxable income after specified future tax consequences . . . 2,206,465 P3

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . Q3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . 2,206,465 R3

Aggregate investment income (line 440 of the T2 return) . . . S3

Subtotal (add lines Q3, R3, and S3) 2,206,465 ▶ 2,206,465 T3

Subtotal (line P3 minus line T3) (if negative, enter "0") ▶ U3

Subtotal (line O3 minus line U3) (if negative, enter "0") 2,106,462 V3

GRIP adjustment for specified future tax consequences to the third previous tax year
(line V3 multiplied by the general rate factor for the tax year 0.68) . . . **540** 1,432,394

Total GRIP adjustment for specified future tax consequences to previous tax years:
(add lines 500, 520, and 540) (if negative, enter "0") . . . 1,432,394 W

Enter amount W on line 560.

Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)

nb. 1 Post amalgamation . . . [ ] Post wind-up . . . [ ]

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary corporation was a CCPC or a DIC in its last tax year. In the calculation below, **corporation** means a predecessor or a subsidiary. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for each predecessor and each subsidiary that was a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Corporation's GRIP at the end of its last tax year . . . AA

Eligible dividends paid by the corporation in its last tax year . . . BB

Excessive eligible dividend designations made by the corporation in its last tax year . . . CC

Subtotal (line BB minus line CC) ▶ DD

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)
(line AA minus line DD) . . . EE

After you complete this calculation for each predecessor and each subsidiary, calculate the total of all the EE lines. Enter this total amount on:

– line 230 for post-amalgamation; or
– line 240 for post-wind-up.

Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC

No. 1 Corporation becoming a CCPC . . . . . . ☐ Post amalgamation . . . . ☐ Post wind-up . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or a DIC in its last tax year. Also, use this part for a corporation becoming a CCPC. In the calculation below, **corporation** means a corporation becoming a CCPC, a predecessor, or a subsidiary.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for each predecessor and each subsidiary that was not a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of its previous/last tax year . . . . FF

The corporation's money on hand immediately before the end of its previous/last tax year . . . . GG

Unused and unexpired losses at the end of the corporation's previous/last tax year:

Non-capital losses . . . . ______

Net capital losses . . . . ______

Farm losses . . . . ______

Restricted farm losses . . . . ______

Limited partnership losses . . . . ______

Subtotal ______ ► ______ HH

Subtotal (**add** lines FF, GG, and HH) ______ II

All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year . . . . ______ JJ

Paid-up capital of all the corporation's issued and outstanding shares of capital stock immediately before the end of its previous/last tax year . . . . KK

All the corporation's reserves deducted in its previous/last tax year . . . . ______ LL

The corporation's capital dividend account immediately before the end of its previous/last tax year . . . . ______ MM

The corporation's low rate income pool immediately before the end of its previous/last tax year . . . . ______ NN

Subtotal (add lines JJ, KK, LL, MM, and NN) ______ ► ______ OO

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC (line II minus line OO) (if negative, enter "0") . . . . ______ PP

After you complete this worksheet for each predecessor and each subsidiary, calculate the total of all the PP lines. Enter this total amount on:

- line 220 for a corporation becoming a CCPC;
- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Part 8 – General rate factor for the tax year

Complete this part to calculate the general rate factor for the tax year. Calculate your results to four decimal places.

0.68	×	number of days in the tax year before January 1, 2010 / number of days in the tax year	365 / 365	.... =	0.6800	QQ
0.69	×	number of days in the tax year in 2010 / number of days in the tax year	/ 365	.... =		RR
0.7	×	number of days in the tax year in 2011 / number of days in the tax year	/ 365	.... =		SS
0.72	×	number of days in the tax year after December 31, 2011 / number of days in the tax year	/ 365	.... =		TT

General rate factor for the tax year (total of lines QQ to TT) .... 0.6800 UU

Part 8 – General rate factor for the tax year

Complete this part to calculate the general rate factor for the tax year. Calculate your results to four decimal places.

0.68	×	number of days in the tax year before January 1, 2010 / number of days in the tax year	365 / 365	=	0.6800	QQ
0.69	×	number of days in the tax year in 2010 / number of days in the tax year	/ 365	=		RR
0.7	×	number of days in the tax year in 2011 / number of days in the tax year	/ 365	=		SS
0.72	×	number of days in the tax year after December 31, 2011 / number of days in the tax year	/ 365	=		TT

General rate factor for the tax year (total of lines QQ to TT) . . . . 0.6800 UU

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SCHEDULE 510

ONTARIO CORPORATE MINIMUM TAX

Name of corporation	Business Number	Tax year-end Year Month Day
BRANT COUNTY POWER INC.	89113 2011 RC0001	2009 12 31

- File this schedule if the corporation is subject to Ontario corporate minimum tax (CMT). CMT is levied under section 55 of the *Taxation Act, 2007* (Ontario).
- Complete Part 1 to determine if the corporation is subject to CMT for the tax year.
- A corporation not subject to CMT in the tax year is still required to file this schedule if it is deducting a CMT credit, has a CMT credit carryforward, or has a CMT loss carryforward or a current year CMT loss.
- A corporation that has Ontario special additional tax on life insurance corporations (SAT) payable in the tax year must complete Part 4 of this schedule even if it is not subject to CMT for the tax year.
- A corporation is exempt from CMT if, throughout the tax year, it was one of the following:
  1) a corporation exempt from income tax under section 149 of the federal *Income Tax Act*;
  2) a mortgage investment corporation under subsection 130.1(6) of the federal Act;
  3) a deposit insurance corporation under subsection 137.1(5) of the federal Act;
  4) a congregation or business agency to which section 143 of the federal Act applies;
  5) an investment corporation as referred to in subsection 130(3) of the federal Act; or
  6) a mutual fund corporation under subsection 131(8) of the federal Act.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Determination of CMT applicability

Total assets of the corporation at the end of the tax year *	112	28,879,171
Share of total assets from partnership(s) and joint venture(s) *	114	
Total assets of associated corporations (amount from line 450 on Schedule 511)	116	
Total assets (total of lines 112 to 116)		28,879,171
Total revenue of the corporation for the tax year **	142	21,768,315
Share of total revenue from partnership(s) and joint venture(s) **	144	
Total revenue of associated corporations (amount from line 550 on Schedule 511)	146	
Total revenue (total of lines 142 to 146)		21,768,315

The corporation is subject to CMT if:
- for tax years ending before July 1, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are more than $5,000,000, or the total revenue for the year of the corporation or the associated group of corporations is more than $10,000,000.
- for tax years ending after June 30, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are equal to or more than $50,000,000, and the total revenue for the year of the corporation or the associated group of corporations is equal to or more than $100,000,000.

If the corporation is not subject to CMT, do not complete the remaining parts unless the corporation is deducting a CMT credit, or has a CMT credit carryforward, a CMT loss carryforward, a current year CMT loss, or SAT payable in the year.

* **Rules for total assets**
- Report total assets according to generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Do not include unrealized gains and losses on assets and foreign currency gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.
- The amount on line 114 is determined at the end of the last fiscal period of the partnership or joint venture that ends in the tax year of the corporation. Add the proportionate share of the assets of the partnership(s) and joint venture(s), and deduct the recorded asset(s) for the investment in partnerships and joint ventures.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the *Taxation Act, 2007* (Ontario) and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the *Taxation Act, 2007* (Ontario).

** **Rules for total revenue**
- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the tax year is less than 51 weeks, multiply the total revenue of the corporation or the partnership, whichever applies, by 365 and divide by the number of days in the tax year.
- The amount on line 144 is determined for the partnership or joint venture fiscal period that ends in the tax year of the corporation. If the partnership or joint venture has 2 or more fiscal periods ending in the filing corporation's tax year, multiply the sum of the total revenue for each of the fiscal periods by 365 and divide by the total number of days in all the fiscal periods.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the *Taxation Act, 2007* (Ontario) and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the *Taxation Act, 2007* (Ontario).

Part 2 – Calculation of adjusted net income/loss for CMT purposes

Net income/loss per financial statements *			210	747,774
Add (to the extent reflected in income/loss):				
Provision for current income taxes/cost of current income taxes	220			
Provision for deferred income taxes (debits)/cost of future income taxes	222	342,923		
Equity losses from corporations	224			
Financial statement loss from partnerships and joint ventures	226			
Dividends deducted as interest expense on financial statements (subsection 57(2) of the *Taxation Act, 2007* (Ontario)), excluding dividends paid by credit unions under subsection 137(4.1) of the federal Act	230			
Other additions (see note below):				
Share of adjusted net income of partnerships and joint ventures **	228			
Total patronage dividends received, not already included in net income/loss	232			
281	282			
283	284			
Subtotal		342,923		342,923 A
Deduct (to the extent reflected in income/loss):				
Provision for recovery of current income taxes/benefit of current income taxes	320			
Provision for deferred income taxes (credits)/benefit of future income taxes	322			
Equity income from corporations	324			
Financial statement income from partnerships and joint ventures	326			
Dividends deductible under section 112, section 113, or subsection 138(6) of the federal Act	330			
Dividends not taxable under section 83 of the federal Act (from Schedule 3)	332			
Gain on donation of listed security or ecological gift	340			
Accounting gain on transfer of property to a corporation under section 85 or 85.1 of the federal Act ***	342			
Accounting gain on transfer of property to/from a partnership under section 85 or 97 of the federal Act ****	344			
Accounting gain on disposition of property under subsection 13(4), subsection 14(6), or section 44 of the federal Act *****	346			
Accounting gain on a windup under subsection 88(1) of the federal Act or an amalgamation under section 87 of the federal Act	348			
Other deductions (see note below):				
Share of adjusted net loss of partnerships and joint ventures **	328			
Tax payable on dividends under subsection 191.1(1) of the federal Act multiplied by 3	334			
Interest deducted/deductible under paragraph 20(1)(c) or (d) of the federal Act, not already included in net income/loss	336			
Patronage dividends paid (from Schedule 16) not already included in net income/loss	338			
381	382			
383	384			
385	386			
387	388			
389	390			
Subtotal				0 B
Adjusted net income/loss for CMT purposes (line 210 plus amount A minus amount B)			490	1,090,647

If the amount on line 490 is positive and the corporation is subject to CMT as determined in Part 1, enter the amount on line 515 in Part 3.

If the amount on line 490 is negative, enter the amount on line 760 in Part 7 (enter as a positive amount).

Note

In accordance with *Ontario Regulation 37/09*, in calculating net income for CMT purposes, accounting income should be adjusted to remove unrealized gains and losses on mark-to-market property, as well as foreign currency gains and losses on assets, that are included in income for accounting purposes but not in income for income tax purposes. In later years, accounting income is adjusted in arriving at net income for CMT purposes by including losses gains or losses when they are realized.

These realized gains and losses apply to the disposition of mark-to-market property:

- that is not capital property in the year;
- that is capital property and realized in the year or the preceding tax year that ends after March 22, 2007.

The mark-to-market rules also apply to partnerships. A corporate partner's share of a partnership's adjusted income flows through on a proportionate basis to the corporate partner.

- * **Rules for net income/loss**
  - Banks must report net income/loss as per the report accepted by the Superintendent of Financial Institutions under the federal *Bank Act*, adjusted so consolidation and equity methods are not used.
  - Life insurance corporations must report net income/loss as per the report accepted by the federal Superintendent of Financial Institutions or equivalent provincial insurance regulator, before SAT and adjusted so consolidation and equity methods are not used. If the life insurance corporation is resident in Canada and carries on business in and outside of Canada, multiply the net income/loss by the ratio of the Canadian reserve liabilities divided by the total reserve liability. The reserve liabilities are calculated in accordance with Regulation 2405(3) of the federal Act.

Part 2 – Calculation of adjusted net income/loss for CMT purposes (continued)

– Other corporations must report net income/loss in accordance with generally accepted accounting principles, except that consolidation and equity methods must not be used. When the equity method has been used for accounting purposes, equity losses and equity income are removed from book income/loss on lines 224 and 324 respectively.

– Corporations, other than insurance corporations, should report net income from line 9999 of the GIFI (Schedule 125) on line 210.

** The share of the adjusted net income of a partnership or joint venture is calculated as if the partnership or joint venture were a corporation and the tax year of the partnership or joint venture were its fiscal period. For a corporation with an indirect interest in a partnership through one or more partnerships, determine the corporation's share according to clause 54(5)(c) of the *Taxation Act, 2007* (Ontario).

*** A joint election will be considered made under subsection 60(1) of the *Taxation Act, 2007* (Ontario) if there is an entry on line 342, and an election has been made for transfer of property to a corporation under subsection 85(1) of the federal Act.

**** A joint election will be considered made under subsection 60(2) of the *Taxation Act, 2007* (Ontario) if there is an entry on line 344, and an election has been made under subsection 85(2) or 97(2) of the federal Act.

***** A joint election will be considered made under subsection 61(1) of the *Taxation Act, 2007* (Ontario) if there is an entry on line 346, and an election has been made under subsection 13(4) or 14(6) and/or section 44 of the federal Act.

For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

Part 3 – Calculation of CMT payable

Adjusted net income for CMT purposes (line 490 in Part 2, if positive) . . . **515** 1,090,647

Deduct:

CMT loss available (amount R from Part 7) . . .

Minus: Adjustment for an acquisition of control * . . . **518**

Adjusted CMT loss available . . . ▶ 0

Net income subject to CMT calculation (if negative, enter "0") . . . **520** 1,090,647

Amount from line 520: 1,090,647 × (Number of days in the tax year before July 1, 2010: 365 / Number of days in the tax year: 365) × 4 % = 43,626 — 1

Amount from line 520: 1,090,647 × (Number of days in the tax year after June 30, 2010: ___ / Number of days in the tax year: 365) × 2.7 % = ___ — 2

Subtotal (amount 1 plus amount 2) . . . 43,626 — 3

Gross CMT: amount on line 3 above x OAF ** . . . **540** 43,626

Deduct:

Foreign tax credit for CMT purposes *** . . . **550**

CMT after foreign tax credit deduction (line 540 minus line 550) (if negative, enter "0") . . . 43,626 — D

Deduct:

Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) . . .

Net CMT payable (if negative, enter "0") . . . 43,626 — E

Enter amount E on line 278 of Schedule 5, *Tax Calculation Supplementary – Corporations*, and complete Part 4.

* Portion of CMT loss available that exceeds the adjusted net income for the tax year from business(es) continued from before the acquisition of control. See subsection 58(3) of the *Taxation Act, 2007* (Ontario).

*** Enter "0" on line 550 for life insurance corporations as they are not eligible for this deduction. For all other corporations, enter the cumulative total of amount J for the province of Ontario from Part 9 of Schedule 21 on line 550.

** **Calculation of the Ontario allocation factor (OAF):**

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation, and enter the result on line F:

Ontario taxable income *** / Taxable income **** = ___

Ontario allocation factor . . . 1.00000 — F

*** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

**** Enter the taxable income amount from line 360 or amount Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000."

Part 4 – Calculation of CMT credit carryforward

CMT credit carryforward at the end of the previous tax year *			G		
Deduct:					
CMT credit expired *	600				
CMT credit carryforward at the beginning of the current tax year * (see note below)			► 620		
Add:					
CMT credit carryforward balances transferred on an amalgamation or the windup of a subsidiary (see note below)			650		
CMT credit available for the tax year (amount on line 620 plus amount on line 650)					H
Deduct:					
CMT credit deducted in the current tax year (amount P from Part 5)					I
Subtotal (amount H minus amount I)					J
Add:					
Net CMT payable (amount E from Part 3)		43,626			
SAT payable (amount O from Part 6 of Schedule 512)					
Subtotal		43,626	►	43,626	K
CMT credit carryforward at the end of the tax year (amount J plus amount K)			670	43,626	L

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line G or line 600;
- for line 620, enter the amount from line 2336 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line G the amount from line 670 of Schedule 510 from the previous tax year.

Note: If you entered an amount on line 620 or line 650, complete Part 6.

Part 5 – Calculation of CMT credit deducted from Ontario corporate income tax payable

CMT credit available for the tax year (amount H from Part 4)					M
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)			1		
For a corporation that is not a life insurance corporation:					
CMT after foreign tax credit deduction (amount D from Part 3)	43,626	2			
For a life insurance corporation:					
Gross CMT (line 540 from Part 3)		3			
Gross SAT (line 460 from Part 6 of Schedule 512)		4			
The greater of amounts 3 and 4		5			
Deduct: line 2 or line 5, whichever applies:		43,626	6		
Subtotal (if negative, enter "0")			►		N
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)					
Deduct:					
Total refundable tax credits excluding Ontario qualifying environmental trust tax credit (amount J6 minus line 450 from Schedule 5)		926			
Subtotal (if negative, enter "0")			►		O
CMT credit deducted in the current tax year (least of amounts M, N, and O)					P

Enter amount P on line 418 of Schedule 5 and on line I in Part 4 of this schedule.

Is the corporation claiming a CMT credit earned before an acquisition of control? **675** 1 Yes ☐ 2 No ☒

If you answered yes to the question at line 675, the CMT credit deducted in the current tax year may be restricted. For information on how the deduction may be restricted, see subsections 53(6) and (7) of the *Taxation Act, 2007* (Ontario).

Part 6 – Analysis of CMT credit available for carryforward by year of origin

Complete this part if:
- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin		CMT credit balance *
10th previous tax year *	680	
9th previous tax year *	681	
8th previous tax year *	682	
7th previous tax year *	683	
6th previous tax year	684	
5th previous tax year	685	
4th previous tax year	686	
3rd previous tax year	687	
2nd previous tax year	688	
1st previous tax year	689	
Total **		

* CMT credit that was earned (by the corporation, predecessors of the corporation, and subsidiaries wound up into the corporation) in each of the previous 10 tax years and has not been deducted.

** Must equal the total of the amounts entered on lines 620 and 650 in Part 4.

Part 7 – Calculation of CMT loss carryforward

CMT loss carryforward at the end of the previous tax year * . . . . . Q

Deduct:

CMT loss expired * 700

CMT loss carryforward at the beginning of the tax year * (see note below) . . . . . ► 720

Add:

CMT loss transferred on an amalgamation under section 87 of the federal Act ** (see note below) 750

CMT loss available (line 720 **plus** line 750) . . . . . R

Deduct:

CMT loss deducted against adjusted net income for the tax year (lesser of line 490 (if positive) and line C in Part 3) . . . . .

Subtotal (if negative, enter "0") S

Add:

Adjusted net loss for CMT purposes (amount from line 490 in Part 2, if negative) (enter as a positive amount) 760

CMT loss carryforward balance at the end of the tax year (amount S **plus** line 760) . . . . . 770 T

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line Q or line 700;
- for line 720, enter the amount from line 2214 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line Q the amount from line 770 of Schedule 510 from the previous tax year.

** Do not transfer a loss on a vertical amalgamation under subsection 87(2.11) of the federal Act or other amalgamation of a parent and its subsidiary.
Note: If you entered an amount on line 720 or line 750, complete Part 8.

Part 8 – Analysis of CMT loss available for carryforward by year of origin

Complete this part if:
– the tax year includes January 1, 2009; or
– the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	Balance earned in a tax year ending before March 23, 2007 *	Balance earned in a tax year ending after March 22, 2007 **
10th previous tax year	810	820
9th previous tax year	811	821
8th previous tax year	812	822
7th previous tax year	813	823
6th previous tax year	814	824
5th previous tax year	815	825
4th previous tax year	816	826
3rd previous tax year	817	827
2nd previous tax year	818	828
1st previous tax year		829
Total ***		

* Adjusted net loss for CMT purposes that was earned (by the corporation, by subsidiaries wound up into or amalgamated with the corporation before March 23, 2007, and by other predecessors of the corporation) in each of the previous 10 tax years that ended before March 23, 2007, and has not been deducted.

** Adjusted net loss for CMT purposes that was earned (by the corporation and its predecessors, but not by a subsidiary predecessor) in each of the previous 20 tax years that ended after March 22, 2007, and has not been deducted.

*** The total of these two columns must equal the total of the amounts entered on lines 720 and 760.

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SCHEDULE 515

ONTARIO CAPITAL TAX ON OTHER THAN FINANCIAL INSTITUTIONS

Name of corporation	Business Number	Tax year-end Year Month Day
BRANT COUNTY POWER INC.	89113 2011 RC0001	2009-12-31

- Complete this schedule for a corporation with a permanent establishment in Ontario at any time in the tax year and that is a corporation other than a financial institution. The Ontario capital tax on other than financial institutions is levied under section 64 of the *Taxation Act, 2007* (Ontario).
- To complete this schedule, you have to complete Schedule 33, *Part I.3 Tax on Large Corporations*. File completed copies of both schedules with the *T2 Corporation Income Tax Return* within six months of the end of the tax year.
- A corporation is exempt from Ontario capital tax if it was one of the following:
  1) a corporation that is liable to the special additional tax according to section 74 of the *Corporations Tax Act* (Ontario);
  2) a credit union;
  3) a deposit insurance corporation according to section 137.1 of the federal *Income Tax Act*;
  4) a family farm corporation for the year as defined by subsection 64(3) of the *Taxation Act, 2007* (Ontario), other than a corporation for which a determination has been made under subsection 31(2) of the federal *Act*;
  5) a family fishing corporation, as defined by subsection 64(3) of the *Taxation Act, 2007* (Ontario); or
  6) a corporation exempt from income tax according to section 149 of the federal *Act*.

Part 1 – Taxable capital of a corporation resident in Canada other than a financial institution

Amount A from Part 1 of Schedule 33	100	22,371,040		
Add:				
Accumulated other comprehensive income at the end of the year	105			
	Subtotal	22,371,040 ▶	22,371,040	A
Deduct:				
Amount B from Part 1 of Schedule 33	110	661,022		
Amount on line 490 from Part 2 of Schedule 33	115	582,850		
	Subtotal	1,243,872 ▶	1,243,872	B
Taxable capital (amount A minus amount B) (if negative, enter "0")			120 21,127,168	

Part 2 – Capital deduction

Complete this part only if the corporation is associated.

Are you electing under subsection 69(2) of the *Taxation Act, 2007* (Ontario)? ..... 190 1 Yes ☐ 2 No ☒

If you answered **no** to the question at line 190, complete line 220. If you answered **yes** to the question at line 190, complete line 305 by using Schedule 516, *Capital Deduction Election of Associated Group for the Allocation of Net Deduction*, to calculate the amount to be entered on line 300.

Taxable capital (from line 120) or taxable capital employed in Canada of a corporation that was a non-resident of Canada (from line 790 in Part 4 of Schedule 33)	200	21,127,168	x 15,000,000 $	=	**Capital deduction** 220	15,000,000
Taxable capital or taxable capital employed in Canada of every corporation with a permanent establishment in Canada and associated for the last tax year *	210	21,127,168				

* This amount includes the filing corporation's taxable capital or taxable capital employed in Canada. Do not include an amount from a financial institution or corporation that is exempt from capital tax under Division E of the *Taxation Act, 2007* (Ontario) or Part III of the *Corporations Tax Act* (Ontario).

Allocation of net deduction (from line 600 for the filing corporation from Schedule 516) / Ontario allocation factor (OAF) (amount I in Part 3)	300		=	**Capital deduction** 305	

Part 3 – Ontario capital tax payable

Taxable capital (enter amount from line 120 in Part 1) or taxable capital employed in Canada of a corporation that was a non-resident of Canada (enter amount from line 790 in Part 4 of Schedule 38), whichever applies **320** 21,127,168

Deduct:
Capital deduction (Enter $15,000,000 if the corporation is not associated. Otherwise, enter the amount from line 220 or line 305, whichever applies, from Part 2) . . . . 15,000,000 B

Net amount (line 320 **minus** amount B) (if negative, enter "0") . . . . 6,127,168 C

Amount C 6,127,168 × (Number of days in the tax year before January 1, 2010: 365 / Number of days in the tax year: 365) × 0.00225 = 13,786 D

Amount C 6,127,168 × (Number of days in the tax year after December 31, 2009 and before July 1, 2010: ______ / Number of days in the tax year: 365) × 0.00150 = ______ E

Subtotal (amount D **plus** amount E) 13,786 F

Amount F 13,786 × OAF (amount on line I) 1.00000 = ... 13,786 G

Amount G 13,786 × (Number of days in the tax year*: 365 / 365) = ... 13,786 H

Deduct:
Capital tax credit for manufacturers (enter amount J from Part 4) . . . . **350** ______

Ontario capital tax payable (amount H **minus** line 350) (if negative, enter "0") **400** 13,786
Enter amount from line 400 on line 282 of Schedule 5, *Tax Calculation Supplementary – Corporations*.

* Enter either 365 if there are at least 51 weeks in the tax year, or the number of days in the tax year, whichever applies.

Calculation of the Ontario allocation factor (OAF)

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line I.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation and enter the result on line I:

Ontario taxable income ** / Taxable income *** = ______

Ontario allocation factor . . . . 1.00000 I

** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

*** Enter the taxable income amount from line 360 or line Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000."

Part 4 – Capital tax credit for manufacturers

Ontario manufacturing labour cost* **405** ______ / Total Ontario labour cost** **410** ______ × 100 = ... **420** ______ %

If the percentage on line 420 is 20% or less, enter "0" on line J.
If the percentage on line 420 is at least 50%, enter amount H from Part 3 on line J.
If the percentage on line 420 is more than 20% but less than 50%, complete the following calculation and enter the result on line J:

(percentage from line 420) – 20% / 30% = ______ % × 13,786 Amount H from Part 3 = ______
33.000 %

Capital tax credit for manufacturers . . . . ______ J
Enter amount J on line 350 in Part 3

* As defined in subsection 83.1(4) of the *Taxation Act, 2007* (Ontario)
** As defined in subsection 83.1(5) of the *Taxation Act, 2007* (Ontario)

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SCHEDULE 524

ONTARIO SPECIALTY TYPES

Name of corporation	Business Number	Tax year-end Year Month Day
BRANT COUNTY POWER INC.	89113 2011 RC0001	2009-12-31

- Use this schedule to identify the specialty type of a corporation carrying on business in the province of Ontario through a permanent establishment if:
  - its tax year includes January 1, 2009;
  - the tax year is the first year after incorporation or an amalgamation; or
  - there is a change to the specialty type.
- If none of the listed specialty types applies, tick box 99 "Other."
- Unless otherwise noted, references to sections, subsections, and clauses are from the *Taxation Act, 2007* (Ontario).

Specialty types

100 Identify the specialty type that applies to your corporation:

- [ ] 01 Family farm corporation – See subsection 64(3).
- [ ] 02 Family fishing corporation – See subsection 64(3).
- [ ] 03 Mortgage investment corporation – See subsection 130.1(6) of the federal *Income Tax Act*.
- [ ] 04 Credit union – See subsection 137(6) of the federal Act.
- [ ] 05 Bank – See subsection 248(1) of the federal Act.
- [ ] 06 Financial institution prescribed by regulation only – See clause 66(2)(?).
- [ ] 09 Registered securities dealer – See subsection 248(1) of the federal Act.
- [ ] 10 Farm feeder finance co-operative corporation
- [ ] 11 Insurance corporation – See subsection 248(1) of the federal Act.
- [ ] 12 Mutual insurance – See subsection 27(2) of the *Taxation Act, 2007* (Ontario) and paragraph 149(1)(m) of the federal Act.
- [ ] 13 Specialty mutual insurance
- [ ] 14 Mutual fund corporation – See subsection 131(8) of the federal Act.
- [ ] 15 Bare trustee corporation
- [ ] 16 Professional corporation (incorporated professional only) – See subsection 248(1) of the federal Act
- [ ] 17 Limited liability corporation
- [ ] 18 Generator of electrical energy for sale, or producer of steam for use in the generation of electrical energy for sale – See subsection 33(7).
- [x] 19 Hydro successor, municipal electrical utility, or subsidiary of either – See subsection 91.1(1) and section 88 of the *Electricity Act, 1998* (Ontario).
- [ ] 20 Producer and seller of steam for uses other than for the generation of electricity – See subsection 33(7).
- [ ] 21 Mining corporation
- [ ] 22 Non-resident corporation
- [ ] 99 Other (if none of the previous descriptions apply)

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SCHEDULE 546

CORPORATIONS INFORMATION ACT ANNUAL RETURN FOR ONTARIO CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
BRANT COUNTY POWER INC.	89113 2011 RC0001	2009-12-31

- This schedule should be completed by a corporation that is incorporated, continued, or amalgamated in Ontario and subject to the *Business Corporations Act* (BCA) or *Corporations Act* (CA), except for registered charities under the federal *Income Tax Act*. This completed schedule serves as a *Corporations Information Act* Annual Return under the Ontario *Corporations Information Act*.
- Complete parts 1 to 4. Complete parts 5 to 7 only to report change(s) in the information recorded on the Ontario Ministry of Government Services (MGS) public record.
- This schedule must set out the required information for the corporation as of the date of delivery of this schedule.
- A completed Ontario *Corporations Information Act* Annual Return must be delivered within six months after the end of the corporation's tax year-end. The MGS considers this return to be delivered on the date that it is filed with the Canada Revenue Agency (CRA) together with the corporation's income tax return.
- It is the corporation's responsibility to ensure that the information shown on the MGS public record is accurate and up to date. To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. For more information, visit **www.ServiceOntario.ca**.
- This schedule contains non-tax information collected under the authority of the Ontario *Corporations Information Act*. This information will be sent to the MGS for the purposes of recording the information on the public record maintained by the MGS.

Part 1 – Identification

100 Corporation's name (exactly as shown on the MGS public record)
BRANT COUNTY POWER INC.

Jurisdiction incorporated, continued, or amalgamated, whichever is the most recent	**110** Date of incorporation or amalgamation, whichever is the most recent (Year Month Day)	**120** Ontario Corporation No.
Ontario	2000-10-18	1433580

Part 2 – Head or registered office address (P.O. box not acceptable)

200 Care of (if applicable)

210 Street number: 65
220 Street name: DUNDAS STREET EAST
230 Suite number:
240 Additional address information
250 Municipality (e.g., city, town): PARIS
260 Province/state: ON
270 Country: CA
280 Postal/zip code: N3L 3H1

Part 3 – Change identifier

Have there been any changes in any of the information most recently filed for the public record maintained by the MGS with respect to names, addresses for service, and the date elected/appointed and date ceased of the directors and five most senior officers, or the corporation's mailing address or language of preference? Obtain a Corporation Profile Report to review the information shown for the corporation on the public record maintained by the MGS. For more information, visit **www.ServiceOntario.ca**.

300 [1] If there have been no changes, enter **1** in this box and then go to "Part 4 – Certification."
If there are changes, enter **2** in this box and complete the applicable parts on the next page, and then go to "Part 4 – Certification."

Part 4 – Certification

I certify that all information given in this *Corporations Information Act* Annual Return is true, correct, and complete.

450 ED (Last name) **451** GLASBERGEN (First name)

454 (Middle name(s))

460 2 Please enter one of the following numbers in this box for the above-named person: enter **1** for director, **2** for officer, or **3** for other individual having knowledge of the affairs of the corporation. If you are a director and officer, enter **1** or **2**.

Note: Sections **13** and **14** of the Ontario *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

Complete the applicable parts to report changes in the information recorded on the MGS public record.

Part 5 – Mailing address

500 Please enter one of the following numbers in this box:
1 - Show no mailing address on the MGS public record.
2 - The corporation's mailing address is the same as the head or registered office address in Part 2 of this schedule.
3 - The corporation's complete mailing address is as follows:

510 Care of (if applicable)

520 Street number | 530 Street name | 540 Suite number

550 Additional address information

560 Municipality (e.g., city, town) | 570 Province/state | 580 Country | 590 Postal/zip code

Part 6 – Language of preference

600 Indicate your language preference by entering 1 for English or 2 for French. This is the language of preference recorded on the MGS public record for communication with the corporation. This may be different from line 990 of the T2 return.

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SCHEDULE 550

ONTARIO CO-OPERATIVE EDUCATION TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
BRANT COUNTY POWER INC.	89113 2011 RC0001	2009-12-31

- Use this schedule to claim an Ontario co-operative education tax credit (CETC) under section 88 of the *Taxation Act, 2007* (Ontario).
- The CETC is a refundable tax credit that is equal to an eligible percentage (10% to 30%) of the eligible expenditures incurred by a corporation for a qualifying work placement. The maximum credit amount is $1,000 for each qualifying work placement ending before March 27, 2009, and $3,000 for each qualifying work placement beginning after March 26, 2009. For a qualifying work placement that straddles March 26, 2009, the maximum credit amount is prorated.
- Eligible expenditures are salaries and wages (including taxable benefits) paid or payable to a student in a qualifying work placement, or fees paid or payable to an employment agency for services performed by the student in a qualifying work placement. These expenditures must be paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario. Expenditures for a work placement (WP) are not eligible expenditures if they are greater than the amounts that would be paid to an arm's length employee.
- A WP must meet all of the following conditions to be a qualifying work placement:
  - the student performs employment duties for a corporation under a qualifying co-operative education program (QCEP);
  - the WP has been developed or approved by an eligible educational institution as a suitable learning situation;
  - the terms of the WP require the student to engage in productive work;
  - the WP is for a period of at least 10 consecutive weeks or, in the case of an internship program, not less than 8 consecutive months and not more than 16 consecutive months;
  - the student is paid for the work performed in the WP;
  - the corporation is required to supervise and evaluate the job performance of the student in the WP;
  - the institution monitors the student's performance in the WP; and
  - the institution has certified the WP as a qualifying work placement.
- Make sure you keep a copy of the letter of certification from the Ontario eligible educational institution containing the name of the student, the employer, the institution, the term of the WP, and the name/discipline of the QCEP to support the claim. Do not submit the letter of certification with the *T2 Corporation Income Tax Return*.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Corporate Information

110 Name of person to contact for more information: CLASBERGEN ED

120 Telephone number including area code: (519) 442-2215

Is the claim filed for a CETC earned through a partnership?* . . . . . **150** 1 Yes [ ] 2 No [X]

If you answered yes to the question at line 150, what is the name of the partnership? . . . . . **160** ____________

Enter the percentage of the partnership's CETC allocated to the corporation . . . . . **170** ______ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 550 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 550 to claim the partner's share of the partnership's CETC. The allocated amounts can not exceed the amount of the partnership's CETC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . . **200** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax under Part III of the *Taxation Act, 2007* (Ontario)? . . . . . **210** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, then the corporation is **not eligible** for the CETC.

Part 3 – Eligible percentage for determining the eligible amount

Corporation's salaries and wages paid in the previous tax year * **300** 1,500,000

For eligible expenditures incurred before March 27, 2009:
- If line 300 is $400,000 or less, enter 15% on line 310.
- If line 300 is $600,000 or more, enter 10% on line 310.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Eligible percentage} = 15\% - \left[5\% \times \left(\frac{\text{amount on line 300} \quad \text{minus} \quad \$ \quad 400{,}000}{\$ \quad 200{,}000} \right) \right]$$

Eligible percentage for determining the eligible amount . . . . **310** 10.000 %

For eligible expenditures incurred after March 26, 2009:
- If line 300 is $400,000 or less, enter 30% on line 312.
- If line 300 is $600,000 or more, enter 25% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Eligible percentage} = 30\% - \left[5\% \times \left(\frac{\text{amount on line 300} \quad \text{minus} \quad \$ \quad 400{,}000}{\$ \quad 200{,}000} \right) \right]$$

Eligible percentage for determining the eligible amount . . . . **312** 25.000 %

* If this is the first tax year of an amalgamated corporation and subsection 80(2) of the *Taxation Act, 2007* (Ontario) applies, enter the salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Calculation of the Ontario co-operative education tax credit

Complete a separate entry for each student for each qualifying work placement that ended in the corporation's tax year. If a qualifying work placement would otherwise exceed four consecutive months, divide the WP into periods of four consecutive months and enter each full period of four consecutive months as a separate WP. If the WP does not divide equally into four-month periods and if the period that is less than 4 months is 10 or more consecutive weeks, then enter that period as a separate WP. If that period is less than 10 consecutive weeks, then include it with the WP for the last period of 4 consecutive months. Consecutive WPs with two or more associated corporations are deemed to be with only one corporation, as designated by the corporations.

	A Name of university, college, or other eligible educational institution **400**	B Name of qualifying co-operative education program **405**
1.	MOHAWK COLLEGE	ACCOUNTING
2.		

	C Name of student **410**	D Start date of WP (see note 1 below) **430**	E End date of WP (see note 2 below) **435**
1.	JAMES SMYKALUK	2009-01-01	2009-04-30
2.			

Note 1: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the start date for the separate WP.

Note 2: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the end date for the separate WP.

Part 4 – Calculation of the Ontario co-operative education tax credit (continued)

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 312 in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
1.	5,050	10.000 %	1,684	25.000 %	11	16
2.		%		%		

	G Eligible amount (eligible expenditures multiplied by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
1.	926	1,626	926		926
2.					

Ontario co-operative education tax credit (total of amounts in column K) 500 926 L

or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount L:

Amount L ________ X percentage on line 170 in Part 1 ____ % = ________ M

Enter amount L or M, whichever applies, on line 452 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 550, add the amounts from line L or M, whichever applies, on all the schedules and enter the total amount on line 452 of Schedule 5.

Note 1: Reduce eligible expenditures by all government assistance, as defined under subsection 88(21) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, for the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.

Note 2: Calculate the eligible amount (Column G) using the following formula:

Column G = (column F1 x percentage on line 310) + (column F2 x percentage on line 312)

Note 3: If the WP ends before March 27, 2009, the maximum credit amount for the WP is $1,000.
If the WP begins after March 26, 2009, the maximum credit amount for the WP is $3,000.
If the WP begins before March 27, 2009, and ends after March 26, 2009, calculate the maximum credit amount using the following formula:

($1,000 x X/Y) + ($3,000 x (Y – X)/Y)

where "X" is the number of consecutive weeks of the WP completed by the student before March 27, 2009, and "Y" is the total number of consecutive weeks of the student's WP.

Note 4: When claiming a CETC for repayment of government assistance, complete a **separate entry** for each repayment and complete columns A to E and J and K with the details for the previous year WP in which the government assistance was received. Include the amount of government assistance repaid in the tax year multiplied by the eligible percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the CETC in that tax year.

2010 CCA schedule

2010					
T2S(8)	Opening	Additions	Rate	CCA	Ending
Class 1	9,005,855		4%	360,234	8,645,621
Class 1	115,849	10,000	6%	7,251	118,598
Class 8	137,221	28,500	20%	30,294	135,427
Class 10	535,115	325,000	30%	209,285	650,831
Class 12	-		100%	-	-
Class 17	23,699		8%	1,896	21,803
Class 45	8,543		45%	3,844	4,699
Class 47	6,306,269	2,660,770	8%	610,932	8,356,107
Class 50	47,347	162,300	55%	70,673	138,974
	$ 16,179,898	$ 3,186,570		$ 1,294,410	$ 18,072,058

2011 CCA Schedule

2011					
T2S(8)	Opening	Additions	Rate	CCA	Ending
Class 1	8,645,621		4%	345,825	8,299,796
Class 1	118,598	60,000	6%	8,916	169,682
Class 8	135,427	10,500	20%	28,135	117,791
Class 10	650,831	130,000	30%	214,749	566,081
Class 12	-		100%	-	-
Class 17	21,803		8%	1,744	20,059
Class 45	4,699		45%	2,114	2,584
Class 47	8,356,107	2,512,654	8%	768,995	10,099,766
Class 50	138,974	180,000	55%	125,935	193,038
	$ 18,072,058	$ 2,893,154		$ 1,496,414	$ 19,468,798

Green Energy Plan O&M Costs

Pursuant to section 2.14 of the Filing Guidelines Brant County Power is not required to submit a "Green Energy Plan" and has not prepared such a formal plan. However, Brant County Power is taking steps to facilitate the green energy policy.

MicroFIT

Effective September 21, 2009, the Board ordered distributors to charge a monthly rate of $5.25 to MicroFIT Generators. Currently, there are 2 MicroFIT Generators in Brant County Power's service territory. Given the current small number of facilities and Brant County is projecting less than 15 such installations for the 2011 Test Year, there has not been a separate break out of O&M Costs for these activities.

Other Green Energy Activities

Brant County Power is proposing to hire 1 addition to staff to further the green energy efforts of Brant County Power and third parties wishing to operate within its service territory. Costs associated with this addition to staff are more than offset by the Other Revenue of $135,000.

As noted elsewhere, Brant County Power had hired a Smart Meter Data Analyst in late 2009. In 2010 costs related to this position were capitalized while in 2011 these costs are being allocated to O&M to reflect the completed installation of the Smart Meters.

Brant County Power intends to apply for RET Vendor status with the Ontario Power Authority to provide services to schools and social housing projects within Brant County. Executive and management time has not been broken down in respect of its pursuit of green energy projects. Additionally Brant County Power intends to develop competitive renewable energy solutions for their shareholder, rate payers and potential clients outside their operating territory.

CDM Costs

Brant County Power does not have any Board approved CDM activities included in this Application

OVERVIEW

The purpose of this evidence is to summarize the method and cost of financing the Applicant's capital requirements for the 2010 Bridge Year and 2011 Test Year. The Application uses the Board's deemed capital structure. In addition background information related to the prior years is provided. BCP's actual capital structure has changed marginally over the previous years.

2010 Bridge Year and 2011 Test Year

Brant County Power has used the Board approved deemed capital structure of 40% equity and 60% debt. The return on equity ("**ROE**"), 9.85%, has been calculated using the Board formula provided in EB-2009-0084 ***Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*** (the "**CoC Report**"). On February 24, 2010 the Board updated the ROE to 9.85%, deemed short term debt to 2.07% and deemed long-term debt to 5.87%. The ROE and deemed short-term debt rates will be updated as directed by the Board.

The cost of debt included in the application, 5.44%, has been determined by using a weighted average of the existing long-term debt instruments for 56% of the capital structure and the Board's deemed short-term rate of 2.07% for 4% of the capital structure. BCP's long-term debt is with TD Canada Trust, a third party financial institution, and consists of a fixed loan of $5million (locked in until 2013) at 6.35% and a second long-term instrument for $2million with a rate of 4%. The weighted average of the long-term debt is 5.68% which is approximately 0.2% less than the Board's deemed long-term debt rate.

The overall Cost of Capital has increased from the 2010 Bridge Year by $167,630 as a result of the increased rate base as the annual rates used have not changed. The 2011 Test Year requirement, $1,623,759, is less than the actual cost of capital presented for the years 2006, 2007, 2008 and 2009. The decrease is driven by the change in debt to equity ratio in the current deemed structure and a lower cost of debt 6.25% (2009) to an effective debt rate of 5.44% (2011). It should be noted, prior to 2010, the tables are calculated based upon the audited financial statements. The 2011 Test Year rate base is $2,420,701 greater than the 2010 Bridge Year as a result of the change in rate base.

In 2010, BCP obtained the second long-term debt instrument which was used, primarily, to fund the payment to Brantford Power Inc. resulting from the Board's Decision in EB-2009-0063. The instrument is a variable rate loan with TD Canada Trust. The payment required pursuant to EB-2009-0063 to Brantford Power Inc. was approximately $2.658million and such payment was made in September 2010 as ordered by the Board.

As detailed below, BCP's interest rate for the first long-term debt instrument is, inclusive of stamping fee, 6.35%. Combined these two debt instruments produce a weighted average cost of debt = 5.68%. This 5.68% is utilized to calculate the long-term debt return portion (56% of rate base) for the 2010 bridge and 2011 test year.

Both long-term debt instruments are to be reviewed prior to BCP's next cost of service rate application. Given the actual debt rates and the proximity to the Board approved deemed long-term debt rate, BCP feels the applied for rates are appropriate. BCP is not anticipating the need for any additional long-term debt during the 2010 Bridge or 2011 Test Year.

2006, 2007, 2008 and 2009 Historical Years

For 2009, BCP's capital structure was 57% equity and 43% debt. BCP has provided historical cost of capital summaries based upon the audited financial statements. Unfortunately, this makes a comparison to the 2010 Bridge and 2011 Test Year less meaningful. The capital increased from $25,533,772 (2006) to $26,740,544 (2008) and further to $28,879,171 (2009). Board Approved capital in 2006, based on 2004 figures, was $15,275,131. The debt and equity rates remained constant during these years.

Brant County Power's $5million dollar debt is financed through a Revolving Term Loan with an interest rate swap. Borrowing is via a floating rate loan [Banker's Acceptances ("BA"s)] with the interest rate fixed by entering into a swap with TD Securities. These BAs are auto renewed approximately every 30 days. BCP is charged an interest rate for the BA as well as a stamping fee at 0.75%. The interest rate is then credited against the interest (at 5.6% as described above) which is charged monthly, thereby leaving the total all-in interest charged at 5.6% plus the stamping fee of 0.75% or 6.35%. This mechanism was utilized to obtain an attractive interest rate which is fixed with 10 year term when the loan was booked in 2003.

Other long-term debt indicated in appendix 2-N relates to other liabilities including (regulatory liabilities and employee future benefit costs). Actual short-term liabilities are from audited financial statements.

For the 2006, 2007 and 2008 BCP used the Board deemed capital structure of 50% debt and 50% equity. For 2006 the Board set the long-term debt rate at 6.25% in EB-2005-0341. The Board's rationale for such a rate was:

> "The Handbook allows third-party debt to attract the actual cost of the debt, provided that the rate does not exceed the maximum allowed at the time of issuance. Since BCP's previous loan expired prior to the date that the 2006 distribution rates will become effective, the previous actual 6.43% rate is not applicable. In the absence of any other information regarding the rate applicable to the replacement loan, the Board finds that the 6.25% deemed debt rate applicable to a utility of BCP's size should apply. The Board considers that the rate will not adversely affect BCP's ability to negotiate debt as needed and to cover current debt. Accordingly, the Board has revised the debt rate to reflect this finding." (page 5, Decision and Order)

Capital Structure

Brant County Power is applying for a deemed current capital structure of 60% debt (56% long-term, 4% short-term) and 40% equity.

Return on Equity

Brant County Power is requesting an equity return of 9.85% for its 2011 Rates based upon the Board approved formula.

Cost of Debt

Brant County Power is requesting a long-term debt return of 5.68% (actual weighted average cost of debt for 2010) and a short-term debt return rate of 2.07% to provide an effective debt rate of 5.44%.

Appendix 2-N
Capitalization and Cost of Capital

2011 Deemed Cost of Capital

Line #	Particulars	Capitalization Ratio		Cost Rate	Return
	Debt	%	$	%	$
1	Long-Term	56%	12,624,330	5.68%	716,882
2	Short-Term	4%	901,737.88	2.07%	18,666
3	**Total Debt**	**60%**	**13,526,068**	**5.44%**	**735,548**
	Equity				
4	Common Equity	40%	9,017,379	9.85%	888,212
5	Preferred Shares				
6	**Total Equity**	**40%**	**9,017,379**		**888,212**
7	**Total**	**100%**	**22,543,447**	**7.20%**	**1,623,759**

2010 Deemed Cost of Capital

Line #	Particulars	Capitalization Ratio		Cost Rate	Return
	Debt	%	$	%	$
1	Long-Term	56%	11,268,738	5.68%	639,903
2	Short-Term	4%	804,909.83	2.07%	16,662
3	**Total Debt**	**60%**	**12,073,647**	**5.44%**	**656,565**
	Equity				
4	Common Equity	40%	8,049,098.30	9.85%	792,836
5	Preferred Shares				
6	**Total Equity**	**40%**	**8,049,098**		**792,836**
7	**Total**	**100%**	**20,122,746**	**7.20%**	**1,449,401**

2010 Debt Details

	Loan	Interest %	Interest Cost
Loan a	5,000,000	6.35%	317,500
Loan b	2,000,000	4.00%	80,000
Weighted Averag	7,000,000	5.68%	397,500

2009 - Actual Cost of Capital

Line #	Particulars	Capitalization Ratio		Cost Rate	Return
	Debt	**%**	**$**	**%**	**$**
1	Long-Term	24%	6,808,290	6.25%	425,518
2	Short-Term	19%	5,570,427	6.25%	348,152
3	**Total Debt**	**43%**	**12,378,717**	**6.25%**	**773,670**
	Equity				
4	Common Equity	57%	16,500,454	9.00%	1,361,313
5	Preferred Shares		-		-
6	**Total Equity**	**57%**	**16,500,454**		**1,361,313**
7	**Total**	**100%**	**28,879,171**	**7.39%**	**2,134,983**

2008 - Actual Cost of Capital

Line #	Particulars	Capitalization Ratio		Cost Rate	Return
	Debt	**%**	**$**	**%**	**$**
1	Long-Term	29%	7,812,749	6.25%	488,297
2	Short-Term	13%	3,563,649	6.25%	222,728
3	**Total Debt**	**43%**	**11,376,398**	**6.25%**	**711,025**
	Equity				
4	Common Equity	57%	15,364,146	9.00%	1,368,942
5	Preferred Shares		-		-
6	**Total Equity**	**57%**	**15,364,146**		**1,368,942**
7	**Total**	**100%**	**26,740,544**	**7.78%**	**2,079,967**

2007 - Actual Cost of Capital

Line #	Particulars	Capitalization Ratio		Cost Rate	Return
	Debt	**%**	**$**	**%**	**$**
1	Long-Term	31%	8,264,133	6.25%	516,508
2	Short-Term	13%	3,396,581	6.25%	212,286
3	**Total Debt**	**44%**	**11,660,714**	**6.25%**	**728,795**
	Equity				
4	Common Equity	56%	14,812,361	9.00%	1,333,112
5	Preferred Shares		-		-
6	**Total Equity**	**56%**	**14,812,361**		**1,333,112**
7	**Total**	**100%**	**26,473,075**	**7.79%**	**2,061,907**

2006 - Actual Cost of Capital

Line #	Particulars	Capitalization Ratio		Cost Rate	Return
	Debt	%	$	%	$
1	Long-Term	37%	9,448,020	6.25%	590,501
2	Short-Term	13%	3,406,126	6.25%	212,883
3	**Total Debt**	**50%**	**12,854,146**	**6.25%**	**803,384**
	Equity				
4	Common Equity	50%	12,679,626	9.00%	1,183,146
5	Preferred Shares		-		-
6	**Total Equity**	**50%**	**12,679,626**		**1,183,146**
7	**Total**	**100%**	**25,533,772**	**7.78%**	**1,986,530**

2006 - Board Approved Cost of Capital

Line #	Particulars	Capitalization Ratio		Cost Rate	Return
	Debt	%	$	%	$
1	Long-Term	50%	7,637,565	6.25%	477,348
2	Short-Term	0%			-
3	**Total Debt**	**50%**	**7,637,565**	**6.25%**	**477,348**
	Equity				
4	Common Equity	50%	7,637,565	9.00%	687,381
5	Preferred Shares				-
6	**Total Equity**	**50%**	**7,637,565**		**687,381**
7	**Total**	**100%**	**15,275,131**	**7.63%**	**1,164,729**

Cost of Capital

Calculation of cost for each capital component

Please see above in appendix 2-N.

Profit or Loss on Redemption of debt and/or preference shares

Not applicable

Forecasts of new debt anticipated in 2010 (bridge) or 2011 (test) year

As discussed above, in 2010 BCP has increased the long-term debt by $2 million. BCP does not anticipate any other new debt for either the bridge or test years.

Copies of Debt Arrangements

As all debt is held with 3rd party lenders (TD Canada Trust), BCP is not providing copies of debt arrangements (only required for affiliated debt).

OVERVIEW OF CALCULATION OF REVENUE DEFICIENCY OR SURPLUS

The information in this Exhibit supports Brant County Power's request in this Application for a decrease in its 2011 Revenue Requirement. Brant County Power requires a distribution revenue requirement of $5,908,802 (proposed revenue of $6,466,128 less other revenue of $557,326) to continue to provide its customers safe reliable supply of electricity, service its debt and pay its deemed PILS.

Brant County Power's target Rate Base is $22,543,447.

Brant County Power's current rates (applied to 2011 load forecast) will derive an after tax return of $922,147 (RoE = 10.2%), creating a revenue sufficiency of $300,388.

Brant County Power is requesting a 9.85% RoE on 40% of the applied for rate base of $22,543,447 or $888,212. Brant County will use the updated information for calculating the RoE as directed by the Board.

DETERMINATION OF NET UTILITY INCOME

Determination of Net Utility Income			
	Existing Rates	Proposed Rates	Revenue (Surplus) or Defficiency
Revenue Sufficiency		-$300,388	
Distribution Revenue	$6,209,190	$6,209,190	$0
Transformer Allowance	-$49,168	-$49,168	
Other Operating Revenue	$606,494	$606,494	$0
Total Revenue	$6,766,516	$6,466,128	-$300,388
Costs and Expenses			$0
Distribution Costs	$2,331,729	$2,331,729	$0
Operation & Maintenance	$1,513,309	$1,513,309	$0
Depreciation & Amortization	$896,214	$896,214	$0
Deemed Interest	$735,548	$735,548	$0
Total Costs and Expenses	$5,476,800	$5,476,800	$0
Utility Income Before Income Taxes	$1,289,716	$989,329	-$300,388
Income Taxes (grossed up)	$367,569	$101,117	-$266,452
Utility Income (loss) After Taxes	$922,147	$888,212	-$33,935
Calculated 2011 RoE	$888,212		
Revenue Sufficiency	$33,935		
Add Tax Change	$266,452		
Total Revenue Deficiency	$300,388		
Existing Rates RoE	10.23%		

Ex.	Tab	Schedule	Contents of Schedule
7 – Cost Allocation			
	1	1	Cost Allocation – 2011 Rebasing Application
		2	2011 Cost Allocation Sheets (incorporate transformer allowance removal)
		3	2004 (Run 3) Informational Filing Cost Allocation Sheets
	2	1	Treatment of Transformer Ownership Allowance
		2	2011 Cost Allocation Output 1 (O1) - prior to transformer adjustments outlined in filing guidelines
	3	1	Revenue to Cost Ratios

COST ALLOCATION OVERVIEW

Introduction:

The purpose of this Exhibit is to summarize the approach to cost allocation. On September 15, 2006 the OEB issued directions on the Cost Allocation Methodology for Electricity Distributors (the "Directions"). On November 15, 2006, the Board issued the Cost Allocation Information Filing Guidelines for Electricity Distributors ("the Guidelines"), the Cost Allocation Model (the "Model") and User Instructions (the "Instructions") for the Model.

Brant County Power (BCP) has utilized the model used for the Cost Allocation in the 2006 EDR process, updated for all test year data (load profiles, customer counts, expenses, net fixed assets, projected capital values etc.). Specifically Brant County Power updated the model in the following specific input sheets:

- I2 – LDC Class
    - Brant County has only utilized the applied for rate classes
        - Residential
        - General Service < 50 kW
        - General Service 50 to 4,999 kW
        - Unmetered Loads
        - Sentinel Lights
        - Street Lights
- I3 – TB Data
    - Brant County Power has utilized the 2011 projected TB to generate expense and rate base accounts that mirror the 2011 applied for revenue requirement.
- I4 – BO Assets
    - Brant County Power has reviewed and revised specific engineering estimates originally used in the 2006 EDR informational filing.
    - All Asset categories are based on 2011 projected net fixed assets.
    - All balance check cells are "balanced".
- I5 – Misc. Data
    - Updated to use current approved (May 1, 2010) distribution rates and smart meter rate adders.
- I6 – Customer Data
    - All customer data, with the exception of the 30 year weather normalized amount (no update available) including using the 2010 actual loss factor.
- I7.1 – Meter Capital
    - Updates to the 2011 projected customer counts.
- I7.2 – Meter Reading
    - Updates to the 2011 projected customer counts.
- I8 – Demand Data
    - Was not updated as new NCP and CP statistics were not available.
- I9 – Direct Allocation
    - Not utilized.

For comparison purposes Brant County Power is providing both 2004 informational filing and updated 2011 proposed allocation results (i.e. I6, I8, O1, O2 and E4).

Brant County Power does have 1 delivery point registered to another LDC (Brantford Power), however, does not propose to use a specific embedded rate class due to the small demand profile for this point.

The 2011 projected annual consumption and demand for this Brantford Power delivery point is 1,067kW which represents less than 0.16% of total load and consumption. Brant County Power considers this point to be a GS < 50kW customer and will use the cost allocation results for this class in total.

EB-2010-0125
Filed: November 5, 2010
Exhibit: 7
Tab: 1
Schedule: 2
Page: 1

2011 COST ALLOCATION MODEL
BRANT COUNTY POWER INC.

Ontario

Sheet I6 Customer Data Worksheet - Optional Third Run

Click Here For Instructions on How to Complete This Worksheet

Total kWhs	273,384,467
Total kWs	393,850
Total Approved Distribution Revenue ($)	$5,908,802

	ID	Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
Billing Data								
kWh from approved EDR model, Sheet 7-1, Col M	CEN	273,384,467	80,122,583	39,095,551	151,750,742	1,707,054	215,167	493,370
kW from approved EDR model, Sheet 7-1, Col S	CDEM	393,850			388,493	4,783	574	
kW, included in CDEM, from customers with line transformer allowance from approved EDR model, Sheet 6-3, Col P		81,947			81,947			
Optional - kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-						
KWh excluding KWh from Wholesale Market Participants	CEN EWMP	-						
kWh - 30 year weather normalized amount	Click here to	221,388,742	79,714,961	36,114,782	103,666,053	1,299,298	77,521	516,128
Approved Distribution Rev from approved EDR, Sheet 7-1, Col AK + Sheet 7-3 Col H	CREV	$5,908,802	$2,938,680	$960,548	$1,921,096	$47,026	$12,345	$29,108
Bad Debt 3 Year Historical Average from Approved EDR Model	BDHA	$60,888	$27,781	$17,018	$16,089	$0	$0	$0
Late Payment 3 Year Historical Average	LPHA	$83,945	$44,224	$20,709	$18,085	$0	$926	$0
Weighting Factor - Services			1.0	2.0	10.0	1.0	1.0	1.0
Weighting Factor - Billings			1.0	2.0	7.0	1.0	0.1	1.0
Number of Bills	CNB	117,554	99,254	14,998	1,167	12	2,063	60
Number of Connections (Unmetered)	CCON	2,857				2,636	172	50
Total Number of Customer from Approved EDR, Sheet 7-1, Col H excluding connections	CCA	9,851	8,271.20	1,250	97	1	171.92	60
Bulk Customer Base	CCB	9,851	8,271	1,250	97	1	172	60
Primary Customer Base	CCP	9,851	8,271	1,250	97	1	172	60
Line Transformer Customer Base	CCLT	9,831	8,271	1,250	77	1	172	60
Secondary Customer Base	CCS	9,831	8,271	1,250	77	1	172	60
Weighted - Services	CWCS	14,398	8,271	2,500	770	2,636	172	50
Weighted Meter -Capital	CWMC	914,230	676,750	134,780	102,700	-	-	-
Weighted Meter Reading	CWMR	204,532	142,431	46,200	15,852	49	-	-
Weighted Bills	CWNB	137,697	99,254	29,996	8,168	12	206	60
Data Mismatch Analysis								
Revenue with 30 year weather normalized kWh		5,194,099	2,923,730	887,313	1,312,365	35,793	4,448	30,450

Weather Normalized Data from Hydro

Click Here For Instructions on How to Complete This Section

	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
kWh - 30 year weather normalized amount	232,606,510	**83,754,118**	37,944,718	108,918,812	1,365,133	81,449	542,280
2006 EDR Distribution Loss Factor		**1.0507**	1.0507	1.0507	1.0507	1.0507	1.0507

Bad Debt Data from EDR 2006

Click Here For Instructions on How to Complete This Section

Sheet ADJ5 rows 26 - 32, column E	48,356	22,063	13,515	12,778			
Sheet ADJ5 rows 26 - 32, column F	54,809	25,007	15,319	14,483			
Sheet ADJ5 rows 26 - 32, column G	79,499	36,273	22,219	21,007			
Three-year average	**60,888**	**27,781**	**17,018**	**16,089**	-	-	-

2011 COST ALLOCATION MODEL
BRANT COUNTY POWER INC.

Ontario

Sheet I8 Demand Data Worksheet - Optional Third Run

This is an input sheet for demand allocators.

CP TEST RESULTS	12 CP
NCP TEST RESULTS	4 NCP

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

Customer Classes		Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
CO-INCIDENT PEAK								
1 CP								
Transformation CP	TCP1	42,773	14,880	7,474	20,361	-	-	58
Bulk Delivery CP	BCP1	42,773	14,880	7,474	20,361	-	-	58
Total Sytem CP	DCP1	42,773	14,880	7,474	20,361	-	-	58
4 CP								
Transformation CP	TCP4	167,141	58,349	28,062	80,488	-	-	242
Bulk Delivery CP	BCP4	167,141	58,349	28,062	80,488	-	-	242
Total Sytem CP	DCP4	167,141	58,349	28,062	80,488	-	-	242
12 CP								
Transformation CP	TCP12	457,553	148,505	86,984	221,382	-	-	682
Bulk Delivery CP	BCP12	457,553	148,505	86,984	221,382	-	-	682
Total Sytem CP	DCP12	457,553	148,505	86,984	221,382	-	-	682
NON CO_INCIDENT PEAK								
1 NCP								
Classification NCP from Load Data Provider	DNCP1	51,878	19,680	10,784	20,902	409	25	78
Primary NCP	PNCP1	51,878	19,680	10,784	20,902	409	25	78
Line Transformer NCP	LTNCP1	47,219	19,680	10,682	16,345	409	25	78
Secondary NCP	SNCP1	24,900	19,061	5,327	-	409	25	78
4 NCP								
Classification NCP from Load Data Provider	DNCP4	194,135	74,149	35,818	82,176	1,601	96	295
Primary NCP	PNCP4	194,135	74,149	35,818	82,176	1,601	96	295
Line Transformer NCP	LTNCP4	175,877	74,149	35,478	64,258	1,601	96	295
Secondary NCP	SNCP4	91,601	71,817	17,792	-	1,601	96	295
12 NCP								
Classification NCP from Load Data Provider	DNCP12	526,388	197,686	94,865	228,629	4,142	248	818
Primary NCP	PNCP12	526,388	197,686	94,865	228,629	4,142	248	818
Line Transformer NCP	LTNCP12	475,638	197,686	93,965	178,779	4,142	248	818
Secondary NCP	SNCP12	243,799	191,468	47,123	-	4,142	248	818

2011 COST ALLOCATION MODEL
BRANT COUNTY POWER INC.

Ontario

Sheet O1 Revenue to Cost Summary Worksheet - Optional Third Run

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
crev	Distribution Revenue (sale)	$5,908,802	$2,938,680	$960,548	$1,921,096	$47,026	$12,345	$29,108
mi	Miscellaneous Revenue (mi)	$557,326	$401,731	$121,409	$33,060	$49	$835	$243
	Total Revenue	$6,466,128	$3,340,411	$1,081,957	$1,954,156	$47,075	$13,180	$29,350
	Expenses							
di	Distribution Costs (di)	$1,240,252	$635,545	$208,882	$288,396	$97,961	$6,389	$3,080
cu	Customer Related Costs (cu)	$984,164	$678,815	$197,831	$72,427	$31,402	$2,862	$827
ad	General and Administration (ad)	$1,620,622	$956,471	$295,854	$264,156	$94,534	$6,749	$2,858
dep	Depreciation and Amortization (dep)	$968,765	$547,699	$158,803	$185,432	$70,075	$4,570	$2,186
INPUT	PILs (INPUT)	$101,117	$55,212	$16,698	$21,758	$6,785	$442	$221
INT	Interest	$735,548	$401,629	$121,467	$158,273	$49,353	$3,219	$1,607
	Total Expenses	$5,650,468	$3,275,371	$999,535	$990,441	$350,110	$24,232	$10,779
	Direct Allocation	$0	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$888,212	$484,987	$146,678	$191,123	$59,596	$3,887	$1,941
	Revenue Requirement (includes NI)	$6,538,679	$3,760,359	$1,146,212	$1,181,564	$409,706	$28,119	$12,720
		Revenue Requirement Input equals Output						
	Rate Base Calculation							
	Net Assets							
dp	Distribution Plant - Gross	$28,002,813	$15,446,856	$4,616,793	$5,663,172	$2,076,202	$135,411	$64,380
gp	General Plant - Gross	$3,849,223	$2,110,619	$635,620	$808,463	$268,430	$17,507	$8,585
accum dep	Accumulated Depreciation	($11,002,991)	($6,125,457)	($1,809,623)	($2,092,652)	($890,701)	($58,092)	($26,467)
co	Capital Contribution	($1,191,455)	($694,577)	($196,584)	($157,793)	($130,519)	($8,512)	($3,470)
	Total Net Plant	$19,657,590	$10,737,440	$3,246,205	$4,221,191	$1,323,412	$86,313	$43,028
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$23,320,775	$6,834,773	$3,335,005	$12,944,938	$145,618	$18,355	$42,086
	OM&A Expenses	$3,845,038	$2,270,831	$702,566	$624,978	$223,897	$16,000	$6,765
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0
	Subtotal	*$27,165,813*	*$9,105,604*	*$4,037,571*	*$13,569,916*	*$369,515*	*$34,355*	*$48,852*
	Working Capital	$4,074,872	$1,365,841	$605,636	$2,035,487	$55,427	$5,153	$7,328
	Total Rate Base	$23,732,462	$12,103,281	$3,851,841	$6,256,678	$1,378,839	$91,467	$50,356
		Rate Base Input Does Not Equal Output						
	Equity Component of Rate Base	$9,492,985	$4,841,312	$1,540,736	$2,502,671	$551,536	$36,587	$20,142
	Net Income on Allocated Assets	$815,661	$65,040	$82,422	$963,715	($303,035)	($11,052)	$18,571
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0
	Net Income	$815,661	$65,040	$82,422	$963,715	($303,035)	($11,052)	$18,571
	RATIOS ANALYSIS							
	REVENUE TO EXPENSES %	98.89%	88.83%	94.39%	165.39%	11.49%	46.87%	230.75%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($72,551)	($419,948)	($64,256)	$772,592	($362,631)	($14,939)	$16,631
	RETURN ON EQUITY COMPONENT OF RATE BASE	8.59%	1.34%	5.35%	38.51%	-54.94%	-30.21%	92.20%

2011 COST ALLOCATION MODEL
BRANT COUNTY POWER INC.

July-19-10
Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - Optional Third Run

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
Customer Unit Cost per month - Avoided Cost	$9.53	$15.26	$74.49	$0.99	$1.36	$1.36
Customer Unit Cost per month - Directly Related	$14.27	$23.69	$109.04	$1.72	$2.34	$2.35
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$20.56	$30.94	$141.81	$12.95	$13.22	$11.16
Fixed Charge per approved 2006 EDR	$10.95	$16.51	$29.41	$0.81	$2.52	$8.25

Information to be Used to Allocate PILs, ROD, ROE and A&G

	Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
General Plant - Gross Assets	$3,849,223	$2,110,619	$635,620	$808,463	$268,430	$17,507	$8,585
General Plant - Accumulated Depreciation	($2,163,159)	($1,186,111)	($357,201)	($454,334)	($150,850)	($9,839)	($4,824)
General Plant - Net Fixed Assets	$1,686,064	$924,508	$278,419	$354,129	$117,579	$7,669	$3,760
General Plant - Depreciation	$113,867	$62,436	$18,803	$23,916	$7,941	$518	$254
Total Net Fixed Assets Excluding General Plant	$17,971,526	$9,812,932	$2,967,787	$3,867,062	$1,205,832	$78,645	$39,268
Total Administration and General Expense	$1,620,622	$956,471	$295,854	$264,156	$94,534	$6,749	$2,858
Total O&M	$2,224,416	$1,314,360	$406,712	$360,823	$129,363	$9,251	$3,907

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

USoA Account #	Accounts	Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	
	Distribution Plant								
1860	Meters	$2,982,677	$2,207,898	$439,720	$335,059	$0	$0	$0	CWMC
	Accumulated Amortization								
	Accum. Amortization of Electric Utility Plant - Meters only	($718,987)	($532,223)	($105,996)	($80,767)	$0	$0	$0	
	Meter Net Fixed Assets	**$2,263,690**	**$1,675,675**	**$333,724**	**$254,292**	**$0**	**$0**	**$0**	
	Misc Revenue								
4082	Retail Services Revenues	$0	$0	$0	$0	$0	$0	$0	CWNB
4084	Service Transaction Requests (STR) Revenues	$0	$0	$0	$0	$0	$0	$0	CWNB
4090	Electric Services Incidental to Energy Sales	$0	$0	$0	$0	$0	$0	$0	CWNB
4220	Other Electric Revenues	$0	$0	$0	$0	$0	$0	$0	NFA
4225	Late Payment Charges	$0	$0	$0	$0	$0	$0	$0	LPHA
	Sub-total	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	
	Operation								
5065	Meter Expense	$18,443	$13,652	$2,719	$2,072	$0	$0	$0	CWMC
5070	Customer Premises - Operation Labour	$148,229	$98,275	$14,850	$1,153	$31,320	$2,043	$588	CCA
5075	Customer Premises - Materials and Expenses	$0	$0	$0	$0	$0	$0	$0	CCA
	Sub-total	*$166,672*	*$111,927*	*$17,569*	*$3,224*	*$31,320*	*$2,043*	*$588*	
	Maintenance								
5175	Maintenance of Meters	$51,217	$37,913	$7,551	$5,753	$0	$0	$0	1860
	Billing and Collection								
5310	Meter Reading Expense	$144,362	$100,530	$32,609	$11,189	$35	$0	$0	CWMR
5315	Customer Billing	$347,894	$250,768	$75,786	$20,637	$30	$521	$152	CWNB
5320	Collecting	$153,216	$110,441	$33,377	$9,089	$13	$230	$67	CWNB
5325	Collecting- Cash Over and Short	$120	$86	$26	$7	$0	$0	$0	CWNB
5330	Collection Charges	$1,500	$1,081	$327	$89	$0	$2	$1	CWNB
	Sub-total	$647,092	$462,907	$142,124	$41,010	$78	$753	$219	
	Total Operation, Maintenance and Billing	$864,981	$612,748	$167,244	$49,988	$31,398	$2,796	$808	
	Amortization Expense - Meters	$117,446	$86,938	$17,314	$13,193	$0	$0	$0	
	Allocated PILs	$11,644	$8,616	$1,717	$1,311	$0	$0	$0	
	Allocated Debt Return	$84,700	$62,678	$12,487	$9,535	$0	$0	$0	
	Allocated Equity Return	$102,279	$75,687	$15,079	$11,514	$0	$0	$0	
	Total	**$1,181,050**	**$846,667**	**$213,841**	**$85,540**	**$31,398**	**$2,796**	**$808**	

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

USoA Account #	Accounts	Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	
	Distribution Plant								
1860	Meters	$2,982,677	$2,207,898	$439,720	$335,059	$0	$0	$0	CWMC
	Accumulated Amortization								
	Accum. Amortization of Electric Utility Plant - Meters only	($718,987)	($532,223)	($105,996)	($80,767)	$0	$0	$0	
	Meter Net Fixed Assets	$2,263,690	$1,675,675	$333,724	$254,292	$0	$0	$0	
	Allocated General Plant Net Fixed Assets	$212,465	$157,871	$31,308	$23,287	$0	$0	$0	
	Meter Net Fixed Assets Including General Plant	$2,476,155	$1,833,545	$365,031	$277,578	$0	$0	$0	
	Misc Revenue								
4082	Retail Services Revenues	$0	$0	$0	$0	$0	$0	$0	CWNB
4084	Service Transaction Requests (STR) Revenues	$0	$0	$0	$0	$0	$0	$0	CWNB
4090	Electric Services Incidental to Energy Sales	$0	$0	$0	$0	$0	$0	$0	CWNB
4220	Other Electric Revenues	$0	$0	$0	$0	$0	$0	$0	NFA
4225	Late Payment Charges	$0	$0	$0	$0	$0	$0	$0	LPHA
	Sub-total	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	
	Operation								
5065	Meter Expense	$18,443	$13,652	$2,719	$2,072	$0	$0	$0	CWMC
5070	Customer Premises - Operation Labour	$148,229	$98,275	$14,850	$1,153	$31,320	$2,043	$588	CCA
5075	Customer Premises - Materials and Expenses	$0	$0	$0	$0	$0	$0	$0	CCA
	Sub-total	*$166,672*	*$111,927*	*$17,569*	*$3,224*	*$31,320*	*$2,043*	*$588*	
	Maintenance								
5175	Maintenance of Meters	$51,217	$37,913	$7,551	$5,753	$0	$0	$0	1860
	Billing and Collection								
5310	Meter Reading Expense	$144,362	$100,530	$32,609	$11,189	$35	$0	$0	CWMR
5315	Customer Billing	$347,894	$250,768	$75,786	$20,637	$30	$521	$152	CWNB
5320	Collecting	$153,216	$110,441	$33,377	$9,089	$13	$230	$67	CWNB
5325	Collecting- Cash Over and Short	$120	$86	$26	$7	$0	$0	$0	CWNB
5330	Collection Charges	$1,500	$1,081	$327	$89	$0	$2	$1	CWNB
	Sub-total	*$647,092*	*$462,907*	*$142,124*	*$41,010*	*$78*	*$753*	*$219*	
	Total Operation, Maintenance and Billing	$864,981	$612,748	$167,244	$49,988	$31,398	$2,796	$808	
	Amortization Expense - Meters	$117,446	$86,938	$17,314	$13,193	$0	$0	$0	
	Amortization Expense - General Plant assigned to Meters	*$14,349*	*$10,662*	*$2,114*	*$1,573*	*$0*	*$0*	*$0*	
	Admin and General	$629,731	$445,902	$121,658	$36,596	$22,945	$2,040	$591	
	Allocated PILs	$12,737	$9,428	$1,878	$1,431	$0	$0	$0	
	Allocated Debt Return	$92,649	$68,583	$13,659	$10,408	$0	$0	$0	
	Allocated Equity Return	$111,879	$82,817	$16,494	$12,568	$0	$0	$0	
	Total	**$1,843,771**	**$1,317,078**	**$340,361**	**$125,756**	**$54,343**	**$4,836**	**$1,398**	

Scenario 3

Minimum System Customer Costs Adjusted for PLCC - High Limit Fixed Customer Charge

USoA Account #	Accounts	Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	
	Distribution Plant								
1565	Conservation and Demand Management Expenditures and Recoveries	$0	$0	$0	$0	$0	$0	$0	CDMPP
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	#N/A
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	BCP
1830-4	Poles, Towers and Fixtures - Primary	$1,385,931	$918,867	$138,847	$10,776	$292,840	$19,099	$5,502	PNCP
1830-5	Poles, Towers and Fixtures - Secondary	$1,204,645	$799,957	$120,879	$7,447	$254,944	$16,628	$4,790	SNCP
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	#N/A
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	BCP
1835-4	Overhead Conductors and Devices - Primary	$1,402,481	$929,839	$140,505	$10,905	$296,337	$19,327	$5,568	PNCP
1835-5	Overhead Conductors and Devices - Secondary	$310,137	$205,950	$31,120	$1,917	$65,636	$4,281	$1,233	SNCP
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	#N/A
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	BCP
1840-4	Underground Conduit - Primary	$103,489	$68,613	$10,368	$805	$21,867	$1,426	$411	PNCP
1840-5	Underground Conduit - Secondary	$192,292	$127,693	$19,295	$1,189	$40,696	$2,654	$765	SNCP
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	#N/A
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	BCP
1845-4	Underground Conductors and Devices - Primary	$353,213	$234,179	$35,386	$2,746	$74,632	$4,868	$1,402	PNCP
1845-5	Underground Conductors and Devices - Secondary	$656,300	$435,823	$65,856	$4,057	$138,895	$9,059	$2,610	SNCP
1850	Line Transformers	$1,943,290	$1,290,463	$194,998	$12,013	$411,267	$26,823	$7,727	LTNCP
1855	Services	$2,616,861	$1,503,271	$454,309	$139,946	$479,088	$31,246	$9,001	CWCS
1860	Meters	$2,982,677	$2,207,898	$439,720	$335,059	$0	$0	$0	CWMC
	Sub-total	*$13,151,317*	*$8,722,553*	*$1,651,284*	*$526,860*	*$2,076,202*	*$135,411*	*$39,008*	
	Accumulated Amortization								
	Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	($5,024,902)	($3,263,247)	($641,783)	($176,384)	($870,369)	($56,766)	($16,353)	
	Customer Related Net Fixed Assets	$8,126,415	$5,459,306	$1,009,501	$350,476	$1,205,832	$78,645	$22,656	
	Allocated General Plant Net Fixed Assets	$768,556	$514,339	$94,705	$32,095	$117,579	$7,669	$2,170	
	Customer Related NFA Including General Plant	$8,894,971	$5,973,645	$1,104,205	$382,571	$1,323,412	$86,313	$24,825	
	Misc Revenue								
4082	Retail Services Revenues	$0	$0	$0	$0	$0	$0	$0	CWNB
4084	Service Transaction Requests (STR) Revenues	$0	$0	$0	$0	$0	$0	$0	CWNB
4090	Electric Services Incidental to Energy Sales	$0	$0	$0	$0	$0	$0	$0	CWNB
4220	Other Electric Revenues	$0	$0	$0	$0	$0	$0	$0	NFA
4225	Late Payment Charges	$0	$0	$0	$0	$0	$0	$0	LPHA
4235	Miscellaneous Service Revenues	($557,326)	($401,731)	($121,409)	($33,060)	($49)	($835)	($243)	CWNB
	Sub-total	*($557,326)*	*($401,731)*	*($121,409)*	*($33,060)*	*($49)*	*($835)*	*($243)*	
	Operating and Maintenance								
5005	Operation Supervision and Engineering	$11,804	$7,562	$1,406	$223	$2,410	$157	$45	1815-1855
5010	Load Dispatching	$0	$0	$0	$0	$0	$0	$0	1815-1855
5020	Overhead Distribution Lines and Feeders - Operation Labour	$14,832	$9,839	$1,487	$107	$3,136	$205	$59	1830 & 1835
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$2,000	$1,327	$200	$14	$423	$28	$8	1830 & 1835
5035	Overhead Distribution Transformers- Operation	$7,907	$5,251	$793	$49	$1,673	$109	$31	1850
5040	Underground Distribution Lines and Feeders - Operation Labour	$2,206	$1,464	$221	$15	$467	$30	$9	1840 & 1845
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$0	$0	$0	$0	$0	$0	$0	1840 & 1845
5055	Underground Distribution Transformers - Operation	$4,004	$2,659	$402	$25	$847	$55	$16	1850
5065	Meter Expense	$18,443	$13,652	$2,719	$2,072	$0	$0	$0	CWMC
5070	Customer Premises - Operation Labour	$148,229	$98,275	$14,850	$1,153	$31,320	$2,043	$588	CCA
5075	Customer Premises - Materials and Expenses	$0	$0	$0	$0	$0	$0	$0	CCA
5085	Miscellaneous Distribution Expense	$147,477	$94,483	$17,571	$2,782	$30,111	$1,964	$566	1815-1855
5090	Underground Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	1840 & 1845
5095	Overhead Distribution Lines and Feeders - Rental Paid	$8,000	$5,307	$802	$58	$1,691	$110	$32	1830 & 1835
5096	Other Rent	$0	$0	$0	$0	$0	$0	$0	O&M
5105	Maintenance Supervision and Engineering	$11,804	$7,562	$1,406	$223	$2,410	$157	$45	1815-1855
5120	Maintenance of Poles, Towers and Fixtures	$31,723	$21,048	$3,180	$223	$6,708	$437	$126	1830
5125	Maintenance of Overhead Conductors and Devices	$62,109	$41,190	$6,224	$465	$13,127	$856	$247	1835
5130	Maintenance of Overhead Services	$81,996	$47,103	$14,235	$4,385	$15,012	$979	$282	1855
5135	Overhead Distribution Lines and Feeders - Right of Way	$53,678	$35,608	$5,381	$387	$11,348	$740	$213	1830 & 1835
5145	Maintenance of Underground Conduit	$380	$252	$38	$3	$80	$5	$2	1840
5150	Maintenance of Underground Conductors and Devices	$4,408	$2,926	$442	$30	$932	$61	$18	1845
5155	Maintenance of Underground Services	$22,553	$12,956	$3,915	$1,206	$4,129	$269	$78	1855
5160	Maintenance of Line Transformers	$16,327	$10,842	$1,638	$101	$3,455	$225	$65	1850
5175	Maintenance of Meters	$51,217	$37,913	$7,551	$5,753	$0	$0	$0	1860
	Sub-total	*$701,096*	*$457,219*	*$84,464*	*$19,272*	*$129,281*	*$8,432*	*$2,429*	
	Billing and Collection								
5305	Supervision	$0	$0	$0	$0	$0	$0	$0	CWNB
5310	Meter Reading Expense	$144,362	$100,530	$32,609	$11,189	$35	$0	$0	CWMR
5315	Customer Billing	$347,894	$250,768	$75,786	$20,637	$30	$521	$152	CWNB
5320	Collecting	$153,216	$110,441	$33,377	$9,089	$13	$230	$67	CWNB
5325	Collecting- Cash Over and Short	$120	$86	$26	$7	$0	$0	$0	CWNB
5330	Collection Charges	$1,500	$1,081	$327	$89	$0	$2	$1	CWNB
5335	Bad Debt Expense	$75,000	$34,220	$20,962	$19,818	$0	$0	$0	BDHA
5340	Miscellaneous Customer Accounts Expenses	$44,183	$31,848	$9,625	$2,621	$4	$66	$19	CWNB
	Sub-total	*$766,275*	*$528,975*	*$172,711*	*$63,449*	*$82*	*$819*	*$238*	
	Sub Total Operating, Maintenance and Biling	*$1,467,371*	*$986,194*	*$257,175*	*$82,721*	*$129,363*	*$9,251*	*$2,667*	
	Amortization Expense - Customer Related	$421,749	$281,902	$53,558	$18,935	$62,134	$4,052	$1,167	
	Amortization Expense - General Plant assigned to Meters	$51,904	$34,735	$6,396	$2,168	$7,941	$518	$147	
	Admin and General	$1,068,532	$717,662	$187,076	$60,560	$94,534	$6,749	$1,952	
	Allocated PILs	$45,723	$30,717	$5,680	$1,972	$6,785	$442	$127	
	Allocated Debt Return	$332,602	$223,441	$41,317	$14,344	$49,353	$3,219	$927	
	Allocated Equity Return	$401,634	$269,817	$49,893	$17,322	$59,596	$3,887	$1,120	
	PLCC Adjustment for Line Transformer	$36,250	$31,079	$4,695	$289	$0	$0	$186	
	PLCC Adjustment for Primary Costs	$70,586	$60,158	$9,304	$764	$0	$0	$360	
	PLCC Adjustment for Secondary Costs	$127,809	$110,484	$16,640	$0	$0	$0	$685	
	Total	$2,997,545	**$1,941,016**	**$449,048**	**$163,907**	**$409,657**	**$27,284**	**$6,632**	

Below: Grouping to avoid disclosure

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

Accounts	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
Distribution Plant							
CWMC	$ 2,982,677	$ 2,207,898	$ 439,720	$ 335,059	$ -	$ -	$ -
Accumulated Amortization							
Accum. Amortization of Electric Utility Plant - Meters only	$ (718,987)	$ (532,223)	$ (105,996)	$ (80,767)	$ -	$ -	$ -
Meter Net Fixed Assets	$ 2,263,690	$ 1,675,675	$ 333,724	$ 254,292	$ -	$ -	$ -
Misc Revenue							
CWNB	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-total	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Operation							
CWMC	$ 18,443	$ 13,652	$ 2,719	$ 2,072	$ -	$ -	$ -
CCA	$ 148,229	$ 98,275	$ 14,850	$ 1,153	$ 31,320	$ 2,043	$ 588
Sub-total	$ 166,672	$ 111,927	$ 17,569	$ 3,224	$ 31,320	$ 2,043	$ 588
Maintenance							
1860	$ 51,217	$ 37,913	$ 7,551	$ 5,753	$ -	$ -	$ -
Billing and Collection							
CWMR	$ 144,362	$ 100,530	$ 32,609	$ 11,189	$ 35	$ -	$ -
CWNB	$ 502,730	$ 362,377	$ 109,515	$ 29,821	$ 44	$ 753	$ 219
Sub-total	$ 647,092	$ 462,907	$ 142,124	$ 41,010	$ 78	$ 753	$ 219
Total Operation, Maintenance and Billing	$ 864,981	$ 612,748	$ 167,244	$ 49,988	$ 31,398	$ 2,796	$ 808
Amortization Expense - Meters	$ 117,446	$ 86,938	$ 17,314	$ 13,193	$ -	$ -	$ -
Allocated PILs	$ 11,644	$ 8,616	$ 1,717	$ 1,311	$ -	$ -	$ -
Allocated Debt Return	$ 84,700	$ 62,678	$ 12,487	$ 9,535	$ -	$ -	$ -
Allocated Equity Return	$ 102,279	$ 75,687	$ 15,079	$ 11,514	$ -	$ -	$ -
Total	**$ 1,181,050**	**$ 846,667**	**$ 213,841**	**$ 85,540**	**$ 31,398**	**$ 2,796**	**$ 808**

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

Accounts	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
Distribution Plant							
CWMC	$ 2,982,677	$ 2,207,898	$ 439,720	$ 335,059	$ -	$ -	$ -
Accumulated Amortization							
Accum. Amortization of Electric Utility Plant - Meters only	$ (718,987)	$ (532,223)	$ (105,996)	$ (80,767)	$ -	$ -	$ -
Meter Net Fixed Assets	$ 2,263,690	$ 1,675,675	$ 333,724	$ 254,292	$ -	$ -	$ -
Allocated General Plant Net Fixed Assets	$ 212,465	$ 157,871	$ 31,308	$ 23,287	$ -	$ -	$ -
Meter Net Fixed Assets Including General Plant	$ 2,476,155	$ 1,833,545	$ 365,031	$ 277,578	$ -	$ -	$ -
Misc Revenue							
CWNB	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-total	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*
Operation							
CWMC	$ 18,443	$ 13,652	$ 2,719	$ 2,072	$ -	$ -	$ -
CCA	$ 148,229	$ 98,275	$ 14,850	$ 1,153	$ 31,320	$ 2,043	$ 588
Sub-total	*$ 166,672*	*$ 111,927*	*$ 17,569*	*$ 3,224*	*$ 31,320*	*$ 2,043*	*$ 588*
Maintenance							
1860	$ 51,217	$ 37,913	$ 7,551	$ 5,753	$ -	$ -	$ -
Billing and Collection							
CWMR	$ 144,362	$ 100,530	$ 32,609	$ 11,189	$ 35	$ -	$ -
CWNB	$ 502,730	$ 362,377	$ 109,515	$ 29,821	$ 44	$ 753	$ 219
Sub-total	*$ 647,092*	*$ 462,907*	*$ 142,124*	*$ 41,010*	*$ 78*	*$ 753*	*$ 219*
Total Operation, Maintenance and Billing	$ 864,981	$ 612,748	$ 167,244	$ 49,988	$ 31,398	$ 2,796	$ 808
Amortization Expense - Meters	$ 117,446	$ 86,938	$ 17,314	$ 13,193	$ -	$ -	$ -
Amortization Expense - General Plant assigned to Meters	$ 14,349	$ 10,662	$ 2,114	$ 1,573	$ -	$ -	$ -
Admin and General	$ 629,731	$ 445,902	$ 121,658	$ 36,596	$ 22,945	$ 2,040	$ 591
Allocated PILs	$ 12,737	$ 9,428	$ 1,878	$ 1,431	$ -	$ -	$ -
Allocated Debt Return	$ 92,649	$ 68,583	$ 13,659	$ 10,408	$ -	$ -	$ -
Allocated Equity Return	$ 111,879	$ 82,817	$ 16,494	$ 12,568	$ -	$ -	$ -
Total	**$ 1,843,771**	**$ 1,317,078**	**$ 340,361**	**$ 125,756**	**$ 54,343**	**$ 4,836**	**$ 1,398**

Scenario 3

Minimum System Customer Costs Adjusted for PLCC - High Limit Fixed Customer Charge

USoA Account #	Accounts	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
	Distribution Plant							
	CDMPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Poles, Towers and Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	PNCP	$ 3,245,115	$ 2,151,498	$ 325,106	$ 25,232	$ 685,676	$ 44,720	$ 12,883
	SNCP	$ 2,363,374	$ 1,569,423	$ 237,151	$ 14,610	$ 500,171	$ 32,621	$ 9,397
	Overhead Conductors and Devices	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	LTNCP	$ 1,943,290	$ 1,290,463	$ 194,998	$ 12,013	$ 411,267	$ 26,823	$ 7,727
	CWCS	$ 2,616,861	$ 1,503,271	$ 454,309	$ 139,946	$ 479,088	$ 31,246	$ 9,001
	CWMC	$ 2,982,677	$ 2,207,898	$ 439,720	$ 335,059	$ -	$ -	$ -
	Sub-total	*$ 13,151,317*	*$ 8,722,553*	*$ 1,651,284*	*$ 526,860*	*$ 2,076,202*	*$ 135,411*	*$ 39,008*
	Accumulated Amortization							
	Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	$ (5,024,902)	$ (3,263,247)	$ (641,783)	$ (176,384)	$ (870,369)	$ (56,766)	$ (16,353)
	Customer Related Net Fixed Assets	$ 8,126,415	$ 5,459,306	$ 1,009,501	$ 350,476	$ 1,205,832	$ 78,645	$ 22,656
	Allocated General Plant Net Fixed Assets	$ 768,556	$ 514,339	$ 94,705	$ 32,095	$ 117,579	$ 7,669	$ 2,170
	Customer Related NFA Including General Plant	$ 8,894,971	$ 5,973,645	$ 1,104,205	$ 382,571	$ 1,323,412	$ 86,313	$ 24,825
	Misc Revenue							
	CWNB	$ (557,326)	$ (401,731)	$ (121,409)	$ (33,060)	$ (49)	$ (835)	$ (243)
	NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	LPHA	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Sub-total	*$ (557,326)*	*$ (401,731)*	*$ (121,409)*	*$ (33,060)*	*$ (49)*	*$ (835)*	*$ (243)*
	Operating and Maintenance							
	1815-1855	$ 171,084	$ 109,607	$ 20,384	$ 3,227	$ 34,931	$ 2,278	$ 656
	1830 & 1835	$ 78,510	$ 52,081	$ 7,870	$ 566	$ 16,598	$ 1,083	$ 312
	1850	$ 28,238	$ 18,752	$ 2,834	$ 175	$ 5,976	$ 390	$ 112
	1840 & 1845	$ 2,206	$ 1,464	$ 221	$ 15	$ 467	$ 30	$ 9
	CWMC	$ 18,443	$ 13,652	$ 2,719	$ 2,072	$ -	$ -	$ -
	CCA	$ 148,229	$ 98,275	$ 14,850	$ 1,153	$ 31,320	$ 2,043	$ 588
	O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1830	$ 31,723	$ 21,048	$ 3,180	$ 223	$ 6,708	$ 437	$ 126
	1835	$ 62,109	$ 41,190	$ 6,224	$ 465	$ 13,127	$ 856	$ 247
	1855	$ 104,549	$ 60,059	$ 18,151	$ 5,591	$ 19,141	$ 1,248	$ 360
	1840	$ 380	$ 252	$ 38	$ 3	$ 80	$ 5	$ 2
	1845	$ 4,408	$ 2,926	$ 442	$ 30	$ 932	$ 61	$ 18
	1860	$ 51,217	$ 37,913	$ 7,551	$ 5,753	$ -	$ -	$ -
	Sub-total	*$ 701,096*	*$ 457,219*	*$ 84,464*	*$ 19,272*	*$ 129,281*	*$ 8,432*	*$ 2,429*
	Billing and Collection							
	CWNB	$ 546,913	$ 394,225	$ 119,140	$ 32,442	$ 48	$ 819	$ 238
	CWMR	$ 144,362	$ 100,530	$ 32,609	$ 11,189	$ 35	$ -	$ -
	BDHA	$ 75,000	$ 34,220	$ 20,962	$ 19,818	$ -	$ -	$ -
	Sub-total	*$ 766,275*	*$ 528,975*	*$ 172,711*	*$ 63,449*	*$ 82*	*$ 819*	*$ 238*
	Sub Total Operating, Maintenance and Biling	*$ 1,467,371*	*$ 986,194*	*$ 257,175*	*$ 82,721*	*$ 129,363*	*$ 9,251*	*$ 2,667*
	Amortization Expense - Customer Related	$ 421,749	$ 281,902	$ 53,558	$ 18,935	$ 62,134	$ 4,052	$ 1,167
	Amortization Expense - General Plant assigned to Meters	$ 51,904	$ 34,735	$ 6,396	$ 2,168	$ 7,941	$ 518	$ 147
	Admin and General	$ 1,068,532	$ 717,662	$ 187,076	$ 60,560	$ 94,534	$ 6,749	$ 1,952
	Allocated PILs	$ 45,723	$ 30,717	$ 5,680	$ 1,972	$ 6,785	$ 442	$ 127
	Allocated Debt Return	$ 332,602	$ 223,441	$ 41,317	$ 14,344	$ 49,353	$ 3,219	$ 927
	Allocated Equity Return	$ 401,634	$ 269,817	$ 49,893	$ 17,322	$ 59,596	$ 3,887	$ 1,120
	PLCC Adjustment for Line Transformer	$ 36,250	$ 31,079	$ 4,695	$ 289	$ -	$ -	$ 186
	PLCC Adjustment for Primary Costs	$ 70,586	$ 60,158	$ 9,304	$ 764	$ -	$ -	$ 360
	PLCC Adjustment for Secondary Costs	$ 127,809	$ 110,484	$ 16,640	$ -	$ -	$ -	$ 685
	Total	**$ 2,997,545**	**$ 1,941,016**	**$ 449,048**	**$ 163,907**	**$ 409,657**	**$ 27,284**	**$ 6,632**

2011 COST ALLOCATION MODEL

BRANT COUNTY POWER INC.

Ontario

Sheet E4 Trial Balance Allocation Detail Worksheet - Optional Third Run

Details:
The worksheet below details how costs are treated, categorized, and grouped.

This sheet shows what accounts are included in the COSS, and how they are grouped into working capital and rate base. It shows how accounts are categorized in the customer and demand related costs. It will then show how the categorized costs are allocated to customer and demand related components. It will also show how Miscellaneous Revenue and General Plant and Administration costs are allocated. Finally, it will show how costs are being grouped together for presentation purposes.

Uniform System of Accounts - Detail Accounts:					Classification and Allocation			Allocation Demand Related	Allocation Customer Related	Allocation A&G Related	Allocation Misc Related				
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint	Demand ID	Customer ID	A & G ID	Misc ID	cp	ncp	non-demand	FINAL
1565	Conservation and Demand Management Expenditures and Recoveries	CDM Expenditures and Recoveries	dp			O&M			O&M						
1608	Franchises and Consents	Other Distribution Assets	gp							NFA ECC					
1805	Land		dp	DDCP											
1805-1	Land Station >50 kV		dp	TCP	TCP12			TCP12				TCP12			TCP12
1805-2	Land Station <50 kV		dp	DCP	DCP12			DCP12				DCP12			DCP12
1806	Land Rights		dp	DDCP											
1806-1	Land Rights Station >50 kV		dp	TCP	TCP12			TCP12				TCP12			TCP12
1806-2	Land Rights Station <50 kV		dp	DCP	DCP12			DCP12				DCP12			DCP12
1808	Buildings and Fixtures		dp	DDCP											
1808-1	Buildings and Fixtures > 50 kV		dp	TCP	TCP12			TCP12				TCP12			TCP12
1808-2	Buildings and Fixtures < 50 KV		dp	DCP	DCP12			DCP12				DCP12			DCP12
1810	Leasehold Improvements		dp	DDCP											
1810-1	Leasehold Improvements >50 kV		dp	TCP	TCP12			TCP12				TCP12			TCP12
1810-2	Leasehold Improvements <50 kV		dp	DCP	DCP12			DCP12				DCP12			DCP12
1815	Transformer Station Equipment - Normally Primary above 50 kV		dp	TCP	TCP12			TCP12				TCP12			TCP12
1820	Distribution Station Equipment - Normally Primary below 50 kV		dp	DCP	DCP12			DCP12				DCP12			DCP12
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)		dp	DCP	DCP12			DCP12				DCP12			DCP12
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)		dp	PNCP	PNCP4			PNCP4					PNCP4		PNCP4
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)		dp			CEN			CEN						
1825	Storage Battery Equipment		dp	DDCP											
1825-1	Storage Battery Equipment > 50 kV		dp	TCP	TCP12			TCP12				TCP12			TCP12
1825-2	Storage Battery Equipment <50 kV		dp	DCP	DCP12			DCP12				DCP12			DCP12
1830	Poles, Towers and Fixtures		dp	DDNCP											
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery		dp	BCP	BCP12			BCP12				BCP12			BCP12
1830-4	Poles, Towers and Fixtures - Primary		dp	PNCP	PNCP4	CCP	x	PNCP4	CCP				PNCP4		PNCP4
1830-5	Poles, Towers and Fixtures - Secondary		dp	SNCP	SNCP4	CCS	x	SNCP4	CCS				SNCP4		SNCP4
1835	Overhead Conductors and Devices		dp	DDNCP											
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery		dp	BCP	BCP12			BCP12				BCP12			BCP12
1835-4	Overhead Conductors and Devices - Primary		dp	PNCP	PNCP4	CCP	x	PNCP4	CCP				PNCP4		PNCP4
1835-5	Overhead Conductors and Devices - Secondary		dp	SNCP	SNCP4	CCS	x	SNCP4	CCS				SNCP4		SNCP4
1840	Underground Conduit		dp	DDNCP											

1840	Underground Conduit		dp	DDNCP												
1840-3	Underground Conduit - Bulk Delivery	Land and Buildings	dp	BCP	BCP12			BCP12					BCP12			BCP12
1840-4	Underground Conduit - Primary	Land and Buildings	dp	PNCP	PNCP4	CCP	x	PNCP4	CCP					PNCP4		PNCP4
1840-5	Underground Conduit - Secondary	Land and Buildings	dp	SNCP	SNCP4	CCS	x	SNCP4	CCS					SNCP4		SNCP4
1845	Underground Conductors and Devices	Land and Buildings	dp	DDNCP												
1845-3	Underground Conductors and Devices - Bulk Delivery	TS Primary Above 50	dp	BCP	BCP12			BCP12					BCP12			BCP12
1845-4	Underground Conductors and Devices - Primary	DS	dp	PNCP	PNCP4	CCP	x	PNCP4	CCP					PNCP4		PNCP4
1845-5	Underground Conductors and Devices - Secondary	Other Distribution Assets	dp	SNCP	SNCP4	CCS	x	SNCP4	CCS					SNCP4		SNCP4
1850	Line Transformers	Poles, Wires	dp	LTNCP	LTNCP4	CCLT	x	LTNCP4	CCLT					LTNCP4		LTNCP4
1855	Services	Services and Meters	dp			CWCS			CWCS							
1860	Meters	Services and Meters	dp			CWMC			CWMC							
1905	Land	Land and Buildings	gp							NFA ECC						
1906	Land Rights	Land and Buildings	gp							NFA ECC						
1908	Buildings and Fixtures	General Plant	gp							NFA ECC						
1910	Leasehold Improvements	General Plant	gp							NFA ECC						
1915	Office Furniture and Equipment	Equipment	gp							NFA ECC						
1920	Computer Equipment - Hardware	IT Assets	gp							NFA ECC						
1925	Computer Software	IT Assets	gp							NFA ECC						
1930	Transportation Equipment	Equipment	gp							NFA ECC						
1935	Stores Equipment	Equipment	gp							NFA ECC						
1940	Tools, Shop and Garage Equipment	Equipment	gp							NFA ECC						
1945	Measurement and Testing Equipment	Equipment	gp							NFA ECC						
1950	Power Operated Equipment	Equipment	gp							NFA ECC						
1955	Communication Equipment	Equipment	gp							NFA ECC						
1960	Miscellaneous Equipment	Equipment	gp							NFA ECC						
1970	Load Management Controls - Customer Premises	Other Distribution Assets	gp							NFA ECC						
1975	Load Management Controls - Utility Premises	Other Distribution Assets	gp							NFA ECC						
1980	System Supervisory Equipment	Other Distribution Assets	gp							NFA ECC						
1990	Other Tangible Property	Other Distribution Assets	gp							NFA ECC						
1995	Contributions and Grants - Credit	Contributions and Grants	co		Break out	Breakout		Break out	Breakout							
2005	Property Under Capital Leases	Other Distribution Assets	gp							NFA ECC						
2010	Electric Plant Purchased or Sold	Other Distribution Assets	gp							NFA ECC						
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	Accumulated Amortization	accum dep		Break out	Breakout		Break out	Breakout							
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	Accumulated Amortization	accum dep		Break out	Breakout		Break out	Breakout							
3046	Balance Transferred From Income	Equity	NI								NFA					
4080	Distribution Services Revenue	Distribution Services Revenue	CREV								CREV					
4082	Retail Services Revenues	Other Distribution Revenue	mi								CWNB					
4084	Service Transaction Requests (STR) Revenues	Other Distribution Revenue	mi								CWNB					
4090	Electric Services Incidental to Energy Sales	Other Distribution Revenue	mi								CWNB					
4205	Interdepartmental Rents	Other Distribution Revenue	mi								NFA					
4210	Rent from Electric Property	Other Distribution Revenue	mi								NFA					
4215	Other Utility Operating Income	Other Distribution Revenue	mi								NFA					
4220	Other Electric Revenues	Other Distribution Revenue	mi								NFA					

4225	Late Payment Charges	Late Payment Charges	mi								LPHA				
4235	Miscellaneous Service Revenues	Specific Service Charges	mi								CWNB				
4240	Provision for Rate Refunds	Other Distribution Revenue	mi								NFA				
4245	Government Assistance Directly Credited to Income	Other Distribution Revenue	mi								NFA				
4305	Regulatory Debits	Other Income & Deductions	mi								NFA				
4310	Regulatory Credits	Other Income & Deductions	mi								NFA				
4315	Revenues from Electric Plant Leased to Others	Other Income & Deductions	mi								NFA				
4320	Expenses of Electric Plant Leased to Others	Other Income & Deductions	mi								NFA				
4325	Revenues from Merchandise, Jobbing, Etc.	Other Income & Deductions	mi								NFA				
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	Other Income & Deductions	mi								NFA				
4335	Profits and Losses from Financial Instrument Hedges	Other Income & Deductions	mi								NFA				
4340	Profits and Losses from Financial Instrument Investments	Other Income & Deductions	mi								NFA				
4345	Gains from Disposition of Future Use Utility Plant	Other Income & Deductions	mi								NFA				
4350	Losses from Disposition of Future Use Utility Plant	Other Income & Deductions	mi								NFA				
4355	Gain on Disposition of Utility and Other Property	Other Income & Deductions	mi								NFA				
4360	Loss on Disposition of Utility and Other Property	Other Income & Deductions	mi								NFA				
4365	Gains from Disposition of Allowances for Emission	Other Income & Deductions	mi								NFA				
4370	Losses from Disposition of Allowances for Emission	Other Income & Deductions	mi								NFA				
4390	Miscellaneous Non-Operating Income	Other Income & Deductions	mi								NFA				
4395	Rate-Payer Benefit Including Interest	Other Income & Deductions	mi								NFA				
4398	Foreign Exchange Gains and Losses, Including Amortization	Other Income & Deductions	mi								NFA				
4405	Interest and Dividend Income	Other Income & Deductions	mi								NFA				
4415	Equity in Earnings of Subsidiary Companies	Other Income & Deductions	mi								NFA				
4705	Power Purchased	Power Supply Expenses (Working Capital)	cop							CEN EWMP					
4708	Charges-WMS	Power Supply Expenses (Working Capital)	cop							CEN EWMP					
4710	Cost of Power Adjustments	Power Supply Expenses (Working Capital)	cop							CEN EWMP					
4712	Charges-One-Time	Power Supply Expenses (Working Capital)	cop							CEN EWMP					
4714	Charges-NW	Power Supply Expenses (Working Capital)	cop							CEN					
4715	System Control and Load Dispatching	Other Power Supply Expenses	cop							CEN EWMP					
4716	Charges-CN	Power Supply Expenses (Working Capital)	cop							CEN					
4730	Rural Rate Assistance Expense	Power Supply Expenses (Working Capital)	cop							CEN EWMP					
5005	Operation Supervision and Engineering	Operation (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x	1815-1855 D	1815-1855 C					1815-1855 D	1815-1855 D
5010	Load Dispatching	Operation (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x	1815-1855 D	1815-1855 C					1815-1855 D	1815-1855 D
5012	Station Buildings and Fixtures Expense	Operation (Working Capital)	di	1808 D	1808 D	1808 C		1808 D	1808 C					1808 D	1808 D

5014	Transformer Station Equipment - Operation Labour	Operation (Working Capital)	di	1815 D	1815 D	1815 C		1815 D	1815 C						1815 D	1815 D
5015	Transformer Station Equipment - Operation Supplies and Expenses	Operation (Working Capital)	di	1815 D	1815 D	1815 C		1815 D	1815 C						1815 D	1815 D
5016	Distribution Station Equipment - Operation Labour	Operation (Working Capital)	di	1820 D	1820 D	1820 C		1820 D	1820 C						1820 D	1820 D
5017	Distribution Station Equipment - Operation Supplies and Expenses	Operation (Working Capital)	di	1820 D	1820 D	1820 C		1820 D	1820 C						1820 D	1820 D
5020	Overhead Distribution Lines and Feeders - Operation Labour	Operation (Working Capital)	di	1830 & 1835 D	830 & 1835	1830 & 1835 C	x	830 & 1835	1830 & 1835 C						1830 & 1835 D	1830 & 1835 D
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	Operation (Working Capital)	di	1830 & 1835 D	830 & 1835	1830 & 1835 C	x	830 & 1835	1830 & 1835 C						1830 & 1835 D	1830 & 1835 D
5030	Overhead Subtransmission Feeders - Operation	Operation (Working Capital)	di	1830 & 1835 D	830 & 1835	1830 & 1835 C		830 & 1835	1830 & 1835 C						1830 & 1835 D	1830 & 1835 D
5035	Overhead Distribution Transformers- Operation	Operation (Working Capital)	di	1850 D	1850 D	1850 C	x	1850 D	1850 C						1850 D	1850 D
5040	Underground Distribution Lines and Feeders - Operation Labour	Operation (Working Capital)	di	1840 & 1845 D	840 & 1845	1840 & 1845 C	x	840 & 1845	1840 & 1845 C						1840 & 1845 D	1840 & 1845 D
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	Operation (Working Capital)	di	1840 & 1845 D	840 & 1845	1840 & 1845 C	x	840 & 1845	1840 & 1845 C						1840 & 1845 D	1840 & 1845 D
5050	Underground Subtransmission Feeders - Operation	Operation (Working Capital)	di	1840 & 1845 D	840 & 1845	1840 & 1845 C		840 & 1845	1840 & 1845 C						1840 & 1845 D	1840 & 1845 D
5055	Underground Distribution Transformers - Operation	Operation (Working Capital)	di	1850 D	1850 D	1850 C	x	1850 D	1850 C						1850 D	1850 D
5065	Meter Expense	Operation (Working Capital)	cu			CWMC			CWMC							
5070	Customer Premises - Operation Labour	Operation (Working Capital)	cu			CCA			CCA							
5075	Customer Premises - Materials and Expenses	Operation (Working Capital)	cu			CCA			CCA							
5085	Miscellaneous Distribution Expense	Operation (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x	1815-1855 D	1815-1855 C						1815-1855 D	1815-1855 D
5090	Underground Distribution Lines and Feeders - Rental Paid	Operation (Working Capital)	di	1840 & 1845 D	840 & 1845	1840 & 1845 C	x	840 & 1845	1840 & 1845 C						1840 & 1845 D	1840 & 1845 D
5095	Overhead Distribution Lines and Feeders - Rental Paid	Operation (Working Capital)	di	1830 & 1835 D	830 & 1835	1830 & 1835 C	x	830 & 1835	1830 & 1835 C						1830 & 1835 D	1830 & 1835 D
5096	Other Rent	Operation (Working Capital)	di							O&M						
5105	Maintenance Supervision and Engineering	Maintenance (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x	1815-1855 D	1815-1855 C						1815-1855 D	1815-1855 D
5110	Maintenance of Buildings and Fixtures - Distribution Stations	Maintenance (Working Capital)	di	1808 D	1808 D	1808 C		1808 D	1808 C						1808 D	1808 D
5112	Maintenance of Transformer Station Equipment	Maintenance (Working Capital)	di	1815 D	1815 D	1815 C		1815 D	1815 C						1815 D	1815 D
5114	Maintenance of Distribution Station Equipment	Maintenance (Working Capital)	di	1820 D	1820 D	1820 C		1820 D	1820 C						1820 D	1820 D
5120	Maintenance of Poles, Towers and Fixtures	Maintenance (Working Capital)	di	1830 D	1830 D	1830 C	x	1830 D	1830 C						1830 D	1830 D
5125	Maintenance of Overhead Conductors and Devices	Maintenance (Working Capital)	di	1835 D	1835 D	1835 C	x	1835 D	1835 C						1835 D	1835 D
5130	Maintenance of Overhead Services	Maintenance (Working Capital)	di	1855 D	1855 D	1855 C		1855 D	1855 C						1855 D	1855 D
5135	Overhead Distribution Lines and Feeders - Right of Way	Maintenance (Working Capital)	di	1830 & 1835 D	830 & 1835	1830 & 1835 C	x	830 & 1835	1830 & 1835 C						1830 & 1835 D	1830 & 1835 D
5145	Maintenance of Underground Conduit	Maintenance (Working Capital)	di	1840 D	1840 D	1840 C	x	1840 D	1840 C						1840 D	1840 D
5150	Maintenance of Underground Conductors and Devices	Maintenance (Working Capital)	di	1845 D	1845 D	1845 C	x	1845 D	1845 C						1845 D	1845 D
5155	Maintenance of Underground Services	Maintenance (Working Capital)	di	1855 D	1855 D	1855 C		1855 D	1855 C						1855 D	1855 D
5160	Maintenance of Line Transformers	Maintenance (Working Capital)	di	1850 D	1850 D	1850 C	x	1850 D	1850 C						1850 D	1850 D
5175	Maintenance of Meters	Maintenance (Working Capital)	cu	1860 D	1860 D	1860 C		1860 D	1860 C						1860 D	1860 D

5305	Supervision	Billing and Collection (Working Capital)	cu			CWNB			CWNB						
5310	Meter Reading Expense	Billing and Collection (Working Capital)	cu			CWMR			CWMR						
5315	Customer Billing	Billing and Collection (Working Capital)	cu			CWNB			CWNB						
5320	Collecting	Billing and Collection (Working Capital)	cu			CWNB			CWNB						
5325	Collecting- Cash Over and Short	Billing and Collection (Working Capital)	cu			CWNB			CWNB						
5330	Collection Charges	Billing and Collection (Working Capital)	cu			CWNB			CWNB						
5335	Bad Debt Expense	Bad Debt Expense (Working Capital)	cu			BDHA			BDHA						
5340	Miscellaneous Customer Accounts Expenses	Billing and Collection (Working Capital)	cu			CWNB			CWNB						
5405	Supervision	Community Relations (Working Capital)	ad							O&M					
5410	Community Relations - Sundry	Community Relations (Working Capital)	ad							O&M					
5415	Energy Conservation	Community Relations - CDM (Working Capital)	ad							O&M					
5420	Community Safety Program	Community Relations (Working Capital)	ad							NFA ECC					
5425	Miscellaneous Customer Service and Informational Expenses	Community Relations (Working Capital)	ad							O&M					
5505	Supervision	Other Distribution Expenses	ad							O&M					
5510	Demonstrating and Selling Expense	Other Distribution Expenses	ad							O&M					
5515	Advertising Expense	Advertising Expenses	ad							O&M					
5520	Miscellaneous Sales Expense	Other Distribution Expenses	ad							O&M					
5605	Executive Salaries and Expenses	Administrative and General Expenses (Working Capital)	ad							O&M					
5610	Management Salaries and Expenses	Administrative and General Expenses (Working Capital)	ad							O&M					
5615	General Administrative Salaries and Expenses	Administrative and General Expenses (Working Capital)	ad							O&M					
5620	Office Supplies and Expenses	Administrative and General Expenses (Working Capital)	ad							O&M					
5625	Administrative Expense Transferred Credit	Administrative and General Expenses (Working Capital)	ad							O&M					
5630	Outside Services Employed	Administrative and General Expenses (Working Capital)	ad							O&M					
5635	Property Insurance	Insurance Expense (Working Capital)	ad							NFA ECC					
5640	Injuries and Damages	Administrative and General Expenses (Working Capital)	ad							O&M					
5645	Employee Pensions and Benefits	Administrative and General Expenses (Working Capital)	ad							O&M					
5650	Franchise Requirements	Administrative and General Expenses (Working Capital)	ad							O&M					
5655	Regulatory Expenses	Administrative and General Expenses (Working Capital)	ad							O&M					
5660	General Advertising Expenses	Advertising Expenses	ad							O&M					
5665	Miscellaneous General Expenses	Administrative and General Expenses (Working Capital)	ad							O&M					

5670	Rent	Administrative and General Expenses (Working Capital)	ad							O&M					
5675	Maintenance of General Plant	Administrative and General Expenses (Working Capital)	ad							O&M					
5680	Electrical Safety Authority Fees	Administrative and General Expenses (Working Capital)	ad							O&M					
5685	Independent Market Operator Fees and Penalties	Power Supply Expenses (Working Capital)	cop							NFA ECC					
5705	Amortization Expense - Property, Plant, and Equipment	Amortization of Assets	dep	PRORATED	Break out	Breakout			Breakout					PRORATED	PRORATED
5710	Amortization of Limited Term Electric Plant	Amortization of Assets	dep	PRORATED	Break out	Breakout			Breakout					PRORATED	PRORATED
5715	Amortization of Intangibles and Other Electric Plant	Amortization of Assets	dep	PRORATED	Break out	Breakout			Breakout					PRORATED	PRORATED
5720	Amortization of Electric Plant Acquisition Adjustments	Other Amortization Unclassified	dep	PRORATED	Break out	Breakout			Breakout					PRORATED	PRORATED
5730	Amortization of Unrecovered Plant and Regulatory Study Costs	Amortization of Assets	dep							O&M					
5735	Amortization of Deferred Development Costs	Amortization of Assets	dep							O&M					
5740	Amortization of Deferred Charges	Amortization of Assets	dep							O&M					
6005	Interest on Long Term Debt	Interest Expense - Unclassifed	INT							NFA					
6105	Taxes Other Than Income Taxes	Other Distribution Expenses	ad							NFA					
6110	Income Taxes	Income Tax Expense - Unclassified	Input							NFA					
6205	Donations	Charitable Contributions	ad							O&M					
6210	Life Insurance	Insurance Expense (Working Capital)	ad							O&M					
6215	Penalties	Other Distribution Expenses	ad							O&M					
6225	Other Deductions	Other Distribution Expenses	ad							O&M					

2006 COST ALLOCATION INFORMATION FILING
BRANT COUNTY POWER INC.
EB-2005-0341 EB-2007-0002
February-28-06
Sheet I6 Customer Data Worksheet - Optional Third Run

Click Here For Instructions on How to Complete This Worksheet

Total kWhs	187,612,914
Total kWs	255,552
Total Approved Distribution Revenue ($)	$4,841,336

			1	2	3	7	8	9
	ID	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
Billing Data								
kWh from approved EDR model, Sheet 7-1, Col M	CEN	187,612,914	74,169,055	32,842,421	78,444,771	1,482,334	227,148	447,185
kW from approved EDR model, Sheet 7-1, Col S	CDEM	255,552	-	-	251,241	3,680	631	-
kW, included in CDEM, from customers with line transformer allowance from approved EDR model, Sheet 6-3, Col P		145,234			145,234	-	-	-
Optional - kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-						
KWh excluding KWh from Wholesale Market Participants	CEN EWMP	187,612,914	74,169,055	32,842,421	78,444,771	1,482,334	227,148	447,185
kWh - 30 year weather normalized amount	Click here to	221,635,550	79,803,828	36,155,043	103,781,622	1,300,746	77,607	516,703
Approved Distribution Rev from approved EDR, Sheet 7-1, Col AK + Sheet 7-3 Col H	CREV	$4,841,337	$2,565,169	$855,358	$1,355,978	$40,034	$12,326	$12,472
Bad Debt 3 Year Historical Average from Approved EDR Model	BDHA	$46,774	$21,341	$13,073	$12,360	$0	$0	$0
Late Payment 3 Year Historical Average	LPHA	$155,412	$81,875	$38,340	$33,482	$0	$1,715	$0
Weighting Factor - Services			1.0	2.0	10.0	1.0	1.0	1.0
Weighting Factor - Billings			1.0	2.0	7.0	1.0	0.1	1.0
Number of Bills	CNB	109,056	89,652	15,432	1,440	12	2,004	516
Number of Connections (Unmetered)	CCON	2,861	-	-	-	2,576	242	43
Total Number of Customer from Approved EDR, Sheet 7-1, Col H excluding connections	CCA	9,055	7,471	1,286	120	1	167	10
Bulk Customer Base	CCB	-						
Primary Customer Base	CCP	9,055	7,471	1,286	120	1	167	10
Line Transformer Customer Base	CCLT	9,030	7,471	1,273	108	1	167	10
Secondary Customer Base	CCS	8,052	7,236	638		1	167	10
Weighted - Services	CWCS	11,373	7,236	1,276	-	2,576	242	43
Weighted Meter -Capital	CWMC	914,230	676,750	134,780	102,700	-	-	-
Weighted Meter Reading	CWMR	204,532	142,431	46,200	15,852	49	-	-
Weighted Bills	CWNB	131,324	89,652	30,864	10,080	12	200	516
Data Mismatch Analysis								
Revenue with 30 year weather normalized kWh		5,549,380	2,760,050	941,633	1,793,945	35,130	4,211	14,411

Weather Normalized Data from Hydro

Click Here For Instructions on How to Complete This Section

	Total	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
kWh - 30 year weather normalized amount	232,606,510	**83,754,118**	37,944,718	108,918,812	1,365,133	81,449	542,280
2006 EDR Distribution Loss Factor		**1.0495**	1.0495	1.0495	1.0495	1.0495	1.0495

Bad Debt Data from EDR 2006

Click Here For Instructions on How to Complete This Section

Sheet ADJ5 rows 26 - 32, column E	50,000	19,415	15,292	15,293			
Sheet ADJ5 rows 26 - 32, column F	40,085	18,299	10,893	10,893			
Sheet ADJ5 rows 26 - 32, column G	50,237	26,310	13,034	10,893			
Three-year average	**46,774**	**21,341**	**13,073**	**12,360**	**-**	**-**	**-**

NCP TEST RESULTS	4 NCP

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

Customer Classes		Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
CO-INCIDENT PEAK								
1 CP								
Transformation CP	TCP1	42,773	14,880	7,474	20,361	-	-	58
Bulk Delivery CP	BCP1	42,773	14,880	7,474	20,361	-	-	58
Total Sytem CP	DCP1	42,773	14,880	7,474	20,361	-	-	58
4 CP								
Transformation CP	TCP4	167,141	58,349	28,062	80,488	-	-	242
Bulk Delivery CP	BCP4	167,141	58,349	28,062	80,488	-	-	242
Total Sytem CP	DCP4	167,141	58,349	28,062	80,488	-	-	242
12 CP								
Transformation CP	TCP12	457,553	148,505	86,984	221,382	-	-	682
Bulk Delivery CP	BCP12	457,553	148,505	86,984	221,382	-	-	682
Total Sytem CP	DCP12	457,553	148,505	86,984	221,382	-	-	682
NON CO_INCIDENT PEAK								
1 NCP								
Classification NCP from Load Data Provider	DNCP1	51,878	19,680	10,784	20,902	409	25	78
Primary NCP	PNCP1	51,878	19,680	10,784	20,902	409	25	78
Line Transformer NCP	LTNCP1	47,219	19,680	10,682	16,345	409	25	78
Secondary NCP	SNCP1	24,900	19,061	5,327	-	409	25	78
4 NCP								
Classification NCP from Load Data Provider	DNCP4	194,135	74,149	35,818	82,176	1,601	96	295
Primary NCP	PNCP4	194,135	74,149	35,818	82,176	1,601	96	295
Line Transformer NCP	LTNCP4	175,877	74,149	35,478	64,258	1,601	96	295
Secondary NCP	SNCP4	91,601	71,817	17,792	-	1,601	96	295
12 NCP								
Classification NCP from Load Data Provider	DNCP12	526,388	197,686	94,865	228,629	4,142	248	818
Primary NCP	PNCP12	526,388	197,686	94,865	228,629	4,142	248	818
Line Transformer NCP	LTNCP12	475,638	197,686	93,965	178,779	4,142	248	818
Secondary NCP	SNCP12	243,799	191,468	47,123	-	4,142	248	818

BRANT COUNTY POWER INC.
EB-2005-0341 EB-2007-0002
February-28-06
Sheet O1 Revenue to Cost Summary Worksheet - Optional Third Run

Class Revenue, Cost Analysis, and Return on Rate Base

			1	2	3	7	8	9
Rate Base Assets		Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
crev	Distribution Revenue (sale)	$4,841,337	$2,565,169	$855,358	$1,355,978	$40,034	$12,326	$12,472
mi	Miscellaneous Revenue (mi)	$660,215	$370,380	$115,589	$115,455	$51,246	$5,933	$1,613
	Total Revenue	$5,501,552	$2,935,549	$970,947	$1,471,433	$91,280	$18,259	$14,085
	Expenses							
di	Distribution Costs (di)	$1,262,824	$692,302	$177,925	$202,711	$170,277	$15,997	$3,611
cu	Customer Related Costs (cu)	$1,045,685	$706,907	$230,027	$89,036	$14,644	$2,334	$2,736
ad	General and Administration (ad)	$1,040,115	$621,203	$179,819	$140,184	$87,484	$8,595	$2,830
dep	Depreciation and Amortization (dep)	$860,144	$489,169	$120,482	$126,666	$111,059	$10,434	$2,334
INPUT	PILs (INPUT)	$281,859	$151,462	$41,436	$53,980	$31,324	$2,943	$713
INT	Interest	$477,348	$256,511	$70,175	$91,419	$53,050	$4,985	$1,208
	Total Expenses	$4,967,975	$2,917,554	$819,864	$703,997	$467,839	$45,288	$13,433
	Direct Allocation	$0	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$687,381	$369,376	$101,052	$131,644	$76,391	$7,178	$1,740
	Revenue Requirement (includes NI)	$5,655,356	$3,286,930	$920,916	$835,640	$544,230	$52,467	$15,173
		Revenue Requirement Input equals Output						
	Rate Base Calculation							
	Net Assets							
dp	Distribution Plant - Gross	$14,605,349	$8,041,889	$2,103,320	$2,520,128	$1,738,262	$163,330	$38,419
gp	General Plant - Gross	$1,591,467	$868,409	$230,883	$285,401	$185,218	$17,404	$4,151
accum dep	Accumulated Depreciation	($2,759,001)	($1,577,742)	($384,702)	($395,699)	($359,558)	($33,780)	($7,521)
co	Capital Contribution	($1,357,195)	($832,446)	($175,478)	($108,522)	($216,054)	($20,297)	($4,397)
	Total Net Plant	$12,080,620	$6,500,110	$1,774,023	$2,301,308	$1,347,868	$126,657	$30,652
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$17,915,950	$7,082,716	$3,136,262	$7,491,023	$141,554	$21,691	$42,704
	OM&A Expenses	$3,348,623	$2,020,412	$587,770	$431,932	$272,406	$26,926	$9,178
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0
	Subtotal	*$21,264,573*	*$9,103,129*	*$3,724,032*	*$7,922,954*	*$413,960*	*$48,617*	*$51,881*
	Working Capital	$3,189,686	$1,365,469	$558,605	$1,188,443	$62,094	$7,293	$7,782
	Total Rate Base	$15,270,306	$7,865,579	$2,332,628	$3,489,751	$1,409,962	$133,950	$38,434
		Rate Base Input equals Output						
	Equity Component of Rate Base	$7,635,153	$3,932,790	$1,166,314	$1,744,876	$704,981	$66,975	$19,217
	Net Income on Allocated Assets	$533,577	$17,995	$151,083	$767,436	($376,558)	($27,030)	$652
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0
	Net Income	$533,577	$17,995	$151,083	$767,436	($376,558)	($27,030)	$652
	RATIOS ANALYSIS							
	REVENUE TO EXPENSES %	97.28%	89.31%	105.43%	176.08%	16.77%	34.80%	92.83%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($153,804)	($351,381)	$50,031	$635,792	($452,950)	($34,208)	($1,088)
	RETURN ON EQUITY COMPONENT OF RATE BASE	6.99%	0.46%	12.95%	43.98%	-53.41%	-40.36%	3.39%

2006 COST ALLOCATION INFORMATION FILING
BRANT COUNTY POWER INC.
EB-2005-0341 EB-2007-0002
February-28-06
Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - Optional Third Run

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1	2	3	7	8	9
	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
Customer Unit Cost per month - Avoided Cost	$7.40	$12.00	$42.66	$0.47	$0.41	$4.25
Customer Unit Cost per month - Directly Related	$10.55	$17.51	$66.18	$0.70	$0.75	$6.18
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$27.00	$34.60	$95.98	$17.61	$17.68	$22.39
Fixed Charge per approved 2006 EDR	$11.14	$16.59	$29.37	$0.80	$2.50	$8.17

Information to be Used to Allocate PILs, ROD, ROE and A&G

	Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
General Plant - Gross Assets	$1,591,467	$868,409	$230,883	$285,401	$185,218	$17,404	$4,151
General Plant - Accumulated Depreciation	($581,173)	($317,126)	($84,314)	($104,223)	($67,638)	($6,356)	($1,516)
General Plant - Net Fixed Assets	$1,010,294	$551,283	$146,569	$181,178	$117,580	$11,048	$2,635
General Plant - Depreciation	$234,894	$128,174	$34,077	$42,124	$27,338	$2,569	$613
Total Net Fixed Assets Excluding General Plant	$11,070,325	$5,948,827	$1,627,454	$2,120,130	$1,230,288	$115,609	$28,017
Total Administration and General Expense	$1,040,115	$621,203	$179,819	$140,184	$87,484	$8,595	$2,830
Total O&M	$2,308,478	$1,399,191	$407,946	$291,744	$184,919	$18,330	$6,347

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

USoA Account #	Accounts	Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	
	Distribution Plant								
1860	Meters	$897,806	$664,592	$132,359	$100,855	$0	$0	$0	CWMC
	Accumulated Amortization								
	Accum. Amortization of Electric Utility Plant - Meters only	($167,352)	($123,881)	($24,672)	($18,799)	$0	$0	$0	
	Meter Net Fixed Assets	**$730,454**	**$540,711**	**$107,687**	**$82,056**	**$0**	**$0**	**$0**	
	Misc Revenue								
4082	Retail Services Revenues	($10,204)	($6,966)	($2,398)	($783)	($1)	($16)	($40)	CWNB
4084	Service Transaction Requests (STR) Revenues	($29)	($20)	($7)	($2)	($0)	($0)	($0)	CWNB
4090	Electric Services Incidental to Energy Sales	$0	$0	$0	$0	$0	$0	$0	CWNB
4220	Other Electric Revenues	$0	$0	$0	$0	$0	$0	$0	NFA
4225	Late Payment Charges	($85,606)	($45,099)	($21,119)	($18,443)	$0	($945)	$0	LPHA
	Sub-total	*($95,839)*	*($52,085)*	*($23,524)*	*($19,228)*	*($1)*	*($960)*	*($40)*	
	Operation								
5065	Meter Expense	$85,735	$63,464	$12,639	$9,631	$0	$0	$0	CWMC
5070	Customer Premises - Operation Labour	$63,534	$40,438	$6,961	$650	$13,943	$1,310	$233	CCA
5075	Customer Premises - Materials and Expenses	$2,710	$1,725	$297	$28	$595	$56	$10	CCA
	Sub-total	*$151,979*	*$105,627*	*$19,897*	*$10,308*	*$14,538*	*$1,366*	*$243*	
	Maintenance								
5175	Maintenance of Meters	$4,463	$3,304	$658	$501	$0	$0	$0	1860
	Billing and Collection								
5310	Meter Reading Expense	$202,254	$140,845	$45,685	$15,675	$48	$0	$0	CWMR
5315	Customer Billing	$256,325	$174,987	$60,242	$19,675	$23	$391	$1,007	CWNB
5320	Collecting	$249,042	$170,015	$58,530	$19,116	$23	$380	$979	CWNB
5325	Collecting- Cash Over and Short	$72	$49	$17	$6	$0	$0	$0	CWNB
5330	Collection Charges	$738	$504	$173	$57	$0	$1	$3	CWNB
	Sub-total	$708,431	$486,399	$164,648	$54,528	$95	$772	$1,989	
	Total Operation, Maintenance and Billing	$864,873	$595,331	$185,203	$65,337	$14,633	$2,138	$2,232	
	Amortization Expense - Meters	$45,305	$33,537	$6,679	$5,089	$0	$0	$0	
	Allocated PILs	$17,039	$12,599	$2,515	$1,925	$0	$0	$0	
	Allocated Debt Return	$28,857	$21,338	$4,260	$3,260	$0	$0	$0	
	Allocated Equity Return	$41,554	$30,727	$6,134	$4,694	$0	$0	$0	
	Total	**$901,790**	**$641,446**	**$181,267**	**$61,077**	**$14,632**	**$1,178**	**$2,191**	

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

USoA Account #	Accounts	Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	
	Distribution Plant								
1860	Meters	$897,806	$664,592	$132,359	$100,855	$0	$0	$0	CWMC
	Accumulated Amortization								
	Accum. Amortization of Electric Utility Plant - Meters only	($167,352)	($123,881)	($24,672)	($18,799)	$0	$0	$0	
	Meter Net Fixed Assets	$730,454	$540,711	$107,687	$82,056	$0	$0	$0	
	Allocated General Plant Net Fixed Assets	$66,819	$50,108	$9,698	$7,012	$0	$0	$0	
	Meter Net Fixed Assets Including General Plant	$797,273	$590,820	$117,385	$89,068	$0	$0	$0	
	Misc Revenue								
4082	Retail Services Revenues	($10,204)	($6,966)	($2,398)	($783)	($1)	($16)	($40)	CWNB
4084	Service Transaction Requests (STR) Revenues	($29)	($20)	($7)	($2)	($0)	($0)	($0)	CWNB
4090	Electric Services Incidental to Energy Sales	$0	$0	$0	$0	$0	$0	$0	CWNB
4220	Other Electric Revenues	$0	$0	$0	$0	$0	$0	$0	NFA
4225	Late Payment Charges	($85,606)	($45,099)	($21,119)	($18,443)	$0	($945)	$0	LPHA
	Sub-total	*($95,839)*	*($52,085)*	*($23,524)*	*($19,228)*	*($1)*	*($960)*	*($40)*	
	Operation								
5065	Meter Expense	$85,735	$63,464	$12,639	$9,631	$0	$0	$0	CWMC
5070	Customer Premises - Operation Labour	$63,534	$40,438	$6,961	$650	$13,943	$1,310	$233	CCA
5075	Customer Premises - Materials and Expenses	$2,710	$1,725	$297	$28	$595	$56	$10	CCA
	Sub-total	*$151,979*	*$105,627*	*$19,897*	*$10,308*	*$14,538*	*$1,366*	*$243*	
	Maintenance								
5175	Maintenance of Meters	$4,463	$3,304	$658	$501	$0	$0	$0	1860
	Billing and Collection								
5310	Meter Reading Expense	$202,254	$140,845	$45,685	$15,675	$48	$0	$0	CWMR
5315	Customer Billing	$256,325	$174,987	$60,242	$19,675	$23	$391	$1,007	CWNB
5320	Collecting	$249,042	$170,015	$58,530	$19,116	$23	$380	$979	CWNB
5325	Collecting- Cash Over and Short	$72	$49	$17	$6	$0	$0	$0	CWNB
5330	Collection Charges	$738	$504	$173	$57	$0	$1	$3	CWNB
	Sub-total	*$708,431*	*$486,399*	*$164,648*	*$54,528*	*$95*	*$772*	*$1,989*	
	Total Operation, Maintenance and Billing	$864,873	$595,331	$185,203	$65,337	$14,633	$2,138	$2,232	
	Amortization Expense - Meters	$45,305	$33,537	$6,679	$5,089	$0	$0	$0	
	Amortization Expense - General Plant assigned to Meters	*$15,535*	*$11,650*	*$2,255*	*$1,630*	*$0*	*$0*	*$0*	
	Admin and General	$386,261	$264,311	$81,635	$31,395	$6,923	$1,003	$995	
	Allocated PILs	$18,598	$13,767	$2,742	$2,089	$0	$0	$0	
	Allocated Debt Return	$31,497	$23,315	$4,643	$3,538	$0	$0	$0	
	Allocated Equity Return	$45,355	$33,574	$6,687	$5,095	$0	$0	$0	
	Total	**$1,311,586**	**$923,399**	**$266,320**	**$94,946**	**$21,554**	**$2,180**	**$3,186**	

Scenario 3

Minimum System Customer Costs Adjusted for PLCC - High Limit Fixed Customer Charge

USoA Account #	Accounts	Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	
	Distribution Plant								
1565	Conservation and Demand Management Expenditures and Recoveries	$73,666	$44,650	$13,018	$9,310	$5,901	$585	$203	CDMPP
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	#N/A
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	BCP
1830-4	Poles, Towers and Fixtures - Primary	$1,447,669	$921,412	$158,605	$14,800	$317,703	$29,846	$5,303	PNCP
1830-5	Poles, Towers and Fixtures - Secondary	$108,964	$73,448	$6,476	$0	$26,147	$2,456	$436	SNCP
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	#N/A
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	BCP
1835-4	Overhead Conductors and Devices - Primary	$1,007,974	$641,555	$110,432	$10,305	$221,208	$20,781	$3,693	PNCP
1835-5	Overhead Conductors and Devices - Secondary	$318,308	$214,557	$18,918	$0	$76,382	$7,176	$1,275	SNCP
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	#N/A
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	BCP
1840-4	Underground Conduit - Primary	$207,158	$131,852	$22,696	$2,118	$45,462	$4,271	$759	PNCP
1840-5	Underground Conduit - Secondary	$4,228	$2,850	$251	$0	$1,014	$95	$17	SNCP
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	#N/A
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	BCP
1845-4	Underground Conductors and Devices - Primary	$371,255	$236,296	$40,674	$3,795	$81,475	$7,654	$1,360	PNCP
1845-5	Underground Conductors and Devices - Secondary	$660,009	$444,884	$39,226	$0	$158,378	$14,879	$2,644	SNCP
1850	Line Transformers	$1,669,167	$1,064,659	$181,410	$15,391	$367,094	$34,486	$6,128	LTNCP
1855	Services	$1,931,543	$1,228,932	$216,711	$0	$437,497	$41,100	$7,303	CWCS
1860	Meters	$897,806	$664,592	$132,359	$100,855	$0	$0	$0	CWMC

	Sub-total	*$8,697,747*	*$5,669,687*	*$940,774*	*$156,573*	*$1,738,262*	*$163,330*	*$29,120*	
	Accumulated Amortization								
	Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	($2,420,779)	($1,574,264)	($251,945)	($30,395)	($507,974)	($47,721)	($8,479)	
	Customer Related Net Fixed Assets	$6,276,969	$4,095,423	$688,829	$126,179	$1,230,288	$115,609	$20,641	
	Allocated General Plant Net Fixed Assets	$582,916	$379,527	$62,036	$10,783	$117,580	$11,048	$1,941	
	Customer Related NFA Including General Plant	$6,859,884	$4,474,950	$750,865	$136,961	$1,347,868	$126,657	$22,582	
	Misc Revenue								
4082	Retail Services Revenues	($10,204)	($6,966)	($2,398)	($783)	($1)	($16)	($40)	CWNB
4084	Service Transaction Requests (STR) Revenues	($29)	($20)	($7)	($2)	($0)	($0)	($0)	CWNB
4090	Electric Services Incidental to Energy Sales	$0	$0	$0	$0	$0	$0	$0	CWNB
4220	Other Electric Revenues	$0	$0	$0	$0	$0	$0	$0	NFA
4225	Late Payment Charges	($85,606)	($45,099)	($21,119)	($18,443)	$0	($945)	$0	LPHA
4235	Miscellaneous Service Revenues	($103,349)	($70,554)	($24,289)	($7,933)	($9)	($158)	($406)	CWNB
	Sub-total	*($199,188)*	*($122,639)*	*($47,813)*	*($27,161)*	*($10)*	*($1,118)*	*($446)*	
	Operating and Maintenance								
5005	Operation Supervision and Engineering	$22,168	$14,232	$2,282	$133	$4,970	$467	$83	1815-1855
5010	Load Dispatching	$0	$0	$0	$0	$0	$0	$0	1815-1855
5020	Overhead Distribution Lines and Feeders - Operation Labour	$39,440	$25,322	$4,028	$343	$8,775	$824	$146	1830 & 1835
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$8,930	$5,733	$912	$78	$1,987	$187	$33	1830 & 1835
5035	Overhead Distribution Transformers- Operation	$25,002	$15,947	$2,717	$231	$5,499	$517	$92	1850
5040	Underground Distribution Lines and Feeders - Operation Labour	$4,749	$3,118	$393	$23	$1,094	$103	$18	1840 & 1845
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$668	$439	$55	$3	$154	$14	$3	1840 & 1845
5055	Underground Distribution Transformers - Operation	$9,556	$6,095	$1,039	$88	$2,102	$197	$35	1850
5065	Meter Expense	$85,735	$63,464	$12,639	$9,631	$0	$0	$0	CWMC
5070	Customer Premises - Operation Labour	$63,534	$40,438	$6,961	$650	$13,943	$1,310	$233	CCA
5075	Customer Premises - Materials and Expenses	$2,710	$1,725	$297	$28	$595	$56	$10	CCA
5085	Miscellaneous Distribution Expense	$101,674	$65,277	$10,467	$611	$22,797	$2,142	$381	1815-1855
5090	Underground Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	1840 & 1845
5095	Overhead Distribution Lines and Feeders - Rental Paid	$2,340	$1,502	$239	$20	$521	$49	$9	1830 & 1835
5096	Other Rent	$0	$0	$0	$0	$0	$0	$0	O&M
5105	Maintenance Supervision and Engineering	$22,146	$14,218	$2,280	$133	$4,965	$466	$83	1815-1855
5120	Maintenance of Poles, Towers and Fixtures	$53,179	$33,987	$5,640	$506	$11,747	$1,104	$196	1830
5125	Maintenance of Overhead Conductors and Devices	$141,491	$91,332	$13,799	$1,099	$31,748	$2,983	$530	1835
5130	Maintenance of Overhead Services	$80,293	$51,086	$9,009	$0	$18,186	$1,709	$304	1855
5135	Overhead Distribution Lines and Feeders - Right of Way	$108,658	$69,763	$11,097	$946	$24,176	$2,271	$404	1830 & 1835
5145	Maintenance of Underground Conduit	$0	$0	$0	$0	$0	$0	$0	1840
5150	Maintenance of Underground Conductors and Devices	$11,093	$7,327	$859	$41	$2,580	$242	$43	1845
5155	Maintenance of Underground Services	$19,119	$12,165	$2,145	$0	$4,331	$407	$72	1855
5160	Maintenance of Line Transformers	$112,053	$71,472	$12,178	$1,033	$24,644	$2,315	$411	1850
5175	Maintenance of Meters	$4,463	$3,304	$658	$501	$0	$0	$0	1860
	Sub-total	*$919,000*	*$597,948*	*$99,695*	*$16,098*	*$184,813*	*$17,362*	*$3,085*	
	Billing and Collection								
5305	Supervision	$71,518	$48,824	$16,808	$5,489	$7	$109	$281	CWNB
5310	Meter Reading Expense	$202,254	$140,845	$45,685	$15,675	$48	$0	$0	CWMR
5315	Customer Billing	$256,325	$174,987	$60,242	$19,675	$23	$391	$1,007	CWNB
5320	Collecting	$249,042	$170,015	$58,530	$19,116	$23	$380	$979	CWNB
5325	Collecting- Cash Over and Short	$72	$49	$17	$6	$0	$0	$0	CWNB
5330	Collection Charges	$738	$504	$173	$57	$0	$1	$3	CWNB
5335	Bad Debt Expense	$52,379	$23,899	$14,640	$13,841	$0	$0	$0	BDHA
5340	Miscellaneous Customer Accounts Expenses	$56,914	$38,854	$13,376	$4,369	$5	$87	$224	CWNB
	Sub-total	*$889,242*	*$597,976*	*$209,472*	*$78,227*	*$106*	*$968*	*$2,494*	
	Sub Total Operating, Maintenance and Biling	*$1,808,243*	*$1,195,924*	*$309,166*	*$94,324*	*$184,919*	*$18,330*	*$5,579*	
	Amortization Expense - Customer Related	$419,394	$273,514	$45,438	$7,457	$83,722	$7,865	$1,398	
	Amortization Expense - General Plant assigned to Meters	$135,528	$88,240	$14,423	$2,507	$27,338	$2,569	$451	
	Admin and General	$811,125	$530,958	$136,277	$45,323	$87,484	$8,595	$2,488	
	Allocated PILs	$159,816	$104,273	$17,538	$3,213	$31,324	$2,943	$526	
	Allocated Debt Return	$270,660	$176,593	$29,702	$5,441	$53,050	$4,985	$890	
	Allocated Equity Return	$389,751	$254,294	$42,771	$7,835	$76,391	$7,178	$1,282	
	PLCC Adjustment for Line Transformer	$30,705	$25,796	$4,385	$375	$0	$0	$149	
	PLCC Adjustment for Primary Costs	$49,204	$41,037	$7,219	$711	$0	$0	$236	
	PLCC Adjustment for Secondary Costs	$42,511	$36,516	$5,766	$0	$0	$0	$229	
	Total	$3,672,911	**$2,397,808**	**$530,133**	**$137,852**	**$544,217**	**$51,348**	**$11,552**	

Below: Grouping to avoid disclosure

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

Accounts	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
Distribution Plant							
CWMC	$ 897,806	$ 664,592	$ 132,359	$ 100,855	$ -	$ -	$ -
Accumulated Amortization							
Accum. Amortization of Electric Utility Plant - Meters only	$ (167,352)	$ (123,881)	$ (24,672)	$ (18,799)	$ -	$ -	$ -
Meter Net Fixed Assets	$ 730,454	$ 540,711	$ 107,687	$ 82,056	$ -	$ -	$ -
Misc Revenue							
CWNB	$ (10,233)	$ (6,986)	$ (2,405)	$ (785)	$ (1)	$ (16)	$ (40)
NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ (85,606)	$ (45,099)	$ (21,119)	$ (18,443)	$ -	$ (945)	$ -
Sub-total	$ (95,839)	$ (52,085)	$ (23,524)	$ (19,228)	$ (1)	$ (960)	$ (40)
Operation							
CWMC	$ 85,735	$ 63,464	$ 12,639	$ 9,631	$ -	$ -	$ -
CCA	$ 66,244	$ 42,163	$ 7,258	$ 677	$ 14,538	$ 1,366	$ 243
Sub-total	$ 151,979	$ 105,627	$ 19,897	$ 10,308	$ 14,538	$ 1,366	$ 243
Maintenance							
1860	$ 4,463	$ 3,304	$ 658	$ 501	$ -	$ -	$ -
Billing and Collection							
CWMR	$ 202,254	$ 140,845	$ 45,685	$ 15,675	$ 48	$ -	$ -
CWNB	$ 506,177	$ 345,555	$ 118,962	$ 38,852	$ 46	$ 772	$ 1,989
Sub-total	$ 708,431	$ 486,399	$ 164,648	$ 54,528	$ 95	$ 772	$ 1,989
Total Operation, Maintenance and Billing	$ 864,873	$ 595,331	$ 185,203	$ 65,337	$ 14,633	$ 2,138	$ 2,232
Amortization Expense - Meters	$ 45,305	$ 33,537	$ 6,679	$ 5,089	$ -	$ -	$ -
Allocated PILs	$ 17,039	$ 12,599	$ 2,515	$ 1,925	$ -	$ -	$ -
Allocated Debt Return	$ 28,857	$ 21,338	$ 4,260	$ 3,260	$ -	$ -	$ -
Allocated Equity Return	$ 41,554	$ 30,727	$ 6,134	$ 4,694	$ -	$ -	$ -
Total	**$ 901,790**	**$ 641,446**	**$ 181,267**	**$ 61,077**	**$ 14,632**	**$ 1,178**	**$ 2,191**

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

Accounts	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
Distribution Plant							
CWMC	$ 897,806	$ 664,592	$ 132,359	$ 100,855	$ -	$ -	$ -
Accumulated Amortization							
Accum. Amortization of Electric Utility Plant - Meters only	$ (167,352)	$ (123,881)	$ (24,672)	$ (18,799)	$ -	$ -	$ -
Meter Net Fixed Assets	$ 730,454	$ 540,711	$ 107,687	$ 82,056	$ -	$ -	$ -
Allocated General Plant Net Fixed Assets	$ 66,819	$ 50,108	$ 9,698	$ 7,012	$ -	$ -	$ -
Meter Net Fixed Assets Including General Plant	$ 797,273	$ 590,820	$ 117,385	$ 89,068	$ -	$ -	$ -
Misc Revenue							
CWNB	$ (10,233)	$ (6,986)	$ (2,405)	$ (785)	$ (1)	$ (16)	$ (40)
NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ (85,606)	$ (45,099)	$ (21,119)	$ (18,443)	$ -	$ (945)	$ -
Sub-total	*$ (95,839)*	*$ (52,085)*	*$ (23,524)*	*$ (19,228)*	*$ (1)*	*$ (960)*	*$ (40)*
Operation							
CWMC	$ 85,735	$ 63,464	$ 12,639	$ 9,631	$ -	$ -	$ -
CCA	$ 66,244	$ 42,163	$ 7,258	$ 677	$ 14,538	$ 1,366	$ 243
Sub-total	*$ 151,979*	*$ 105,627*	*$ 19,897*	*$ 10,308*	*$ 14,538*	*$ 1,366*	*$ 243*
Maintenance							
1860	$ 4,463	$ 3,304	$ 658	$ 501	$ -	$ -	$ -
Billing and Collection							
CWMR	$ 202,254	$ 140,845	$ 45,685	$ 15,675	$ 48	$ -	$ -
CWNB	$ 506,177	$ 345,555	$ 118,962	$ 38,852	$ 46	$ 772	$ 1,989
Sub-total	*$ 708,431*	*$ 486,399*	*$ 164,648*	*$ 54,528*	*$ 95*	*$ 772*	*$ 1,989*
Total Operation, Maintenance and Billing	$ 864,873	$ 595,331	$ 185,203	$ 65,337	$ 14,633	$ 2,138	$ 2,232
Amortization Expense - Meters	$ 45,305	$ 33,537	$ 6,679	$ 5,089	$ -	$ -	$ -
Amortization Expense - General Plant assigned to Meters	$ 15,535	$ 11,650	$ 2,255	$ 1,630	$ -	$ -	$ -
Admin and General	$ 386,261	$ 264,311	$ 81,635	$ 31,395	$ 6,923	$ 1,003	$ 995
Allocated PILs	$ 18,598	$ 13,767	$ 2,742	$ 2,089	$ -	$ -	$ -
Allocated Debt Return	$ 31,497	$ 23,315	$ 4,643	$ 3,538	$ -	$ -	$ -
Allocated Equity Return	$ 45,355	$ 33,574	$ 6,687	$ 5,095	$ -	$ -	$ -
Total	**$ 1,311,586**	**$ 923,399**	**$ 266,320**	**$ 94,946**	**$ 21,554**	**$ 2,180**	**$ 3,186**

Scenario 3

Minimum System Customer Costs Adjusted for PLCC - High Limit Fixed Customer Charge

USoA Account #	Accounts	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
	Distribution Plant							
	CDMPP	$ 73,666	$ 44,650	$ 13,018	$ 9,310	$ 5,901	$ 585	$ 203
	Poles, Towers and Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	PNCP	$ 3,034,056	$ 1,931,116	$ 332,407	$ 31,018	$ 665,848	$ 62,553	$ 11,115
	SNCP	$ 1,091,509	$ 735,739	$ 64,870	$ -	$ 261,921	$ 24,606	$ 4,372
	Overhead Conductors and Devices	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	LTNCP	$ 1,669,167	$ 1,064,659	$ 181,410	$ 15,391	$ 367,094	$ 34,486	$ 6,128
	CWCS	$ 1,931,543	$ 1,228,932	$ 216,711	$ -	$ 437,497	$ 41,100	$ 7,303
	CWMC	$ 897,806	$ 664,592	$ 132,359	$ 100,855	$ -	$ -	$ -
	Sub-total	*$ 8,697,747*	*$ 5,669,687*	*$ 940,774*	*$ 156,573*	*$ 1,738,262*	*$ 163,330*	*$ 29,120*
	Accumulated Amortization							
	Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	$ (2,420,779)	$ (1,574,264)	$ (251,945)	$ (30,395)	$ (507,974)	$ (47,721)	$ (8,479)
	Customer Related Net Fixed Assets	$ 6,276,969	$ 4,095,423	$ 688,829	$ 126,179	$ 1,230,288	$ 115,609	$ 20,641
	Allocated General Plant Net Fixed Assets	$ 582,916	$ 379,527	$ 62,036	$ 10,783	$ 117,580	$ 11,048	$ 1,941
	Customer Related NFA Including General Plant	$ 6,859,884	$ 4,474,950	$ 750,865	$ 136,961	$ 1,347,868	$ 126,657	$ 22,582
	Misc Revenue							
	CWNB	$ (113,582)	$ (77,540)	$ (26,694)	$ (8,718)	$ (10)	$ (173)	$ (446)
	NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	LPHA	$ (85,606)	$ (45,099)	$ (21,119)	$ (18,443)	$ -	$ (945)	$ -
	Sub-total	*$ (199,188)*	*$ (122,639)*	*$ (47,813)*	*$ (27,161)*	*$ (10)*	*$ (1,118)*	*$ (446)*
	Operating and Maintenance							
	1815-1855	$ 145,987	$ 93,727	$ 15,029	$ 877	$ 32,733	$ 3,075	$ 546
	1830 & 1835	$ 159,367	$ 102,321	$ 16,276	$ 1,388	$ 35,459	$ 3,331	$ 592
	1850	$ 146,611	$ 93,514	$ 15,934	$ 1,352	$ 32,244	$ 3,029	$ 538
	1840 & 1845	$ 5,416	$ 3,556	$ 448	$ 26	$ 1,248	$ 117	$ 21
	CWMC	$ 85,735	$ 63,464	$ 12,639	$ 9,631	$ -	$ -	$ -
	CCA	$ 66,244	$ 42,163	$ 7,258	$ 677	$ 14,538	$ 1,366	$ 243
	O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1830	$ 53,179	$ 33,987	$ 5,640	$ 506	$ 11,747	$ 1,104	$ 196
	1835	$ 141,491	$ 91,332	$ 13,799	$ 1,099	$ 31,748	$ 2,983	$ 530
	1855	$ 99,412	$ 63,250	$ 11,154	$ -	$ 22,517	$ 2,115	$ 376
	1840	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1845	$ 11,093	$ 7,327	$ 859	$ 41	$ 2,580	$ 242	$ 43
	1860	$ 4,463	$ 3,304	$ 658	$ 501	$ -	$ -	$ -
	Sub-total	*$ 919,000*	*$ 597,948*	*$ 99,695*	*$ 16,098*	*$ 184,813*	*$ 17,362*	*$ 3,085*
	Billing and Collection							
	CWNB	$ 634,609	$ 433,232	$ 149,147	$ 48,710	$ 58	$ 968	$ 2,494
	CWMR	$ 202,254	$ 140,845	$ 45,685	$ 15,675	$ 48	$ -	$ -
	BDHA	$ 52,379	$ 23,899	$ 14,640	$ 13,841	$ -	$ -	$ -
	Sub-total	*$ 889,242*	*$ 597,976*	*$ 209,472*	*$ 78,227*	*$ 106*	*$ 968*	*$ 2,494*
	Sub Total Operating, Maintenance and Biling	*$ 1,808,243*	*$ 1,195,924*	*$ 309,166*	*$ 94,324*	*$ 184,919*	*$ 18,330*	*$ 5,579*
	Amortization Expense - Customer Related	$ 419,394	$ 273,514	$ 45,438	$ 7,457	$ 83,722	$ 7,865	$ 1,398
	Amortization Expense - General Plant assigned to Meters	$ 135,528	$ 88,240	$ 14,423	$ 2,507	$ 27,338	$ 2,569	$ 451
	Admin and General	$ 811,125	$ 530,958	$ 136,277	$ 45,323	$ 87,484	$ 8,595	$ 2,488
	Allocated PILs	$ 159,816	$ 104,273	$ 17,538	$ 3,213	$ 31,324	$ 2,943	$ 526
	Allocated Debt Return	$ 270,660	$ 176,593	$ 29,702	$ 5,441	$ 53,050	$ 4,985	$ 890
	Allocated Equity Return	$ 389,751	$ 254,294	$ 42,771	$ 7,835	$ 76,391	$ 7,178	$ 1,282
	PLCC Adjustment for Line Transformer	$ 30,705	$ 25,796	$ 4,385	$ 375	$ -	$ -	$ 149
	PLCC Adjustment for Primary Costs	$ 49,204	$ 41,037	$ 7,219	$ 711	$ -	$ -	$ 236
	PLCC Adjustment for Secondary Costs	$ 42,511	$ 36,516	$ 5,766	$ -	$ -	$ -	$ 229
	Total	**$ 3,672,911**	**$ 2,397,808**	**$ 530,133**	**$ 137,852**	**$ 544,217**	**$ 51,348**	**$ 11,552**

2006 COST ALLOCATION INFORMATION FILING
BRANT COUNTY POWER INC.
EB-2005-0341 EB-2007-0002
February-28-06
Sheet E4 Trial Balance Allocation Detail Worksheet - Optional Third Run

Details:
The worksheet below details how costs are treated, categorized, and grouped.

This sheet shows what accounts are included in the COSS, and how they are grouped into working capital and rate base. It shows how accounts are categorized in the customer and demand related costs. It will then show how the categorized costs are allocated to customer and demand related components. It will also show how Miscellaneous Revenue and General Plant and Administration costs are allocated. Finally, it will show how costs are being grouped together for presentation purposes.

Uniform System of Accounts - Detail Accounts:					Classification and Allocation			Allocation Demand Related	Allocation Customer Related	Allocation A&G Related	Allocation Misc Related				
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint	Demand ID	Customer ID	A & G ID	Misc ID	cp	ncp	non-demand	FINAL
1565	Conservation and Demand Management Expenditures and Recoveries	CDM Expenditures and Recoveries	dp			O&M			O&M						
1608	Franchises and Consents	Other Distribution Assets	gp							NFA ECC					
1805	Land		dp	DDCP											
1805-1	Land Station >50 kV		dp	TCP	TCP12			TCP12				TCP12			TCP12
1805-2	Land Station <50 kV		dp	DCP	DCP12			DCP12				DCP12			DCP12
1806	Land Rights		dp	DDCP											
1806-1	Land Rights Station >50 kV		dp	TCP	TCP12			TCP12				TCP12			TCP12
1806-2	Land Rights Station <50 kV		dp	DCP	DCP12			DCP12				DCP12			DCP12
1808	Buildings and Fixtures		dp	DDCP											
1808-1	Buildings and Fixtures > 50 kV		dp	TCP	TCP12			TCP12				TCP12			TCP12
1808-2	Buildings and Fixtures < 50 KV		dp	DCP	DCP12			DCP12				DCP12			DCP12
1810	Leasehold Improvements		dp	DDCP											
1810-1	Leasehold Improvements >50 kV		dp	TCP	TCP12			TCP12				TCP12			TCP12
1810-2	Leasehold Improvements <50 kV		dp	DCP	DCP12			DCP12				DCP12			DCP12
1815	Transformer Station Equipment - Normally Primary above 50 kV		dp	TCP	TCP12			TCP12				TCP12			TCP12
1820	Distribution Station Equipment - Normally Primary below 50 kV		dp	DCP	DCP12			DCP12				DCP12			DCP12
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)		dp	DCP	DCP12			DCP12				DCP12			DCP12
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)		dp	PNCP	PNCP4			PNCP4					PNCP4		PNCP4
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)		dp			CEN			CEN						
1825	Storage Battery Equipment		dp	DDCP											
1825-1	Storage Battery Equipment > 50 kV		dp	TCP	TCP12			TCP12				TCP12			TCP12
1825-2	Storage Battery Equipment <50 kV		dp	DCP	DCP12			DCP12				DCP12			DCP12
1830	Poles, Towers and Fixtures		dp	DDNCP											
1830-3	Poles, Towers and Fixtures Subtransmission Bulk Delivery		dp	BCP	BCP12			BCP12				BCP12			BCP12
1830-4	Poles, Towers and Fixtures Primary		dp	PNCP	PNCP4	CCP	x	PNCP4	CCP				PNCP4		PNCP4
1830-5	Poles, Towers and Fixtures Secondary		dp	SNCP	SNCP4	CCS	x	SNCP4	CCS				SNCP4		SNCP4
1835	Overhead Conductors and Devices		dp	DDNCP											
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery		dp	BCP	BCP12			BCP12				BCP12			BCP12
1835-4	Overhead Conductors and Devices - Primary		dp	PNCP	PNCP4	CCP	x	PNCP4	CCP				PNCP4		PNCP4
1835-5	Overhead Conductors and Devices - Secondary		dp	SNCP	SNCP4	CCS	x	SNCP4	CCS				SNCP4		SNCP4
1840	Underground Conduit		dp	DDNCP											
1840-3	Underground Conduit - Bulk Delivery	Land and Buildings	dp	BCP	BCP12			BCP12				BCP12			BCP12
1840-4	Underground Conduit - Primary	Land and Buildings	dp	PNCP	PNCP4	CCP	x	PNCP4	CCP				PNCP4		PNCP4
1840-5	Underground Conduit - Secondary	Land and Buildings	dp	SNCP	SNCP4	CCS	x	SNCP4	CCS				SNCP4		SNCP4
1845	Underground Conductors and Devices	Land and Buildings	dp	DDNCP											
1845-3	Underground Conductors and Devices - Bulk Delivery	TS Primary Above 50	dp	BCP	BCP12			BCP12				BCP12			BCP12
1845-4	Underground Conductors and Devices - Primary	DS	dp	PNCP	PNCP4	CCP	x	PNCP4	CCP				PNCP4		PNCP4
1845-5	Underground Conductors and Devices - Secondary	Other Distribution Assets	dp	SNCP	SNCP4	CCS	x	SNCP4	CCS				SNCP4		SNCP4
1850	Line Transformers	Poles, Wires	dp	LTNCP	LTNCP4	CCLT	x	LTNCP4	CCLT				LTNCP4		LTNCP4
1855	Services	Services and Meters	dp			CWCS			CWCS						
1860	Meters	Services and Meters	dp			CWMC			CWMC						
1905	Land	Land and Buildings	gp							NFA ECC					
1906	Land Rights	Land and Buildings	gp							NFA ECC					
1908	Buildings and Fixtures	General Plant	gp							NFA ECC					
1910	Leasehold Improvements	General Plant	gp							NFA ECC					
1915	Office Furniture and Equipment	Equipment	gp							NFA ECC					

1920	Computer Equipment - Hardware	IT Assets	gp							NFA ECC					
1925	Computer Software	IT Assets	gp							NFA ECC					
1930	Transportation Equipment	Equipment	gp							NFA ECC					
1935	Stores Equipment	Equipment	gp							NFA ECC					
1940	Tools, Shop and Garage Equipment	Equipment	gp							NFA ECC					
1945	Measurement and Testing Equipment	Equipment	gp							NFA ECC					
1950	Power Operated Equipment	Equipment	gp							NFA ECC					
1955	Communication Equipment	Equipment	gp							NFA ECC					
1960	Miscellaneous Equipment	Equipment	gp							NFA ECC					
1970	Load Management Controls - Customer Premises	Other Distribution Assets	gp							NFA ECC					
1975	Load Management Controls - Utility Premises	Other Distribution Assets	gp							NFA ECC					
1980	System Supervisory Equipment	Other Distribution Assets	gp							NFA ECC					
1990	Other Tangible Property	Other Distribution Assets	gp							NFA ECC					
1995	Contributions and Grants - Credit	Contributions and Grants	co		Break out	Breakout		Break out	Breakout						
2005	Property Under Capital Leases	Other Distribution Assets	gp							NFA ECC					
2010	Electric Plant Purchased or Sold	Other Distribution Assets	gp							NFA ECC					
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	Accumulated Amortization	accum dep		Break out	Breakout		Break out	Breakout						
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	Accumulated Amortization	accum dep		Break out	Breakout		Break out	Breakout						
3046	Balance Transferred From Income	Equity	NI								NFA				
4080	Distribution Services Revenue	Distribution Services Revenue	CREV								CREV				
4082	Retail Services Revenues	Other Distribution Revenue	mi								CWNB				
4084	Service Transaction Requests (STR) Revenues	Other Distribution Revenue	mi								CWNB				
4090	Electric Services Incidental to Energy Sales	Other Distribution Revenue	mi								CWNB				
4205	Interdepartmental Rents	Other Distribution Revenue	mi								NFA				
4210	Rent from Electric Property	Other Distribution Revenue	mi								NFA				
4215	Other Utility Operating Income	Other Distribution Revenue	mi								NFA				
4220	Other Electric Revenues	Other Distribution Revenue	mi								NFA				
4225	Late Payment Charges	Late Payment Charges	mi								LPHA				
4235	Miscellaneous Service Revenues	Specific Service Charges	mi								CWNB				
4240	Provision for Rate Refunds	Other Distribution Revenue	mi								NFA				
4245	Government Assistance Directly Credited to Income	Other Distribution Revenue	mi								NFA				
4305	Regulatory Debits	Other Income & Deductions	mi								NFA				
4310	Regulatory Credits	Other Income & Deductions	mi								NFA				
4315	Revenues from Electric Plant Leased to Others	Other Income & Deductions	mi								NFA				
4320	Expenses of Electric Plant Leased to Others	Other Income & Deductions	mi								NFA				
4325	Revenues from Merchandise, Jobbing, Etc.	Other Income & Deductions	mi								NFA				
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	Other Income & Deductions	mi								NFA				
4335	Profits and Losses from Financial Instrument Hedges	Other Income & Deductions	mi								NFA				
4340	Profits and Losses from Financial Instrument Investments	Other Income & Deductions	mi								NFA				
4345	Gains from Disposition of Future Use Utility Plant	Other Income & Deductions	mi								NFA				
4350	Losses from Disposition of Future Use Utility Plant	Other Income & Deductions	mi								NFA				
4355	Gain on Disposition of Utility and Other Property	Other Income & Deductions	mi								NFA				
4360	Loss on Disposition of Utility and Other Property	Other Income & Deductions	mi								NFA				
4365	Gains from Disposition of Allowances for Emission	Other Income & Deductions	mi								NFA				
4370	Losses from Disposition of Allowances for Emission	Other Income & Deductions	mi								NFA				
4390	Miscellaneous Non-Operating Income	Other Income & Deductions	mi								NFA				
4395	Rate-Payer Benefit Including Interest	Other Income & Deductions	mi								NFA				
4398	Foreign Exchange Gains and Losses, Including Amortization	Other Income & Deductions	mi								NFA				
4405	Interest and Dividend Income	Other Income & Deductions	mi								NFA				
4415	Equity in Earnings of Subsidiary Companies	Other Income & Deductions	mi								NFA				
4705	Power Purchased	Power Supply Expenses (Working Capital)	cop							CEN EWMP					

4708	Charges-WMS	Power Supply Expenses (Working Capital)	cop							CEN EWMP						
4710	Cost of Power Adjustments	Power Supply Expenses (Working Capital)	cop							CEN EWMP						
4712	Charges-One-Time	Power Supply Expenses (Working Capital)	cop							CEN EWMP						
4714	Charges-NW	Power Supply Expenses (Working Capital)	cop							CEN						
4715	System Control and Load Dispatching	Other Power Supply Expenses	cop							CEN EWMP						
4716	Charges-CN	Power Supply Expenses (Working Capital)	cop							CEN						
4730	Rural Rate Assistance Expense	Power Supply Expenses (Working Capital)	cop							CEN EWMP						
5005	Operation Supervision and Engineering	Operation (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x	1815-1855 D	1815-1855 C						1815-1855 D	1815-1855 D
5010	Load Dispatching	Operation (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x	1815-1855 D	1815-1855 C						1815-1855 D	1815-1855 D
5012	Station Buildings and Fixtures Expense	Operation (Working Capital)	di	1808 D	1808 D	1808 C		1808 D	1808 C						1808 D	1808 D
5014	Transformer Station Equipment - Operation Labour	Operation (Working Capital)	di	1815 D	1815 D	1815 C		1815 D	1815 C						1815 D	1815 D
5015	Transformer Station Equipment - Operation Supplies and Expenses	Operation (Working Capital)	di	1815 D	1815 D	1815 C		1815 D	1815 C						1815 D	1815 D
5016	Distribution Station Equipment - Operation Labour	Operation (Working Capital)	di	1820 D	1820 D	1820 C		1820 D	1820 C						1820 D	1820 D
5017	Distribution Station Equipment - Operation Supplies and Expenses	Operation (Working Capital)	di	1820 D	1820 D	1820 C		1820 D	1820 C						1820 D	1820 D
5020	Overhead Distribution Lines and Feeders - Operation Labour	Operation (Working Capital)	di	1830 & 1835 D	830 & 1835	1830 & 1835 C	x	830 & 1835	1830 & 1835 C						1830 & 1835 D	1830 & 1835 D
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	Operation (Working Capital)	di	1830 & 1835 D	830 & 1835	1830 & 1835 C	x	830 & 1835	1830 & 1835 C						1830 & 1835 D	1830 & 1835 D
5030	Overhead Subtransmission Feeders - Operation	Operation (Working Capital)	di	1830 & 1835 D	830 & 1835	1830 & 1835 C		830 & 1835	1830 & 1835 C						1830 & 1835 D	1830 & 1835 D
5035	Overhead Distribution Transformers- Operation	Operation (Working Capital)	di	1850 D	1850 D	1850 C	x	1850 D	1850 C						1850 D	1850 D
5040	Underground Distribution Lines and Feeders - Operation Labour	Operation (Working Capital)	di	1840 & 1845 D	840 & 1845	1840 & 1845 C	x	840 & 1845	1840 & 1845 C						1840 & 1845 D	1840 & 1845 D
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	Operation (Working Capital)	di	1840 & 1845 D	840 & 1845	1840 & 1845 C	x	840 & 1845	1840 & 1845 C						1840 & 1845 D	1840 & 1845 D
5050	Underground Subtransmission Feeders - Operation	Operation (Working Capital)	di	1840 & 1845 D	840 & 1845	1840 & 1845 C		840 & 1845	1840 & 1845 C						1840 & 1845 D	1840 & 1845 D
5055	Underground Distribution Transformers - Operation	Operation (Working Capital)	di	1850 D	1850 D	1850 C	x	1850 D	1850 C						1850 D	1850 D
5065	Meter Expense	Operation (Working Capital)	cu			CWMC			CWMC							
5070	Customer Premises - Operation Labour	Operation (Working Capital)	cu			CCA			CCA							
5075	Customer Premises - Materials and Expenses	Operation (Working Capital)	cu			CCA			CCA							
5085	Miscellaneous Distribution Expense	Operation (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x	1815-1855 D	1815-1855 C						1815-1855 D	1815-1855 D
5090	Underground Distribution Lines and Feeders - Rental Paid	Operation (Working Capital)	di	1840 & 1845 D	840 & 1845	1840 & 1845 C	x	840 & 1845	1840 & 1845 C						1840 & 1845 D	1840 & 1845 D
5095	Overhead Distribution Lines and Feeders - Rental Paid	Operation (Working Capital)	di	1830 & 1835 D	830 & 1835	1830 & 1835 C	x	830 & 1835	1830 & 1835 C						1830 & 1835 D	1830 & 1835 D
5096	Other Rent	Operation (Working Capital)	di							O&M						
5105	Maintenance Supervision and Engineering	Maintenance (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x	1815-1855 D	1815-1855 C						1815-1855 D	1815-1855 D
5110	Maintenance of Buildings and Fixtures - Distribution Stations	Maintenance (Working Capital)	di	1808 D	1808 D	1808 C		1808 D	1808 C						1808 D	1808 D
5112	Maintenance of Transformer Station Equipment	Maintenance (Working Capital)	di	1815 D	1815 D	1815 C		1815 D	1815 C						1815 D	1815 D
5114	Maintenance of Distribution Station Equipment	Maintenance (Working Capital)	di	1820 D	1820 D	1820 C		1820 D	1820 C						1820 D	1820 D
5120	Maintenance of Poles, Towers and Fixtures	Maintenance (Working Capital)	di	1830 D	1830 D	1830 C	x	1830 D	1830 C						1830 D	1830 D
5125	Maintenance of Overhead Conductors and Devices	Maintenance (Working Capital)	di	1835 D	1835 D	1835 C	x	1835 D	1835 C						1835 D	1835 D
5130	Maintenance of Overhead Services	Maintenance (Working Capital)	di	1855 D	1855 D	1855 C		1855 D	1855 C						1855 D	1855 D
5135	Overhead Distribution Lines and Feeders - Right of Way	Maintenance (Working Capital)	di	1830 & 1835 D	830 & 1835	1830 & 1835 C	x	830 & 1835	1830 & 1835 C						1830 & 1835 D	1830 & 1835 D
5145	Maintenance of Underground Conduit	Maintenance (Working Capital)	di	1840 D	1840 D	1840 C	x	1840 D	1840 C						1840 D	1840 D
5150	Maintenance of Underground Conductors and Devices	Maintenance (Working Capital)	di	1845 D	1845 D	1845 C	x	1845 D	1845 C						1845 D	1845 D
5155	Maintenance of Underground Services	Maintenance (Working Capital)	di	1855 D	1855 D	1855 C		1855 D	1855 C						1855 D	1855 D
5160	Maintenance of Line Transformers	Maintenance (Working Capital)	di	1850 D	1850 D	1850 C	x	1850 D	1850 C						1850 D	1850 D
5175	Maintenance of Meters	Maintenance (Working Capital)	cu	1860 D	1860 D	1860 C		1860 D	1860 C						1860 D	1860 D
5305	Supervision	Billing and Collection (Working Capital)	cu			CWNB			CWNB							

5310	Meter Reading Expense	Billing and Collection (Working Capital)	cu			CWMR			CWMR						
5315	Customer Billing	Billing and Collection (Working Capital)	cu			CWNB			CWNB						
5320	Collecting	Billing and Collection (Working Capital)	cu			CWNB			CWNB						
5325	Collecting- Cash Over and Short	Billing and Collection (Working Capital)	cu			CWNB			CWNB						
5330	Collection Charges	Billing and Collection (Working Capital)	cu			CWNB			CWNB						
5335	Bad Debt Expense	Bad Debt Expense (Working Capital)	cu			BDHA			BDHA						
5340	Miscellaneous Customer Accounts Expenses	Billing and Collection (Working Capital)	cu			CWNB			CWNB						
5405	Supervision	Community Relations (Working Capital)	ad							O&M					
5410	Community Relations - Sundry	Community Relations (Working Capital)	ad							O&M					
5415	Energy Conservation	Community Relations - CDM (Working Capital)	ad							O&M					
5420	Community Safety Program	Community Relations (Working Capital)	ad							NFA ECC					
5425	Miscellaneous Customer Service and Informational Expenses	Community Relations (Working Capital)	ad							O&M					
5505	Supervision	Other Distribution Expenses	ad							O&M					
5510	Demonstrating and Selling Expense	Other Distribution Expenses	ad							O&M					
5515	Advertising Expense	Advertising Expenses	ad							O&M					
5520	Miscellaneous Sales Expense	Other Distribution Expenses	ad							O&M					
5605	Executive Salaries and Expenses	Administrative and General Expenses (Working Capital)	ad							O&M					
5610	Management Salaries and Expenses	Administrative and General Expenses (Working Capital)	ad							O&M					
5615	General Administrative Salaries and Expenses	Administrative and General Expenses (Working Capital)	ad							O&M					
5620	Office Supplies and Expenses	Administrative and General Expenses (Working Capital)	ad							O&M					
5625	Administrative Expense Transferred Credit	Administrative and General Expenses (Working Capital)	ad							O&M					
5630	Outside Services Employed	Administrative and General Expenses (Working Capital)	ad							O&M					
5635	Property Insurance	Insurance Expense (Working Capital)	ad							NFA ECC					
5640	Injuries and Damages	Administrative and General Expenses (Working Capital)	ad							O&M					
5645	Employee Pensions and Benefits	Administrative and General Expenses (Working Capital)	ad							O&M					
5650	Franchise Requirements	Administrative and General Expenses (Working Capital)	ad							O&M					
5655	Regulatory Expenses	Administrative and General Expenses (Working Capital)	ad							O&M					
5660	General Advertising Expenses	Advertising Expenses	ad							O&M					
5665	Miscellaneous General Expenses	Administrative and General Expenses (Working Capital)	ad							O&M					
5670	Rent	Administrative and General Expenses (Working Capital)	ad							O&M					
5675	Maintenance of General Plant	Administrative and General Expenses (Working Capital)	ad							O&M					
5680	Electrical Safety Authority Fees	Administrative and General Expenses (Working Capital)	ad							O&M					
5685	Independent Market Operator Fees and Penalties	Power Supply Expenses (Working Capital)	cop							NFA ECC					
5705	Amortization Expense - Property, Plant, and Equipment	Amortization of Assets	dep	PRORATED	Break out	Breakout			Breakout					PRORATED	PRORATED
5710	Amortization of Limited Term Electric Plant	Amortization of Assets	dep	PRORATED	Break out	Breakout			Breakout					PRORATED	PRORATED
5715	Amortization of Intangibles and Other Electric Plant	Amortization of Assets	dep	PRORATED	Break out	Breakout			Breakout					PRORATED	PRORATED
5720	Amortization of Electric Plant Acquisition Adjustments	Other Amortization Unclassified	dep	PRORATED	Break out	Breakout			Breakout					PRORATED	PRORATED
5730	Amortization of Unrecovered Plant and Regulatory Study Costs	Amortization of Assets	dep							O&M					
5735	Amortization of Deferred Development Costs	Amortization of Assets	dep							O&M					
5740	Amortization of Deferred Charges	Amortization of Assets	dep							O&M					

6005	Interest on Long Term Debt	Interest Expense - Unclassifed	INT							NFA					
6105	Taxes Other Than Income Taxes	Other Distribution Expenses	ad							NFA					
6110	Income Taxes	Income Tax Expense - Unclassified	Input							NFA					
6205	Donations	Charitable Contributions	ad							O&M					
6210	Life Insurance	Insurance Expense (Working Capital)	ad							O&M					
6215	Penalties	Other Distribution Expenses	ad							O&M					
6225	Other Deductions	Other Distribution Expenses	ad							O&M					

Treatment of Transformer Ownership

Brant County Power has utilized the 2004 information filing cost allocation model (with updates for 2011 test year). Brant County Power has adjusted the model as described in the Filing Guidelines.

Brant County Power is providing a version of 2011 updated Cost Allocation Model O1 – prior to removal of transformer revenues and expenses as required. Please see next page.

Ontario

2011 COST ALLOCATION MODEL - WITH TRANSFORMER ALLOWANCE

BRANT COUNTY POWER INC.

July-19-10

Sheet O1 Revenue to Cost Summary Worksheet - Optional Third Run

Class Revenue, Cost Analysis, and Return on Rate Base

			1	2	3	7	8	9
Rate Base Assets		Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
crev	Distribution Revenue (sale)	$5,908,802	$2,938,680	$960,548	$1,921,096	$47,026	$12,345	$29,108
mi	Miscellaneous Revenue (mi)	$557,326	$410,325	$124,000	$25,397	($3,246)	$694	$157
	Total Revenue	$6,466,128	$3,349,005	$1,084,548	$1,946,493	$43,780	$13,038	$29,264
	Expenses							
di	Distribution Costs (di)	$1,289,420	$661,745	$217,134	$298,708	$101,976	$6,651	$3,206
cu	Customer Related Costs (cu)	$984,164	$678,815	$197,831	$72,427	$31,402	$2,862	$827
ad	General and Administration (ad)	$1,571,454	$925,480	$286,363	$257,768	$92,461	$6,584	$2,799
dep	Depreciation and Amortization (dep)	$968,765	$547,699	$158,803	$185,432	$70,075	$4,570	$2,186
INPUT	PILs (INPUT)	$101,117	$55,212	$16,698	$21,758	$6,785	$442	$221
INT	Interest	$735,548	$401,629	$121,467	$158,273	$49,353	$3,219	$1,607
	Total Expenses	$5,650,468	$3,270,581	$998,295	$994,366	$352,052	$24,328	$10,846
	Direct Allocation	$0	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$888,212	$484,987	$146,678	$191,123	$59,596	$3,887	$1,941
	Revenue Requirement (includes NI)	$6,538,679	$3,755,568	$1,144,973	$1,185,488	$411,648	$28,215	$12,787
		Revenue Requirement Input Does Not Equal Output						
	Rate Base Calculation							
	<u>Net Assets</u>							
dp	Distribution Plant - Gross	$28,002,813	$15,446,856	$4,616,793	$5,663,172	$2,076,202	$135,411	$64,380
gp	General Plant - Gross	$3,849,223	$2,110,619	$635,620	$808,463	$268,430	$17,507	$8,585
accum dep	Accumulated Depreciation	($11,002,991)	($6,125,457)	($1,809,623)	($2,092,652)	($890,701)	($58,092)	($26,467)
co	Capital Contribution	($1,191,455)	($694,577)	($196,584)	($157,793)	($130,519)	($8,512)	($3,470)
	Total Net Plant	$19,657,590	$10,737,440	$3,246,205	$4,221,191	$1,323,412	$86,313	$43,028
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$23,320,775	$6,834,773	$3,335,005	$12,944,938	$145,618	$18,355	$42,086
	OM&A Expenses	$3,845,038	$2,266,040	$701,327	$628,903	$225,839	$16,097	$6,832
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0
	Subtotal	*$27,165,813*	*$9,100,813*	*$4,036,332*	*$13,573,841*	*$371,458*	*$34,451*	*$48,919*
	Working Capital	$4,074,872	$1,365,122	$605,450	$2,036,076	$55,719	$5,168	$7,338
	Total Rate Base	$23,732,462	$12,102,562	$3,851,655	$6,257,267	$1,379,130	$91,481	$50,366
		Rate Base Input Does Not Equal Output						
	Equity Component of Rate Base	$9,492,985	$4,841,025	$1,540,662	$2,502,907	$551,652	$36,592	$20,146
	Net Income on Allocated Assets	$815,661	$78,424	$86,252	$952,127	($308,272)	($11,290)	$18,418
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0
	Net Income	$815,661	$78,424	$86,252	$952,127	($308,272)	($11,290)	$18,418
	RATIOS ANALYSIS							
	REVENUE TO EXPENSES %	98.89%	89.17%	94.72%	164.19%	10.64%	46.21%	228.87%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($72,551)	($406,563)	($60,425)	$761,004	($367,868)	($15,177)	$16,478
	RETURN ON EQUITY COMPONENT OF RATE BASE	8.59%	1.62%	5.60%	38.04%	-55.88%	-30.85%	91.42%

Revenue to Cost Ratios

The proposed revenue to cost ratios are within the Board approved range. The residential and GS customers have equivalent revenue to cost ratios which Brant County Power suggests is fair and reasonable. Existing rates showed the GS>50kW classification having a revenue to cost ratio that was unreasonably high. Brant County Power has moved the Streetlight and Sentinel Lights to the minimum of the Board approved range in the first year rather than phasing such a cost in over 2 years. Brant County Power would propose to move Streetlights and Sentinel to approximately a 1:1 revenue cost ratio during its next rebasing.

	Total	Residential	GS < 50 kW	GS > 50 kW	Street Light	Sentinel Light	Unmetered
2004 Informational Filing							
Revenue	5,501,552	2,935,549	970,947	1,471,433	91,280	18,259	14,085
Allocated Expenses	5,655,356	3,286,930	920,916	835,640	544,230	52,467	15,173
RC %	**97%**	**89%**	**105%**	**176%**	**17%**	**35%**	**93%**
2011 Updated CA Model - Existing Rates							
2011 Revenue with Deficiency	6,209,190	2,899,028	1,019,455	2,217,864	46,708	11,503	14,633
Deficiency	329,489	153,836	54,097	117,691	2,479	610	776
2011 Adjusted Revenue	6,538,679	3,052,864	1,073,552	2,335,554	49,187	12,113	15,409
Allocated Expenses	6,538,679	3,760,359	1,146,212	1,181,564	409,706	28,119	12,720
RC %	**100%**	**81%**	**94%**	**198%**	**12%**	**43%**	**121%**
2011 - Updated CA Model - Proposed Rates							
Revenue	6,466,128	3,798,695	1,157,898	1,193,610	283,612	19,465	12,849
Allocated Expenses	6,466,128	3,718,635	1,133,494	1,168,454	405,160	27,807	12,579
RC %	**100%**	**102%**	**102%**	**102%**	**70%**	**70%**	**102%**

Rate Design: Overview

This Exhibit documents the calculation of Brant County Power's proposed distribution rates by rate class for the 2011 test year, based on rate design as proposed in this Exhibit. Brant County Power has determined its total 2011 service revenue requirement to be $6,466,128.

The total revenue offsets in the amount of $557,326 (including transformer allowances) reduce Brant County Power's total service revenue requirement to a base revenue requirement to $5,980,802 which is used to determine the proposed distribution rates. The base revenue requirement is derived from Brant County Power's 2011 capital and operating forecasts, weather normalized usage, forecasted customer counts, and the board approved methodology for capital structure and return on equity.

Brant County Power is not including any new rate classes, other than the MicroFIT Generator less than 10kW which was established by the Board in its Decision and Order EB-2009-0326 which stated:

> microFIT Generator
> *"This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system."*

The Board established a fixed monthly charge of $5.25/month for each connected facility. Brant County currently has 3 such facilities in its licensed distribution territory. At this time Brant County Power does not anticipate that revenue will exceed $1000 for the forecast 2011 Test Year.Brant County Power has assumed this revenue is included in "Other Revenue".

Brant County Power is not requesting a change to its rate classifications. Brant County Power did consider a new rate classification for embedded distributors. Brant County Power only has a single embedded distributor, Brantford Power Inc., and the load for this delivery point does not warrant a new rate classification. Brant County Power is requesting that additional clarification be added to the General Service rate classifications. The current definition refer to a monthly average demand. Brant County is requesting that this be clarified by adding text to the rate categories. "The average monthly demand is determined by taking the average of the 5 highest monthly demands over the previous 12 months." Where the average is within 5% of limit of the classification, Brant County Power may elect not to switch rate classifications for the customer. This will avoid switching rate classifications for customers and provide rate stability. Brant County Power will update the Conditions of Service to reflect such change.

Customer impacts (which are all below the OEB 10% target) include charges beyond the control of BCP management. (i.e. Brant County is now charged for distribution by Brantford Power Inc. with a current annual cost of approximately $375,000). The Brantford Power charge represents 6% of the base revenue requirement. This increase is caught in the LV wheeling charge on the tariff sheet and is offset by a variance account balance owing to BCP customers. Brant County Power would propose that the only change from 2010 approved rates RTRs would be to incorporate any uniform changes to Wholesale RTR's within the province.

Brant County Power has sought to mitigate the impact on customers through careful examination of its OM&A expenditures and capital program while maintaining service standards and planning for a sustainable business.

Fixed / Variable Proportion

This schedule is intended to provide evidence as set out in section 2.9.1 of the Filing Guidelines. Brant County Power has provided the tables below showing the current fixed/variable split, the proposed fixed variable split and the comparison to the floor and ceiling amounts. Brant County Power confirms, as directed in Filing Guidelines, the analysis below is net of any rate adders and riders.

		Fixed		Variable	
Summary	RC%	Rate	%	Rate	%
Residential	102.15%	11.00	31.1%	0.0303	68.9%
GS < 50 kW	102.15%	17.00	25.1%	0.0205	74.9%
GS > 50 kW	102.15%	95.00	11.7%	2.3436	88.3%
Street Light	70.00%	1.50	18.3%	44.2301	81.7%
Sentinel Light	70.00%	2.00	29.4%	0.0209	70.6%
Unmetered Load	102.15%	2.00	10.6%	0.0209	89.4%

	Fixed %	Variable %	Total %
2010 - Fixed / Variable Proportion (current)			
Residential	38.2%	61.8%	100.0%
General Service < 50 kW	26.4%	73.6%	100.0%
General Service 50 to 4,999 kW	1.7%	98.3%	100.0%
Street Light	54.8%	45.2%	100.0%
Sentinel Light	57.3%	42.7%	100.0%
Unmetered Load	34.7%	65.3%	100.0%
2011 - Fixed / Variable Proportion (proposed)			
Residential	31.1%	68.9%	100.0%
General Service < 50 kW	25.1%	74.9%	100.0%
General Service 50 to 4,999 kW	11.7%	88.3%	100.0%
Street Light	18.3%	81.7%	100.0%
Sentinel Light	29.4%	70.6%	100.0%
Unmetered Load	10.6%	89.4%	100.0%

	Current Fixed Rate	Proposed Fixed Rate	2011 CA Floor	2011 CA Ceiling
Residential	11.02	11.00	10.14	21.48
General Service < 50 kW	16.94	17.00	16.25	32.05
General Service 50 to 4,999 kW	29.47	95.00	88	155.94
Street Light	0.81	1.50	1.1	13.79
Sentinel Light	2.53	2.00	1.46	14.02
Unmetered Load	8.27	2.00	1.54	11.94

Brant County Power is proposing distribution rates that change the current fixed / variable ratio of revenue requirement recovery. The proposed changes are all within the floor to ceiling range specified and tend to have the fixed portion closer to the floor value. The changes for each class are detailed below:

- Residential class
    - Fixed charge was rounded down to an even $11 per month (down $0.02 per customer per month).
    - The proposed 2011 fixed charge is within the floor / ceiling values calculated in the 2011 cost allocation model.
    - The fixed recovery % has decreased by approximately 7.1% (2010 approved to 2011 proposed).

- General Service < 50 kW class
  - Fixed charge was rounded up to an even $17 per month (up $0.06 per customer per month).
  - The proposed 2011 fixed charge is within the floor / ceiling values calculated in the 2011 cost allocation model.
  - The fixed recovery % has decreased by approximately 1.3% (2010 approved to 2011 proposed).
- General Service 50 to 4,999 kW
  - Fixed charge moved up to $95 per month (up $65.53 per customer per month).
  - The proposed 2011 fixed charge is within the floor / ceiling values calculated in the 2011 cost allocation model which was the main driver (as well as revenue stability from the class) for the movement of the fixed charge.
  - The fixed recovery % has increased by approximately 10% (2010 approved to 2011 proposed) as a result of the floor / ceiling values calculated in the 2011 cost allocation model. The fixed portion is still less than 11% of the total.
- Street Lights
  - Fixed charge moved up to $1.50 per month (up $0.69 per customer per month).
  - The proposed 2011 fixed charge is within the floor / ceiling values calculated in the 2011 cost allocation model.
  - The fixed recovery % has decreased by approximately 36% (2010 approved to 2011 proposed), which is a result of a small movement in the fixed charge (and revenue) while a drastic change in revenue to cost ratios proposed within this application.
- Sentinel Lights
  - Fixed charge was rounded down to an even $2 per month (down $0.53 per customer per month).
  - The proposed 2011 fixed charge is within the floor / ceiling values calculated in the 2011 cost allocation model.
  - The fixed recovery % has decreased by 28% (2010 approved to 2011 proposed), which is a result of a small reduction movement in the fixed charge (and revenue) and a drastic change in revenue to cost ratios proposed within this application.
- Unmetered Loads
  - Fixed charge was moved down to $2 per month (down $6.27 per customer per month).
  - The proposed 2011 fixed charge is within the floor / ceiling values calculated in the 2011 cost allocation model.
  - The fixed recovery % has decreased by approximately 25% (2010 approved to 2011 proposed).
    - Brant County believes that the fixed charges for all unmetered loads (including street light and sentinel lights) should be in close proximity due to similar load and service characteristics.

Retail Transmission Service Rates

As a result of the Board's decision in EB-2009-0063 (August, 2010), Brant County Power's dispute with its host distributor, Brantford Power Inc. has been resolved. Brantford had significantly underbilled Brant County Power for a period of several years. Therefore, customers have historically been underpaying for such service. The errors and the Board's decision to require payment of the previously unbilled amounts means that a simple trend analysis of the 2008/2009 costs is not appropriate. Brant County does not plan to revisit the prior year financial statements as there would be significant costs of such restatements while no change in the net income would result.

As part of the 2010 IRM process (EB-2009-0258), Brant County Power provided details that outlined specific costs forecasted for 2010 (this data has been inserted below) transmission and connection services.

Brant County Power requests that the only change from 2010 approved rates would be for any uniform changes to Wholesale RTR's within the province (which will be incorporated before final rate approval is received).

Brant County Power requests no changes to its existing Specific Service Charges and Retail Service Charges. The 2011 proposed rates are the same as the 2009 and 2010 actual rates in force.

2010 RTR Submission

	Network Variance							Connection Variance					
	Expenses	Revenues	Variance	BP Est Costs	Total Variance	Cummulative Variance		Expenses	Revenues	Variance	BP Est Costs	Total Varianc	Cummulative Variance
Q1 2009	166,875	233,777.00	**-66,902.00**	**47,436.14**	**-19,465.86**	**-19,465.86**		130,898.00	200,778.00	**-69,880.00**	**41,090.20**	**-28,789.80**	**-28,789.80**
Q2 2009	192,953	147,176.00	**45,777.00**	**42,817.47**	**88,594.47**	**69,128.61**		160,513.00	112,420.00	**48,093.00**	**36,203.37**	**84,296.37**	**55,506.57**
Total	**359,828.00**	**380,953.00**	**-21,125.00**	**90,253.61**	**69,128.61**			**291,411.00**	**313,198.00**	**-21,787.00**	**77,293.57**	**55,506.57**	
Trend (total variance / revenues)			**18.15%**	**decrease to customer**						**17.72%**	**decrease to customer**		
G-2008-0001 regulated changes			**15.60%**	**increase to customer**						**5.20%**	**decrease to customer**		
Cummulative Change			**33.75%**							**22.92%**			

Excerpt from EB-2009-0258 Decision

"In EB-2009-0258 the Board determined:

Retail Transmission Service Rates

Electricity distributors are charged the Ontario Uniform Transmission Rates ("UTRs") at the wholesale level and subsequently pass these charges on to their distribution customers through the Retail Transmission Service Rates ("RTSRs"). There are two RTSRs, whereas there are three UTRs. The two RTSRs are for network and connection. The wholesale line and transformation connection rates are combined into one retail connection service charge. Deferral accounts are used to capture timing differences and differences in the rate that a distributor pays for wholesale transmission service compared to the retail rate that the distributor is authorized to charge when billing its customers (i.e., deferral accounts 1584 and 1586).

On May 28, 2009, the Board issued its Decision and Rate Order in proceeding EB-2008-0272, which set new UTRs for Ontario transmitters, effective July 1, 2009. The new UTRs effective July 1, 2009 were as follows:

- Network Service Rate was increased from $2.57 to $2.66 per kW per month, a 3.5% increase;
- Line Connection Service Rate remained unchanged at $0.70 per kW per month; and
- Transformation Connection Service Rate was decreased from $1.62 to $1.57 per kW per month, for a combined Line and Transformation Connection Service Rates reduction of 2.2%.

On July 22, 2009 the Board issued an amended "Guideline for *Electricity Distribution Retail Transmission Service Rates*" ("RTSR Guideline"), which provided electricity distributors with instructions on the evidence needed, and the process to be used, to adjust RTSRs to reflect the changes in the UTRs effective July 1, 2009. The Board set as a proxy at that time an increase of 3.5% for the Network Service Rate and reduction of 2.2% for the combined Line and Transformation Connection Service Rates. The Board also noted that there would be further changes to the UTRs in January 2010. The objective of resetting the rates is to minimize the prospective balances in deferral accounts 1584 and 1586.

On January 21, 2010, the Board approved new UTRs effective January 1, 2010. The new UTRs were as follows:

- Network Service Rate has increased from $2.66 to $2.97 per kW per month, an 11.7% increase over the July 1, 2009 level or 15.6% over the rate in effect prior to July 1, 2009;
- Line Connection Service Rate has increased from $0.70 to $0.73 per kW per month; and
- Transformation Connection Service Rate has increased from $1.57 to $1.71 per kW per month, for a combined Line and Transformation Connection Service Rate increase of 7.5% over the July 1, 2009 level or 5.2% over the rate in effect prior to July 1, 2009.

In 2008, Brant County Power received a decision (EB-2008-0110) adjusting RTSRs for both a change in UTRs and to minimize the change in the 1584 and 1586 variance account balances. BCP requested and received approval for a reduction in its RTSRs by 39%. Subsequent to this decision, it came to BCP's attention that Brantford Power had not been billing all Transmission charges on all Brantford Power's feeders supplying Brant County Power customers. As a result historical transmission costs have been under stated.

Brant County Power applied for an adjustment to its RTSR rates based on a comparison of its RTS revenue under existing rates and adjusted wholesale transmission costs reflecting the July 1, 2009 UTRs and included the impact of Brantford Power's adjusted billings. Therefore, Brant County Power proposed to increase all of its RTS Network Rates by 15.6%, and decreased all of its RTS Connection Rates by 5.2%.

In its reply submission, Brant County Power updated its analysis to reflect the January 1, 2010 UTRs. As a result, Brant County Power requested an increase of 33.75% to the RTSR Network Service rate and an increase of about 22.92% to the RTSR Line and Transformation Connection Service Rate. The Board found that Brant County Power had provided a reasonable analysis and accepted the methodology used by Brant County Power to reset it RTSRs. The Board therefore will approve the revised RTSRs proposed by Brant County Power and will include these in the draft Rate Order."

End of Board Decision Excerpt.

Proposed Rates (currently no change from 2010 approved rates)

	Retail Transmission	Retail Connection	Billing Determinent
Residential	0.0052	0.0039	kWh
General Service < 50 kW	0.0048	0.0034	kWh
General Service 50 to 4,999 kW			
Regular	1.9188	1.4110	kW
Interval Metered < 1,000 kW	2.0355	1.5594	kW
Interval Metered > 1,000 kW	2.0378	1.5468	kW
Street Light	1.4472	1.0908	kW
Sentinel Light	1.4544	1.1137	kW
Unmetered Load	0.0048	0.0034	kWh

Low Voltage Charges

As with the Retail Transmission Charges, the EB-2009-0063 involved impacts to the expenses charged by Brantford Power to Brant County Power for Low Voltage Wheeling Services.

Brant County has used the value approved in EB-2009-0063 as an adder to the 2009 LV expenses paid to Hydro One.

2009 Actual LV expenses paid to Hydro One = $303,455

2010 LV expenses (actual/projected)

- Hydro One - $305,913
- Brantford Power - $375,000
- Total - $680,913

2011 LV Expenses (Projected)

- Hydro One - $305,332
- Brantford Power - $375,000
- Total - $680,832

Customer Class	2009 LV Rates	2011 Billing Determinents	2011 Draft Revenue (current rates)	2011 LV Expense	2011 Proposed LV Rates	2011 LV Revenue
Residential	0.0007	80,122,583	56,085.81		0.0023	184,281.94
GS < 50	0.0007	39,095,551	27,366.89		0.0023	89,919.77
GS > 50	0.3196	388,493	124,162.36		1.0364	402,634.15
Street Light	0.2394	4,783	1,145.05		0.7763	3,713.04
Sentinel Light	0.2048	574	117.56		0.6641	381.19
Unmetered	0.0007	493,370	345.36		0.0023	1,134.75
Total			209,223.02	678,455.00		682,064.84

Loss Factor Adjustments

Brant County Power is embedded through 3 delivery points through Brantford Power. Otherwise, all supply points are through Hydro One.

Brant County Power has proposed a loss factor of 4.82% (equal to 2009 actual results). The four year average loss factor is 6.29% but the losses in 2006 seem to be an anomaly. The three year average for 2007, 2008 and 2009 is 5.47% with the annual losses being reduced each year. A snapshot look at a one year loss factor value shows BCP slightly lower than the 5% target set by the OEB at 4.82%. The proposed loss factor is lower than the historical averages and actuals as BCP questions the 2006 value and believes that 2010 and 2011 capital projects will move the actual loss factors lower. Using this one year approach seems to be a conservative approach that will line up with projected changes in future losses and this approach benefits the end use rate payer;

Every year Brant County Power is investing capital to convert old lines from 8,320 volts to 27,600 volts, install new higher efficiency transformers, re-conductor lines. Brant County Power has, in some cases, been able to eliminate older, less efficient sub-stations. Brant County Power plans this work in to: (i) facilitate new growth to replace facilities; (ii) replace facilities that are at end of life; or (iii) to make system improvements to reduce our line loss. In addition, Brant County Power anticipates that the installation of the Smart Meters will aid in the ability to identify areas of concern and permit Brant County Power to better manage its system and reduce losses in the future.

Appendix 2-P
Loss Factors

		2006	2007	2008	2009	2010 - Bridge	2011 - Test
Losses in Distributor's System							
A1	"Wholesale" kWh dleivered to distributor (higher value)						
A2	"Wholesale" kWh delivered to distributor (lower value)	242,722,450	306,747,610	297,492,850	285,044,124	293,500,326	292,363,223
B	Portion of "Wholesale" kWh delivered to distributor for Large Use customer	-	-	-	-	-	-
C	Net "Wholesale" kWh delivered to distributor (A2 - B)	242,722,450	306,747,610	297,492,850	285,044,124	293,500,326	292,363,223
D	"Retail" kWh delivered by distributor	221,518,681	287,802,804	281,438,922	271,310,355	274,747,754	273,384,466
E	Portion of "Retail" kWh delivered by distributor for large use customers	-	-	-	-	-	-
F	Net "Retail" kWh delivered by distributor (D - E)	221,518,681	287,802,804	281,438,922	271,310,355	274,747,754	273,384,466
G	Loss Factor in Distributors System	8.74%	6.18%	5.40%	4.82%	6.39%	6.49%
Losses Upstream of Distributors System							
H	Supply Facility Loss Factor	1	1	1	1	1	1
Total Losses							
I	Total Loss Factor (G * H)	8.74%	6.18%	5.40%	4.82%	4.82%	4.82%

Draft Tariff Sheet

Brant County Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2011

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

EB-2010-0125

RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separate metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. All customers are single-phase. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	11.00
Smart Meter Funding Adder	$	1.00
Distribution Volumetric Rate	$/kWh	0.0303
Low Voltage Service Rate	$/kWh	0.0023
Retail Transmission Rate – Network Service Rate	$/kWh	0.0052
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0039
LRAM & SSM Rate Rider	$/kWh	0.0025
Deferral / Variance Account Rate Rider	$/kWh	-0.0057

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25
Special Purpose Charge	$/kWh	0.000405

Brant County Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2011

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EB-2010-0125

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification applies to a non-residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	17.00
Smart Meter Funding Adder	$	1.00
Distribution Volumetric Rate	$/kWh	0.0205
Low Voltage Service Rate	$/kWh	0.0023
Retail Transmission Rate – Network Service Rate	$/kWh	0.0048
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0034
LRAM & SSM Rate Rider	$/kWh	0.0016
Deferral / Variance Account Rate Rider	$/kWh	-0.0059

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25
Special Purpose Charge	$/kWh	0.000405

Brant County Power Inc.
TARIFF OF RATES AND CHARGES
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EB-2010-0125

GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

This classification applies to a non-residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Note that for the application of the Retail Transmission Rate – Network Service Rate and the Retail Transmission Rate – Line and Transformation Connection Service Rate the following sub-classifications apply:

General Service 50 to 1,000 kW non-interval metered
General Service 50 to 1,000 kW interval metered
General Service >1,000 to 5, 000 kW interval metered.

Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.
It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

Brant County Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2011

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EB-2010-0125

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	95.00
Smart Meter Funding Adder	$	1.00
Distribution Volumetric Rate	$/kW	2.3436
Low Voltage Service Rate	$/kW	1.0364
Retail Transmission Rate – Network Service Rate	$/kW	1.9188
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.4110
Retail Transmission Rate – Network Service Rate – Interval Metered <1,000 kW Rate	$/kW	2.0355
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered <1,000 kW	$/kW	1.5594
Retail Transmission Rate – Network Service Rate – Interval Metered >1,000 kW	$/kW	2.0378
Retail Transmission Rate – Line and Transformation Connection Service Rate– Interval Metered >1,000 kW	$/kW	1.5468
LRAM & SSM Rate Rider	$/kW	0.0067
Deferral / Variance Account Rate Rider	$/kW	-2.4165

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25
Special Purpose Charge	$/kWh	0.000405

Brant County Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2011

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EB-2010-0125

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/ documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	2.00
Distribution Volumetric Rate	$/kWh	0.0209
Low Voltage Service Rate	$/kWh	0.0023
Retail Transmission Rate – Network Service Rate	$/kWh	0.0048
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0034
LRAM & SSM Rate Rider	$/kWh	0.0016
Deferral / Variance Account Rate Rider	$/kWh	-0.0059

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25
Special Purpose Charge	$/kWh	0.000405

Brant County Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2011

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EB-2010-0125

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification applies to safety/security lighting with a Residential, General Service or Large Use customer. This is typically exterior lighting, and unmetered. Consumption is estimated based on the equipment rating and estimated hours of use. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.
It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	2.00
Distribution Volumetric Rate	$/kW	21.8402
Low Voltage Service Rate	$/kW	0.6641
Retail Transmission Rate – Network Service Rate	$/kW	1.4544
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.1137
LRAM & SSM Rate Rider	$/kW	0.0129
Deferral / Variance Account Rate Rider	$/kW	-1.9471

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25
Special Purpose Charge	$/kWh	0.000405

Brant County Power Inc.
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EB-2010-0125

STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.
It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	1.50
Distribution Volumetric Rate	$/kW	44.2301
Low Voltage Service Rate	$/kW	0.7763
Retail Transmission Rate – Network Service Rate	$/kW	1.4472
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.0908
LRAM & SSM Rate Rider	$/kW	0.8746
Deferral / Variance Account Rate Rider	$/kW	-1.5273

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25
Special Purpose Charge	$/kWh	0.000405

Brant County Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2011

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

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microFIT GENERATOR SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	5.25

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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)

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

Customer Administration

Arrears certificate	$	15.00
Statement of account	$	15.00
Pulling post-dated cheques	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement letter	$	15.00
Income tax letter	$	15.00
Notification charge	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Charge to certify cheque	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account

Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Collection of account charge – no disconnection – after regular hours	$	165.00
Disconnect/Reconnect Charge at Meter – during regular hours	$	65.00
Disconnect/Reconnect Charges at Meter – after regular hours	$	185.00
Disconnect/Reconnect Charge at Pole – during regular hours	$	185.00
Disconnect/Reconnect Charges at Pole – after regular hours	$	415.00
Service call – customer-owned equipment	$	30.00
Service call – after regular hours	$	165.00
Temporary service install and remove – overhead – no transformer	$	500.00
Temporary service install and remove – underground – no transformer	$	300.00
Temporary service install and remove – overhead – with transformer	$	1000.00
Rural system expansion / line connection fee	$	500.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

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

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

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0482
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0160
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0383
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0065

Customer Impacts

The purpose of this Schedule is to provide a summary of the bill impacts resulting from the requested rate order. Table 8a below provides a summary of the changes to each rate classification both as a percentage and a monthly dollar amount.

Table 8a

Rate Classification	Minimum Change %	Minimum Change $	Maximum Change %	Maximum Change $
Residential	3.23%	$0.88	5.85%	$16.53
GS<50kW	-0.45%	-$8.93	2.58%	$3.87
GS - 50kW to 4,999kW	-4.37%	-$262.37	-5.38%	-$1608.17
Unmetered	n/a	n/a	-3.48%	-$3.98
Sentinel	n/a	n/a	44.98%	$13.71
Streetlighting	n/a	n/a	227.36%	$46.58
MicroFit Generator	No Change			

Brant County Power is in its first cost of service hearing based upon a forward test year. Brant County has sought to set new rates in a manner that is consistent with regulatory principles and policies and balances the interests of ratepayers. The rates are within the Board approved ratios. Brant County has moved to the minimum of the Sentinel and Streetlighting classifications in the first year to limit the contribution of the remaining classes. Commercial/industrial ratepayers will see a rate decrease while residential customers will see small increase. With the proposed changes to the fixed:variable split, Brant County is providing residential customers with an ability reduce the potential impact through conservation efforts.

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Customer Class: **Residential**

Consumption 100 **kWh**

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	monthly	$ 10.9500	1	$ 10.95	$ 11.0000	1	$ 11.00	$ 0.05	0.46%
Smart Meter Rate Adder	monthly	$ 1.0000	1	$ 1.00	$ 1.0000	1	$ 1.00	$ -	0.00%
Service Charge Rate Adder(s)			1	$ -		1	$ -	$ -	
Service Charge Rate Rider(s)			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0216	100	$ 2.16	$ 0.0303	100	$ 3.03	$ 0.87	40.24%
Low Voltage Rate Adder	per kWh	$ 0.0008	100	$ 0.08	$ 0.0023	100	$ 0.23	$ 0.15	187.50%
Volumetric Rate Adder(s)			100	$ -		100	$ -	$ -	
Volumetric Rate Rider(s)			100	$ -		100	$ -	$ -	
Smart Meter Disposition Rider			100	$ -		100	$ -	$ -	
LRAM & SSM Rate Rider			100	$ -	$ 0.0025	100	$ 0.25	$ 0.25	
Deferral/Variance Account Disposition Rate Rider	per kWh		100	$ -	-$ 0.0057	100	-$ 0.57	-$ 0.57	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Sub-Total A - Distribution				**$ 14.19**			**$ 14.94**	**$ 0.75**	**5.27%**
RTSR - Network	per kWh	$ 0.0052	104.95	$ 0.55	$ 0.0052	104.82	$ 0.55	-$ 0.00	-0.12%
RTSR - Line and Transformation Connection	per kWh	$ 0.0039	104.95	$ 0.41	$ 0.0039	104.82	$ 0.41	-$ 0.00	-0.12%
Sub-Total B - Delivery (including Sub-Total A)				**$ 15.15**			**$ 15.89**	**$ 0.75**	**4.93%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	104.95	$ 0.55	$ 0.0052	104.82	$ 0.55	-$ 0.00	-0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	104.95	$ 0.14	$ 0.0013	104.82	$ 0.14	-$ 0.00	-0.12%
Special Purpose Charge	per kWh		104.95	$ -	$ 0.0004050	104.82	$ 0.04	$ 0.04	
Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	104.95	$ 0.73	$ 0.0070	104.82	$ 0.73	-$ 0.00	-0.12%
Energy	per kWh	$ 0.0694	104.95	$ 7.28	$ 0.0694	104.82	$ 7.27	-$ 0.01	-0.12%
	per kWh			$ -	$ -		$ -	$ -	
				$ -			$ -	$ -	
Total Bill (before Taxes)				**$ 24.10**			**$ 24.87**	**$ 0.78**	**3.23%**
HST		13%		$ 3.13	13%		$ 3.23	$ 0.10	3.23%
Total Bill (including Sub-total B)				**$ 27.23**			**$ 28.11**	**$ 0.88**	**3.23%**

Loss Factor (%)	4.95%	4.82%

Customer Class: **Residential**

Consumption 250 **kWh**

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	monthly	$ 10.9500	1	$ 10.95	$ 11.0000	1	$ 11.00	$ 0.05	0.46%
Smart Meter Rate Adder	monthly	$ 1.0000	1	$ 1.00	$ 1.0000	1	$ 1.00	$ -	0.00%
Service Charge Rate Adder(s)		$ -	1	$ -	$ -	1	$ -	$ -	
Service Charge Rate Rider(s)		$ -	1	$ -	$ -	1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0216	250	$ 5.40	$ 0.0303	250	$ 7.57	$ 2.17	40.24%
Low Voltage Rate Adder	per kWh	$ 0.0008	250	$ 0.20	$ 0.0023	250	$ 0.58	$ 0.38	187.50%
Volumetric Rate Adder(s)		$ -	250	$ -	$ -	250	$ -	$ -	
Volumetric Rate Rider(s)		$ -	250	$ -	$ -	250	$ -	$ -	
Smart Meter Disposition Rider		$ -	250	$ -	$ -	250	$ -	$ -	
LRAM & SSM Rate Rider		$ -	250	$ -	$ 0.0025	250	$ 0.63	$ 0.63	
Deferral/Variance Account Disposition Rate Rider	per kWh	$ -	250	$ -	-$ 0.0057	250	-$ 1.43	-$ 1.43	
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
Sub-Total A - Distribution				**$ 17.55**			**$ 19.35**	**$ 1.80**	**10.23%**
RTSR - Network	per kWh	$ 0.0052	262.375	$ 1.36	$ 0.0052	262.05	$ 1.36	-$ 0.00	-0.12%
RTSR - Line and Transformation Connection	per kWh	$ 0.0039	262.375	$ 1.02	$ 0.0039	262.05	$ 1.02	-$ 0.00	-0.12%
Sub-Total B - Delivery (including Sub-Total A)				**$ 19.94**			**$ 21.73**	**$ 1.79**	**8.99%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	262.375	$ 1.36	$ 0.0052	262.05	$ 1.36	-$ 0.00	-0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	262.375	$ 0.34	$ 0.0013	262.05	$ 0.34	-$ 0.00	-0.12%
Special Purpose Charge	per kWh	$ -	262.375	$ -	$ 0.0004	262.05	$ 0.11	$ 0.11	
Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	262.375	$ 1.84	$ 0.0070	262.05	$ 1.83	-$ 0.00	-0.12%
Energy	per kWh	$ 0.0694	262.375	$ 18.21	$ 0.0694	262.05	$ 18.19	-$ 0.02	-0.12%
	per kWh	$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
Total Bill (before Taxes)				**$ 41.94**			**$ 43.81**	**$ 1.87**	**4.46%**
HST		13%		$ 5.45	13%		$ 5.70	$ 0.24	4.46%
Total Bill (including Sub-total B)				**$ 47.39**			**$ 49.51**	**$ 2.12**	**4.47%**
Loss Factor (%)		4.95%			4.82%				

Customer Class: **Residential**

Consumption 500 kWh

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	monthly	$ 10.9500	1	$ 10.95	$ 11.0000	1	$ 11.00	$ 0.05	0.46%
Smart Meter Rate Adder	monthly	$ 1.0000	1	$ 1.00	$ 1.0000	1	$ 1.00	$ -	0.00%
Service Charge Rate Adder(s)		$ -	1	$ -	$ -	1	$ -	$ -	
Service Charge Rate Rider(s)		$ -	1	$ -	$ -	1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0216	500	$ 10.80	$ 0.0303	500	$ 15.15	$ 4.35	40.24%
Low Voltage Rate Adder	per kWh	$ 0.0008	500	$ 0.40	$ 0.0023	500	$ 1.15	$ 0.75	187.50%
Volumetric Rate Adder(s)		$ -	500	$ -	$ -	500	$ -	$ -	
Volumetric Rate Rider(s)		$ -	500	$ -	$ -	500	$ -	$ -	
Smart Meter Disposition Rider		$ -	500	$ -	$ -	500	$ -	$ -	
LRAM & SSM Rate Rider		$ -	500	$ -	$ 0.0025	500	$ 1.25	$ 1.25	
Deferral/Variance Account Disposition Rate Rider	per kWh	$ -	500	$ -	-$ 0.0057	500	-$ 2.85	-$ 2.85	
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
Sub-Total A - Distribution				**$ 23.15**			**$ 26.69**	**$ 3.54**	**15.30%**
RTSR - Network	per kWh	$ 0.0052	524.75	$ 2.73	$ 0.0052	524.1	$ 2.73	-$ 0.00	-0.12%
RTSR - Line and Transformation Connection	per kWh	$ 0.0039	524.75	$ 2.05	$ 0.0039	524.1	$ 2.04	-$ 0.00	-0.12%
Sub-Total B - Delivery (including Sub-Total A)				**$ 27.93**			**$ 31.46**	**$ 3.54**	**12.66%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	524.75	$ 2.73	$ 0.0052	524.1	$ 2.73	-$ 0.00	-0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	524.75	$ 0.68	$ 0.0013	524.1	$ 0.68	-$ 0.00	-0.12%
Special Purpose Charge	per kWh	$ -	524.75	$ -	$ 0.0004	524.1	$ 0.21	$ 0.21	
Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	524.75	$ 3.67	$ 0.0070	524.1	$ 3.67	-$ 0.00	-0.12%
Energy	per kWh	$ 0.0694	524.75	$ 36.42	$ 0.0694	524.1	$ 36.37	-$ 0.05	-0.12%
	per kWh	$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
Total Bill (before Taxes)				**$ 71.68**			**$ 75.37**	**$ 3.69**	**5.15%**
HST		13%		$ 9.32	13%		$ 9.80	$ 0.48	5.15%
Total Bill (including Sub-total B)				**$ 81.00**			**$ 85.17**	**$ 4.17**	**5.15%**

Loss Factor (%)	4.95%		4.82%

Customer Class: **Residential**

Consumption 800 **kWh**

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Monthly Service Charge	monthly	$ 10.9500	1	$ 10.95	$ 11.0000	1	$ 11.00	$ 0.05	0.46%
Smart Meter Rate Adder	monthly	$ 1.0000	1	$ 1.00	$ 1.0000	1	$ 1.00	$ -	0.00%
Service Charge Rate Adder(s)		$ -	1	$ -	$ -	1	$ -	$ -	
Service Charge Rate Rider(s)		$ -	1	$ -	$ -	1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0216	800	$ 17.28	$ 0.0303	800	$ 24.23	$ 6.95	40.24%
Low Voltage Rate Adder	per kWh	$ 0.0008	800	$ 0.64	$ 0.0023	800	$ 1.84	$ 1.20	187.50%
Volumetric Rate Adder(s)		$ -	800	$ -	$ -	800	$ -	$ -	
Volumetric Rate Rider(s)		$ -	800	$ -	$ -	800	$ -	$ -	
Smart Meter Disposition Rider		$ -	800	$ -	$ -	800	$ -	$ -	
LRAM & SSM Rate Rider		$ -	800	$ -	$ 0.0025	800	$ 2.00	$ 2.00	
Deferral/Variance Account Disposition Rate Rider	per kWh	$ -	800	$ -	-$ 0.0057	800	-$ 4.57	-$ 4.57	
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
Sub-Total A - Distribution				**$ 29.87**			**$ 35.51**	**$ 5.64**	**18.87%**
RTSR - Network	per kWh	$ 0.0052	839.6	$ 4.37	$ 0.0052	838.56	$ 4.36	-$ 0.01	-0.12%
RTSR - Line and Transformation Connection	per kWh	$ 0.0039	839.6	$ 3.27	$ 0.0039	838.56	$ 3.27	-$ 0.00	-0.12%
Sub-Total B - Delivery (including Sub-Total A)				**$ 37.51**			**$ 43.14**	**$ 5.63**	**15.00%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	839.6	$ 4.37	$ 0.0052	838.56	$ 4.36	-$ 0.01	-0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	839.6	$ 1.09	$ 0.0013	838.56	$ 1.09	-$ 0.00	-0.12%
Special Purpose Charge	per kWh	$ -	839.6	$ -	$ 0.0004	838.56	$ 0.34	$ 0.34	
Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	839.6	$ 5.88	$ 0.0070	838.56	$ 5.87	-$ 0.01	-0.12%
Energy	per kWh	$ 0.0694	839.6	$ 58.27	$ 0.0694	838.56	$ 58.20	-$ 0.07	-0.12%
	per kWh	$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
Total Bill (before Taxes)				**$ 107.36**			**$ 113.24**	**$ 5.88**	**5.48%**
HST		13%		$ 13.96	13%		$ 14.72	$ 0.76	5.48%
Total Bill (including Sub-total B)				**$ 121.32**			**$ 127.97**	**$ 6.65**	**5.48%**

Loss Factor (%) 4.95% 4.82%

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Customer Class: **Residential**

Consumption 1000 **kWh**

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	monthly	$ 10.9500	1	$ 10.95	$ 11.0000	1	$ 11.00	$ 0.05	0.46%
Smart Meter Rate Adder	monthly	$ 1.0000	1	$ 1.00	$ 1.0000	1	$ 1.00	$ -	0.00%
Service Charge Rate Adder(s)		$ -	1	$ -	$ -	1	$ -	$ -	
Service Charge Rate Rider(s)		$ -	1	$ -	$ -	1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0216	1000	$ 21.60	$ 0.0303	1000	$ 30.29	$ 8.69	40.24%
Low Voltage Rate Adder	per kWh	$ 0.0008	1000	$ 0.80	$ 0.0023	1000	$ 2.30	$ 1.50	187.50%
Volumetric Rate Adder(s)		$ -	1000	$ -	$ -	1000	$ -	$ -	
Volumetric Rate Rider(s)		$ -	1000	$ -	$ -	1000	$ -	$ -	
Smart Meter Disposition Rider		$ -	1000	$ -	$ -	1000	$ -	$ -	
LRAM & SSM Rate Rider		$ -	1000	$ -	$ 0.0025	1000	$ 2.50	$ 2.50	
Deferral/Variance Account Disposition Rate Rider	per kWh	$ -	1000	$ -	-$ 0.0057	1000	-$ 5.71	-$ 5.71	
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
Sub-Total A - Distribution				**$ 34.35**			**$ 41.38**	**$ 7.03**	**20.48%**
RTSR - Network	per kWh	$ 0.0052	1049.5	$ 5.46	$ 0.0052	1048.2	$ 5.45	-$ 0.01	-0.12%
RTSR - Line and Transformation Connection	per kWh	$ 0.0039	1049.5	$ 4.09	$ 0.0039	1048.2	$ 4.09	-$ 0.01	-0.12%
Sub-Total B - Delivery (including Sub-Total A)				**$ 43.90**			**$ 50.92**	**$ 7.02**	**15.99%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	1049.5	$ 5.46	$ 0.0052	1048.2	$ 5.45	-$ 0.01	-0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	1049.5	$ 1.36	$ 0.0013	1048.2	$ 1.36	-$ 0.00	-0.12%
Special Purpose Charge	per kWh	$ -	1049.5	$ -	$ 0.0004	1048.2	$ 0.42	$ 0.42	
Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	1049.5	$ 7.35	$ 0.0070	1048.2	$ 7.34	-$ 0.01	-0.12%
Energy	per kWh	$ 0.0694	1049.5	$ 72.84	$ 0.0694	1048.2	$ 72.75	-$ 0.09	-0.12%
	per kWh	$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
Total Bill (before Taxes)				**$ 131.15**			**$ 138.49**	**$ 7.34**	**5.60%**
HST		13%		$ 17.05	13%		$ 18.00	$ 0.95	5.60%
Total Bill (including Sub-total B)				**$ 148.20**			**$ 156.50**	**$ 8.30**	**5.60%**
Loss Factor (%)		4.95%			4.82%				

Customer Class: Residential

Consumption 1500 kWh

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	monthly	$ 10.9500	1	$ 10.95	$ 11.0000	1	$ 11.00	$ 0.05	0.46%
Smart Meter Rate Adder	monthly	$ 1.0000	1	$ 1.00	$ 1.0000	1	$ 1.00	$ -	0.00%
Service Charge Rate Adder(s)		$ -	1	$ -	$ -	1	$ -	$ -	
Service Charge Rate Rider(s)		$ -	1	$ -	$ -	1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0216	1500	$ 32.40	$ 0.0303	1500	$ 45.44	$ 13.04	40.24%
Low Voltage Rate Adder	per kWh	$ 0.0008	1500	$ 1.20	$ 0.0023	1500	$ 3.45	$ 2.25	187.50%
Volumetric Rate Adder(s)		$ -	1500	$ -	$ -	1500	$ -	$ -	
Volumetric Rate Rider(s)		$ -	1500	$ -	$ -	1500	$ -	$ -	
Smart Meter Disposition Rider		$ -	1500	$ -	$ -	1500	$ -	$ -	
LRAM & SSM Rate Rider		$ -	1500	$ -	$ 0.0025	1500	$ 3.75	$ 3.75	
Deferral/Variance Account Disposition Rate Rider	per kWh	$ -	1500	$ -	-$ 0.0057	1500	-$ 8.56	-$ 8.56	
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
Sub-Total A - Distribution				**$ 45.55**			**$ 56.08**	**$ 10.53**	**23.11%**
RTSR - Network	per kWh	$ 0.0052	1574.25	$ 8.19	$ 0.0052	1572.3	$ 8.18	-$ 0.01	-0.12%
RTSR - Line and Transformation Connection	per kWh	$ 0.0039	1574.25	$ 6.14	$ 0.0039	1572.3	$ 6.13	-$ 0.01	-0.12%
Sub-Total B - Delivery (including Sub-Total A)				**$ 59.88**			**$ 70.38**	**$ 10.51**	**17.55%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	1574.25	$ 8.19	$ 0.0052	1572.3	$ 8.18	-$ 0.01	-0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	1574.25	$ 2.05	$ 0.0013	1572.3	$ 2.04	-$ 0.00	-0.12%
Special Purpose Charge	per kWh	$ -	1574.25	$ -	$ 0.0004	1572.3	$ 0.64	$ 0.64	
Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	1574.25	$ 11.02	$ 0.0070	1572.3	$ 11.01	-$ 0.01	-0.12%
Energy	per kWh	$ 0.0694	1574.25	$ 109.25	$ 0.0694	1572.3	$ 109.12	-$ 0.14	-0.12%
	per kWh	$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
Total Bill (before Taxes)				**$ 190.63**			**$ 201.61**	**$ 10.98**	**5.76%**
HST		13%		$ 24.78	13%		$ 26.21	$ 1.43	5.76%
Total Bill (including Sub-total B)				**$ 215.41**			**$ 227.82**	**$ 12.41**	**5.76%**
Loss Factor (%)		4.95%			4.82%				

Customer Class: Residential

Consumption 2000 kWh

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	monthly	$ 10.9500	1	$ 10.95	$ 11.0000	1	$ 11.00	$ 0.05	0.46%
Smart Meter Rate Adder	monthly	$ 1.0000	1	$ 1.00	$ 1.0000	1	$ 1.00	$ -	0.00%
Service Charge Rate Adder(s)		$ -	1	$ -	$ -	1	$ -	$ -	
Service Charge Rate Rider(s)		$ -	1	$ -	$ -	1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0216	2000	$ 43.20	$ 0.0303	2000	$ 60.58	$ 17.38	40.24%
Low Voltage Rate Adder	per kWh	$ 0.0008	2000	$ 1.60	$ 0.0023	2000	$ 4.60	$ 3.00	187.50%
Volumetric Rate Adder(s)		$ -	2000	$ -	$ -	2000	$ -	$ -	
Volumetric Rate Rider(s)		$ -	2000	$ -	$ -	2000	$ -	$ -	
Smart Meter Disposition Rider		$ -	2000	$ -	$ -	2000	$ -	$ -	
LRAM & SSM Rate Rider		$ -	2000	$ -	$ 0.0025	2000	$ 5.00	$ 5.00	
Deferral/Variance Account Disposition Rate Rider	per kWh	$ -	2000	$ -	-$ 0.0057	2000	-$ 11.41	-$ 11.41	
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
Sub-Total A - Distribution				**$ 56.75**			**$ 70.77**	**$ 14.02**	**24.70%**
RTSR - Network	per kWh	$ 0.0052	2099	$ 10.91	$ 0.0052	2096.4	$ 10.90	-$ 0.01	-0.12%
RTSR - Line and Transformation Connection	per kWh	$ 0.0039	2099	$ 8.19	$ 0.0039	2096.4	$ 8.18	-$ 0.01	-0.12%
Sub-Total B - Delivery (including Sub-Total A)				**$ 75.85**			**$ 89.84**	**$ 13.99**	**18.45%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	2099	$ 10.91	$ 0.0052	2096.4	$ 10.90	-$ 0.01	-0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	2099	$ 2.73	$ 0.0013	2096.4	$ 2.73	-$ 0.00	-0.12%
Special Purpose Charge	per kWh	$ -	2099	$ -	$ 0.0004	2096.4	$ 0.85	$ 0.85	
Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2099	$ 14.69	$ 0.0070	2096.4	$ 14.67	-$ 0.02	-0.12%
Energy	per kWh	$ 0.0694	2099	$ 145.67	$ 0.0694	2096.4	$ 145.49	-$ 0.18	-0.12%
	per kWh	$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
Total Bill (before Taxes)				**$ 250.11**			**$ 264.73**	**$ 14.63**	**5.85%**
HST		13%		$ 32.51	13%		$ 34.42	$ 1.90	5.85%
Total Bill (including Sub-total B)				**$ 282.62**			**$ 299.15**	**$ 16.53**	**5.85%**

	Current Board-Approved	Proposed
Loss Factor (%)	4.95%	4.82%

Customer Class: **General Service < 50 kW**

Consumption 1000 kWh

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	monthly	$ 16.5100	1	$ 16.51	$ 17.0000	1	$ 17.00	$ 0.49	2.97%
Smart Meter Rate Adder	monthly	$ 1.0000	1	$ 1.00	$ 1.0000	1	$ 1.00	$ -	0.00%
Service Charge Rate Adder(s)			1	$ -		1	$ -	$ -	
Service Charge Rate Rider(s)			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0186	1000	$ 18.60	$ 0.0205	1000	$ 20.46	$ 1.86	9.98%
Low Voltage Rate Adder	per kWh	$ 0.0007	1000	$ 0.70	$ 0.0023	1000	$ 2.30	$ 1.60	228.57%
Volumetric Rate Adder(s)			1000	$ -		1000	$ -	$ -	
Volumetric Rate Rider(s)			1000	$ -		1000	$ -	$ -	
Smart Meter Disposition Rider			1000	$ -		1000	$ -	$ -	
LRAM & SSM Rate Rider			1000	$ -	$ 0.0016	1000	$ 1.60	$ 1.60	
Deferral/Variance Account Disposition Rate Rider	per kWh		1000	$ -	-$ 0.0059	1000	-$ 5.92	-$ 5.92	
GA - Rate Rider (if applicable)				$ -	$ 0.0035	1000	$ 3.50	$ 3.50	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Sub-Total A - Distribution				**$ 36.81**			**$ 39.93**	**$ 3.12**	**8.48%**
RTSR - Network	per kWh	$ 0.0048	1049.5	$ 5.04	$ 0.0048	1048.2	$ 5.03	-$ 0.01	-0.12%
RTSR - Line and Transformation Connection	per kWh	$ 0.0034	1049.5	$ 3.57	$ 0.0034	1048.2	$ 3.56	-$ 0.00	-0.12%
Sub-Total B - Delivery (including Sub-Total A)				**$ 45.42**			**$ 48.53**	**$ 3.11**	**6.85%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	1049.5	$ 5.46	$ 0.0052	1048.2	$ 5.45	-$ 0.01	-0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	1049.5	$ 1.36	$ 0.0013	1048.2	$ 1.36	-$ 0.00	-0.12%
Special Purpose Charge	per kWh		1049.5	$ -	$ 0.0004050	1048.2	$ 0.42	$ 0.42	
Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	1049.5	$ 7.35	$ 0.0070	1048.2	$ 7.34	-$ 0.01	-0.12%
Energy	per kWh	$ 0.0694	1049.5	$ 72.84	$ 0.0694	1048.2	$ 72.75	-$ 0.09	-0.12%
	per kWh	$ -		$ -	$ -		$ -	$ -	
				$ -			$ -	$ -	
Total Bill (before Taxes)				**$ 132.67**			**$ 136.10**	**$ 3.43**	**2.58%**
HST		13%		$ 17.25	13%		$ 17.69	$ 0.45	2.58%
Total Bill (including Sub-total B)				**$ 149.92**			**$ 153.79**	**$ 3.87**	**2.58%**

Loss Factor (%)	4.95%	4.82%

Customer Class: **General Service < 50 kW**

Consumption **2000** **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	monthly	$ 16.5100	1	$ 16.51	$ 17.0000	1	$ 17.00	$ 0.49	2.97%
Smart Meter Rate Adder	monthly	$ 1.0000	1	$ 1.00	$ 1.0000	1	$ 1.00	$ -	0.00%
Service Charge Rate Adder(s)		$ -	1	$ -	$ -	1	$ -	$ -	
Service Charge Rate Rider(s)		$ -	1	$ -	$ -	1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0186	2000	$ 37.20	$ 0.0205	2000	$ 40.91	$ 3.71	9.98%
Low Voltage Rate Adder	per kWh	$ 0.0007	2000	$ 1.40	$ 0.0023	2000	$ 4.60	$ 3.20	228.57%
Volumetric Rate Adder(s)		$ -	2000	$ -	$ -	2000	$ -	$ -	
Volumetric Rate Rider(s)		$ -	2000	$ -	$ -	2000	$ -	$ -	
Smart Meter Disposition Rider		$ -	2000	$ -	$ -	2000	$ -	$ -	
LRAM & SSM Rate Rider		$ -	2000	$ -	$ 0.0016	2000	$ 3.20	$ 3.20	
Deferral/Variance Account Disposition Rate Rider	per kWh	$ -	2000	$ -	-$ 0.0059	2000	-$ 11.85	-$ 11.85	
		$ -		$ -	$ 0.0035		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
Sub-Total A - Distribution				**$ 56.11**			**$ 54.87**	**-$ 1.24**	**-2.21%**
RTSR - Network	per kWh	$ 0.0048	2099	$ 10.08	$ 0.0048	2096.4	$ 10.06	-$ 0.01	-0.12%
RTSR - Line and Transformation Connection	per kWh	$ 0.0034	2099	$ 7.14	$ 0.0034	2096.4	$ 7.13	-$ 0.01	-0.12%
Sub-Total B - Delivery (including Sub-Total A)				**$ 73.32**			**$ 72.06**	**-$ 1.26**	**-1.72%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	2099	$ 10.91	$ 0.0052	2096.4	$ 10.90	-$ 0.01	-0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	2099	$ 2.73	$ 0.0013	2096.4	$ 2.73	-$ 0.00	-0.12%
Special Purpose Charge	per kWh	$ -	2099	$ -	$ 0.0004	2096.4	$ 0.85	$ 0.85	
Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2099	$ 14.69	$ 0.0070	2096.4	$ 14.67	-$ 0.02	-0.12%
Energy	per kWh	$ 0.0694	2099	$ 145.67	$ 0.0694	2096.4	$ 145.49	-$ 0.18	-0.12%
	per kWh	$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
Total Bill (before Taxes)				**$ 247.58**			**$ 246.95**	**-$ 0.63**	**-0.25%**
HST		13%		$ 32.19	13%		$ 32.10	-$ 0.08	-0.25%
Total Bill (including Sub-total B)				**$ 279.76**			**$ 279.05**	**-$ 0.71**	**-0.25%**
Loss Factor (%)		4.95%			4.82%				

Customer Class: **General Service < 50 kW**

Consumption 5000 kWh

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	monthly	$ 16.5100	1	$ 16.51	$ 17.0000	1	$ 17.00	$ 0.49	2.97%
Smart Meter Rate Adder	monthly	$ 1.0000	1	$ 1.00	$ 1.0000	1	$ 1.00	$ -	0.00%
Service Charge Rate Adder(s)		$ -	1	$ -	$ -	1	$ -	$ -	
Service Charge Rate Rider(s)		$ -	1	$ -	$ -	1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0186	5000	$ 93.00	$ 0.0205	5000	$ 102.28	$ 9.28	9.98%
Low Voltage Rate Adder	per kWh	$ 0.0007	5000	$ 3.50	$ 0.0023	5000	$ 11.50	$ 8.00	228.57%
Volumetric Rate Adder(s)		$ -	5000	$ -	$ -	5000	$ -	$ -	
Volumetric Rate Rider(s)		$ -	5000	$ -	$ -	5000	$ -	$ -	
Smart Meter Disposition Rider		$ -	5000	$ -	$ -	5000	$ -	$ -	
LRAM & SSM Rate Rider		$ -	5000	$ -	$ 0.0016	5000	$ 8.00	$ 8.00	
Deferral/Variance Account Disposition Rate Rider	per kWh	$ -	5000	$ -	-$ 0.0059	5000	-$ 29.61	-$ 29.61	
		$ -		$ -	$ 0.0035		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
Sub-Total A - Distribution				**$ 114.01**			**$ 110.17**	**-$ 3.84**	**-3.37%**
RTSR - Network	per kWh	$ 0.0048	5247.5	$ 25.19	$ 0.0048	5241	$ 25.16	-$ 0.03	-0.12%
RTSR - Line and Transformation Connection	per kWh	$ 0.0034	5247.5	$ 17.84	$ 0.0034	5241	$ 17.82	-$ 0.02	-0.12%
Sub-Total B - Delivery (including Sub-Total A)				**$ 157.04**			**$ 153.15**	**-$ 3.89**	**-2.48%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	5247.5	$ 27.29	$ 0.0052	5241	$ 27.25	-$ 0.03	-0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	5247.5	$ 6.82	$ 0.0013	5241	$ 6.81	-$ 0.01	-0.12%
Special Purpose Charge	per kWh	$ -	5247.5	$ -	$ 0.0004	5241	$ 2.12	$ 2.12	
Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	5247.5	$ 36.73	$ 0.0070	5241	$ 36.69	-$ 0.05	-0.12%
Energy	per kWh	$ 0.0694	5247.5	$ 364.18	$ 0.0694	5241	$ 363.73	-$ 0.45	-0.12%
	per kWh	$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
Total Bill (before Taxes)				**$ 592.31**			**$ 590.00**	**-$ 2.31**	**-0.39%**
HST		13%		$ 77.00	13%		$ 76.70	-$ 0.30	-0.39%
Total Bill (including Sub-total B)				**$ 669.31**			**$ 666.70**	**-$ 2.61**	**-0.39%**
Loss Factor (%)		4.95%			4.82%				

Customer Class: **General Service < 50 kW**

Consumption 10000 **kWh**

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	monthly	$ 16.5100	1	$ 16.51	$ 17.0000	1	$ 17.00	$ 0.49	2.97%
Smart Meter Rate Adder	monthly	$ 1.0000	1	$ 1.00	$ 1.0000	1	$ 1.00	$ -	0.00%
Service Charge Rate Adder(s)		$ -	1	$ -	$ -	1	$ -	$ -	
Service Charge Rate Rider(s)		$ -	1	$ -	$ -	1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0186	10000	$ 186.00	$ 0.0205	10000	$ 204.57	$ 18.57	9.98%
Low Voltage Rate Adder	per kWh	$ 0.0007	10000	$ 7.00	$ 0.0023	10000	$ 23.00	$ 16.00	228.57%
Volumetric Rate Adder(s)		$ -	10000	$ -	$ -	10000	$ -	$ -	
Volumetric Rate Rider(s)		$ -	10000	$ -	$ -	10000	$ -	$ -	
Smart Meter Disposition Rider		$ -	10000	$ -	$ -	10000	$ -	$ -	
LRAM & SSM Rate Rider		$ -	10000	$ -	$ 0.0016	10000	$ 16.00	$ 16.00	
Deferral/Variance Account Disposition Rate Rider	per kWh	$ -	10000	$ -	-$ 0.0059	10000	-$ 59.23	-$ 59.23	
		$ -		$ -	$ 0.0035		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
Sub-Total A - Distribution				**$ 210.51**			**$ 202.34**	**-$ 8.17**	**-3.88%**
RTSR - Network	per kWh	$ 0.0048	10495	$ 50.38	$ 0.0048	10482	$ 50.31	-$ 0.06	-0.12%
RTSR - Line and Transformation Connection	per kWh	$ 0.0034	10495	$ 35.68	$ 0.0034	10482	$ 35.64	-$ 0.04	-0.12%
Sub-Total B - Delivery (including Sub-Total A)				**$ 296.57**			**$ 288.29**	**-$ 8.28**	**-2.79%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	10495	$ 54.57	$ 0.0052	10482	$ 54.51	-$ 0.07	-0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	10495	$ 13.64	$ 0.0013	10482	$ 13.63	-$ 0.02	-0.12%
Special Purpose Charge	per kWh	$ -	10495	$ -	$ 0.0004	10482	$ 4.25	$ 4.25	
Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	10495	$ 73.47	$ 0.0070	10482	$ 73.37	-$ 0.09	-0.12%
Energy	per kWh	$ 0.0694	10495	$ 728.35	$ 0.0694	10482	$ 727.45	-$ 0.90	-0.12%
	per kWh	$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
Total Bill (before Taxes)				**$ 1,166.85**			**$ 1,161.75**	**-$ 5.11**	**-0.44%**
HST		13%		$ 151.69	13%		$ 151.03	-$ 0.66	-0.44%
Total Bill (including Sub-total B)				**$ 1,318.55**			**$ 1,312.77**	**-$ 5.78**	**-0.44%**

Loss Factor (%) Current: 4.95% Proposed: 4.82%

Customer Class: **General Service < 50 kW**

Consumption 15000 **kWh**

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	monthly	$ 16.5100	1	$ 16.51	$ 17.0000	1	$ 17.00	$ 0.49	2.97%
Smart Meter Rate Adder	monthly	$ 1.0000	1	$ 1.00	$ 1.0000	1	$ 1.00	$ -	0.00%
Service Charge Rate Adder(s)		$ -	1	$ -	$ -	1	$ -	$ -	
Service Charge Rate Rider(s)		$ -	1	$ -	$ -	1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0186	15000	$ 279.00	$ 0.0205	15000	$ 306.85	$ 27.85	9.98%
Low Voltage Rate Adder	per kWh	$ 0.0007	15000	$ 10.50	$ 0.0023	15000	$ 34.50	$ 24.00	228.57%
Volumetric Rate Adder(s)		0.00%	15000	0	0.00%	15000	$ -	$ -	
Volumetric Rate Rider(s)		$ -	15000	$ -	$ -	15000	$ -	$ -	
Smart Meter Disposition Rider		$ -	15000	$ -	$ -	15000	$ -	$ -	
LRAM & SSM Rate Rider		$ -	15000	$ -	$ 0.0016	15000	$ 24.00	$ 24.00	
Deferral/Variance Account Disposition Rate Rider	per kWh	$ -	15000	$ -	-$ 0.0059	15000	-$ 88.84	-$ 88.84	
		$ -		$ -	$ 0.0035		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
Sub-Total A - Distribution				**$ 307.01**			**$ 294.51**	**-$ 12.50**	**-4.07%**
RTSR - Network	per kWh	$ 0.0048	15742.5	$ 75.56	$ 0.0048	15723	$ 75.47	-$ 0.09	-0.12%
RTSR - Line and Transformation Connection	per kWh	$ 0.0034	15742.5	$ 53.52	$ 0.0034	15723	$ 53.46	-$ 0.07	-0.12%
Sub-Total B - Delivery (including Sub-Total A)				**$ 436.10**			**$ 423.44**	**-$ 12.66**	**-2.90%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	15742.5	$ 81.86	$ 0.0052	15723	$ 81.76	-$ 0.10	-0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	15742.5	$ 20.47	$ 0.0013	15723	$ 20.44	-$ 0.03	-0.12%
Special Purpose Charge	per kWh	$ -	15742.5	$ -	$ 0.0004	15723	$ 6.37	$ 6.37	
Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	15742.5	$ 110.20	$ 0.0070	15723	$ 110.06	-$ 0.14	-0.12%
Energy	per kWh	$ 0.0694	15742.5	$ 1,092.53	$ 0.0694	15723	$ 1,091.18	-$ 1.35	-0.12%
	per kWh	$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
Total Bill (before Taxes)				**$ 1,741.40**			**$ 1,733.50**	**-$ 7.91**	**-0.45%**
HST		13%		$ 226.38	13%		$ 225.35	-$ 1.03	-0.45%
Total Bill (including Sub-total B)				**$ 1,967.78**			**$ 1,958.85**	**-$ 8.93**	**-0.45%**

Loss Factor (%) Current: 4.95% Proposed: 4.82%

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Customer Class: **General Service 50 to 4,999**

Consumption	**60**	**kW**
	25000	kWh

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	monthly	$ 29.4100	1	$ 29.41	$ 95.0000	1	$ 95.00	$ 65.59	223.02%
Smart Meter Rate Adder	monthly	$ 1.0000	1	$ 1.00	$ 1.0000	1	$ 1.00	$ -	0.00%
Service Charge Rate Adder(s)			1	$ -		1	$ -	$ -	
Service Charge Rate Rider(s)			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate		$ 5.5249	60	$ 331.49	$ 2.3436	60	$ 140.62	-$ 190.88	-57.58%
Low Voltage Rate Adder		$ 0.3254	60	$ 19.52	$ 1.0364	60	$ 62.18	$ 42.66	218.50%
Volumetric Rate Adder(s)			60	$ -		60	$ -	$ -	
Volumetric Rate Rider(s)			60	$ -		60	$ -	$ -	
Smart Meter Disposition Rider			60	$ -		60	$ -	$ -	
LRAM & SSM Rate Rider			60	$ -	$ 0.0067	60	$ 0.40	$ 0.40	
Deferral/Variance Account Disposition Rate Rider			60	$ -	-$ 2.4165	60	-$ 144.99	-$ 144.99	
GA - Rate Rider (if applicable)				$ -	$ 0.0035	25000	$ 87.43	$ 87.43	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Sub-Total A - Distribution				**$ 381.43**			**$ 241.64**	**-$ 139.79**	**-36.65%**
RTSR - Network		$ 1.9188	62.97	$ 120.83	$ 1.9188	62.892	$ 120.68	-$ 0.15	-0.12%
RTSR - Line and Transformation Connection		$ 1.4110	62.97	$ 88.85	$ 1.4110	62.892	$ 88.74	-$ 0.11	-0.12%
Sub-Total B - Delivery (including Sub-Total A)				**$ 591.11**			**$ 451.06**	**-$ 140.05**	**-23.69%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	26237.5	$ 136.44	$ 0.0052	26205	$ 136.27	-$ 0.17	-0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	26237.5	$ 34.11	$ 0.0013	26205	$ 34.07	-$ 0.04	-0.12%
Special Purpose Charge	per kWh		26237.5	$ -	$ 0.0004050	26205	$ 10.61	$ 10.61	
Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	26237.5	$ 183.66	$ 0.0070	26205	$ 183.44	-$ 0.23	-0.12%
Energy	per kWh	$ 0.0694	26237.5	$ 1,820.88	$ 0.0694	26205	$ 1,818.63	-$ 2.26	-0.12%
	per kWh	$ -		$ -	$ -		$ -	$ -	
				$ -			$ -	$ -	
Total Bill (before Taxes)				**$ 2,766.44**			**$ 2,634.31**	**-$ 132.13**	**-4.78%**
HST		13%		$ 359.64	13%		$ 342.46	-$ 17.18	-4.78%
Total Bill (including Sub-total B)				**$ 3,126.08**			**$ 2,976.78**	**-$ 149.30**	**-4.78%**

Loss Factor (%)	4.95%		4.82%

Customer Class: **General Service 50 to 4,999**

		Current Board-Approved			Proposed			Impact	
Consumption		100 kW							
		50000 kWh							
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	monthly	$ 29.4100	1	$ 29.41	$ 95.0000	1	$ 95.00	$ 65.59	223.02%
Smart Meter Rate Adder	monthly	$ 1.0000	1	$ 1.00	$ 1.0000	1	$ 1.00	$ -	0.00%
Service Charge Rate Adder(s)		$ -	1	$ -	$ -	1	$ -	$ -	
Service Charge Rate Rider(s)		$ -	1	$ -	$ -	1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 5.5249	100	$ 552.49	$ 2.3436	100	$ 234.36	-$ 318.13	-57.58%
Low Voltage Rate Adder	per kWh	$ 0.3254	100	$ 32.54	$ 1.0364	100	$ 103.64	$ 71.10	218.50%
Volumetric Rate Adder(s)		$ -	100	$ -	$ -	100	$ -	$ -	
Volumetric Rate Rider(s)		$ -	100	$ -	$ -	100	$ -	$ -	
Smart Meter Disposition Rider		$ -	100	$ -	$ -	100	$ -	$ -	
LRAM & SSM Rate Rider		$ -	100	$ -	$ 0.0067	100	$ 0.67	$ 0.67	
Deferral/Variance Account Disposition Rate Rider	per kWh	$ -	100	$ -	-$ 2.4165	100	-$ 241.65	-$ 241.65	
		$ -		$ -	$ 0.0035	50000	$ 174.85	$ 174.85	
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
Sub-Total A - Distribution				**$ 615.44**			**$ 367.87**	**-$ 247.57**	**-40.23%**
RTSR - Network	per kWh	$ 1.9188	104.95	$ 201.38	$ 1.9188	104.82	$ 201.13	-$ 0.25	-0.12%
RTSR - Line and Transformation Connection	per kWh	$ 1.4110	104.95	$ 148.08	$ 1.4110	104.82	$ 147.90	-$ 0.18	-0.12%
Sub-Total B - Delivery (including Sub-Total A)				**$ 964.90**			**$ 716.90**	**-$ 248.00**	**-25.70%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	52475	$ 272.87	$ 0.0052	52410	$ 272.53	-$ 0.34	-0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	52475	$ 68.22	$ 0.0013	52410	$ 68.13	-$ 0.08	-0.12%
Special Purpose Charge	per kWh	$ -	52475	$ -	$ 0.0004	52410	$ 21.23	$ 21.23	
Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	52475	$ 367.33	$ 0.0070	52410	$ 366.87	-$ 0.46	-0.12%
Energy	per kWh	$ 0.0694	52475	$ 3,641.77	$ 0.0694	52410	$ 3,637.25	-$ 4.51	-0.12%
	per kWh	$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
Total Bill (before Taxes)				**$ 5,315.33**			**$ 5,083.17**	**-$ 232.16**	**-4.37%**
HST		13%		$ 690.99	13%		$ 660.81	-$ 30.18	-4.37%
Total Bill (including Sub-total B)				**$ 6,006.32**			**$ 5,743.98**	**-$ 262.34**	**-4.37%**
Loss Factor (%)		4.95%			4.82%				

Customer Class: General Service 50 to 4,999

Consumption 500 kW
250000 kWh

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	monthly	$ 29.4100	1	$ 29.41	$ 95.0000	1	$ 95.00	$ 65.59	223.02%
Smart Meter Rate Adder	monthly	$ 1.0000	1	$ 1.00	$ 1.0000	1	$ 1.00	$ -	0.00%
Service Charge Rate Adder(s)		$ -	1	$ -	$ -	1	$ -	$ -	
Service Charge Rate Rider(s)		$ -	1	$ -	$ -	1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 5.5249	500	$ 2,762.45	$ 2.3436	500	$ 1,171.80	-$ 1,590.65	-57.58%
Low Voltage Rate Adder	per kWh	$ 0.3254	500	$ 162.70	$ 1.0364	500	$ 518.20	$ 355.50	218.50%
Volumetric Rate Adder(s)		$ -	500	$ -	$ -	500	$ -	$ -	
Volumetric Rate Rider(s)		$ -	500	$ -	$ -	500	$ -	$ -	
Smart Meter Disposition Rider		$ -	500	$ -	$ -	500	$ -	$ -	
LRAM & SSM Rate Rider		$ -	500	$ -	$ 0.0067	500	$ 3.35	$ 3.35	
Deferral/Variance Account Disposition Rate Rider	per kWh	$ -	500	$ -	-$ 2.4165	500	-$ 1,208.25	-$ 1,208.25	
		$ -		$ -	$ 0.0035	250000	$ 874.27	$ 874.27	
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
Sub-Total A - Distribution				**$ 2,955.56**			**$ 1,455.37**	**-$ 1,500.19**	**-50.76%**
RTSR - Network	per kWh	$ 1.9188	524.75	$ 1,006.89	$ 1.9188	524.1	$ 1,005.64	-$ 1.25	-0.12%
RTSR - Line and Transformation Connection	per kWh	$ 1.4110	524.75	$ 740.42	$ 1.4110	524.1	$ 739.51	-$ 0.92	-0.12%
Sub-Total B - Delivery (including Sub-Total A)				**$ 4,702.87**			**$ 3,200.52**	**-$ 1,502.35**	**-31.95%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	262375	$ 1,364.35	$ 0.0052	262050	$ 1,362.66	-$ 1.69	-0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	262375	$ 341.09	$ 0.0013	262050	$ 340.67	-$ 0.42	-0.12%
Special Purpose Charge	per kWh	$ -	262375	$ -	$ 0.0004	262050	$ 106.13	$ 106.13	
Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	262375	$ 1,836.63	$ 0.0070	262050	$ 1,834.35	-$ 2.28	-0.12%
Energy	per kWh	$ 0.0694	262375	$ 18,208.83	$ 0.0694	262050	$ 18,186.27	-$ 22.56	-0.12%
	per kWh	$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
Total Bill (before Taxes)				**$ 26,454.01**			**$ 25,030.85**	**-$ 1,423.16**	**-5.38%**
HST		13%		$ 3,439.02	13%		$ 3,254.01	-$ 185.01	-5.38%
Total Bill (including Sub-total B)				**$ 29,893.03**			**$ 28,284.86**	**-$ 1,608.17**	**-5.38%**

Loss Factor (%) Current: 4.95% Proposed: 4.82%

Customer Class: **General Service 50 to 4,999**

Consumption 1000 kW
500000 kWh

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	monthly	$ 29.4100	1	$ 29.41	$ 95.0000	1	$ 95.00	$ 65.59	223.02%
Smart Meter Rate Adder	monthly	$ 1.0000	1	$ 1.00	$ 1.0000	1	$ 1.00	$ -	0.00%
Service Charge Rate Adder(s)		$ -	1	$ -	$ -	1	$ -	$ -	
Service Charge Rate Rider(s)		$ -	1	$ -	$ -	1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 5.5249	1000	$ 5,524.90	$ 2.3436	1000	$ 2,343.59	-$ 3,181.31	-57.58%
Low Voltage Rate Adder	per kWh	$ 0.3254	1000	$ 325.40	$ 1.0364	1000	$ 1,036.40	$ 711.00	218.50%
Volumetric Rate Adder(s)		$ -	1000	$ -	$ -	1000	$ -	$ -	
Volumetric Rate Rider(s)		$ -	1000	$ -	$ -	1000	$ -	$ -	
Smart Meter Disposition Rider		$ -	1000	$ -	$ -	1000	$ -	$ -	
LRAM & SSM Rate Rider		$ -	1000	$ -	$ 0.0067	1000	$ 6.70	$ 6.70	
Deferral/Variance Account Disposition Rate Rider	per kWh	$ -	1000	$ -	-$ 2.4165	1000	-$ 2,416.49	-$ 2,416.49	
		$ -		$ -	$ 0.0035	500000	$ 1,748.54	$ 1,748.54	
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
Sub-Total A - Distribution				**$ 5,880.71**			**$ 2,814.74**	**-$ 3,065.97**	**-52.14%**
RTSR - Network	per kWh	$ 1.9188	1049.5	$ 2,013.78	$ 1.9188	1048.2	$ 2,011.29	-$ 2.49	-0.12%
RTSR - Line and Transformation Connection	per kWh	$ 1.4110	1049.5	$ 1,480.84	$ 1.4110	1048.2	$ 1,479.01	-$ 1.83	-0.12%
Sub-Total B - Delivery (including Sub-Total A)				**$ 9,375.34**			**$ 6,305.04**	**-$ 3,070.29**	**-32.75%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	524750	$ 2,728.70	$ 0.0052	524100	$ 2,725.32	-$ 3.38	-0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	524750	$ 682.18	$ 0.0013	524100	$ 681.33	-$ 0.85	-0.12%
Special Purpose Charge	per kWh	$ -	524750	$ -	$ 0.0004	524100	$ 212.26	$ 212.26	
Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	524750	$ 3,673.25	$ 0.0070	524100	$ 3,668.70	-$ 4.55	-0.12%
Energy	per kWh	$ 0.0694	524750	$ 36,417.65	$ 0.0694	524100	$ 36,372.54	-$ 45.11	-0.12%
	per kWh	$ -		$ -	$ -		$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
Total Bill (before Taxes)				**$ 52,877.36**			**$ 49,965.44**	**-$ 2,911.92**	**-5.51%**
HST		13%		$ 6,874.06	13%		$ 6,495.51	-$ 378.55	-5.51%
Total Bill (including Sub-total B)				**$ 59,751.42**			**$ 56,460.95**	**-$ 3,290.47**	**-5.51%**
Loss Factor (%)		4.95%			4.82%				

Customer Class: **USL**

Consumption **806** **kWh**

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	monthly	$ 8.2500	1	$ 8.25	$ 2.0000	1	$ 2.00	-$ 6.25	-75.76%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Service Charge Rate Adder(s)			1	$ -		1	$ -	$ -	
Service Charge Rate Rider(s)			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0186	806	$ 14.99	$ 0.0209	806	$ 16.84	$ 1.85	12.35%
Low Voltage Rate Adder	per kWh	$ 0.0007	806	$ 0.56	$ 0.0023	806	$ 1.85	$ 1.29	228.57%
Volumetric Rate Adder(s)			806	$ -		806	$ -	$ -	
Volumetric Rate Rider(s)			806	$ -		806	$ -	$ -	
Smart Meter Disposition Rider			806	$ -		806	$ -	$ -	
LRAM & SSM Rate Rider			806	$ -	$ 0.0016	806	$ 1.29	$ 1.29	
Deferral/Variance Account Disposition Rate Rider	per kWh		806	$ -	-$ 0.0059	806	-$ 4.77	-$ 4.77	
GA - Rate Rider (if applicable)				$ -	$ 0.0035	806	$ 2.82	$ 2.82	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Sub-Total A - Distribution				**$ 23.81**			**$ 20.03**	**-$ 3.77**	**-15.86%**
RTSR - Network	per kWh	$ 0.0048	845.897	$ 4.06	$ 0.0048	844.849	$ 4.06	-$ 0.01	-0.12%
RTSR - Line and Transformation Connection	per kWh	$ 0.0034	845.897	$ 2.88	$ 0.0034	844.849	$ 2.87	-$ 0.00	-0.12%
Sub-Total B - Delivery (including Sub-Total A)				**$ 30.74**			**$ 26.96**	**-$ 3.78**	**-12.31%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	845.897	$ 4.40	$ 0.0052	844.849	$ 4.39	-$ 0.01	-0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	845.897	$ 1.10	$ 0.0013	844.849	$ 1.10	-$ 0.00	-0.12%
Special Purpose Charge	per kWh		845.897	$ -	$ 0.0004050	844.849	$ 0.34	$ 0.34	
Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	845.897	$ 5.92	$ 0.0070	844.849	$ 5.91	-$ 0.01	-0.12%
Energy	per kWh	$ 0.0694	845.897	$ 58.71	$ 0.0694	844.849	$ 58.63	-$ 0.07	-0.12%
	per kWh			$ -	$ -		$ -	$ -	
				$ -			$ -	$ -	
Total Bill (before Taxes)				**$ 101.12**			**$ 97.59**	**-$ 3.53**	**-3.49%**
HST		13%		$ 13.15	13%		$ 12.69	-$ 0.46	-3.49%
Total Bill (including Sub-total B)				**$ 114.26**			**$ 110.28**	**-$ 3.98**	**-3.48%**
Loss Factor (%)		4.95%			4.82%				

Customer Class: **Sentinel Lights**

	Consumption	1	kW							
		150	kWh							
		Current Board-Approved			Proposed			Impact		
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	
Monthly Service Charge	monthly	$ 2.5200	1	$ 2.52	$ 2.0000	1	$ 2.00	-$ 0.52	-20.63%	
Smart Meter Rate Adder			1	$ -		1	$ -	$ -		
Service Charge Rate Adder(s)			1	$ -		1	$ -	$ -		
Service Charge Rate Rider(s)			1	$ -		1	$ -	$ -		
Distribution Volumetric Rate		$ 8.2496	1	$ 8.25	$ 21.8402	1	$ 21.84	$ 13.59	164.74%	
Low Voltage Rate Adder		$ 0.2089	1	$ 0.21	$ 0.6641	1	$ 0.66	$ 0.46	217.90%	
Volumetric Rate Adder(s)			1	$ -		1	$ -	$ -		
Volumetric Rate Rider(s)			1	$ -		1	$ -	$ -		
Smart Meter Disposition Rider			1	$ -		1	$ -	$ -		
LRAM & SSM Rate Rider			1	$ -	-$ 0.0129	1	-$ 0.01	-$ 0.01		
Deferral/Variance Account Disposition Rate Rider			1	$ -	-$ 1.9471	1	-$ 1.95	-$ 1.95		
GA - Rate Rider (if applicable)				$ -	$ 0.0035	150	$ 0.52	$ 0.52		
				$ -			$ -	$ -		
				$ -			$ -	$ -		
				$ -			$ -	$ -		
Sub-Total A - Distribution				**$ 10.98**			**$ 23.07**	**$ 12.09**	**110.13%**	
RTSR - Network		$ 1.4544	1.0495	$ 1.53	$ 1.4544	1.0482	$ 1.52	-$ 0.00	-0.12%	
RTSR - Line and Transformation Connection		$ 1.1137	1.0495	$ 1.17	$ 1.1137	1.0482	$ 1.17	-$ 0.00	-0.12%	
Sub-Total B - Delivery (including Sub-Total A)				**$ 13.67**			**$ 25.76**	**$ 12.09**	**88.40%**	
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	157.425	$ 0.82	$ 0.0052	157.23	$ 0.82	-$ 0.00	-0.12%	
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	157.425	$ 0.20	$ 0.0013	157.23	$ 0.20	-$ 0.00	-0.12%	
Special Purpose Charge	per kWh		157.425	$ -	$ 0.0004050	157.23	$ 0.06	$ 0.06		
Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%	
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	157.425	$ 1.10	$ 0.0070	157.23	$ 1.10	-$ 0.00	-0.12%	
Energy	per kWh	$ 0.0694	157.425	$ 10.93	$ 0.0694	157.23	$ 10.91	-$ 0.01	-0.12%	
	per kWh	$ -		$ -	$ -		$ -	$ -		
				$ -			$ -	$ -		
Total Bill (before Taxes)				**$ 26.97**			**$ 39.11**	**$ 12.13**	**44.99%**	
HST		13%		$ 3.51	13%		$ 5.08	$ 1.58	44.99%	
Total Bill (including Sub-total B)				**$ 30.48**			**$ 44.19**	**$ 13.71**	**44.98%**	
Loss Factor (%)		4.95%			4.82%					

Customer Class: **Street Lights**

Consumption		**1**	**kW**						
		150	kWh						
		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	monthly	$ 0.8100	1	$ 0.81	$ 1.5000	1	$ 1.50	$ 0.69	85.19%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Service Charge Rate Adder(s)			1	$ -		1	$ -	$ -	
Service Charge Rate Rider(s)			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate		$ 4.1543	1	$ 4.15	$ 44.2301	1	$ 44.23	$ 40.08	964.68%
Low Voltage Rate Adder		$ 0.2412	1	$ 0.24	$ 0.7763	1	$ 0.78	$ 0.54	221.85%
Volumetric Rate Adder(s)			1	$ -		1	$ -	$ -	
Volumetric Rate Rider(s)			1	$ -		1	$ -	$ -	
Smart Meter Disposition Rider			1	$ -		1	$ -	$ -	
LRAM & SSM Rate Rider			1	$ -	$ 0.8746	1	$ 0.87	$ 0.87	
Deferral/Variance Account Disposition Rate Rider			1	$ -	-$ 1.5273	1	-$ 1.53	-$ 1.53	
GA - Rate Rider (if applicable)				$ -	$ 0.0035	150	$ 0.52	$ 0.52	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Sub-Total A - Distribution				**$ 5.21**			**$ 46.38**	**$ 41.17**	**790.95%**
RTSR - Network		$ -	1.0495	$ -	$ -	1.0482	$ -	$ -	
RTSR - Line and Transformation Connection		$ -	1.0495	$ -	$ -	1.0482	$ -	$ -	
Sub-Total B - Delivery (including Sub-Total A)				**$ 5.21**			**$ 46.38**	**$ 41.17**	**790.95%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	157.425	$ 0.82	$ 0.0052	157.23	$ 0.82	-$ 0.00	-0.12%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	157.425	$ 0.20	$ 0.0013	157.23	$ 0.20	-$ 0.00	-0.12%
Special Purpose Charge	per kWh		157.425	$ -	$ 0.0004050	157.23	$ 0.06	$ 0.06	
Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	157.425	$ 1.10	$ 0.0070	157.23	$ 1.10	-$ 0.00	-0.12%
Energy	per kWh	$ 0.0694	157.425	$ 10.93	$ 0.0694	157.23	$ 10.91	-$ 0.01	-0.12%
	per kWh	$ -		$ -	$ -		$ -	$ -	
				$ -			$ -	$ -	
Total Bill (before Taxes)				**$ 18.51**			**$ 59.73**	**$ 41.22**	**222.74%**
HST		13%		$ 2.41	13%		$ 7.76	$ 5.36	222.74%
Total Bill (including Sub-total B)				**$ 20.91**			**$ 67.49**	**$ 46.58**	**222.76%**
Loss Factor (%)		4.95%			4.82%				

Ex.	Tab	Schedule	Contents of Schedule

9 – Deferral and Variance Accounts

	1		
		1	Status of Deferral and variance accounts
		2	Disposition of Deferral and Variance Accounts
		3	Smart Meters

STATUS OF DEFERRAL AND VARIANCE ACCOUNTS

Brant County Power (BCP) was instructed in EB-2009-0258 (2010 IRM decision) to file for disposition of deferral and variance account balances in the 2011 CoS application.

List of Deferral Accounts (principal, interest, total) as at December 31, 2009

USoA	Description	Principal (Dec. 31, 2009)	Interest on Dec 31, 2009 balance to Apr. 30 2011	Total	Continued in 2011	Interest Rate Applied for Carrying Charges (DR or CR)										
						Jan 2005 to Mar 2006	Apr to June 2006	July 2006 to Sept 2007	Oct 2007 to Mar 2008	Apr to June 2008	July to Dec 2008	Jan to Mar 2009	Apr to Sept 2009	Oct 2009 to June 2010	July to Sept 2010	Oct to Dec 2010
1550	Low Voltage	$57,027	($21,094)	$35,933	YES	7.25%	4.14%	4.59%	5.14%	4.08%	3.35%	2.45%	1.00%	0.55%	0.89%	1.20%
1580	RSVA WMS	($600,396)	$103,627	($496,769)	YES	7.25%	4.14%	4.59%	5.14%	4.08%	3.35%	2.45%	1.00%	0.55%	0.89%	1.20%
1584	RSVA NW	($1,639,976)	($133,526)	($1,773,502)	YES	7.25%	4.14%	4.59%	5.14%	4.08%	3.35%	2.45%	1.00%	0.55%	0.89%	1.20%
1586	RSVA CN	($1,533,354)	($95,277)	($1,628,631)	YES	7.25%	4.14%	4.59%	5.14%	4.08%	3.35%	2.45%	1.00%	0.55%	0.89%	1.20%
1588	RSVA COP Excluding GA	$143,933	($28,006)	$115,927	YES	7.25%	4.14%	4.59%	5.14%	4.08%	3.35%	2.45%	1.00%	0.55%	0.89%	1.20%
1588	RSVA COP GA	$1,180,849	$24,562	$1,205,411	YES	7.25%	4.14%	4.59%	5.14%	4.08%	3.35%	2.45%	1.00%	0.55%	0.89%	1.20%
1590	Recovery of Reg. Assets	$0	$314,713	$314,713	YES	7.25%	4.14%	4.59%	5.14%	4.08%	3.35%	2.45%	1.00%	0.55%	0.89%	1.20%
1508	OEB Cost Assessment	$27,701	$5,056	$32,757	NO	7.25%	4.14%	4.59%	5.14%	4.08%	3.35%	2.45%	1.00%	0.55%	0.89%	1.20%
1508	OMERS Pension	$124,358	$17,451	$141,809	NO	3.88%	4.14%	4.59%	5.14%	4.08%	3.35%	2.45%	1.00%	0.55%	0.89%	1.20%
1518	RCVA – Retail	($61,590)	($3,658)	($65,248)	YES	7.25%	4.14%	4.59%	5.14%	4.08%	3.35%	2.45%	1.00%	0.55%	0.89%	1.20%
1548	RCVA – STR	$33,765	$2,030	$35,795	YES	7.25%	4.14%	4.59%	5.14%	4.08%	3.35%	2.45%	1.00%	0.55%	0.89%	1.20%
1525	Misc. Deferred Debits	$7,211	$2,005	$9,216	YES	7.25%	4.14%	4.59%	5.14%	4.08%	3.35%	2.45%	1.00%	0.55%	0.89%	1.20%
1555	Smart Meter Capital	($93,604)	($3,957)	($97,561)	YES	7.25%	4.14%	4.59%	5.14%	4.08%	3.35%	2.45%	1.00%	0.55%	0.89%	1.20%
1556	Smart Meter OM&A	$79,474	$2,139	$81,613	YES	7.25%	4.14%	4.59%	5.14%	4.08%	3.35%	2.45%	1.00%	0.55%	0.89%	1.20%
1565	CDM	$0	$0	$0	NO	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1566	CDM – Contra	$0	$0	$0	NO	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1582	RSVA One Time	$0	$0	$0	YES	7.25%	4.14%	4.59%	5.14%	4.08%	3.35%	2.45%	1.00%	0.55%	0.89%	1.20%
1562	PILS	$945,868	$184,311	$1,130,179	NO	7.25%	4.14%	4.59%	5.14%	4.08%	3.35%	2.45%	1.00%	0.55%	0.89%	1.20%
Total		**($1,328,734)**	**$370,376**	**($958,358)**												

BCP has used the above listed variance accounts as prescribed in the Accounting Procedures Handbook (APH), APH Frequently Asked Questions and other OEB direction.

BCP is not requesting any additional deferral and variance accounts.

<u>Continuity Schedule</u>

Note, working version of excel model filed with application

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Brant County Power	**LICENCE NUMBER**	ED-2002-0522
NAME OF CONTACT	Ed Glasbergen	**DOCID NUMBER**	EB-200X-XXXX
E-mail Address	eglasbergen@brantcountypower.com		
VERSION NUMBER	v8.0	**PHONE NUMBER**	519-442-2215
Date	Oct. 25, 2010	**(extension)**	

Enter appropriate data in cells which are highlighted in yellow only.
Enter the total applied for Regulatory Asset amounts for each account in the appropriate cells below:
Debits should be recorded as positive numbers and credits should be recorded as negative numbers.
Repeat cells going across as necessary for each year in application
If account balances have been disposed in a previous application, for applicable accounts, fill out the Continuity Schedule from the date of last disposition.

		2005								
Account Description	**Account Number**	**Opening Principal Amounts as of Jan-1-05 [1]**	**Transactions (additions) during 2005, excluding interest and adjustments [6]**	**Transactions (reductions) during 2005, excluding interest and adjustments [6]**	**Adjustments during 2005 - instructed by Board [2, 2A]**	**Adjustments during 2005 - other [3]**	**Closing Principal Balance as of Dec-31-05**	**Opening Interest Amounts as of Jan-1-05**	**Interest Jan-1 to Dec31-05**	**Closing Interest Amounts as of Dec-31-05**
Group 1 Accounts										
Low Voltage Account	1550	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
RSVA - Wholesale Market Service Charge	1580	$ 410,484	$ 224,905		$ -	$ -	$ 635,390	$ 79,923	$ 34,986	$ 114,909
RSVA - Retail Transmission Network Charge	1584	$ (155,488)	$ (194,210)		$ -	$ -	$ (349,698)	$ 4,286	$ (20,000)	$ (15,714)
RSVA - Retail Transmission Connection Charge	1586	$ (142,371)	$ 118,711		$ -	$ -	$ (23,660)	$ 572	$ 21,900	$ 22,472
RSVA - Power (excluding Global Adjustment)	1588	$ (368,733)	$ 149,639		$ -	$ -	$ (219,093)	$ 13,821	$ (42,029)	$ (28,208)
RSVA - Power - Sub-Account - Global Adjustment	1588	$ -	$ (73,306)		$ -	$ -	$ (73,306)	$ -	$ (4,116)	$ (4,116)
Recovery of Regulatory Asset Balances	1590	$ (655,853)	$ (818,387)		$ -	$ -	$ (1,474,239)	$ (14,232)	$ (77,126)	$ (91,358)
Disposition and Recovery of Regulatory Balances[10]	1595	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ (911,960)	$ (592,646)		$ -	$ -	$ (1,504,606)	$ 84,370	$ (86,384)	$ (2,014)
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ (911,960)	$ (519,340)		$ -	$ -	$ (1,431,300)	$ 84,370	$ (82,269)	$ 2,101
RSVA - Power - Sub-Account - Global Adjustment	**1588**	$ -	$ (73,306)		$ -	$ -	$ (73,306)	$ -	$ (4,116)	$ (4,116)
Group 2 Accounts										
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 7,445	$ 15,192		$ -	$ -	$ 22,637	$ 180	$ 999	$ 1,179
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -	$ 90,442	$ -	$ -	$ -	$ 90,442	$ -	$ 1,580	$ 1,580
Other Regulatory Assets - Sub-Account Deferred IFRS Transition Costs	1508	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508						$ -			$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508						$ -			$ -
Retail Cost Variance Account - Retail	1518	$ 11,757		$ (7,973)	$ -	$ -	$ 3,784	$ 817	$ 589	$ 1,407
Retail Cost Variance Account - STR	1548	$ -	$ 7,390	$ -	$ -	$ -	$ 7,390	$ -	$ (40)	$ (40)
Misc. Deferred Debits	1525	$ 16,759	$ 7,211	$ -		$ 11,348	$ 35,318	$ 2,392	$ 2,723	$ 5,115
LV Variance Account	1550	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Renewable Connection Capital Deferral Account	1531									
Renewable Connection OM&A Deferral Account	1532									
Smart Grid Capital Deferral Account	1534									
Smart Grid OM&A Deferral Account	1535									
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555						$ -			$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs	1555						$ -			$ -
Smart Meter OM&A Variance	1556	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Conservation and Demand Management Expenditures and Recoveries	1565	$ -		$ (78,962)	$ -	$ -	$ (78,962)	$ -	$ -	$ -
CDM Contra	1566	$ -	$ 78,962				$ 78,962			$ -
Qualifying Transition Costs [5]	1570		n/a	n/a			$ -			$ -
Pre-Market Opening Energy Variances Total [5]	1571		n/a	n/a			$ -			$ -
Extra-Ordinary Event Costs	1572						$ -			$ -
Deferred Rate Impact Amounts	1574						$ -			$ -
RSVA - One-time Wholesale Market Service	1582	$ 62,213	$ -				$ 62,213	$ 4,510	$ 4,510	$ 9,021
Other Deferred Credits	2425						$ -			$ -
Group 2 Sub-Total		$ 98,174	$ 199,196	$ (86,935)	$ -	$ 11,348	$ 221,784	$ 7,900	$ 10,361	$ 18,261
Deferred Payments in Lieu of Taxes	1562	$ 86,546	$ 225,900				$ 312,445	$ 36,121	$ 12,065	$ 48,186
2006 PILs & Taxes Variance	1592						$ -			$ -
Sub-total										
Total		$ (813,785)	$ (393,449)	$ (86,935)	$ -	$ 11,348	$ (1,282,822)	$ 92,270	$ (76,023)	$ 16,246
The following is not included in the total claim but are included on a memo basis:										
Deferred PILs Contra Account [8]	1563						$ -			$ -
Disposition and Recovery of Regulatory Balances[10]	1595									

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Brant County Power
NAME OF CONTACT	Ed Glasbergen
E-mail Address	eglasbergen@brantcountypower.com
VERSION NUMBER	v8.0
Date	Oct. 25, 2010

Account Description	Account Number	2006 Opening Principal Amounts as of Jan-1-06	Transactions (additions) during 2006, excluding interest and adjustments [6]	Transactions (reductions) during 2006, excluding interest and adjustments [6]	Adjustments during 2006 - instructed by Board [2, 2A]	Adjustments during 2006 - other [3]	Transfer of Board-approved amounts to 1590 as per 2006 EDR	Closing Principal Balance as of Dec-31-06	Opening Interest Amounts as of Jan-1-06	Interest Jan-1 to Dec31-06	Transfer of Board-approved amounts to 1590 as per 2006 EDR	Closing Interest Amounts as of Dec-31-06
Group 1 Accounts												
Low Voltage Account	1550	$ -	$ (61,022)		$ -	$ -	$ -	$ (61,022)	$ -	$ (650)	$ -	$ (650)
RSVA - Wholesale Market Service Charge	1580	$ 635,390	$ (275,730)		$ -	$ -	$ (410,484)	$ (50,824)	$ 114,909	$ 136,521	$ (118,235)	$ 133,196
RSVA - Retail Transmission Network Charge	1584	$ (349,698)	$ (549,782)		$ -	$ (70,521)	$ 276,790	$ (693,211)	$ (15,714)	$ (26,253)	$ 14,214	$ (27,753)
RSVA - Retail Transmission Connection Charge	1586	$ (23,660)	$ (461,669)		$ -	$ 184,633	$ (304,392)	$ (605,087)	$ 22,472	$ (14,754)	$ (7,872)	$ (153)
RSVA - Power (excluding Global Adjustment)	1588	$ (219,093)	$ (460,401)		$ -	$ -	$ 368,733	$ (310,762)	$ (28,208)	$ (15,965)	$ 20,594	$ (23,579)
RSVA - Power - Sub-Account - Global Adjustment	1588	$ (73,306)	$ 450,752		$ -	$ -	$ -	$ 377,447	$ (4,116)	$ 8,092	$ -	$ 3,977
Recovery of Regulatory Asset Balances	1590	$ (1,474,239)	$ (18,176)		$ -	$ -	$ 1,492,415	$ (0)	$ (91,358)	$ (237,511)	$ 514,858	$ 185,989
Disposition and Recovery of Regulatory Balances[10]	1595	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ (1,504,606)	$ (1,376,027)		$ -	$ 114,112	$ 1,423,061	$ (1,343,459)	$ (2,014)	$ (150,519)	$ 423,560	$ 271,026
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ (1,431,300)	$ (1,826,779)		$ -	$ 114,112	$ 1,423,061	$ (1,720,906)	$ 2,101	$ (158,612)	$ 423,560	$ 267,050
RSVA - Power - Sub-Account - Global Adjustment	**1588**	$ (73,306)	$ 450,752		$ -	$ -	$ -	$ 377,447	$ (4,116)	$ 8,092	$ -	$ 3,977
Group 2 Accounts												
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 22,637	$ 5,064	$ -	$ -	$ -	$ -	$ 27,701	$ 1,179	$ 1,466	$ -	$ 2,644
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ 90,442	$ 33,916	$ -	$ -	$ -	$ -	$ 124,358	$ 1,580	$ 5,043	$ -	$ 6,622
Other Regulatory Assets - Sub-Account Deferred IFRS Transition Costs	1508	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508	$ -						$ -	$ -			$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508	$ -						$ -	$ -			$ -
Retail Cost Variance Account - Retail	1518	$ 3,784		$ (13,431)	$ -	$ -	$ (11,757)	$ (21,405)	$ 1,407	$ (368)	$ (1,914)	$ (875)
Retail Cost Variance Account - STR	1548	$ 7,390	$ 5,672	$ -	$ -	$ -	$ -	$ 13,062	$ (40)	$ 383	$ -	$ 343
Misc. Deferred Debits	1525	$ 35,318		$ -	$ -	$ -	$ (28,107)	$ 7,211	$ 5,115	$ 1,166	$ (4,903)	$ 1,378
LV Variance Account	1550	$ -	$ (61,022)	$ -	$ -	$ -	$ -	$ (61,022)	$ -	$ (650)	$ -	$ (650)
Renewable Connection Capital Deferral Account	1531											
Renewable Connection OM&A Deferral Account	1532											
Smart Grid Capital Deferral Account	1534											
Smart Grid OM&A Deferral Account	1535											
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555	$ -		$ (17,453)	$ -	$ -	$ -	$ (17,453)	$ -	$ (218)	$ -	$ (218)
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555	$ -						$ -	$ -			$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs	1555	$ -						$ -	$ -			$ -
Smart Meter OM&A Variance	1556	$ -	$ 14,302	$ -	$ -	$ -	$ -	$ 14,302	$ -	$ -	$ -	$ -
Conservation and Demand Management Expenditures and Recoveries	1565	$ (78,962)		$ (32,293)	$ -	$ -	$ -	$ (111,255)	$ -			$ -
CDM Contra	1566	$ 78,962	$ 32,293					$ 111,255	$ -			$ -
Qualifying Transition Costs [5]	1570	$ -	n/a	n/a				$ -	$ -			$ -
Pre-Market Opening Energy Variances Total [5]	1571	$ -	n/a	n/a				$ -	$ -			$ -
Extra-Ordinary Event Costs	1572	$ -						$ -	$ -			$ -
Deferred Rate Impact Amounts	1574	$ -						$ -	$ -			$ -
RSVA - One-time Wholesale Market Service	1582	$ 62,213	$ -				$ (62,213)	$ -	$ 9,021	$ 1,296	$ (10,316)	$ 0
Other Deferred Credits	2425	$ -						$ -	$ -			$ -
Group 2 Sub-Total		$ 221,784	$ 30,225	$ (63,178)	$ -	$ -	$ (102,077)	$ 86,754	$ 18,261	$ 8,118	$ (17,134)	$ 9,244
Deferred Payments in Lieu of Taxes	1562	$ 312,445	$ 867,506					$ 1,179,951	$ 48,186	$ 33,381		$ 81,567
2006 PILs & Taxes Variance	1592	$ -						$ -	$ -			$ -
Sub-total												
Total		$ (1,282,822)	$ (1,345,802)	$ (63,178)	$ -	$ 114,112	$ 1,320,984	$ (1,256,705)	$ 16,246	$ (142,401)	$ 406,426	$ 280,271
The following is not included in the total claim but are included on a memo basis:												
Deferred PILs Contra Account [8]	1563	$ -						$ -	$ -			$ -
Disposition and Recovery of Regulatory Balances[10]	1595											

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Brant County Power
NAME OF CONTACT	Ed Glasbergen
E-mail Address	eglasbergen@brantcountypower.com
VERSION NUMBER	v8.0
Date	Oct. 25, 2010

		2007								
Account Description	**Account Number**	**Opening Principal Amounts as of Jan-1-07**	**Transactions (additions) during 2007, excluding interest and adjustments [6]**	**Transactions (reductions) during 2007, excluding interest and adjustments [6]**	**Adjustments during 2007 - instructed by Board [2, 2A]**	**Adjustments during 2007 - other [3]**	**Closing Principal Balance as of Dec-31-07**	**Opening Interest Amounts as of Jan-1-07**	**Interest Jan-1 to Dec31-07**	**Closing Interest Amounts as of Dec-31-07**
Group 1 Accounts										
Low Voltage Account	1550	$ (61,022)	$ (229,097)		$ -	$ -	$ (290,118)	$ (650)	$ (9,969)	$ (10,619)
RSVA - Wholesale Market Service Charge	1580	$ (50,824)	$ (350,451)		$ -	$ -	$ (401,276)	$ 133,196	$ (10,015)	$ 123,180
RSVA - Retail Transmission Network Charge	1584	$ (693,211)	$ (551,411)		$ -	$ -	$ (1,244,622)	$ (27,753)	$ (45,176)	$ (72,929)
RSVA - Retail Transmission Connection Charge	1586	$ (605,087)	$ (511,083)		$ -	$ -	$ (1,116,171)	$ (153)	$ (40,175)	$ (40,328)
RSVA - Power (excluding Global Adjustment)	1588	$ (310,762)	$ 310,165		$ -	$ -	$ (597)	$ (23,579)	$ (2,971)	$ (26,550)
RSVA - Power - Sub-Account - Global Adjustment	1588	$ 377,447	$ (118,944)		$ -	$ -	$ 258,503	$ 3,977	$ 10,829	$ 14,806
Recovery of Regulatory Asset Balances	1590	$ (0)	$ -		$ -	$ -	$ (0)	$ 185,989	$ 76,787	$ 262,776
Disposition and Recovery of Regulatory Balances [10]	1595	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ (1,343,459)	$ (1,450,822)		$ -	$ -	$ (2,794,281)	$ 271,026	$ (20,691)	$ 250,336
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ (1,720,906)	$ (1,331,878)		$ -	$ -	$ (3,052,784)	$ 267,050	$ (31,520)	$ 235,530
RSVA - Power - Sub-Account - Global Adjustment	**1588**	$ 377,447	$ (118,944)		$ -	$ -	$ 258,503	$ 3,977	$ 10,829	$ 14,806
Group 2 Accounts										
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 27,701	$ -	$ -	$ -	$ -	$ 27,701	$ 2,644	$ 1,310	$ 3,954
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ 124,358	$ -	$ -	$ -	$ -	$ 124,358	$ 6,622	$ 5,879	$ 12,501
Other Regulatory Assets - Sub-Account Deferred IFRS Transition Costs	1508	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508	$ -					$ -	$ -		$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508	$ -					$ -	$ -		$ -
Retail Cost Variance Account - Retail	1518	$ (21,405)		$ (12,058)	$ -	$ -	$ (33,463)	$ (875)	$ (1,229)	$ (2,104)
Retail Cost Variance Account - STR	1548	$ 13,062	$ 7,689	$ -	$ -	$ -	$ 20,751	$ 343	$ 707	$ 1,050
Misc. Deferred Debits	1525	$ 7,211	$ -	$ -	$ -	$ -	$ 7,211	$ 1,378	$ 341	$ 1,718
LV Variance Account	1550	$ (61,022)	$ (229,097)	$ -	$ -	$ -	$ (290,118)	$ (650)	$ (9,969)	$ (10,619)
Renewable Connection Capital Deferral Account	1531									
Renewable Connection OM&A Deferral Account	1532									
Smart Grid Capital Deferral Account	1534									
Smart Grid OM&A Deferral Account	1535									
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555	$ (17,453)		$ (28,319)	$ -	$ -	$ (45,772)	$ (218)	$ (1,455)	$ (1,673)
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555	$ -					$ -	$ -		$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs	1555	$ -					$ -	$ -		$ -
Smart Meter OM&A Variance	1556	$ 14,302	$ 11,749	$ -	$ -	$ -	$ 26,052	$ -	$ 959	$ 959
Conservation and Demand Management Expenditures and Recoveries	1565	$ (111,255)	$ 67,441				$ (43,814)	$ -		$ -
CDM Contra	1566	$ 111,255		$ (67,441)			$ 43,814	$ -		$ -
Qualifying Transition Costs [5]	1570	$ -	n/a	n/a			$ -	$ -		$ -
Pre-Market Opening Energy Variances Total [5]	1571	$ -	n/a	n/a			$ -	$ -		$ -
Extra-Ordinary Event Costs	1572	$ -					$ -	$ -		$ -
Deferred Rate Impact Amounts	1574	$ -					$ -	$ -		$ -
RSVA - One-time Wholesale Market Service	1582	$ -					$ -	$ 0		$ 0
Other Deferred Credits	2425	$ -					$ -	$ -		$ -
Group 2 Sub-Total		$ 86,754	$ (142,218)	$ (107,818)	$ -	$ -	$ (163,282)	$ 9,244	$ (3,459)	$ 5,786
Deferred Payments in Lieu of Taxes	1562	$ 1,179,951					$ 1,179,951	$ 81,567	$ 55,782	$ 137,349
2006 PILs & Taxes Variance	1592	$ -					$ -	$ -		$ -
Sub-total										
Total		$ (1,256,705)	$ (1,593,040)	$ (107,818)	$ -	$ -	$ (2,957,563)	$ 280,271	$ (24,149)	$ 256,121
The following is not included in the total claim but are included on a memo basis:										
Deferred PILs Contra Account [8]	1563	$ -					$ -			$ -
Disposition and Recovery of Regulatory Balances [10]	1595									

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Brant County Power
NAME OF CONTACT	Ed Glasbergen
E-mail Address	eglasbergen@brantcountypower.com
VERSION NUMBER	v8.0
Date	Oct. 25, 2010

2008

Account Description	Account Number	Opening Principal Amounts as of Jan-1-08	Transactions (additions) during 2008, excluding interest and adjustments [6]	Transactions (reductions) during 2008, excluding interest and adjustments [6]	Adjustments during 2008 - instructed by Board [2, 2A]	Adjustments during 2008 - other [3]	Closing Principal Balance as of Dec-31-08	Opening Interest Amounts as of Jan-1-08	Interest Jan-1 to Dec31-08	Closing Interest Amounts as of Dec-31-08
Group 1 Accounts										
Low Voltage Account	1550	$ (290,118)	$ 172,186		$ -	$ -	$ (117,932)	$ (10,619)	$ (10,475)	$ (21,094)
RSVA - Wholesale Market Service Charge	1580	$ (401,276)	$ (149,476)		$ -	$ -	$ (550,751)	$ 123,180	$ (19,553)	$ 103,627
RSVA - Retail Transmission Network Charge	1584	$ (1,244,622)	$ (507,292)		$ -	$ -	$ (1,751,915)	$ (72,929)	$ (60,597)	$ (133,526)
RSVA - Retail Transmission Connection Charge	1586	$ (1,116,171)	$ (496,105)		$ -	$ -	$ (1,612,276)	$ (40,328)	$ (54,948)	$ (95,277)
RSVA - Power (excluding Global Adjustment)	1588	$ (597)	$ 261,354		$ -	$ -	$ 260,756	$ (26,550)	$ (1,456)	$ (28,006)
RSVA - Power - Sub-Account - Global Adjustment	1588	$ 258,503	$ 140,439		$ -	$ -	$ 398,942	$ 14,806	$ 9,756	$ 24,562
Recovery of Regulatory Asset Balances	1590	$ (0)	$ -		$ -	$ -	$ (0)	$ 262,776	$ 51,397	$ 314,173
Disposition and Recovery of Regulatory Balances[10]	1595	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ (2,794,281)	$ (578,895)		$ -	$ -	$ (3,373,176)	$ 250,336	$ (85,875)	$ 164,460
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ (3,052,784)	$ (719,334)		$ -	$ -	$ (3,772,118)	$ 235,530	$ (95,632)	$ 139,898
RSVA - Power - Sub-Account - Global Adjustment	**1588**	$ 258,503	$ 140,439		$ -	$ -	$ 398,942	$ 14,806	$ 9,756	$ 24,562
Group 2 Accounts										
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 27,701	$ -	$ -	$ -	$ -	$ 27,701	$ 3,954	$ 1,102	$ 5,056
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ 124,358	$ -	$ -	$ -	$ -	$ 124,358	$ 12,501	$ 4,949	$ 17,451
Other Regulatory Assets - Sub-Account Deferred IFRS Transition Costs	1508	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508	$ -					$ -	$ -		$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508	$ -					$ -	$ -		$ -
Retail Cost Variance Account - Retail	1518	$ (33,463)		$ (13,840)	$ -	$ -	$ (47,302)	$ (2,104)	$ (1,554)	$ (3,658)
Retail Cost Variance Account - STR	1548	$ 20,751	$ 6,998	$ -	$ -	$ -	$ 27,749	$ 1,050	$ 980	$ 2,030
Misc. Deferred Debits	1525	$ 7,211	$ -	$ -	$ -	$ -	$ 7,211	$ 1,718	$ 287	$ 2,005
LV Variance Account	1550	$ (290,118)	$ 172,186	$ -	$ -	$ -	$ (117,932)	$ (10,619)	$ (10,475)	$ (21,094)
Renewable Connection Capital Deferral Account	1531									
Renewable Connection OM&A Deferral Account	1532									
Smart Grid Capital Deferral Account	1534									
Smart Grid OM&A Deferral Account	1535									
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555	$ (45,772)		$ (28,300)	$ -	$ -	$ (74,072)	$ (1,673)	$ (2,284)	$ (3,957)
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555	$ -					$ -	$ -		$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs	1555	$ -					$ -	$ -		$ -
Smart Meter OM&A Variance	1556	$ 26,052	$ 14,916				$ 40,968	$ 959	$ 1,180	$ 2,139
Conservation and Demand Management Expenditures and Recoveries	1565	$ (43,814)	$ 43,814				$ -	$ -		$ -
CDM Contra	1566	$ 43,814		$ (43,814)			$ -	$ -		$ -
Qualifying Transition Costs [5]	1570	$ -	n/a	n/a			$ -	$ -		$ -
Pre-Market Opening Energy Variances Total [5]	1571	$ -	n/a	n/a			$ -	$ -		$ -
Extra-Ordinary Event Costs	1572	$ -					$ -	$ -		$ -
Deferred Rate Impact Amounts	1574	$ -					$ -	$ -		$ -
RSVA - One-time Wholesale Market Service	1582	$ -					$ -	$ 0		$ 0
Other Deferred Credits	2425	$ -					$ -	$ -		$ -
Group 2 Sub-Total		$ (163,282)	$ 237,915	$ (85,953)	$ -	$ -	$ (11,320)	$ 5,786	$ (5,814)	$ (28)
Deferred Payments in Lieu of Taxes	1562	$ 1,179,951					$ 1,179,951	$ 137,349	$ 46,962	$ 184,311
2006 PILs & Taxes Variance	1592	$ -					$ -	$ -		$ -
Sub-total						**see PILs reconciliation requested**				
Total		$ (2,957,563)	$ (340,980)	$ (85,953)	$ -	$ -	$ (3,384,496)	$ 256,121	$ (91,689)	$ 164,432
The following is not included in the total claim but are included on a memo basis:										
Deferred PILs Contra Account [8]	1563	$ -					$ -	$ -		$ -
Disposition and Recovery of Regulatory Balances[10]	1595									

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Brant County Power
NAME OF CONTACT	Ed Glasbergen
E-mail Address	eglasbergen@brantcountypower.com
VERSION NUMBER	v8.0
Date	Oct. 25, 2010

Account Description	Account Number	2009: Opening Principal Amounts as of Jan-1-09	Transactions (additions) during 2009, excluding interest and adjustments [6]	Transactions (reductions) during 2009, excluding interest and adjustments [6]	Adjustments during 2009 - instructed by Board [2, 2A]	Adjustments during 2009 - other [3]	Closing Principal Balance as of Dec-31-09	Opening Interest Amounts as of Jan-1-09	Interest Jan-1 to Dec31-09	Closing Interest Amounts as of Dec-31-09	Projected Interest on Dec 31 -09 balance from Jan 1, 2010 to Dec 31, 2010 [9]	Projected Interest on Dec 31 -09 balance from Jan 1, 2011 to April 30, 2011 [9, 10]	Total Claim before Forecasted Transactions in 2010 and 2011	Optional: *Forecasted Transactions, Excluding Interest from Jan 1, 2010 to Dec 31, 2010*	*Forecasted Transactions, Excluding Interest from Jan 1, 2011 to April 30, 2011* [10]	*Projected Interest from Jan 1, 2010 to April 30, 2011 on Forecasted Transactions (Excl Interest) from Jan 1, 2010 to Dec 31, 2010*	*Projected Interest from Jan 1, 2011 to April 30, 2011 on Forecasted Transactions (Excl Interest) from Jan 1, 2011 to Apr 30, 2011* [10]	*Forecasted Transactions in 2010 and 2011, not included in Total Claim*
Group 1 Accounts																		
Low Voltage Account	1550	(117,932)	174,959		-	-	57,027	(21,094)	(766)	(21,860)	454.79	228	35,850					-
RSVA - Wholesale Market Service Charge	1580	(550,751)	(49,545)		-	-	(600,296)	103,627	(6,517)	97,110	-$ 4,787.36	(2,401)	(510,374)					-
RSVA - Retail Transmission Network Charge	1584	(1,751,915)	111,939		-	-	(1,639,976)	(133,526)	(19,291)	(152,817)	-$ 13,078.81	(6,560)	(1,812,432)					-
RSVA - Retail Transmission Connection Charge	1586	(1,612,276)	78,922		-	-	(1,533,354)	(95,277)	(18,106)	(113,382)	-$ 12,228.50	(6,133)	(1,665,098)					-
RSVA - Power (excluding Global Adjustment)	1588	260,756	(116,823)		-	-	143,933	(28,006)	(47)	(28,052)	1,147.87	576	117,604					-
RSVA - Power - Sub-Account - Global Adjustment	1588	398,942	781,906		-	-	1,180,849	24,562	6,664	31,226	9,417.27	4,723	1,226,215					-
Recovery of Regulatory Asset Balances	1590	(0)	-		-	-	(0)	314,173	-	314,173	-$ 0.00	(0)	314,173					-
Disposition and Recovery of Regulatory Balances [10]	1595	-	-		-	-	-	-	-	-	-	-	-					-
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		(3,373,176)	981,358		-	-	(2,391,818)	164,460	(38,062)	126,398	(19,075)	(9,567)	(2,294,062)	-	-	-	-	-
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		(3,772,118)	199,452		-	-	(3,572,667)	139,898	(44,726)	95,172	(28,492)	(14,291)	(3,520,277)	-	-	-	-	-
RSVA - Power - Sub-Account - Global Adjustment	**1588**	398,942	781,906		-	-	1,180,849	24,562	6,664	31,226	9,417	4,723	1,226,215	-	-	-	-	-
Group 2 Accounts																		
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	27,701	-	-	-	-	27,701	5,056	315	5,371	220.92	111	33,404					-
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	124,358	-	-	-	-	124,358	17,451	1,415	18,865	991.75	497	144,712					-
Other Regulatory Assets - Sub-Account Deferred IFRS Transition Costs	1508	-	-	-	-	-	-	-	-	-	-	-	-					-
Other Regulatory Assets - Sub-Account - Other [7]	1508	-					-	-		-	-	-	-					-
Other Regulatory Assets - Sub-Account - Other [7]	1508	-					-	-		-	-	-	-					-
Retail Cost Variance Account - Retail	1518	(47,302)		(14,288)	-	-	(61,590)	(3,658)	(585)	(4,242)	-$ 491.18	(246)	(66,570)					-
Retail Cost Variance Account - STR	1548	27,749	6,016	-	-	-	33,765	2,030	340	2,370	269.28	135	36,539					-
Misc. Deferred Debits	1525	7,211	-	-	-	-	7,211	2,005	82	2,087	57.50	29	9,384					-
LV Variance Account	1550	(117,932)	174,959	-	-	-	57,027	(21,094)	(766)	(21,860)	454.79	228	35,850					-
Renewable Connection Capital Deferral Account	1531										-	-	-					-
Renewable Connection OM&A Deferral Account	1532										-	-	-					-
Smart Grid Capital Deferral Account	1534										-	-	-					-
Smart Grid OM&A Deferral Account	1535										-	-	-					-
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555	(74,072)		(19,532)	-	-	(93,604)	(3,957)	(935)	(4,892)	-$ 746.50	(374)	(99,617)					-
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555	-					-	-		-	-	-	-					-
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs	1555	-					-	-		-	-	-	-					-
Smart Meter OM&A Variance	1556	40,968	38,507				79,474	2,139	619	2,758	633.81	318	83,184					-
Conservation and Demand Management Expenditures and Recoveries	1565	-					-	-		-	-	-	-					-
CDM Contra	1566	-					-	-		-	-	-	-					-
Qualifying Transition Costs [5]	1570	-	n/a	n/a			-	-		-	-	-	-					-
Pre-Market Opening Energy Variances Total [5]	1571	-	n/a	n/a			-	-		-	-	-	-					-
Extra-Ordinary Event Costs	1572	-					-	-		-	-	-	-					-
Deferred Rate Impact Amounts	1574	-					-	-		-	-	-	-					-
RSVA - One-time Wholesale Market Service	1582	-					-	0		0	-	-	0					-
Other Deferred Credits	2425	-					-	-		-	-	-	-					-
Group 2 Sub-Total		(11,320)	219,482	(33,820)	-	-	174,341	(28)	486	457	1,390	697	176,887	-	-	-	-	-
Deferred Payments in Lieu of Taxes	1562	1,179,951				(234,083)	945,868	184,311	13,422	197,733	7,543.30	3,783	1,154,928					-
2006 PILs & Taxes Variance	1592	-					-	-		-	-	-	-					-
Sub-total						see PILs reconciliation requested							1,154,928					-
Total		(3,384,496)	1,200,840	(33,820)	-	-	(2,217,477)	164,432	(37,577)	126,856	(17,684)	(8,870)	(2,117,175)	-	-	-	-	-
The following is not included in the total claim but are included on a memo basis:																		
Deferred PILs Contra Account [8]	1563	-					-	-		-	-	-	-					-
Disposition and Recovery of Regulatory Balances [10]	1595																	

<u>Explanation of Difference Between RRR and Continuity Schedule / Request for Disposition</u>

BCP performed a variance and deferral account review utilizing Ian McKenzie Business Services Inc. (IMBSI) dating from Jan 1, 2005 to Dec 31, 2009. This process produced some significant changes in many variance accounts filed with the OEB.

BCP corrected 2009 year-end balances in the RRR filings, however, did not adjust quarterly RRR filings.

BCP has provided the summary report created by IMBSI to assist with the understanding of the deferral and variance account changes. (note, appendices providing summary information and journal entries are not included for confidentiality purposes).

IMBSI Report

on

Review & Rebuild of 2005 to 2009 Regulatory Deferral & Variance Accounts

for

Brant County Power

Box 39114
London Ontario, N5Y5L1
Phone: 519-691-6501
Email:
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May 20, 2010

Table of Contents

Overview

Brant County Power (BCP) contracted with Ian McKenzie Business Services Inc. (IMBSI) to provide an independent review and assessment of all deferral and variance account balances as of December 31, 2009.

BCP was in the process of submitting its 2010 Incentive Rate Making (IRM) application to the Ontario Energy Board (OEB) and was not able to provide proper continuity schedules, for the period from Jan. 1, 2005 to Dec. 31, 2009, which reconciled to the General Ledger (GL) balances nor to the Electricity Record Keeping & Reporting Requirement (RRR) filings.

Other business factors contributed to BCPs desire to have the independent review performed:

1. Ensure accurate information provided through RRR filings to regulator
2. Ensure proper determination of annual profit and loss
3. Ensure ability to file accurate Cost of Service rate application
4. Provide due diligence assurance to management and the Board of Directors regarding regulatory asset balances
5. Ensure LDC is held whole with respect to all variance and deferral accounts, as the OEB has made decisions denying retroactive recovery of prior period accounting errors

During the review BCP received approval for 2010 distribution rates from the OEB. The decision specifically dealt with BCPs deferral & variance account balances. The OEB has postponed the disposition of all of BCPs deferral & variance accounts until the May 2011 Cost of Service (CoS) rate application rates are approved. This has allowed BCP staff to fully implement the revised deferral / variance process and should allow for final decisions to be reached on the outstanding Brantford Power hearings. This report will be a key tool utilized by both BCP and OEB staff during the 2011 CoS rate application approval process.

After initial review of BCP variance & deferral accounts, source documents and working files, IMBSI and BCP staff agreed that a total rebuild of 2005 to 2009 variance & deferral account activities was required to provide appropriate continuity schedules and support for GL adjusting entries. Details of the specific areas of concern are outlined later in this report.

IMBSI and BCP staff worked with BCPs external auditor and obtained sign-off on all revisions. The revisions have been booked to the appropriate time periods (pre-2008, 2008 & 2009).

General Findings

IMBSI discovered four general findings.

1. Accrual vs. Cash Methodology

The OEB APH specifies that LDCs have an option of choosing one of two accounting methods for interest improvement (the time value of money on variance & deferral account balances). LDCs may use either the cash or accrual basis for the interest improvement calculations. The OEB definition of the cash method matches expenses in the month they are paid to revenues billed in the same month. The accrual method matches the expenses in the month of consumption to the sales for the same month. The sales are calculated using the following formula:

Sales = Monthly Billed + Month End Unbilled – Month Starting Unbilled

BCP has been using a hybrid method where it matches expenses on an accrual basis to revenues on a cash basis (i.e. January consumed expense to January billed revenue which includes a portion of prior month's sales and January sales).

It was agreed between BCP staff and IMBSI to utilize the accrual basis for the re-build of the variance & deferral accounts for the following reasons:

i. Accrual method provides a more accurate (from GAAP matching perspective) process for interest improvement
ii. Provides consistency between interest improvement and financial reporting
iii. Provides a benefit for RRR flings matching GL balances

2. Interest Improvement Methodology

The OEB APH specifies that monthly interest improvement calculations be based on monthly opening balances using OEB prescribed interest rates. During the review process, it was discovered that BCP had been using varying methods (monthly & quarterly) for interest improvement calculations.

3. Financial Reporting

The GL did not reflect monthly changes to the variance & deferral accounts and the associated interest improvement. Individual accounts used varying posting dates (monthly, quarterly & year-end) resulting in inaccurate monthly financial reporting for variance & deferral account balances, interest revenue and interest expense. As of May 2010, monthly accounting is a requirement by the regulator (including moving expense / revenue differentials to variance accounts).

4. Clearing of Revenues and Expense to Variance & Deferral Accounts

The OEB specifies that proper treatment of variance & deferral account revenues and expenses requires an adjustment of the difference between the revenue and expense be moved (via JE) to the associated variance & deferral account. This results in the trial balance reflecting positive equal and off-setting values for both revenues and expenses for the year. This becomes paramount during a rate rebasing year to ensure that all expenses are appropriately considered in the working capital determination, which impacts financial returns to the LDC. There is also a loss of historical revenue and expense tracking.

At year-end, BCP correctly accounted for all Retail Settlement Variance Account (RSVAS) transactions, however, this process was not performed for the Retail Cost Variance Account (RCVA) 1518 – Non-STR. Revenue captured in USoA 4082 was cleared to 1518 resulting in a zero balance for year-end revenue.

IMBSI Rebuild of Variance & Deferral Accounts

IMBSI has rebuilt the BCP variance & deferral balances using the accrual basis and applying OEB prescribed interest rates and methodology.

The starting point, for all deferral & variance accounts (with the exception of USoA 1590), was the Dec. 31, 2004 GL balance which reflected values approved by the OEB as part of the 2006 rate approval process. Recent OEB decisions have confirmed that any accounting differences prior to the date of final disposition (Dec. 31, 2004) will not result in any changes in the historical deferral & variance account balances and will not be passed along to end use rate payers.

Recommendations

IMBSI recommends interest improvement is calculated according to OEB prescribed methodology and utilizing OEB prescribed interest rates.

IMBSI recommends initiating an unbilled process to allow for accurate and consistent financial and regulatory accounting meeting OEB accrual definition.

IMBSI recommends that the proper methodology (moving the difference between revenues and expense to the variance account) be utilized to adjust revenue and expense accounts for all deferral and variance accounts.

IMBSI recommends that BCP maintain detailed deferral account continuity schedules from Jan. 1, 2010 forward.

IMBSI recommends that the above recommendations be implemented and performed on a monthly basis.

Variance & Deferral Account – Specific Findings

1508 – OEB Assessment

Purpose of Account

Prior to 2006 the costs included in BCPs rates were based on the costs incurred in 1999/2000 when rates were unbundled. The OEB recognized that the level of regulatory costs paid to the OEB had increased significantly since that time. As a result LDCs were allowed to accumulate the difference between actual costs paid and the 1999/2000 level of costs included in the rates for the OEBs fiscal year 2004 and 2005 (period from April 1, 2004 to March 31, 2006). As a result net income was higher and these costs would be recovered from customers in the future through the disposition of regulatory assets.

As of the 2006 rate decision, current OEB assessment costs have been permanently engrained in approved distribution rates.

Findings

IMBSI discovered that BCP had not been tracking the allowed OEB cost assessment deferral costs for the allowed period of April 1, 2004 to March 31, 2006. The rebuilt values include identified assessment deferral and interest improvement of $33,072 to the benefit of BCP.

1508 – OMERS Contributions

Purpose of Account

Prior to 2006 the costs included in BCPs rates were based on the costs incurred in 1999/2000 when rates were unbundled. There was a pension contribution holiday in effect at the time. As the holiday expired LDCs began to incur costs. The OEB recognized that the level of pension costs had increased significantly. As a result LDCs were allowed to accumulate the difference between actual pension costs paid and the 1999/2000 level of costs included in the rates but only for the period from January 1, 2005 to April 30, 2006.

As of the 2006 rate decision, current OMERS costs have been permanently engrained in approved distribution rates.

Findings – OEB & OMERS Combined

BCP correctly accumulated the OMERS deferral principal portion costs. IMBSI has correctly calculated the interest improvement as per OEB prescribed methodology.

1518 – STR / 1548 – Non-STR (Retail Cost Variance Accounts)

Purpose of Accounts

The deregulation of the electricity marketplace in May 2002 introduced a new party into the electricity marketplace, retailers.

LDCs were required to conduct business and perform services for retailers for the first time. This resulted in increased costs for LDCs and the OEB developed a series of incremental retailer specific rates to compensate the LDCs. However, these proxy recovery rates were developed before any actual cost history had emerged. As a result LDCs are required to track their actual incremental costs of proving these services and any differences, when compared to the revenues received, are moved to a deferral account for potential future disposition.

There are 2 variance accounts dealing with 2 different types of services.

Findings - Combined

IMBSI found that BCP was incorrectly attributing EBT costs to USoA 1518 Non-STR variance account. IMBSI properly categorized these costs into USoA 1548 STR variance. In addition, IMBSI identified incremental settlement costs which have been attributed to USoA 1518 Non-STR variance account.

1525 Miscellaneous Debits

Purpose of Account

This account includes all debits not elsewhere provided in the USoA chart of accounts which will benefit future periods and are carried forward and charged to expense over the term of the benefit.

Findings

IMBSI rebuild resulted in an immaterial difference to the GL balance of $1,017.

1550 Low Voltage

Purpose of Account

Hydro One received approval for a series of rates to charge LDCs for their use of its distribution system. These rates became effective on May 1, 2006. The 2006 LDC rate application process required LDCs to include an estimate of these annual costs as part of their distribution rate application. The variance account is meant to track the difference between the Hydro One costs and revenue recovered from retail customers via distribution rates.

In addition, BCP pays Brantford Power (BP) for LV charges on three supply points (Powerline Rd, Colbourne St. East & Colbourne St. West).

Findings

BCP failed to remove LV revenue from distribution revenue for the period commencing May 2006 to Dec. 2009.

BCP charged all BP charges (Network, Connection and LV) to USoA 1550. IMBSI has properly allocated the network and connection portion of BP invoices to the proper RSVA.

1555 – Smart Meter Capital Revenue & 1556 – Smart Meter OM&A

Purpose of Accounts

These accounts are meant to track the cumulative operating expenses, capital expenditures, and revenues associated with implementing smart meters. The OEB has established a separate funding process for smart meter implementation. BCP is collecting a nominal portion of revenue from metered customers via a small proxy slice of the customer class fixed distribution charges.

Findings

IMBSI rebuild resulted in an immaterial difference to both USoA (1555 - $2,270 & 1556 - $3,789).

1565 - Conservation & Demand Management (CDM) & 1566 – CDM Contra Account

Purpose of Accounts

These accounts are used exclusively to track the costs incurred for conservation and demand management expenditures and the revenue amount equivalent to the distributor's (first generation) third tranche of MARR as approved by the Board in 2005 rates.

The actual expenditures incurred should be properly allocated to Operating and Capital accounts based on the nature of the expenditure.

Findings

IMBSI has determined that BCP met their full obligations relating to 3rd Tranche CDM expenditure.

IMBSI identified all expenditures were expensed to an OM&A account in spite of 3 projects from the original OEB approved CDM plan being capital in nature. IMBSI has properly capitalized the dollar value of these projects.

IMBSI identified that Ontario Power Authority (OPA) CDM program revenue & expenses have been charged to 1565 in error. IMBSI has corrected historical posting relating to the OPA CDM expenditures and has provided guidance on future OPA CDM activity (revenues & expenses should be charged to non-utility revenue and expense USoAs as per APH direction).

1580 - 1588 – Retail Settlement Variance Accounts (RSVA)

Purpose of Accounts

These accounts track the differences between various commodity and non-competitive cost of power expenses and the associated retail revenues. The intent is that LDCs will not be financially impacted from the revenue vs. expense differences. These variances are tracked on a cumulative basis in the RSVAs for recovery / repayment at a future date based upon OEB rate approvals.

Findings

Due to the inability to obtain continuity schedules for the RSVA accounts that tied into the GL accounts it was mutually agreed to rebuild all RSVA accounts from source documents (IESO invoices, Hydro One invoices, BP invoices, billed revenues from the GL and unbilled adjustments to revenues) for the period Jan. 1, 2005 to Dec. 31, 2009. IMBSI also correctly reflected the reversal of principal and interest approved as part of the 2006 rate application.

As part of the source document rebuild, IMBSI utilized expense and revenue reconciliations to audited GL values where available. The reconciliations were within acceptable tolerance bands for all revenue accounts and for the most part all expense accounts. Specifically the network and connection expense accounts were not reconciled to the GL, however, were rebuilt using monthly actual source invoices from suppliers.

1590 Recovery of Regulatory Asset Balances

Purpose of Account

The OEB allowed for the recovery of regulatory asset balances commencing with the 2002 rate application. LDCs are required to track on a cumulative basis the actual recoveries from customers. Regulatory asset balances as of December 31, 2004 were permanently dispositioned as part of the 2006 rate application process. The rate adders to obtain these recoveries stopped with the implementation of 2008 rates on Sept. 1, 2008. As a result, BCP continued to recover regulatory assets beyond the initial anticipated 24 month term when 2006 rates were set. It is expected that in future the amounts approved will be compared to the amounts actually recovered (1590 account) and the difference may be subject to a secondary disposition process.

Findings

IMBSI found that BCP significantly overstated the recoveries from customers (approx. $346,000 benefit to BCP).

IMBSI found BCP incorrectly reversed the approved regulatory asset recovery from the May 2006 rate application (approx. $42,000 detriment to BCP).

The IMBSI rebuild resulted in a favourable interest improvement of approximately $8,000.

Summary

The net impact to the Regulatory Asset accounts (shown in Appendix A) is an unfavourable decrease of $252,603.

Details regarding all journal entries are provided in Appendix B. Interest improvement continuity schedules and principal values have been forwarded to BCP staff.

The impact of all JEs on the financial statements is summarized in Appendix C.

In addition to the decrease in Regulatory Asset values there is a net fixed asset increase of $152,284 and a net reduction to P&L of $100,319 before tax.

Potentially off-setting this reduction to P&L would be income tax recoveries related to 2009 (to be validated by external auditors).

It is anticipated that these revised regulatory accounting balances will be approved as part of the 2011 CoS approval process.

Disposition of Deferral and Variance Accounts

BCP is filing December 31, 2009 audited variance account balances (reconciled to 2009 Y/E RRR filing), however we are not requesting disposition of the balances as the end of 2009.

BCP has been involved in an OEB hearing (EB-2009-0063) which was challenging the level of costs charged by Brantford Power (BP) to Brant County Power (BCP) as well as the period that specific retail transmission rates could be applied to 2 supply points.

BP was not invoicing for their retail transmission charges on 2 separate supply points over a period of time. BCP was of the opinion that the period BP could fix this billing error was limited, however the OEB has ruled otherwise. As a result, the current 2009 audited variance balances do not include a portion of network and connection expenses (i.e. amount of money owed to BCP customer overstated).

Similarly BCP challenged the amount of low voltage (LV) charges being billed by BP to BCP. The OEB agreed and adjusted the billing rates for BCP (as an embedded distributor). Again, the accounting for the 1550 – LV variance account will be impacted by this result. The 2009 audited balances do not include all expenses levied by BP.

BCP proposes to re-file the variance account section of this application using Dec. 31, 2010 audited balances (correcting for all above noted items) later in this process (as soon as value are available). Failure to utilize this proposal will create customer rate shock (upon next deferral and variance account disposition) as expenses related prior to 2010 will not be included in the 2011 variance account disposition. A second problem with this proposal not being accepted, is that BCP customers will be charged interest on balances residing in variance account for multiple years (depending on timing of next variance account disposition) longer than required.

BCP is of the opinion that using the 2010 audited balances will ensure the overall customer bill impacts do not have a yo-yo effect over the next few years, and that this proposal ensures timely remittance of actual funds owed to BCP customers.

Accounts Not Seeking Disposition

1562 – Deferred PILS

BCP is not seeking disposition of the 1562 account as the OEB currently has a generic proceeding on this topic. BCP will continue to track interest on the outstanding balance and will apply for disposition when instructed by the OEB.

1555 / 1556 – Smart Meter Variance Accounts

BCP is not seeking disposition of the Smart Meter variance accounts as OEB has instructed that these accounts will be dealt with after full implementation of the Smart Meter program and all cost and finalized.

List of Deferral and Variance Accounts Requested for Disposition

USoA	Description	Principal (Dec. 31, 2009)	Interest on Dec 31, 2009 balance to Apr. 30 2011	Total
1550	Low Voltage	$57,027	($21,094)	$35,933
1580	RSVA WMS	($600,396)	$103,627	($496,769)
1584	RSVA NW	($1,639,976)	($133,526)	($1,773,502)
1586	RSVA CN	($1,533,354)	($95,277)	($1,628,631)
1588	RSVA COP Excluding GA	$143,933	($28,006)	$115,927
1588	RSVA COP GA	$1,180,849	$24,562	$1,205,411
1590	Recovery of Reg. Assets	$0	$314,713	$314,713
1508	OEB Cost Assessment	$27,701	$5,056	$32,757
1508	OMERS Pension	$124,358	$17,451	$141,809
1518	RCVA – Retail	($61,590)	($3,658)	($65,248)
1548	RCVA – STR	$33,765	$2,030	$35,795
1525	Misc. Deferred Debits	$7,211	$2,005	$9,216
1565	CDM	$0	$0	$0
1566	CDM – Contra	$0	$0	$0
1582	RSVA One Time	$0	$0	$0
Total		**($2,260,472)**	**$187,883**	**($2,072,589)**

Calculation of Proposed Regulatory Asset Recovery Rate Riders – Non GA

Allocation to Customer Classes Based on kWh

USoA	Description	Principal (Dec. 31, 2009)	Interest on Dec 31, 2009 balance	Total
1550	Low Voltage	$57,027	($21,094)	$35,933
1580	RSVA WMS	($600,396)	$103,627	($496,769)
1584	RSVA NW	($1,639,976)	($133,526)	($1,773,502)
1586	RSVA CN	($1,533,354)	($95,277)	($1,628,631)
1588	RSVA COP Excluding GA	$143,933	($28,006)	$115,927
1590	Recovery of Reg. Assets	$0	$314,713	$314,713
Total		($3,572,766)	$140,437	($3,432,329)

Class	Allocation: 2011 Projected kWh	Allocation: %	Amount Clamied	Allocated Claim
Residential	80,122,583	29.31%		($1,005,935)
General Service < 50 kW	39,095,551	14.30%		($490,843)
General Service 50 to 4,999 kW	151,750,742	55.51%		($1,905,223)
Unmetered Load	493,370	0.18%		($6,194)
Sentinel Light	215,167	0.08%		($2,701)
Street Light	1,707,054	0.62%		($21,432)
Total	273,384,467	100.00%	($3,432,329)	($3,432,329)

Allocation to Customer Classes Based on Distribution Revenue

USoA	Description	Principal (Dec. 31, 2009)	Interest on Dec 31, 2009 balance	Total
1508	OEB Cost Assessment	$27,701	$5,056	$32,757
1508	OMERS Pension	$124,358	$17,451	$141,809
1518	RCVA – Retail	($61,590)	($3,658)	($65,248)
1548	RCVA – STR	$33,765	$2,030	$35,795
1525	Misc. Deferred Debits	$7,211	$2,005	$9,216
Total		$131,445	$22,884	$154,329

Class	Allocation: 2011 Projected Distribution Revenue	Allocation: %	Amount Clamied	Allocated Claim
Residential	3,832,932	59.18%		$91,330
General Service < 50 kW	1,163,283	17.96%		$27,718
General Service 50 to 4,999 kW	1,161,728	17.94%		$27,681
Unmetered Load	12,758	0.20%		$304
Sentinel Light	19,578	0.30%		$466
Street Light	286,627	4.43%		$6,830
Total	6,476,905	100.00%	$154,329	$154,329

Total Customer Class Allocated Recoveries

Class	Allocted Recoveries: kWh	Allocted Recoveries: Distribution Revenue	Total Recovery	Billing Determinent: Type	Billing Determinent: 2011 Projected Stats	Proposed Years Recovery	Reg. Asset Rate Rider
Residential	($1,005,935)	$91,330	($914,606)	kWh	80,122,583	2	($0.0057)
General Service < 50 kW	($490,843)	$27,718	($463,125)	kWh	39,095,551	2	($0.0059)
General Service 50 to 4,999 kW	($1,905,223)	$27,681	($1,877,542)	kW	388,493	2	($2.4164)
Unmetered Load	($6,194)	$304	($5,890)	kWh	493,370	2	($0.0060)
Sentinel Light	($2,701)	$466	($2,235)	kW	574	2	($1.9468)
Street Light	($21,432)	$6,830	($14,602)	kW	4,783	2	($1.5265)
Total	($3,432,329)	$154,329	($3,278,000)				

BCP has used a combination of previous OEB direction and logic in determining the 2011 regulatory asset rate riders (recovering 2010 year-end balances).

Previously the OEB has indicated that RSVA accounts (excluding GA subaccount of 1588) and 1550 (LV variance account) should be allocated to customer classes based on percentage share of kWh. BCP has used the 2011 projected load forecast as an allocation basis for these variance accounts

Generically the other variance accounts (1508 OEB & OMERS, 1518 RCVA Retail, 1548 RCVA STR and 1525 Misc. Deferred Debits) are considered to be driven from expenses that would otherwise (if the variance accounts did not exist) be considered distribution expenses. BCP proposes to use percentage cost allocation adjusted 2011 distribution revenue as an allocation basis for these expenses. BCP believes that using kWh as an allocation method would place an unfair amount of these expenses on the GS 50 to 4,999 customer class.

The customer class allocated kWh and distribution rate variance account dollars are then divided by the respective classes 2011 projected load profile and then divided by two (number of proposed years of customer repayment of net variance account balance) to derive the retail rate.

Calculation of Proposed Regulatory Asset Recovery Rate Riders – Global Adjustment (non-RPP customers)

Non-RPP Rate Rider

USoA	Description	Principal (Dec. 31, 2009)	Interest on Dec 31, 2009 balance	Total	2009 Actual Non-RPP Billed kWh	Proposed Years of Recovery	GA Rate Rider
1588	RSVA COP GA	$1,180,849	$24,562	$1,205,411	172,344,868	2	0.0035

As all Non-RPP customers contribute to the Global Adjustment sub-account evenly, this variance balances does not need to be attributed to customer classes. The rate rider of $0.0035 / kWh will be applied to all non-RPP customers metered kWh's.

Timing of Recoveries / Rebates of Variance Accounts

BCP is proposing to use a 2 year recovery period for all rate riders (as opposed to the default 1 year period). The main rationale for this approach is to avoid customer rate shock.

BCP will be raising distribution rates when comparing May 2011 to May 2010 bills. Using a longer period to dispose of variance accounts (net amount due to customers) allows for a 2 stage approach to implementing the bill impacts.

Smart Meters

BCP is proposing to keep unchanged the $1.00 / month / metered customer approved in the 2010 IRM rate case.

As we are not filing for disposition of the Smart Meter Variance Accounts or a change in the Smart Meter rate rider, we are not providing any further evidence on this matter.

Ex.	Tab	Schedule	Contents of Schedule
10 – LRAM & SSM			
	1		
		1	Overview of request
		2	LRAM Report

OVERVIEW

Brant Count Power Inc (BCP) herewith submits an application to the Ontario Energy Board (OEB) for the approval and recovery of historical Lost Revenue Mechanism (LRAM) and Shared Savings Mechanism (SSM) amounts related to new and ongoing Conservation and Demand Management (CDM) activities in 2005, 2006, 2007, 2008 and 2009. It is requested that these amounts be recovered through a rate rider over a one year period beginning May 1 2011. Total amount for recovery is $269,825, including carrying charges of $9,834. Amounts for SSM and LRAM recovery are summarized in Table 1.

Table 1: Summary of Requested LRAM and SSM Amounts

Customer Class	LRAM	Carrying Charges	SSM	Total
Residential	$174,018	$8,759	$18,625	$201,401
GS < 50 kW	$62,479	$988	($1,838)	$61,629
GS 50 to 4,999 kW	$2,992	$55	($429)	$2,618
Street lighting	$1,699	$32	$2,452	$4,183
Sentinel lights	$0	$0	($7)	($7)
Total	**$241,188**	**$9,834**	**$18,802**	**$269,825**

NOTES:

1. Totals may differ from the sum of rows or columns due to rounding

SSM Amounts

All CDM programs for which SSM amounts are sought were undertaken in connection with BCP's Third Tranche CDM spending obligations in 2005, 2006, 2007 and 2008.

The total SSM sought for recovery is $18,802, which is based on the results of the Total Resource Cost test (TRC test) that BCP used to evaluate the results of its programs. The stream of future net benefits is evaluated using net present value (NPV). In accordance with CDM guidelines, BCP is requesting recovery of 5% of the net benefits of the CDM programs.

Table 2 on the following page provides the SSM amounts by program and rate class.

Table 2: SSM Amounts by Program and Rate Class

Program	Net TRC					Total Net TRC	SSM
	Residential	GS < 50 kW	GS 50 to 4,999 kW	Street lighting	Sentinel lights		
Education, development and admin programs	($8,731)	($4,711)	($4,240)		($148)	($17,830)	($891)
Conservation County (CFL giveaway, daycare centre retrofit, education and awards day)	($10,512)	($24,958)	($4,338)			($39,809)	($1,990)
Cold Water Wash	$7,764					$7,764	$388
Every Kilowatt Counts (2006-2007)	$324,708					$324,708	$16,235
Garage door replacement		($7,092)				($7,092)	($355)
Lighten your electricity bill	$33,786					$33,786	$1,689
CFL giveaways	$18,516					$18,516	$926
Seasonal LED exchanges	$6,959					$6,959	$348
Traffic and streetlight conversion				$49,044		$49,044	$2,452
Total Net TRC	$372,490	($36,761)	($8,578)	$49,044	($148)	**$376,047**	
Total SSM	$18,625	($1,838)	($429)	$2,452	($7)		**$18,802**

NOTES:

1. Totals may differ from the sum of rows or columns due to rounding
2. Similar programs have been grouped for simplicity
3. Details by year and program are presented in Table 3 of the IndEco report in Schedule 2 of this exhibit.

LRAM Amounts

The LRAM adjusts for volumetric variances between actual CDM results and the corresponding quantities used in rate setting. The requested LRAM amounts are derived from savings composed of:

Third Tranche CDM programs implemented in 2005, 2006, 2007 and 2008;
Ontario Power Authority (OPA) programs implemented in 2006, 2007, 2008 and 2009.

The results for OPA programs in 2009 are preliminary, and will be updated once OPA provides final results. The lost revenues are calculated from the year of introduction through to December 31 2010.

None of the load reductions estimated were factored into the load forecast underpinning 2005, 2006, 2007, 2008 or 2009 rates. Therefore, BCP proposed recovery of LRAM amounts related to the entire load reduction, net of free rider quantities. The calculation of the load reduction is based on the energy and demand savings and the lifespan of the technology by rate class. The reduction in demand related to these programs has been incorporated into the rate forecast for May 1, 2011 onward. However, energy savings related to OPA programs delivered in 2010 or later have not been captured. Load losses from CDM programs for the period through December 31 2010, net of free riders, are shown in Table 3.

The total LRAM amount sought for recovery is $251,022 of which $112,446 is related to Third Tranche programs and $138,576 is a result of OPA programs. These values include $9,834 in carrying charges. Carrying charges were calculated using OEB approved rates. Resulting lost revenues are summarized in Table 4.

Verification and Evaluation of Results

BCP engaged IndEco Strategic Consulting Inc. to review its CDM program results and TRC calculations and aid in the calculation of recovery amounts using OEB guidelines. IndEco reported that the values provided in this application are considered valid. The full report prepared by IndEco is available Schedule 2 of this exhibit.

Recovery

BCP requests recovery of the LRAM and SSM amounts by way of volumetric rate riders over a one year period, effective May 1 2011, with the foregone revenue from each customer class allocated to that class for recovery. Table 5 sets the corresponding amounts by class, as well as the corresponding rate rider based on forecasted 2011 volume.

Impact on customer bills has been included in the Rate Generator Model and summarized in the applicant's Manager's Summary.

Table 3: Cumulative Net Energy and Demand Savings By Rate Class through 2010 from CDM Programs

Funding Stream	Program	Net savings			
		Residential (kWh)	GS < 50 kW (kWh)	GS 50 to 4,999 kW (kW-mo)	Street lighting (kW-mo)
OPA	Cool & Hot Savings Rebate	590,427			
	ERIP		421,934	549	
	Every Kilowatt Counts PSE (2008-2009)	822,304			
	Great Refrigerator Roundup/Secondary fridge retirement pilot	794,997			
	High Performance New Construction		46,089		
	peaksaver®	10,714	564		
	Power Savings Blitz		2,735,947		
	Social Housing Pilot	93,749			
	Summer Sweepstakes	925,735			
	Subtotal	*3,237,926*	*3,204,533*	*549*	
Third Tranche	Conservation County (CFL giveaway, daycare centre retrofit)	85,374	49,806		
	Cold water wash	164,005			
	Every Kilowatt Counts (2006-2007)	3,942,410			
	Garage door replacement		34,596		
	Lighten your electricity bill	274,095			
	CFL giveaways	131,476			
	Seasonal LED light exchange	33,098			
	Traffic and streetlight conversion				394
	Subtotal	*4,630,457*	*84,402*		*394*
Total		**7,868,383**	**3,288,935**	**549**	**394**

NOTES:

1. Totals may differ from the sum of rows or columns due to rounding
2. Similar programs have been grouped for simplicity
3. Details by year and program are presented in Table 4 of the IndEco report in Schedule 2 of this exhibit.

Table 4: Summary of LRAM Claim by Program and Rate Class

Funding Stream	Program	Net savings				Total
		Residential (kWh)	GS < 50 kW (kWh)	GS 50 to 4,999 kW (kW-mo)	Street lighting (kW-mo)	
OPA	Cool & Hot Savings Rebate	$13,552				$13,552
	ERIP		$8,194	$3,047		$11,241
	Every Kilowatt Counts PSE (2008-2009)	$18,631				$18,631
	Great Refrigerator Roundup/Secondary fridge retirement pilot	$18,116				$18,116
	High Performance New Construction		$888			$888
	peaksaver®	$241	$11			$252
	Power Savings Blitz		$52,700			$52,700
	Social Housing Pilot	$2,171				$2,171
	Summer Sweepstakes	$21,024				$21,024
	Subtotal	*$73,735*	*$61,793*	*$3,047*	*$0*	*$138,576*
Third Tranche	Conservation County (CFL giveaway, daycare centre retrofit)	$1,954	$994			$2,948
	Cold water wash	$3,395				$3,395
	Every Kilowatt Counts (2006-2007)	$93,637				$93,637
	Garage door replacement		$680			$680
	Lighten your electricity bill	$6,274				$6,274
	CFL giveaways	$3,016				$3,016
	Seasonal LED light exchange	$765				$765
	Traffic and streetlight conversion				$1,731	$1,731
	Subtotal	*$109,041*	*$1,674*	*$0*	*$1,731*	*$112,446*
Total		**$182,777**	**$63,467**	**$3,047**	**$1,731**	**$251,022**

NOTES:

1. Totals may differ from the sum of rows or columns due to rounding
2. Similar programs have been grouped for simplicity
3. Details by year and program are presented in Table 7 of the IndEco report in Schedule 2 of this exhibit.

Table 5: LRAM/SSM Amounts and Rate Riders by Class

Customer Class	LRAM	Carrying Charges	SSM	Total	Unit	2011 Forecasted Billed kWh/kW	1-yr Rate Rider $/unit
Residential	$174,018	$8,759	$18,625	$201,401	kWh	80,122,583	0.0025
GS < 50 kW	$62,479	$988	($1,838)	$61,629	kWh	39,095,551	0.0016
GS 50 to 4,999 kW	$2,992	$55	($429)	$2,618	kW	388,493	0.0067
Street lighting	$1,699	$32	$2,452	$4,183	kW	4,783	0.8746
Sentinel lights	$0	$0	($7)	($7)	kW	574	(0.0129)
Total	$241,188	$9,834	$18,802	$269,825	--	--	--

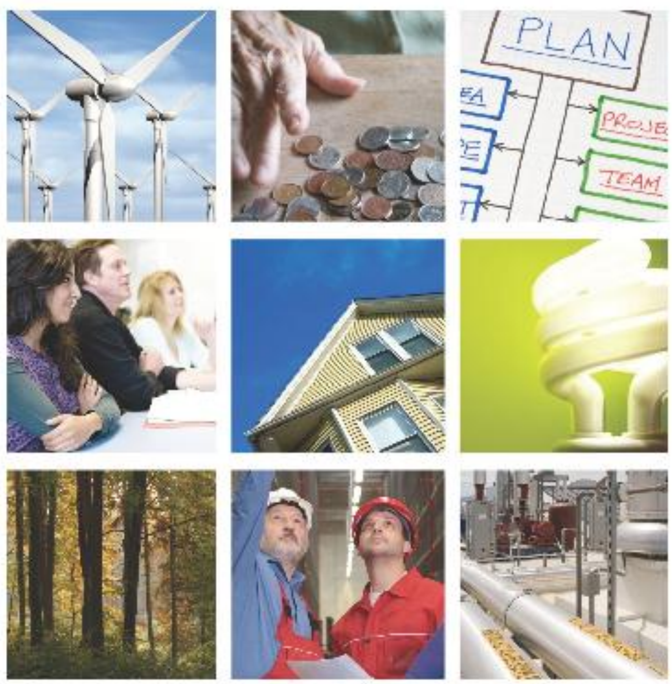
NOTES:

1. Totals differ from the sum of rows or columns due to rounding

LRAM / SSM Report

Strategic Solutions for a Changing World™

Brant County Power Inc.
LRAM/SSM



Third party review:

Brant County Power Inc.
LRAM and SSM claims

This document was prepared for Brant County Power Inc. by IndEco Strategic Consulting Inc.

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IndEco report B0620

22 October 2010

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Executive summary

A third party review of the Conservation and Demand Management (CDM) programs run by Brant County Power Inc. (BCP) was required as part of its application to the Ontario Energy Board (OEB) for collection of Lost Revenue Adjustment Mechanism (LRAM) and Shared Savings Mechanism (SSM) claims.

IndEco Strategic Consulting Inc. (IndEco) acted as third party reviewer by examining the participant rates, program costs, equipment specifications, and calculations that enter into the energy savings and Total Resource Costs (TRC) submitted by BCP to the OEB. The review was completed as detailed in the OEB *Guidelines for Electricity Distributor Conservation and Demand Management*.

The third party review included BCP's CDM activities in 2005, 2006, 2007, 2008 and 2009 supported through Third Tranche of Market Adjustment Revenue Requirement (MARR) funding, and Ontario Power Authority (OPA) funding.

Net benefits, calculated using the TRC test, used OEB recommended inputs. For prescriptive programs, inputs were taken primarily from the OEB *Total Resource Cost Guide*, or program evaluations provided by the OPA. TRC inputs for custom programs also relied upon manufacturer specifications and BCP's evaluations. Net TRC benefits totalled over $370,000 dollars.

Lost revenues are calculated using estimated energy savings or monthly peak demand savings using the best available and most current input assumptions. Energy savings originally reported in Brant County Power's annual filings have been updated to reflect new assumptions available since then, including more recent input assumptions from the OPA, and the results of OPA's program evaluations. In the span of six years, these savings totalled over 7 GWh in the residential rate class and 3 GWh in the GS < 50 kW rate class. Savings in the GS 50 to 4,999 kW and the Street Lighting rate classes totalled approximately 540 and 390 kW-months, respectively.

IndEco concludes that BCP's electricity rates should be adjusted to reflect LRAM and SSM claims of $251,022 and $18,802 respectively.

Introduction

Lost Revenue Adjustment Mechanism and Shared Savings Mechanism claims can benefit a local distribution company (LDC) by removing the disincentive for energy conservation, and by providing it with a portion of net economic benefits from conservation and demand management activities, respectively.

LRAM is designed to ensure that the LDC does not have a disincentive to promote energy efficiency and energy conservation by compensating the LDC for revenues lost as a result of its conservation initiatives. It requires the calculation of electricity savings over the period between the last rate application, and the time of the application. In turn, this calculation requires information on what the electricity use would have been in the absence of the LDC initiatives, and what it was with the LDC initiative. Some of the inputs to the calculation include: hours the equipment is used, wattage rating of the old and new equipment, and lifetime of the equipment if it is less than the period over which the LRAM is being claimed. Also required are the number of participants, or pieces of equipment installed, and an estimate of the free-rider rate, which is the fraction of the savings that would have occurred anyway, in the absence of the program. These savings are estimated by rate class, and revenue losses are determined by multiplying those losses by the cost of distribution per unit for each rate class. Carrying charges are calculated using deferral and variance account interest rates prescribed by the OEB.[1]

The SSM rewards the LDC for its CDM initiatives by sharing a percentage of the net economic benefits that result from the initiatives over their lifetime. For CDM activities by Ontario electricity distributors, that percentage has been set at five percent by the Ontario Energy Board (OEB). Key inputs to the calculation of SSM include all of the LRAM inputs, and in addition, the total lifetime of each technology installed, equipment costs, program costs, projected electricity costs (and water and natural gas if relevant) over that lifetime.

Although these input data requirements are sometimes measured, they sometimes use values from published sources, or assumptions provided by the Ontario Energy Board, or other reputable agencies. Collectively all these data are sometimes referred to as "TRC inputs" after the Total Resource Cost test that is used to calculate total economic costs and benefits to society. For some types of programs, such as large scale distribution of compact fluorescent bulbs, it would be impractical to measure the hours each bulb is used, and therefore these published sources provide an average value that is typical for this equipment type.

In some cases, estimated values for a particular component of the calculation are available from multiple sources. In these cases,

[1] For prescribed interest rates, see http://www.oeb.gov.on.ca/OEB/Industry/Rules+and+Requirements/Rules+Codes+Guidelines+and+Forms/Prescribed+Interest+Rates

information is taken from the sources highest in the information hierarchy. The information hierarchy (from greatest to least confidence) for LRAM calculations is:

1 Information or results from an OPA conducted or sponsored evaluation of the specific program (e.g. OPA 2010c)
2 Information or results from a third-party evaluation of the specific program
3 Information or results from a site-specific assessment of the application of the technology, including on-site measurement or survey of the specific customer
4 Manufacturer specifications for energy use/demand of the specific technology installed
5 Information from the OPA's most current measures and assumptions lists (OPA 2010a, OPA 2010b)
6 Information from earlier OPA measures and assumptions lists
7 Information from the OEB's TRC guide list of measures and assumptions (OEB 2008b).

In principal, we might have consulted values from the literature and adopted these if they could be shown to be more current, specific or otherwise suitable than the values from sources 4 through 7. However, this was not necessary in this case.

The CDM programs undertaken by Brant Count Power Inc. between 2005 and 2009 included:

- The Conservation County program which included public education and awareness, CFL giveaways, a lighting retrofit of a County-owned daycare facility, and an energy consumption reduction competition for students, households and businesses;
- A conversion of traffic lights and street lights from existing technologies to high efficiency LEDs;
- Seasonal LED light exchanges;
- A cold water wash coupon program and several CFL giveaways (including Project Porchlight);
- Public, staff and general services education and outreach programs;
- Participation in the 2005 Lighten your Electricity Bill, which was a coupon program for energy efficient measures;
- Installation of an energy efficient garage door at the BCP operations centre; and
- Partnership with or delivery of OPA programs, including Every Kilowatt Counts (EKC), ***peaksaver***®, the Great Refrigerator Roundup, Demand Response, the Summer Savings Program, Power Savings Blitz and the Electricity Retrofit Incentive Program (ERIP).

Between 2005 and 2010 (inclusive), these programs led to savings of over 7 GWh in the residential rate class and 3 GWh in the GS < 50 kW rate class. In the rate classes where distribution charges are based on monthly peak kilowatt use, the savings over the six years are approximately 540 and 390 kW-months in the GS 50-4,999 kW and the Street Lighting rate classes, respectively.

Net TRC benefits totalled over $370,000.

Scope

This review examines the measures, energy savings, program costs and net TRC benefits for the fifteen programs in BCP's third tranche CDM portfolio. These programs ran from 2005 until completion as of December 31, 2008. It also includes programs run under contract to the Ontario Power Authority (OPA) in 2006, 2007, 2008 and 2009.

Four programs omitted from this review are:

- A distribution system improvement program;
- A line loss reduction through voltage conversion program;
- A line conversion program; and
- A smart meter pilot program.

Distribution system improvements are not eligible for the shared savings mechanism.[2] The line loss reduction program and the line conversion program were also considered distribution system improvements.

The smart meter pilot program was omitted from CDM cost recovery assessment since cost recovery of smart meter programs is done under a separate OEB variance account.[3]

In the TRC calculation, benefits and costs are reported in current dollars, which requires a discount rate for future dollars. Even though these activities are at the margin, OEB has dictated that the discount rate to be used is the weighted average cost of capital (WACC). The WACC provided by BCP is as follows:

- 2005-2008: 6.43%

Because the WACC is only used to calculate present values for TRC calculations for the SSM, it is only required for these four years in which distributor-funded programs were offered.

[2] OEB, 2007. Report of the Board on the Regulatory Framework for Conservation and Demand Management by Ontario Electricity Distributors in 2007 and Beyond. (March 2). p.12

[3] See OEB Smart Metering Funding and Cost Recovery (File no: G-2008-002).

TRC inputs, and requested SSM and LRAM amounts

TRC inputs

Inputs used to calculate energy savings, TRC costs and TRC benefits for each prescriptive and custom measure were reviewed to ensure accuracy and suitability.

IndEco finds that appropriate measure specifications were used to calculate program energy savings and net TRC benefits. For the calculation of LRAM claims, prescriptive measures used values provided by the 2010 OPA Measures and Assumptions lists (OPA 2010a and OPA 2010b). For the calculation of SSM claims, the best available information at the beginning of the year the program was launched was used. This is consistent with the guidance in section 7.3 of the *OEB Guidelines for Electricity CDM* (OEB 2008a). Custom measures were substantiated through documentation such as invoices of equipment type, wattage, and costs.

Exceptions to the sources of prescriptive measure input assumptions used in the calculation of LRAM claims are as follows:

- The '2006-8 Final+2009 Preliminary.OPA CDM results.Brant County Power Inc.'[4] was used as a source of inputs for OPA funded CDM programs. These evaluated results have been adopted in accordance with Board recommendations that "The Board would consider an evaluation by the OPA or a third party designated by the OPA to be sufficient."[5] OPA advises that these estimates are prepared in a manner consistent with OPA current practice, and are the same values used to report progress against provincial conservation targets.
- One measure from the 2005 Lighten your Electricity Bill program was not found on the 2010 OPA Measures and Assumptions lists. The most current assumptions (SeeLine 2006) were used.
- The switch to cold water wash was not found on the prescriptive 2010 OPA Measures and Assumptions list. OEB's TRC guide list of measures and assumptions (OEB 2008b) was considered the most appropriate source for measure input assumptions.
- The 2005 Garage Door Replacement program and the 2008 Traffic Light and Street Light Conversion programs involved custom measures. Measure input assumptions were provided by Brant County Power.

[4] OPA 2010c. 2006-8 Final+2009 Preliminary.OPA CDM results.Brant County Power Inc. E-mail from J. Yue (OPA) dated 13 August

[5] OEB 2008a. Guidelines for Electricity Distributor Conservation and Demand Management. p.28

Default free-rider rates of 30% for LRAM calculations and 10% for SSM calculations were used for the majority of programs in BCP's CDM portfolio.

Exceptions to the default values proposed by the OEB and the OPA are as follows:

- All OPA programs used the program-specific free-rider rates provided by the '2006-8 Final+2009 Preliminary.OPA CDM results.Brant County Power Inc.'
- The replacement of the garage door at the BCP Operations Centre, the traffic light conversion and the streetlight conversion would not have occurred in the absence of their respective programs; the appropriate free-rider rate for these programs is thus 0%.

A summary list of the assumption sources used for the calculation of the LRAM claim is provided in Table 1.

A summary list of the information sources used for the calculation of the SSM claim is provided in Table 2.

The measure inputs used to calculate SSM and LRAM claims can be found in Table 9 and Table 10 in Appendix A, respectively.

Requested SSM amounts

Equipment costs and benefits were calculated by entering the measure assumptions found in Table 9 of Appendix A into IndEco's TRC calculator. The net TRC benefits were then used to calculate SSM entitlements for each year of every program.

SSM amounts were calculated for all third tranche programs. SSM amounts and TRC benefits net of free riders for all applicable programs are shown in Table 3.

Requested LRAM amounts

LRAM calculations are to be completed with the best information available at the time of the third party review. As such, the energy savings indicated in BCP's annual reports for programs in BCP's CDM portfolio were recalculated with the assumptions found in Table 10 in Appendix A.

The energy savings of the following programs were recalculated (from what is reported in the annual reports) to reflect updated LRAM inputs and free-rider rates:

- 2005 Conservation County - CFLs
- 2005 Conservation County - lighting retrofit
- 2005 Lighten your electricity bill
- 2006 Seasonal LED light exchange
- 2007 CDM other admin costs – NEPA (a CFL giveaway)

- 2007 Project porchlight
- 2007 Walter's greenhouse/Nova Vita Ladies Night (a CFL giveaway)
- 2007 Seasonal LED light exchange

Energy savings for measures installed between 2005 and 31 December 2009 were calculated to the end of 2010.

Table 4 and Table 5 show the net and gross energy savings or demand reductions of each program by rate class. OPA program energy savings in Table 4 and Table 5 were acquired directly from spreadsheets provided by the OPA. Note that the results of 2009 OPA programs are preliminary.

Energy savings were converted to LRAM values by using BCP distribution rates. Distribution rates are in Table 6.

The requested LRAM is presented in Table 7.

Table 1 – Source of information used for the calculation of the LRAM claim

Funding source	Rate class	Program	Source of LRAM inputs
Third-tranche	GS < 50 kW	2005 Garage door replacement	Brant 2006a, Brant 2006b
Third-tranche	Residential	2005 Conservation County - CFLs	OPA 2010a
Third-tranche	GS < 50 kW	2005 Conservation County - lighting retrofit	OPA 2010a, OPA 2010b
Third-tranche	Residential	2005 Lighten your electricity bill	OPA 2010a, SeeLine 2006[1]
Third-tranche	Residential	2005 Cold water wash program	OEB 2008b
Third-tranche	Residential	2006 Seasonal LED light exchange	OPA 2010a
Third-tranche	Residential	2006 Every Kilowatt Counts	OPA 2010c
Third-tranche	Residential	2007 Every Kilowatt Counts	OPA 2010c
Third-tranche	Residential	2007 CDM other admin costs - NEPA	OPA 2010a
Third-tranche	Residential	2007 Project porchlight	OPA 2010a
Third-tranche	Residential	2007 Walter's greenhouse/Nova Vita Ladies Night	OPA 2010a
Third-tranche	Residential	2007 Seasonal LED light exchange	OPA 2010a
Third-tranche	Street lighting	2008 Traffic light conversion	Brant 2009
Third-tranche	Street lighting	2008 Streetlight conversion	Brant 2009
OPA	Residential	2006 Secondary Refrigerator Retirement Pilot	OPA 2010c
OPA	Residential	2006 Cool & Hot Savings Rebate	OPA 2010c
OPA	Residential	2007 Great Refrigerator Roundup	OPA 2010c

Funding source	Rate class	Program	Source of LRAM inputs
OPA	Residential	2007 Cool & Hot Savings Rebate	OPA 2010c
OPA	Residential	2007 Social Housing Pilot	OPA 2010c
OPA	GS < 50 kW, GS 50 to 4999 kW	2007 ERIP	OPA 2010c
OPA	Residential	2008 Great Refrigerator Roundup	OPA 2010c
OPA	Residential	2008 Cool Savings Rebate	OPA 2010c
OPA	Residential	2008 Every Kilowatt Counts Power Savings Event	OPA 2010c
OPA	Residential, GS < 50 kW	2008 peaksaver®	OPA 2010c
OPA	Residential	2008 Summer Sweepstakes	OPA 2010c
OPA	GS < 50 kW, GS 50 to 4999 kW	2008 ERIP	OPA 2010c
OPA	GS < 50 kW	2008 High Performance New Construction	OPA 2010c
OPA	Residential	2009 Great Refrigerator Roundup	OPA 2010c
OPA	Residential	2009 Cool Savings Rebate	OPA 2010c
OPA	Residential	2009 Every Kilowatt Counts Power Savings Event	OPA 2010c
OPA	Residential, GS < 50 kW	2009 peaksaver®	OPA 2010c
OPA	GS < 50 kW, GS 50 to 4999 kW	2009 ERIP	OPA 2010c
OPA	GS < 50 kW	2009 High Performance New Construction	OPA 2010c
OPA	GS < 50 kW	2009 Power Savings Blitz	OPA 2010c

1. SeeLine 2006 was used for input assumptions for one measure not found in OPA 2010a: AC indoor timers.

Table 2 – Source of information used for the calculation of the SSM claim

Funding source	Rate class	Program	Source of SSM inputs
Third-tranche	GS < 50 kW	2005 Garage door replacement	Brant 2006a, Brant 2006b
Third-tranche	Residential	2005 Conservation County - CFLs	OEB 2008b
Third-tranche	GS < 50 kW	2005 Conservation County - lighting retrofit	OEB 2008b
Third-tranche	Residential, GS < 50 kW, GS 50 to 4999 kW	2005 Conservation County - education	Brant 2006a
Third-tranche	Residential, GS < 50 kW, GS 50 to 4999 kW, sentinel lights	2005 Staff development	Brant 2006a
Third-tranche	Residential, GS < 50 kW, GS 50 to 4999 kW, sentinel lights	2005 Planning, administration & monitoring	Brant 2006a
Third-tranche	Residential	2005 Lighten your electricity bill	SeeLine 2006
Third-tranche	Residential	2005 Cold water wash program	OEB 2008b
Third-tranche	Residential	2005 CDM other admin costs - NEPA	Brant 2006a
Third-tranche	GS 50 to 4,999 kW	2005 CDM other admin costs - Breakfast seminar	Brant 2006a
Third-tranche	Residential	2006 Seasonal LED light exchange	OEB 2008b
Third-tranche	Residential, GS < 50 kW, GS 50 to 4999 kW, sentinel lights	2006 Staff development	Brant 2007
Third-tranche	Residential, GS < 50 kW, GS 50 to 4999 kW, sentinel lights	2006 Planning, administration & monitoring	Brant 2007
Third-tranche	Residential, GS < 50 kW, GS 50 to 4999 kW	2006 Energy exhibition - October 14, 2006	Brant 2007
Third-tranche	Residential	2006 CDM other admin costs - NEPA	Brant 2007
Third-tranche	Residential	2007 CDM other admin costs - NEPA	OEB 2008b
Third-tranche	Residential	2007 Project porchlight	OEB 2008b
Third-tranche	Residential	2007 Walter's greenhouse/Nova Vita Ladies Night	OEB 2008b
Third-tranche	Residential	2007 Seasonal LED light exchange	OEB 2008b
Third-tranche	Street lighting	2008 Traffic light conversion	Brant 2009
Third-tranche	Street lighting	2008 Streetlight conversion	Brant 2009
Third-tranche	Residential	2006 Every Kilowatt Counts	OPA 2010c, OPA 2006a, OPA 2006b
Third-tranche	Residential	2007 Every Kilowatt Counts	OPA 2010c, OEB 2008b

1. The sources of SSM inputs were the best available at the onset of the program.

Table 3 – Summary of Net TRC benefits and SSM entitlement

Program	Year	Residential	GS < 50 kW	GS 50 to 4,999 kW	Street lighting	Sentinel lights	Net TRC	SSM amount
CDM other admin costs - Breakfast seminar	2005			($1,247)			*($1,247)*	*($62)*
CDM other admin costs - NEPA	2005	($3,838)					*($3,838)*	*($192)*
	2006	($900)					*($900)*	*($45)*
	2007	$6,289					*$6,289*	*$314*
Cold water wash program	2005	$7,764					*$7,764*	*$388*
Conservation County - CFLs	2005	$9,010					*$9,010*	*$451*
Conservation County - education	2005	($19,522)	($19,522)	($4,338)			*($43,383)*	*($2,169)*
Conservation County - lighting retrofit	2005		($5,436)				*($5,436)*	*($272)*
Energy exhibition - October 14, 2006	2006	($1,318)	($264)	($176)			*($1,758)*	*($88)*
Every Kilowatt Counts	2006	$221,479					*$221,479*	*$11,074*
	2007	$103,229					*$103,229*	*$5,161*
Garage door replacement	2005		($7,092)				*($7,092)*	*($355)*
Lighten your electricity bill	2005	$33,786					*$33,786*	*$1,689*
Planning, administration & monitoring	2005	($6,237)	($3,742)	($2,370)		($125)	*($12,473)*	*($624)*
	2006	($214)	($128)	($81)		($4)	*($427)*	*($21)*
Project porchlight	2007	$13,247					*$13,247*	*$662*
Seasonal LED light exchange	2006	$2,445					*$2,445*	*$122*
	2007	$4,514					*$4,514*	*$226*
Staff development	2005	($531)	($319)	($202)		($11)	*($1,063)*	*($53)*
	2006	($431)	($259)	($164)		($9)	*($862)*	*($43)*
Streetlight conversion	2008				($13,511)		*($13,511)*	*($676)*
Traffic light conversion	2008				$62,555		*$62,555*	*$3,128*
Walter's greenhouse/ Nova Vita Ladies Night	2007	$3,718					*$3,718*	*$186*
Total net TRC benefits		*$372,490*	*($36,761)*	*($8,578)*	*$49,044*	*($148)*	*$376,047*	
Total net SSM								**$18,802**

Table 4 – Cumulative net program energy savings and demand savings by rate class through 2010

Funding source	Program	Program year	Residential (kWh)	GS < 50 kW (kWh)	GS 50 – 4,999 kW (kW-mo)[1]	Street lighting (kW-mo)[1]
OPA[2]	Cool & Hot Savings Rebate	2006	136,293			
		2007	172,074			
	Cool Savings Rebate	2008	137,813			
		2009	144,247			
	ERIP	2007		22,567	42	
		2008		170,738	127	
		2009		228,628	380	
	Every Kilowatt Counts Power Savings Event	2008	697,545			
		2009	124,760			
	Great Refrigerator Roundup	2007	170,807			
		2008	394,527			
		2009	174,452			
	High Performance New Construction	2008		2,138		
		2009		43,950		
	peaksaver®	2008	4,684	247		
		2009	6,030	317		
	Power Savings Blitz	2009		2,735,947		
	Secondary Refrigerator Retirement Pilot	2006	55,211			
	Social Housing Pilot	2007	93,749			
	Summer Sweepstakes	2008	925,735			
OPA net savings by rate class			*3,237,926*	*3,204,533*	*549*	*0*
Third-tranche	CDM other admin costs - Breakfast seminar	2005				
	CDM other admin costs - NEPA	2005				
		2006				
		2007	38,030			
	Cold water wash program	2005	164,005			
	Conservation County - CFLs	2005	85,374			
	Conservation County - education	2005				
	Conservation County - lighting retrofit	2005		49,806		
	Energy exhibition - October 14, 2006	2006				
	Every Kilowatt Counts[3]	2006	2,920,385			
		2007	1,022,025			
	Garage door replacement	2005		34,596		
	Lighten your electricity bill	2005	274,095			
	Planning, administration	2005				

Funding source	**Program**	**Program year**	**Residential (kWh)**	**GS < 50 kW (kWh)**	**GS 50 – 4,999 kW (kW-mo)[1]**	**Street lighting (kW-mo)[1]**
	& monitoring	2006				
	Project porchlight	2007	71,714			
	Seasonal LED light exchange	2006	13,518			
		2007	19,579			
	Staff development	2005				
		2006				
	Streetlight conversion	2008				30
	Traffic light conversion	2008				364
	Walter's greenhouse/Nova Vita Ladies Night	2007	21,732			
Third Tranche net savings by rate class			*4,630,457*	*84,402*	*0*	*394*
Total net savings by rate class			*7,868,383*	*3,288,935*	*549*	*394*
Total net kWh savings			**11,157,318**			
Total net kW savings					**943**	

1. Rates for street lighting and the general service rate class of customers rated at greater than 50 kW are on a monthly demand basis (kW), not an energy one (kWh). Lost revenue results when the customer's monthly peak demand is lower than it otherwise would be as a result of the CDM initiatives. These are measured in kW-month, which is the reduction within one month of the peak kilowatt demand. (So a 2 kW-month reduction could be realized by reducing the peak demand in the month by 1 kW for two months, or by 2 kW for one month.) Excluded are peak demand reductions associated with demand response programs which are not anticipated to impact on revenues.

2. Results from the 2009 OPA programs are preliminary.

3. The EKC program in 2006 and 2007 was a partnership with the OPA. BCP's financial contribution was funded through its third-tranche allocation.

Table 5 – Cumulative gross program energy savings and peak demand savings by rate class through 2010

Funding source	Program	Program year	Residential (kWh)	GS < 50 kW (kWh)	GS 50 – 4,999 kW (kW-mo)	Street lighting (kW-mo)
OPA	Cool & Hot Savings Rebate	2006	172,659			
		2007	337,970			
	Cool Savings Rebate	2008	239,909			
		2009	248,296			
	ERIP	2007		25,075	46	
		2008		302,453	220	
		2009		394,186	655	
	Every Kilowatt Counts Power Savings Event	2008	1,729,270			
		2009	190,451			
	Great Refrigerator Roundup	2007	423,554			
		2008	727,863			
		2009	360,161			
	High Performance New Construction	2008		3,054		
		2009		62,786		
	peaksaver®	2008	5,204	274		
		2009	6,700	353		
	Power Savings Blitz	2009		2,941,878		
	Secondary Refrigerator Retirement Pilot	2006	61,346			
	Social Housing Pilot	2007	93,749			
	Summer Sweepstakes	2008	1,193,173			
OPA gross savings by rate class			*5,790,304*	*3,730,059*	*922*	*0*
Third-tranche	CDM other admin costs - Breakfast seminar	2005				
	CDM other admin costs - NEPA	2005				
		2006				
		2007	54,329			
	Cold water wash program	2005	218,673			
	Conservation County - CFLs	2005	121,963			
	Conservation County - education	2005				
	Conservation County - lighting retrofit	2005		71,152		
	Energy exhibition - October 14, 2006	2006				
	Every Kilowatt Counts	2006	3,244,873			
		2007	1,390,018			
	Garage door replacement	2005		34,596		
	Lighten your electricity bill	2005	391,564			

Funding source	Program	Program year	Residential (kWh)	GS < 50 kW (kWh)	GS 50 – 4,999 kW (kW-mo)	Street lighting (kW-mo)
	Planning, administration & monitoring	2005				
		2006				
	Project porchlight	2007	102,449			
	Seasonal LED light exchange	2006	19,312			
		2007	27,971			
	Staff development	2005				
		2006				
	Streetlight conversion	2008				30
	Traffic light conversion	2008				364
	Walter's greenhouse/Nova Vita Ladies Night	2007	31,045			
Third Tranche gross savings by rate class			*5,602,195*	*105,748*	*0*	*394*
Total gross savings by rate class			*11,392,499*	*3,835,807*	*922*	*394*
Total gross kWh savings			**15,228,306**			
Total gross kW savings					**1,316**	

Table 6 – Distribution rates per rate class

Rate Class	Units	2005	2006	2007	2008	2009	2010
Residential	$/kWh	0.0134	0.0222	0.0224	0.0224	0.0225	0.0216
GS < 50 kW	$/kWh	0.0137	0.0191	0.0193	0.0193	0.0194	0.0186
GS 50 to 4,999 kW	$/kW/mo	3.8976	5.5451	5.595	5.595	5.6124	5.2549
Street lighting	$/kW/mo	3.0896	4.3678	4.4071	4.4071	4.4208	4.1543

Table 7 – Summary of requested LRAM amounts in 2011$[1]

Funding	Program	Year	Residential	GS < 50 kW	GS 50 to 4,999 kW	Street lighting	6-year LRAM
OPA[2]	Cool & Hot Savings Rebate	2006	$3,214	$0	$0	$0	$3,214
		2007	$3,984	$0	$0	$0	$3,984
	Cool Savings Rebate	2008	$3,130	$0	$0	$0	$3,130
		2009	$3,224	$0	$0	$0	$3,224
	ERIP	2007	$0	$450	$240	$0	$690
		2008	$0	$3,341	$714	$0	$4,055
		2009	$0	$4,403	$2,093	$0	$6,496
	Every Kilowatt Counts Power Savings Event	2008	$15,843	$0	$0	$0	$15,843
		2009	$2,788	$0	$0	$0	$2,788
	Great Refrigerator Roundup	2007	$3,955	$0	$0	$0	$3,955
		2008	$8,960	$0	$0	$0	$8,960
		2009	$3,899	$0	$0	$0	$3,899
	High Performance New Construction	2008	$0	$42	$0	$0	$42
		2009	$0	$846	$0	$0	$846
	peaksaver®	2008	$106	$5	$0	$0	$111
		2009	$135	$6	$0	$0	$141
	Power Savings Blitz	2009	$0	$52,700	$0	$0	$52,700
	Secondary Refrigerator Retirement Pilot	2006	$1,302	$0	$0	$0	$1,302
	Social Housing Pilot	2007	$2,171	$0	$0	$0	$2,171
	Summer Sweepstakes	2008	$21,024	$0	$0	$0	$21,024
OPA total			*$73,735*	*$61,793*	*$3,047*	*$0*	*$138,576*
Third-tranche	CDM other admin costs - Breakfast seminar	2005	$0	$0	$0	$0	
	CDM other admin costs - NEPA	2005	$0	$0	$0	$0	
		2006	$0	$0	$0	$0	
		2007	$872	$0	$0	$0	$872
	Cold water wash program	2005	$3,395	$0	$0	$0	$3,395
	Conservation County - CFLs	2005	$1,954	$0	$0	$0	$1,954
	Conservation County - education	2005	$0	$0	$0	$0	
	Conservation County - lighting retrofit	2005	$0	$994	$0	$0	$994
	Energy exhibition - October 14, 2006	2006	$0	$0	$0	$0	
	Every Kilowatt Counts	2006	$69,968	$0	$0	$0	$69,968
		2007	$23,669	$0	$0	$0	$23,669

Funding	Program	Year	Residential	GS < 50 kW	GS 50 to 4,999 kW	Street lighting	6-year LRAM
	Garage door replacement	2005	$0	$680	$0	$0	$680
	Lighten your electricity bill	2005	$6,274	$0	$0	$0	$6,274
	Planning, administration & monitoring	2005	$0	$0	$0	$0	
		2006	$0	$0	$0	$0	
	Project porchlight	2007	$1,645	$0	$0	$0	$1,645
	Seasonal LED light exchange	2006	$316	$0	$0	$0	$316
		2007	$449	$0	$0	$0	$449
	Staff development	2005	$0	$0	$0	$0	
		2006	$0	$0	$0	$0	
	Streetlight conversion	2008	$0	$0	$0	$132	$132
	Traffic light conversion	2008	$0	$0	$0	$1,599	$1,599
	Walter's greenhouse/Nova Vita Ladies Night	2007	$499	$0	$0	$0	$499
Third tranche total			*$109,041*	*$1,674*	*$0*	*$1,731*	*$112,446*
Total			*$182,777*	*$63,467*	*$3,047*	*$1,731*	**$251,022**

1. LRAM amounts by program and program year, and program totals are for energy (or demand) reductions for the years 2005 through 2010.

2. Results from the 2009 OPA programs are preliminary.

Findings

The fifteen third-tranche programs in BCP's CDM portfolio were completed as of December 31, 2008. Although the OEB guidance for this report asks for comments on future program evaluation and improvements to program performance, this expectation is not relevant for these programs that have ended and are not expected to be reinitiated.

IndEco has reviewed the input values and custom project justifications used to calculate the energy savings and net TRC benefits resulting from BCP's portfolio as well as those associated with 2006, 2007, 2008 and 2009 OPA-funded programs.

IndEco has concluded that sufficient detail and documentation exists to recommend increasing Brant County Power's distribution rates in order to collect $251,022 in LRAM and $18,802 in SSM amounts, allocated by rate class as shown in Table 8.

Table 8 – LRAM and SSM amounts by rate class in 2011$

Rate class	LRAM	SSM
Residential	$182,777	$18,625
GS < 50 kW	$63,467	($1,838)
GS 50 to 4,999 kW	$3,047	($429)
Large use	$0	$0
Street lighting	$1,731	$2,452
Sentinel lights	$0	($7)
Total	**$251,022**	**$18,802**

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Appendix A. Inputs used for TRC and energy savings calculations

Table 9 - SSM inputs and contribution to the total SSM for all measures.

Rate class	Program	Energy Efficient Measure	Number of units	Measure life	SSM Free Ridership	Total benefits	Total costs	Annual energy savings (kWh/a)	Contribution to SSM
Residential	2006 Every Kilowatt Counts	Energy Star® Compact Fluorescent Light Bulb - Spring Campaign	2,641	4	10%	$69,899	$6,603	104	$2,848
	2006 Every Kilowatt Counts	Electric Timers - Spring Campaign	74	20	10%	$12,554	$925	183	$523
	2006 Every Kilowatt Counts	Programmable Thermostats - Spring Campaign	32	15	10%	$6,210	$2,080	216	$186
	2006 Every Kilowatt Counts	Energy Star® Ceiling Fans - Spring Campaign	25	20	10%	$3,503	$625	141	$130
	2006 Every Kilowatt Counts	Energy Star® Compact Fluorescent Light Bulb - Autumn Campaign	3,916	4	10%	$103,247	$6,344	104	$4,361
	2006 Every Kilowatt Counts	Seasonal Light Emitting Diode Light String - Autumn Campaign	943	30	10%	$30,177	$8,204	31	$989
	2006 Every Kilowatt Counts	Programmable Thermostats - Autumn Campaign	62	18	10%	$35,800	$1,550	522	$1,541
	2006 Every Kilowatt Counts	Dimmers - Autumn Campaign	49	10	10%	$3,656	$637	139	$136
	2006 Every Kilowatt Counts	Indoor Motion Sensors - Autumn Campaign	18	20	10%	$3,488	$360	209	$141
	2006 Every Kilowatt Counts	Programmable Baseboard Thermostats - Autumn Campaign	4	18	10%	$5,143	$100	1,466	$227
	2007 Every Kilowatt Counts	15 W CFL	4,680	8	22%	$96,548	$9,359	43	$3,400
	2007 Every Kilowatt Counts	20+ W CFL	762	8	22%	$22,671	$653	62	$859
	2007 Every Kilowatt Counts	Energy Star® Light Fixture	18	16	45%	$1,927	$436	123	$41

Rate class	Program	Energy Efficient Measure	Number of units	Measure life	SSM Free Ridership	Total benefits	Total costs	Annual energy savings (kWh/a)	Contribution to SSM
	2007 Every Kilowatt Counts	T8 Fluorescent Tube	36	18	23%	$1,232	$712	37	$20
	2007 Every Kilowatt Counts	Seasonal LED Light String	1,240	5	51%	$5,682	$10,786	14	($125)
	2007 Every Kilowatt Counts	Project Porchlight CFL	985	8	24%	$20,317	$1,970	43	$697
	2007 Every Kilowatt Counts	Solar Light	601	5	87%	$851	$2,854	5	($13)
	2007 Every Kilowatt Counts	Energy Star® Ceiling Fan	38	10	45%	$1,963	$1,774	90	$5
	2007 Every Kilowatt Counts	Furnace Filter	152	1	45%	$388	$1,825	38	($40)
	2007 Every Kilowatt Counts	Power Bar with Timer	17	10	23%	$717	$416	72	$12
	2007 Every Kilowatt Counts	Lighting Control Device	193	10	45%	$9,491	$4,004	72	$151
	2007 Every Kilowatt Counts	Outdoor Motion Sensor	60	10	45%	$5,286	$974	160	$119
	2007 Every Kilowatt Counts	Dimmer Switch	38	10	45%	$528	$496	24	$1
	2007 Every Kilowatt Counts	Programmable Thermostat	37	15	45%	$2,179	$917	75	$35
	2005 Conservation County - CFLs	15 W CFL	500	4	10%	$13,233	$1,000	104.4	$551
	2005 Lighten your electricity bill	15W CFL	575	4	10%	$15,218	$1,150	104.4	$633
	2005 Lighten your electricity bill	Seasonal LED Lights - 5W	55	30	5%	$2,527	$110	44.5	$115
	2005 Lighten your electricity bill	Seasonal LED Lights - Mini Lights	55	30	5%	$965	$110	17.0	$41
	2005 Lighten your electricity bill	Pstat - Space Heating	15	18	10%	$19,194	$900	1459.0	$823
	2005 Lighten your electricity bill	Pstat - Space Cooling	39	18	10%	$9,486	$2,340	158.0	$322
	2005 Lighten your	Outdoor Timer	21	20	10%	$5,685	$420	292.0	$237

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Rate class	Program	Energy Efficient Measure	Number of units	Measure life	SSM Free Ridership	Total benefits	Total costs	Annual energy savings (kWh/a)	Contribution to SSM
	electricity bill								
	2005 Lighten your electricity bill	Indoor Timer	4	20	10%	$530	$28	98.0	$23
	2005 Lighten your electricity bill	Indoor Timer for AC	3	20	10%	$656	$21	109.0	$29
	2005 Lighten your electricity bill	Ceiling Fan	16	20	10%	$0	$672	0.0	($30)
	2005 Cold water wash program	Cold water wash detergent	351	1	25%	$14,529	$3,510	623	$413
	2006 Seasonal LED light exchange	LED Lights	300	30	5%	$5,884	$2,759	19.0	$148
	2006 Seasonal LED light exchange	LED Lights	50	30	5%	$361	$460	7.0	($5)
	2007 CDM other admin costs - NEPA	15 W CFL	350	4	10%	$9,258	$600	104.4	$390
	2007 Project porchlight	15 W CFL	660	4	10%	$17,458	$1,200	104.4	$732
	2007 Walter's greenhouse/Nova Vita Ladies Night	15 W CFL	200	4	10%	$5,290	$400	104.4	$220
	2007 Seasonal LED light exchange	LED Lights	407	30	5%	$8,149	$2,925	19.0	$248
	2007 Seasonal LED light exchange	LED Lights	517	30	5%	$3,814	$3,716	7.0	$5
Residential total						*$575,694*	*$86,926*		*$21,135*
GS < 50 kW	2005 Conservation County - lighting retrofit	2 - T8 32 W (58 W) reflectorized w/EL ballast	48	9	10%	$7,843	$2,544	392	$238
	2005 Conservation County - lighting retrofit	1 - T8 32 W (38 W) w/EL HBF ballast	4	9	10%	$267	$144	160	$6
	2005 Conservation County - lighting retrofit	15 W CFL	15	4	10%	$480	$30	104.4	$20
	2005 Conservation	3 W LED Exit sign	10	25	10%	$2,372	$950	237	$64

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Rate class	Program	Energy Efficient Measure	Number of units	Measure life	SSM Free Ridership	Total benefits	Total costs	Annual energy savings (kWh/a)	Contribution to SSM
	County - lighting retrofit								
	2005 Garage door replacement	Garage door replacement from R5 to R10.5	1	15	0%	$4,908	$12,000	5,766	($355)
GS < 50 kW total						*$15,870*	*$15,668*		*($26)*
Streetlighting	2008 Traffic light conversion	LED traffic lights	4	14	0%	$84,955	$22,400	26,578	$3,128
	2008 Streetlight conversion	LED streetlight	25	14	0%	$8,926	$22,437	456	($676)
Streelighting total						*$93,881*	*$44,837*		*$2,452*
Total						**$685,445**	**$147,431**		**$23,561**

The net TRC benefits are the total technology benefits less the total technology costs (net of free riders) less the total program costs. The total gross technology benefits and costs, from Table 9, are $685,445 and $147,431, respectively. The total net technology benefits and costs are $597,680 and $126,456. The total program cost for all programs is $95,177. Net TRC benefits are thus $376,047. The SSM incentive is 5% of these net TRC benefits, or $18,802.

Table 10 – LRAM inputs and contribution to the total LRAM for all measures.

Program	Energy Efficient Measure	Number of units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Annual peak demand savings (kW/a)	Contribution to LRAM (2011$)	Assumption Source
2006 Secondary Refrigerator Retirement Pilot	Refrigerator Retirement	10	6	10%	1,200	0.272	$1,261	OPA 2010c
2006 Secondary Refrigerator Retirement Pilot	Freezer Retirement	0	6	10%	900	0.204	$41	OPA 2010c
2006 Cool & Hot Savings Rebate	Energy Star® Central Air Conditioner - Cool Savings	28	14	10%	390	0.399	$1,176	OPA 2010c
2006 Cool & Hot Savings Rebate	Programmable Thermostat - Cool Savings	22	18	10%	177	0.181	$406	OPA 2010c
2006 Cool & Hot Savings Rebate	Central Air Conditioner Tune-ups - Cool Savings	19	8	10%	410	0.420	$843	OPA 2010c
2006 Cool & Hot Savings Rebate	Energy Star® Central Air Conditioner - Hot Savings	6	18	43%	155	0.169	$60	OPA 2010c
2006 Cool & Hot Savings Rebate	Efficient Furnace with ECM - Hot Savings	12	15	41%	837	0.496	$710	OPA 2010c
2006 Cool & Hot Savings Rebate	Programmable Thermostat - Hot Savings	11	15	73%	54	0.028	$20	OPA 2010c
2006 Every Kilowatt Counts	Energy Star® Compact Fluorescent Light Bulb - Spring Campaign	2,641	4	10%	104	0.000	$23,851	OPA 2010c
2006 Every Kilowatt Counts	Electric Timers - Spring Campaign	74	20	10%	183	0.000	$1,438	OPA 2010c
2006 Every Kilowatt Counts	Programmable Thermostats - Spring Campaign	32	15	10%	216	0.050	$738	OPA 2010c
2006 Every Kilowatt Counts	Energy Star® Ceiling Fans - Spring Campaign	25	20	10%	141	0.014	$367	OPA 2010c

Program	Energy Efficient Measure	Number of units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Annual peak demand savings (kW/a)	Contribution to LRAM (2011$)	Assumption Source
2006 Every Kilowatt Counts	Energy Star® Compact Fluorescent Light Bulb - Autumn Campaign	3,916	4	10%	104	0.000	$35,363	OPA 2010c
2006 Every Kilowatt Counts	Seasonal Light Emitting Diode Light String - Autumn Campaign	943	30	10%	31	0.000	$3,076	OPA 2010c
2006 Every Kilowatt Counts	Programmable Thermostats - Autumn Campaign	62	18	10%	522	0.118	$3,443	OPA 2010c
2006 Every Kilowatt Counts	Dimmers - Autumn Campaign	49	10	10%	139	0.000	$725	OPA 2010c
2006 Every Kilowatt Counts	Indoor Motion Sensors - Autumn Campaign	18	20	10%	209	0.000	$391	OPA 2010c
2006 Every Kilowatt Counts	Programmable Basebaord Thermostats - Autumn Campaign	4	18	10%	1,466	0.000	$576	OPA 2010c
2007 Great Refrigerator Roundup	Bottom Freezer Fridge	1	9	27%	1,064	0.115	$75	OPA 2010c
2007 Great Refrigerator Roundup	Chest Freezer	24	8	54%	471	0.067	$471	OPA 2010c
2007 Great Refrigerator Roundup	Side by Side Fridge-Freezer	9	9	61%	900	0.097	$281	OPA 2010c
2007 Great Refrigerator Roundup	Single Door Fridge	24	9	61%	721	0.078	$625	OPA 2010c
2007 Great Refrigerator Roundup	Small Freezer (under 10 cubic feet)	1	8	70%	339	0.048	$8	OPA 2010c
2007 Great	Small Fridge (under 10 cubic feet)	2	9	70%	490	0.052	$26	OPA 2010c

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Program	Energy Efficient Measure	Number of units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Annual peak demand savings (kW/a)	Contribution to LRAM (2011$)	Assumption Source
Refrigerator Roundup								
2007 Great Refrigerator Roundup	Top Freezer Fridge	87	9	61%	732	0.079	$2,297	OPA 2010c
2007 Great Refrigerator Roundup	Upright Freezer	5	8	54%	743	0.106	$143	OPA 2010c
2007 Great Refrigerator Roundup	Window Air Conditioner	3	5	57%	240	0.562	$29	OPA 2010c
2007 Cool & Hot Savings Rebate	Energy Star® Central Air Conditioner - Hot Savings	6	18	43%	155	0.169	$47	OPA 2010c
2007 Cool & Hot Savings Rebate	Efficient Furnace with ECM - Hot Savings	12	15	41%	837	0.496	$557	OPA 2010c
2007 Cool & Hot Savings Rebate	Programmable Thermostat - Hot Savings	11	15	73%	54	0.028	$15	OPA 2010c
2007 Cool & Hot Savings Rebate	Energy Star® Central Air Conditioner, Tier 2 - Cool Savings	45	18	43%	155	0.169	$369	OPA 2010c
2007 Cool & Hot Savings Rebate	Energy Star® Central Air Conditioner, Tier 1 - Cool Savings	0	18	43%	NA	NA	$0	OPA 2010c
2007 Cool & Hot Savings Rebate	Medium Efficiency Furnace with ECM - Cool Savings	60	15	41%	837	0.496	$2,731	OPA 2010c
2007 Cool & Hot Savings Rebate	High Efficiency Furnace with ECM - Cool Savings	0	15	41%	NA	NA	$0	OPA 2010c
2007 Cool & Hot Savings Rebate	Programmable Thermostat - Cool Savings	56	15	73%	54	0.028	$76	OPA 2010c
2007 Cool & Hot Savings Rebate	Central Air Conditioner Tune-ups - Cool Savings	55	5	84%	235	0.257	$189	OPA 2010c
2007 Every Kilowatt Counts	15 W CFL	4,680	8	22%	43	0.001	$14,537	OPA 2010c
2007 Every Kilowatt	20+ W CFL	762	8	22%	62	0.002	$3,418	OPA 2010c

Program	Energy Efficient Measure	Number of units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Annual peak demand savings (kW/a)	Contribution to LRAM (2011$)	Assumption Source
Counts								
2007 Every Kilowatt Counts	Energy Star® Light Fixture	18	16	45%	123	0.006	$114	OPA 2010c
2007 Every Kilowatt Counts	T8 Fluorescent Tube	36	18	23%	37	0.001	$95	OPA 2010c
2007 Every Kilowatt Counts	Seasonal LED Light String	1,240	5	51%	14	0.000	$771	OPA 2010c
2007 Every Kilowatt Counts	Project Porchlight CFL	985	8	24%	43	0.001	$2,981	OPA 2010c
2007 Every Kilowatt Counts	Solar Light	601	5	87%	5	0.000	$35	OPA 2010c
2007 Every Kilowatt Counts	Energy Star® Ceiling Fan	38	10	45%	90	0.003	$173	OPA 2010c
2007 Every Kilowatt Counts	Furnace Filter	152	1	45%	38	0.011	$77	OPA 2010c
2007 Every Kilowatt Counts	Power Bar with Timer	17	10	23%	72	0.006	$86	OPA 2010c
2007 Every Kilowatt Counts	Lighting Control Device	193	10	45%	72	0.019	$708	OPA 2010c
2007 Every Kilowatt Counts	Outdoor Motion Sensor	60	10	45%	160	0.000	$489	OPA 2010c
2007 Every Kilowatt Counts	Dimmer Switch	38	10	45%	24	0.001	$46	OPA 2010c

Program	Energy Efficient Measure	Number of units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Annual peak demand savings (kW/a)	Contribution to LRAM (2011$)	Assumption Source
2007 Every Kilowatt Counts	Programmable Thermostat	37	15	45%	75	0.000	$140	OPA 2010c
2007 Social Housing Pilot	Custom Retrofit Projects	19	10	0%	1,229	0.145	$2,171	OPA 2010c
2007 ERIP	Custom Project	0	5	10%	5,555,556	2,000.000	$690	OPA 2010c
2008 Great Refrigerator Roundup	Bottom Freezer Fridge	2	9	45%	775	0.079	$60	OPA 2010c
2008 Great Refrigerator Roundup	Chest Freezer	68	8	48%	740	0.085	$1,780	OPA 2010c
2008 Great Refrigerator Roundup	Side by Side Fridge-Freezer	19	9	45%	775	0.079	$557	OPA 2010c
2008 Great Refrigerator Roundup	Single Door Fridge	37	9	45%	775	0.079	$1,081	OPA 2010c
2008 Great Refrigerator Roundup	Small Freezer (under 10 cubic feet)	1	8	48%	740	0.085	$21	OPA 2010c
2008 Great Refrigerator Roundup	Small Fridge (under 10 cubic feet)	1	9	45%	775	0.079	$32	OPA 2010c
2008 Great Refrigerator Roundup	Top Freezer Fridge	174	9	45%	775	0.079	$5,065	OPA 2010c
2008 Great Refrigerator Roundup	Upright Freezer	13	8	48%	740	0.085	$349	OPA 2010c
2008 Great Refrigerator Roundup	Window Air Conditioner	3	5	64%	197	0.199	$14	OPA 2010c

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Program	Energy Efficient Measure	Number of units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Annual peak demand savings (kW/a)	Contribution to LRAM (2011$)	Assumption Source
2008 Cool Savings Rebate	Energy Star® Central Air Conditioner, Tier 2	9	18	43%	155	0.170	$53	OPA 2010c
2008 Cool Savings Rebate	Energy Star® Central Air Conditioner, Tier 1	0	18	43%	NA	NA	$0	OPA 2010c
2008 Cool Savings Rebate	Medium Efficiency Furnace with ECM	18	15	41%	837	0.496	$620	OPA 2010c
2008 Cool Savings Rebate	High Efficiency Furnace with ECM	0	15	41%	NA	NA	$0	OPA 2010c
2008 Cool Savings Rebate	Programmable Thermostat	14	15	73%	54	0.028	$14	OPA 2010c
2008 Cool Savings Rebate	Central Air Conditioner Tune-ups	0	5	84%	NA	NA	$0	OPA 2010c
2008 Cool Savings Rebate	Energy Star® Central Air Conditioner, Tier 2	44	18	43%	125	0.137	$213	OPA 2010c
2008 Cool Savings Rebate	Energy Star® Central Air Conditioner, Tier 1	0	18	43%	NA	NA	$0	OPA 2010c
2008 Cool Savings Rebate	Efficient Furnace with ECM	66	18	41%	819	0.485	$2,173	OPA 2010c
2008 Cool Savings Rebate	Programmable Thermostat	56	18	73%	54	0.028	$56	OPA 2010c
2008 Every Kilowatt Counts Power Savings Event	Energy Star® Qualified Compact Fluorescent Light Bulbs	1,774	8	48%	53	0.002	$3,345	OPA 2010c
2008 Every Kilowatt Counts Power Savings Event	Energy Star® Qualified Dimmable CFLs	193	6	62%	98	0.003	$485	OPA 2010c
2008 Every Kilowatt Counts Power Savings Event	Energy Star® Qualified Decorative CFLs	2,997	4	61%	30	0.001	$2,392	OPA 2010c
2008 Every Kilowatt	Energy Star® Qualified Compact Fluorescent Floods (Indoor & Outdoor)	832	7	63%	88	0.003	$1,861	OPA 2010c

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Program	Energy Efficient Measure	Number of units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Annual peak demand savings (kW/a)	Contribution to LRAM (2011$)	Assumption Source
Counts Power Savings Event								
2008 Every Kilowatt Counts Power Savings Event	Energy Star® Qualified Light Fixtures	1,291	16	67%	133	0.004	$3,919	OPA 2010c
2008 Every Kilowatt Counts Power Savings Event	T8 Fluorescent Fixtures	235	16	67%	37	0.001	$196	OPA 2010c
2008 Every Kilowatt Counts Power Savings Event	Lighting Control Devices	253	10	55%	102	0.003	$798	OPA 2010c
2008 Every Kilowatt Counts Power Savings Event	Power Bars with Timers	14	10	59%	53	0.004	$20	OPA 2010c
2008 Every Kilowatt Counts Power Savings Event	Car block heater timer	0	0	100%	NA	NA	$0	OPA 2010c
2008 Every Kilowatt Counts Power Savings Event	Heavy Duty Timers	29	10	67%	301	0.017	$200	OPA 2010c
2008 Every Kilowatt Counts Power Savings Event	Programmable Thermostats - Baseboard	81	15	53%	64	0.000	$164	OPA 2010c
2008 Every Kilowatt Counts Power Savings Event	Air Conditioner/Furnace Filters	77	1	65%	38	0.021	$24	OPA 2010c

Program	Energy Efficient Measure	Number of units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Annual peak demand savings (kW/a)	Contribution to LRAM (2011$)	Assumption Source
2008 Every Kilowatt Counts Power Savings Event	Awnings	56	0	100%	NA	NA	$0	OPA 2010c
2008 Every Kilowatt Counts Power Savings Event	Window Films	899	0	100%	NA	NA	$0	OPA 2010c
2008 Every Kilowatt Counts Power Savings Event	Electric Water Heater Blankets	28	0	100%	NA	NA	$0	OPA 2010c
2008 Every Kilowatt Counts Power Savings Event	Pipe Wrap	1,655	6	53%	38	0.003	$2,006	OPA 2010c
2008 Every Kilowatt Counts Power Savings Event	Low-Flow Toilets	216	0	100%	NA	NA	$0	OPA 2010c
2008 Every Kilowatt Counts Power Savings Event	Keep Cool Pilot – Dehumidifier	1	12	65%	500	0.290	$6	OPA 2010c
2008 Every Kilowatt Counts Power Savings Event	Keep Cool Pilot – Room Air Conditioner	1	9	58%	141	0.142	$2	OPA 2010c
2008 Every Kilowatt Counts Power Savings Event	Rewards for Recycling – Dehumidifier	16	12	56%	500	0.290	$232	OPA 2010c
2008 Every Kilowatt	Rewards for Recycling – Room Air Conditioner	17	9	56%	141	0.142	$71	OPA 2010c

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Program	Energy Efficient Measure	Number of units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Annual peak demand savings (kW/a)	Contribution to LRAM (2011$)	Assumption Source
Counts Power Savings Event								
2008 Every Kilowatt Counts Power Savings Event	Rewards for Recycling – Halogen Lamp	13	16	52%	275	0.009	$120	OPA 2010c
2008 peaksaver®	Residential Air Conditioner - Switch	0	13	10%	NA	NA	$0	OPA 2010c
2008 peaksaver®	Residential Air Conditioner - Thermostat	97	13	10%	17	0.865	$102	OPA 2010c
2008 peaksaver®	Residential Electric Water Heater	0	13	10%	NA	NA	$0	OPA 2010c
2008 peaksaver®	Commercial Air Conditioner - Switch	0	13	10%	NA	NA	$0	OPA 2010c
2008 peaksaver®	Commercial Air Conditioner - Thermostat	2	13	10%	74	3.700	$9	OPA 2010c
2008 peaksaver®	Commercial Electric Water Heater	0	13	10%	NA	NA	$0	OPA 2010c
2008 Summer Sweepstakes	Registered qualified active households	173	5	22%	421	0.111	$3,852	OPA 2010c
2008 Summer Sweepstakes	Registered unqualified active households	260	5	22%	421	0.111	$5,777	OPA 2010c
2008 Summer Sweepstakes	Registered qualified inactive households	17	5	22%	421	0.111	$385	OPA 2010c
2008 Summer Sweepstakes	Registered unqualified inactive households	65	5	22%	421	0.111	$1,449	OPA 2010c
2008 Summer Sweepstakes	Non-registered active households	8,430	5	22%	21	0.005	$9,561	OPA 2010c
2008 ERIP	Custom Project	724	15	44%	186	0.000	$3,341	OPA 2010c
2008 ERIP	Custom Project	724	15	42%	0	0.034	$714	OPA 2010c
2008 High Performance New Construction	Custom Project	0	14	30%	410,000	485.714	$42	OPA 2010c
2009 Great Refrigerator Roundup	Bottom Freezer Fridge	1	9	52%	858	0.108	$18	OPA 2010c

Program	Energy Efficient Measure	Number of units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Annual peak demand savings (kW/a)	Contribution to LRAM (2011$)	Assumption Source
2009 Great Refrigerator Roundup	Chest Freezer	56	8	50%	501	0.063	$628	OPA 2010c
2009 Great Refrigerator Roundup	Side by Side Fridge-Freezer	25	9	52%	858	0.108	$462	OPA 2010c
2009 Great Refrigerator Roundup	Single Door Fridge	21	9	52%	858	0.108	$388	OPA 2010c
2009 Great Refrigerator Roundup	Small Freezer (under 10 cubic feet)	0	8	50%	NA	NA	$0	OPA 2010c
2009 Great Refrigerator Roundup	Small Fridge (under 10 cubic feet)	0	9	52%	NA	NA	$0	OPA 2010c
2009 Great Refrigerator Roundup	Top Freezer Fridge	123	9	52%	858	0.108	$2,273	OPA 2010c
2009 Great Refrigerator Roundup	Upright Freezer	6	8	50%	501	0.063	$67	OPA 2010c
2009 Great Refrigerator Roundup	Window Air Conditioner	9	5	57%	266	0.269	$46	OPA 2010c
2009 Great Refrigerator Roundup	Dehumidifier	3	5	57%	266	0.269	$15	OPA 2010c
2009 Cool Savings Rebate	Energy Star® Central Air Conditioner, Tier 2	19	18	43%	196	0.214	$97	OPA 2010c
2009 Cool Savings Rebate	Energy Star® Central Air Conditioner, Tier 1	50	18	43%	196	0.214	$250	OPA 2010c
2009 Cool Savings Rebate	Efficient Furnace with ECM	127	15	41%	847	0.502	$2,838	OPA 2010c
2009 Cool	Programmable Thermostat	89	15	73%	35	0.028	$38	OPA 2010c

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Program	Energy Efficient Measure	Number of units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Annual peak demand savings (kW/a)	Contribution to LRAM (2011$)	Assumption Source
Savings Rebate								
2009 Every Kilowatt Counts Power Savings Event	Standard CFL (single pack)	59	8	24%	53	0.002	$106	OPA 2010c
2009 Every Kilowatt Counts Power Savings Event	Standard CFL (multi (6) pack)	136	8	24%	258	0.008	$1,191	OPA 2010c
2009 Every Kilowatt Counts Power Savings Event	Energy Star Specialty CFL	370	6	24%	63	0.002	$793	OPA 2010c
2009 Every Kilowatt Counts Power Savings Event	Energy Star Light Fixtures	40	16	45%	123	0.004	$120	OPA 2010c
2009 Every Kilowatt Counts Power Savings Event	Energy Star Hard-Wired Indoor Light Fixtures	43	16	45%	123	0.004	$130	OPA 2010c
2009 Every Kilowatt Counts Power Savings Event	Energy Star Ceiling Fans	17	10	45%	90	0.003	$39	OPA 2010c
2009 Every Kilowatt Counts Power Savings Event	Weather Stripping (packages)	40	2	30%	2	0.000	$3	OPA 2010c
2009 Every Kilowatt Counts Power Savings Event	Weather Stripping (door kits)	26	2	64%	2	0.000	$1	OPA 2010c

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Program	Energy Efficient Measure	Number of units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Annual peak demand savings (kW/a)	Contribution to LRAM (2011$)	Assumption Source
2009 Every Kilowatt Counts Power Savings Event	Pipe Wrap – Purchase of 3	29	6	64%	38	0.003	$18	OPA 2010c
2009 Every Kilowatt Counts Power Savings Event	Water Heater Blanket	5	6	64%	270	0.021	$22	OPA 2010c
2009 Every Kilowatt Counts Power Savings Event	Window Film	5	10	64%	45	0.022	$3	OPA 2010c
2009 Every Kilowatt Counts Power Savings Event	Lighting and Appliance Controls – Unspecified	0	10	64%	NA	NA	$0	OPA 2010c
2009 Every Kilowatt Counts Power Savings Event	Lighting and Appliance Controls – Power Bar with Integrated Timer	8	10	64%	72	0.006	$10	OPA 2010c
2009 Every Kilowatt Counts Power Savings Event	Lighting and Appliance Controls – Hard Wired Indoor Timer	5	10	64%	219	0.007	$17	OPA 2010c
2009 Every Kilowatt Counts Power Savings Event	Lighting and Appliance Controls – Hard Wired Motion Sensor	11	10	64%	64	0.002	$11	OPA 2010c
2009 Every Kilowatt Counts Power Savings Event	Lighting and Appliance Controls – Heavy Duty Outdoor Timer includes Pool Timers	13	10	64%	511	0.155	$104	OPA 2010c
2009 Every Kilowatt	Programmable Thermostat (single pack)	9	15	45%	75	0.000	$16	OPA 2010c

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Program	Energy Efficient Measure	Number of units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Annual peak demand savings (kW/a)	Contribution to LRAM (2011$)	Assumption Source
Counts Power Savings Event								
2009 Every Kilowatt Counts Power Savings Event	Programmable Thermostat (multi (3) pack)	3	15	45%	225	0.000	$16	OPA 2010c
2009 Every Kilowatt Counts Power Savings Event	Clothes Line Kit or Cloths Line Umbrella Stand	16	10	50%	226	0.077	$83	OPA 2010c
2009 Every Kilowatt Counts Power Savings Event	Energy Star Dehumidifier Recycling	10	12	56%	342	0.346	$66	OPA 2010c
2009 Every Kilowatt Counts Power Savings Event	Energy Star Room Air Conditioner Recycling	10	9	56%	96	0.098	$19	OPA 2010c
2009 Every Kilowatt Counts Power Savings Event	Halogen Floor Lamp Recycling	4	6	52%	225	0.007	$21	OPA 2010c
2009 peaksaver®	Residential Air Conditioner - Switch	0	13	10%	NA	NA	$0	OPA 2010c
2009 peaksaver®	Residential Air Conditioner - Thermostat	191	13	10%	17	0.865	$132	OPA 2010c
2009 peaksaver®	Residential Electric Water Heater	0	13	10%	NA	NA	$0	OPA 2010c
2009 peaksaver®	Commercial Air Conditioner - Switch	0	13	10%	NA	NA	$0	OPA 2010c
2009 peaksaver®	Commercial Air Conditioner - Thermostat	3	13	10%	74	3.700	$9	OPA 2010c
2009 peaksaver®	Commercial Electric Water Heater	0	13	10%	NA	NA	$0	OPA 2010c
2009 ERIP	Custom Project	171	20	42%	1,537	0.639	$6,496	OPA 2010c
2009 High Performance	Custom Project	0	20	30%	200,667	88.016	$846	OPA 2010c

Program	Energy Efficient Measure	Number of units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Annual peak demand savings (kW/a)	Contribution to LRAM (2011$)	Assumption Source
New Construction								
2009 Power Savings Blitz	2) From: 1 Lamp 8' -T12-75W-Magnetic Ballasts to: 1 - 8' lamp with 80% ballast factor T8-Electronic Ballast - Retail Sector	6	15	7%	162	0.022	$35	OPA 2010c
2009 Power Savings Blitz	4) From: 2 Lamps 8' -T12-75W-Magnetic Ballasts to: 4 - 4' end to end 32 watt lamps with 80% ballast factor T8-Electronic Ballast - Retail Sector	362	15	7%	314	0.043	$4,071	OPA 2010c
2009 Power Savings Blitz	6) From: 2 Lamps 8' -T12-60W-Magnetic Ballasts to: 4 - 4' lamps with either 32 watt ballast of 80% ballast factor or 25 watt lamp T8-Electronic Ballast - Retail Sector	2	15	7%	314	0.043	$22	OPA 2010c
2009 Power Savings Blitz	7) From: 2 Lamps 8' -T12-60W-Magnetic Ballasts to: 2 - 4' 32 watt lamps + Reflector with 90% ballast factor T8-Electronic Ballast - Retail Sector	382	15	7%	550	0.075	$7,525	OPA 2010c
2009 Power Savings Blitz	8) From: 1 Lamp 4' -T12-40W-Magnetic Ballasts to: 1 - 4' lamp with either 32 watt ballast of 80% ballast factor or 25 watt lamp T8-Electronic Ballast - Retail Sector	7	15	7%	92	0.012	$23	OPA 2010c
2009 Power Savings Blitz	9) From: 2 Lamps 4' -T12-40W-Magnetic Ballasts to: 1 - 4' 32 watt lamp + reflector with 90% ballast factor T8-Electronic Ballast - Retail Sector	146	15	7%	253	0.034	$1,323	OPA 2010c
2009 Power Savings Blitz	11) From: 4 Lamps 4' -T12-40W-Magnetic Ballasts to: 2 - 4' 32 watt lamps + reflector T8-Electronic Ballast - Retail Sector	55	15	7%	511	0.070	$1,007	OPA 2010c
2009 Power Savings Blitz	13) From: 1 Lamp 4' -T12-34W-Magnetic Ballasts to: 1 - 4' lamp with either 32 watt ballast of 80% ballast factor or 25 watt lamp T8-Electronic Ballast - Retail Sector	58	15	7%	79	0.011	$164	OPA 2010c
2009 Power Savings Blitz	15) From: 2 Lamps 4' -T12-34W-Magnetic Ballasts to: 2 - 4' lamps with either 32 watt ballast of 80% ballast factor or 25 watt lamps T8-Electronic Ballast - Retail Sector	557	15	7%	87	0.012	$1,736	OPA 2010c
2009 Power Savings Blitz	17) From: 4 Lamps 4' -T12-34W-Magnetic Ballasts to: 4 - 4' lamps with either 32 watt ballast of 80% ballast factor or 25 watt lamps T8-Electronic Ballast - Retail Sector	391	15	7%	192	0.026	$2,689	OPA 2010c
2009 Power Savings Blitz	18) From: 2 Lamps U-Shaped 34-40W-Magnetic Ballasts to: 2 U-Tube Lamps 2' -T8-32W-Electronic Ballast - Retail Sector	29	15	7%	105	0.014	$109	OPA 2010c

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Program	Energy Efficient Measure	Number of units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Annual peak demand savings (kW/a)	Contribution to LRAM (2011$)	Assumption Source
2009 Power Savings Blitz	20) From: 2-15W Lamps Exit Sign - incandescent to: 3W LED Energy Star rated LED Exit Sign - Retail Sector	852	16	7%	237	0.032	$7,232	OPA 2010c
2009 Power Savings Blitz	21) From: 2-15W Lamps Exit Sign - incandescent to: Replace entire fixture with LED sign Energy Star rated LED Exit Sign - Retail Sector	2	16	7%	237	0.032	$17	OPA 2010c
2009 Power Savings Blitz	22) From: 40W Standard Incandescent (A Lamp) to: 11W ENERGY STAR® rated CFL (Screw-in replacement) - Retail Sector	726	2	7%	127	0.017	$3,302	OPA 2010c
2009 Power Savings Blitz	23) From: 60W Standard Incandescent (A Lamp) to: 13W ENERGY STAR® rated CFL (Screw-in replacement) - Retail Sector	32	2	7%	205	0.028	$235	OPA 2010c
2009 Power Savings Blitz	25) From: 150W Standard Incandescent (A Lamp) to: 28W ENERGY STAR® rated CFL (Screw-in replacement) - Retail Sector	74	2	7%	533	0.072	$1,413	OPA 2010c
2009 Power Savings Blitz	26) From: 60W PAR38/30 PAR Lights - Flood or Spot - recessed down lighting to: 15W CFLPAR38/30 ENERGY STAR® rated PAR CFL - Retail Sector	14	2	7%	197	0.027	$99	OPA 2010c
2009 Power Savings Blitz	27) From: 75W PAR38/30 PAR Lights - Flood or Spot - recessed down lighting to: 18W CFLPAR38/30 ENERGY STAR® rated PAR CFL - Retail Sector	10	2	7%	249	0.034	$89	OPA 2010c
2009 Power Savings Blitz	28) From: 100W PAR38/30 PAR Lights - Flood or Spot - recessed down lighting to: 26W CFL PAR38/30 ENERGY STAR® rated PAR CFL - Retail Sector	762	2	7%	323	0.044	$8,816	OPA 2010c
2009 Power Savings Blitz	29) From: 40 - 60W standard incandescent PAR Lights - Track lighting or product highlighting to: 15W CFL Energy Star rated Flood CFL - Retail Sector	372	2	7%	197	0.027	$2,625	OPA 2010c
2009 Power Savings Blitz	30) From: 40 - 60W standard halogen PAR Lights - Track lighting or product highlighting to: 32 Watt IR coated halogen Energy Star rated Flood CFL - Retail Sector	72	1	7%	122	0.017	$161	OPA 2010c
2009 Power Savings Blitz	31) From: 75W standard incandescent PAR Lights - Track lighting or product highlighting to: 18W CFL Energy Star rated Flood CFL - Retail Sector	138	2	7%	249	0.034	$1,231	OPA 2010c
2009 Power Savings Blitz	32) From: 75W standard incandescent PAR Lights - Track lighting or product highlighting to: 50 Watt Halogen Energy	77	1	7%	109	0.015	$154	OPA 2010c

Program	Energy Efficient Measure	Number of units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Annual peak demand savings (kW/a)	Contribution to LRAM (2011$)	Assumption Source
	Star rated Flood CFL - Retail Sector							
2009 Power Savings Blitz	33) From: 90 Watt Halogen PAR Lights - Track lighting or product highlighting to: 23 to 28 watt CFL Par 38/30 Energy Star rated Flood CFL - Retail Sector	203	2	7%	271	0.037	$1,970	OPA 2010c
2009 Power Savings Blitz	34) From: 90 Watt Halogen PAR Lights - Track lighting or product highlighting to: 60 watt Halogen IR Energy Star rated Flood CFL - Retail Sector	30	1	7%	131	0.018	$72	OPA 2010c
2009 Power Savings Blitz	35) From: 100W standard incandescent or greater PAR Lights - Track lighting or product highlighting to: 26W CFL Energy Star rated Flood CFL - Retail Sector	13	2	7%	323	0.044	$150	OPA 2010c
2009 Power Savings Blitz	36) From: 100W standard incandescent or greater PAR Lights - Track lighting or product highlighting to: 50-75 watt halogen Energy Star rated Flood CFL - Retail Sector	73	1	7%	109	0.015	$146	OPA 2010c
2009 Power Savings Blitz	37) From: No Insulation Jacket (50-119 Gal) to: Insulation Jacket 5/32" barrier bubble film laminated between two layers of foil Water Heater (Electrical) - Retail Sector	21	7	7%	318	0.034	$239	OPA 2010c
2009 Power Savings Blitz	46) From: 4 Lamps 8' -T12-75W-Magnetic Ballasts to: 4 - 4' 32 watt lamps + reflector with 90% ballast factor T8-Electronic Ballast - Retail Sector	23	15	7%	612	0.083	$504	OPA 2010c
2009 Power Savings Blitz	48) From: 2 Lamps 8' -T12-75W-Magnetic Ballasts to: 2 - 8' lamps with 90% ballast factor T8-Electronic Ballast - Retail Sector	170	15	7%	314	0.043	$1,912	OPA 2010c
2009 Power Savings Blitz	49) From: 4 Lamps 8' -T12-75W-Magnetic Ballasts to: 4 - 8' lamps with 2 electronic ballasts of 90% ballast factor T8-Electronic Ballast - Retail Sector	7	15	7%	612	0.083	$153	OPA 2010c
2009 Power Savings Blitz	52) From: 2 Lamps 4' -T8 32W-Magnetic Ballasts to: 2 - 4' 25 watt lamps with electronic ballasts T8-Electronic Ballast - Retail Sector	75	15	7%	87	0.012	$234	OPA 2010c
2009 Power Savings Blitz	54) From: 2 - 8' T12 High Output Lamps High Output T12-Magnetic Ballasts to: 2 - 8' High Output T8 lamps with electronic ballasts High Output T8-Electronic Ballast - Retail Sector	7	15	7%	144	0.020	$36	OPA 2010c
2009 Power Savings Blitz	55) From: 175W Metal Halide Metal Halide to: 1 - 150W Metal Halide Direct Lamp replacement Metal Halide Direct	9	12	7%	109	0.015	$35	OPA 2010c

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Program	Energy Efficient Measure	Number of units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Annual peak demand savings (kW/a)	Contribution to LRAM (2011$)	Assumption Source
	Lamp Replacement - Retail Sector							
2009 Power Savings Blitz	57) From: 250W Metal Halide Metal Halide to: 4 - 4' Lamps with either 32 watt ballast of 80% ballast factor or 25 watt lamps T8 Replacement - Retail Sector	52	15	7%	603	0.082	$1,123	OPA 2010c
2009 Power Savings Blitz	64) From: 100 - 150W Incandescent R Lamp Incandescent R Lamp on Dimmers to: 22 - 26W Dimmable CFL R Lamp ENERGY STAR® rated Dimmable CFL R Lamp - Retail Sector	2	2	7%	441	0.060	$32	OPA 2010c
2009 Power Savings Blitz	7) From: 2 Lamps 8' -T12-60W-Magnetic Ballasts to: 2 - 4' 32 watt lamps + Reflector with 90% ballast factor T8-Electronic Ballast - Food Service Sector	2	15	7%	780	0.106	$56	OPA 2010c
2009 Power Savings Blitz	8) From: 1 Lamp 4' -T12-40W-Magnetic Ballasts to: 1 - 4' lamp with either 32 watt ballast of 80% ballast factor or 25 watt lamp T8-Electronic Ballast - Food Service Sector	4	15	7%	130	0.018	$19	OPA 2010c
2009 Power Savings Blitz	15) From: 2 Lamps 4' -T12-34W-Magnetic Ballasts to: 2 - 4' lamps with either 32 watt ballast of 80% ballast factor or 25 watt lamps T8-Electronic Ballast - Food Service Sector	9	15	7%	124	0.017	$40	OPA 2010c
2009 Power Savings Blitz	17) From: 4 Lamps 4' -T12-34W-Magnetic Ballasts to: 4 - 4' lamps with either 32 watt ballast of 80% ballast factor or 25 watt lamps T8-Electronic Ballast - Food Service Sector	9	15	7%	272	0.037	$88	OPA 2010c
2009 Power Savings Blitz	20) From: 2-15W Lamps Exit Sign - incandescent to: 3W LED Energy Star rated LED Exit Sign - Food Service Sector	10	16	7%	237	0.032	$85	OPA 2010c
2009 Power Savings Blitz	22) From: 40W Standard Incandescent (A Lamp) to: 11W ENERGY STAR® rated CFL (Screw-in replacement) - Food Service Sector	8	2	7%	179	0.024	$51	OPA 2010c
2009 Power Savings Blitz	23) From: 60W Standard Incandescent (A Lamp) to: 13W ENERGY STAR® rated CFL (Screw-in replacement) - Food Service Sector	10	2	7%	291	0.040	$104	OPA 2010c
2009 Power Savings Blitz	25) From: 150W Standard Incandescent (A Lamp) to: 28W ENERGY STAR® rated CFL (Screw-in replacement) - Food Service Sector	4	2	7%	755	0.103	$108	OPA 2010c
2009 Power Savings Blitz	28) From: 100W PAR38/30 PAR Lights - Flood or Spot - recessed down lighting to: 26W CFL PAR38/30 ENERGY STAR® rated PAR CFL - Food Service Sector	2	2	7%	458	0.062	$33	OPA 2010c

Program	Energy Efficient Measure	Number of units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Annual peak demand savings (kW/a)	Contribution to LRAM (2011$)	Assumption Source
2009 Power Savings Blitz	29) From: 40 - 60W standard incandescent PAR Lights - Track lighting or product highlighting to: 15W CFL Energy Star rated Flood CFL - Food Service Sector	1	2	7%	278	0.038	$10	OPA 2010c
2009 Power Savings Blitz	31) From: 75W standard incandescent PAR Lights - Track lighting or product highlighting to: 18W CFL Energy Star rated Flood CFL - Food Service Sector	2	2	7%	353	0.048	$25	OPA 2010c
2009 Power Savings Blitz	32) From: 75W standard incandescent PAR Lights - Track lighting or product highlighting to: 50 Watt Halogen Energy Star rated Flood CFL - Food Service Sector	22	1	7%	155	0.021	$63	OPA 2010c
2009 Power Savings Blitz	33) From: 90 Watt Halogen PAR Lights - Track lighting or product highlighting to: 23 to 28 watt CFL Par 38/30 Energy Star rated Flood CFL - Food Service Sector	12	2	7%	384	0.052	$165	OPA 2010c
2009 Power Savings Blitz	48) From: 2 Lamps 8' -T12-75W-Magnetic Ballasts to: 2 - 8' lamps with 90% ballast factor T8-Electronic Ballast - Food Service Sector	4	15	7%	446	0.061	$64	OPA 2010c
2009 Power Savings Blitz	11) From: 4 Lamps 4' -T12-40W-Magnetic Ballasts to: 2 - 4' 32 watt lamps + reflector T8-Electronic Ballast - Office Sector	5	15	7%	444	0.060	$80	OPA 2010c
2009 Power Savings Blitz	13) From: 1 Lamp 4' -T12-34W-Magnetic Ballasts to: 1 - 4' lamp with either 32 watt ballast of 80% ballast factor or 25 watt lamp T8-Electronic Ballast - Office Sector	3	15	7%	68	0.009	$7	OPA 2010c
2009 Power Savings Blitz	15) From: 2 Lamps 4' -T12-34W-Magnetic Ballasts to: 2 - 4' lamps with either 32 watt ballast of 80% ballast factor or 25 watt lamps T8-Electronic Ballast - Office Sector	21	15	7%	76	0.010	$57	OPA 2010c
2009 Power Savings Blitz	17) From: 4 Lamps 4' -T12-34W-Magnetic Ballasts to: 4 - 4' lamps with either 32 watt ballast of 80% ballast factor or 25 watt lamps T8-Electronic Ballast - Office Sector	33	15	7%	167	0.023	$197	OPA 2010c
2009 Power Savings Blitz	22) From: 40W Standard Incandescent (A Lamp) to: 11W ENERGY STAR® rated CFL (Screw-in replacement) - Office Sector	11	2	7%	110	0.015	$43	OPA 2010c
2009 Power Savings Blitz	28) From: 100W PAR38/30 PAR Lights - Flood or Spot - recessed down lighting to: 26W CFL PAR38/30 ENERGY STAR® rated PAR CFL - Office Sector	45	2	7%	281	0.038	$453	OPA 2010c
2009 Power	31) From: 75W standard incandescent PAR Lights - Track	4	2	7%	216	0.029	$31	OPA 2010c

Program	Energy Efficient Measure	Number of units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Annual peak demand savings (kW/a)	Contribution to LRAM (2011$)	Assumption Source
Savings Blitz	lighting or product highlighting to: 18W CFL Energy Star rated Flood CFL - Office Sector							
2009 Power Savings Blitz	48) From: 2 Lamps 8' -T12-75W-Magnetic Ballasts to: 2 - 8' lamps with 90% ballast factor T8-Electronic Ballast - Office Sector	7	15	7%	273	0.037	$68	OPA 2010c
2009 Power Savings Blitz	56) From: 400W Metal Halide Metal Halide to: 1 - 350W Metal Halide Direct Lamp replacement Metal Halide Direct Lamp Replacement - Office Sector	1	12	7%	190	0.026	$7	OPA 2010c
2009 Power Savings Blitz	64) From: 100 - 150W Incandescent R Lamp Incandescent R Lamp on Dimmers to: 22 - 26W Dimmable CFL R Lamp ENERGY STAR® rated Dimmable CFL R Lamp - Office Sector	10	2	7%	383	0.052	$137	OPA 2010c
2009 Power Savings Blitz	65) From: 40 - 60W standard halogen PAR Lights - Track lighting or product highlighting to: 32 Watt halogen IR MR16 Energy Star rated Flood CFL - Office Sector	12	1	7%	106	0.014	$23	OPA 2010c
2005 Garage door replacement	Garage door replacement from R5 to R10.5	1	15	0%	5,766	1.000	$680	Brant 2006b
2005 Conservation County - CFLs	15 W CFL	500	8	30%	44	0.001	$1,954	OPA 2010a
2005 Conservation County - lighting retrofit	2 - T8 32 W (58 W) reflectorized w/EL ballast	48	9	30%	211	0.091	$778	OPA 2010b
2005 Conservation County - lighting retrofit	1 - T8 32 W (38 W) w/EL HBF ballast	4	9	30%	118	0.051	$36	OPA 2010b
2005 Conservation County - lighting retrofit	15 W CFL	15	8	30%	44	0.001	$51	OPA 2010a
2005	3 W LED Exit sign	10	10	30%	166	0.019	$128	OPA 2010b

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Program	Energy Efficient Measure	Number of units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Annual peak demand savings (kW/a)	Contribution to LRAM (2011$)	Assumption Source
Conservation County - lighting retrofit								
2005 Lighting your electricity bill	15W CFL	575	8	30%	44	0.001	$2,247	OPA 2010a
2005 Lighting your electricity bill	Seasonal LED Lights - 5W	55	5	30%	14	0.000	$60	OPA 2010a
2005 Lighting your electricity bill	Seasonal LED Lights - Mini Lights	55	5	30%	5	0.000	$21	OPA 2010a
2005 Lighting your electricity bill	Pstat - Space Heating	15	11	30%	2,151	0.176	$2,843	OPA 2010a
2005 Lighting your electricity bill	Pstat - Space Cooling	39	11	30%	203	0.176	$698	OPA 2010a
2005 Lighting your electricity bill	Outdoor Timer	21	10	30%	68	0.000	$126	OPA 2010a
2005 Lighting your electricity bill	Indoor Timer	4	10	30%	219	0.010	$77	OPA 2010a
2005 Lighting your electricity bill	Indoor Timer for AC	3	20	30%	109	0.170	$29	SeeLine 2006
2005 Lighting your electricity bill	Ceiling Fan	16	10	30%	123	0.004	$173	OPA 2010a
2005 Cold water wash program	Cold water wash detergent	351	1	25%	623	0.021	$3,395	OEB 2008
2006 Seasonal LED light	LED Lights	300	5	30%	14	0.000	$298	OPA 2010a

Program	Energy Efficient Measure	Number of units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/a)	Annual peak demand savings (kW/a)	Contribution to LRAM (2011$)	Assumption Source
exchange								
2006 Seasonal LED light exchange	LED Lights	50	5	30%	5	0.000	$18	OPA 2010a
2007 CDM other admin costs - NEPA	15 W CFL	350	8	30%	44	0.001	$872	OPA 2010a
2007 Project porchlight	15 W CFL	660	8	30%	44	0.001	$1,645	OPA 2010a
2007 Walter's greenhouse/Nova Vita Ladies Night	15 W CFL	200	8	30%	44	0.001	$499	OPA 2010a
2007 Seasonal LED light exchange	LED Lights	407	5	30%	14	0.000	$309	OPA 2010a
2007 Seasonal LED light exchange	LED Lights	517	5	30%	5	0.000	$140	OPA 2010a
2008 Traffic light conversion	LED traffic lights	4	14	0%	26,578	3.034	$1,599	Brant 2009
2008 Streetlight conversion	LED streetlight	25	14	0%	456	0.040	$132	Brant 2009
Total							**$251,022**	

Table 11 – Residential LRAM contributions and carrying charges.

Program	Year of savings	Energy savings (kWh)	Energy rate ($/kWh)	LRAM (programyear$)	Carrying charges ($)	LRAM (2011$)
2006 Every Kilowatt Counts	2005	0	0.0134	$0	$0	$0
	2006	707,298	0.0222	$15,702	$2,192	$17,894
	2007	707,298	0.0224	$15,843	$1,477	$17,320
	2008	707,298	0.0224	$15,843	$734	$16,577
	2009	707,298	0.0225	$15,914	$273	$16,187
	2010	91,193	0.0216	$1,970	$19	$1,989
2006 Every Kilowatt Counts Sum		2,920,385		$65,273	$4,695	$69,968
2007 Every Kilowatt Counts	2005	0	0.0134	$0	$0	$0
	2006	0	0.0222	$0	$0	$0
	2007	257,872	0.0224	$5,776	$538	$6,315
	2008	254,718	0.0224	$5,706	$264	$5,970
	2009	254,718	0.0225	$5,731	$98	$5,830
	2010	254,718	0.0216	$5,502	$53	$5,555
2007 Every Kilowatt Counts Sum		1,022,025		$22,715	$954	$23,669
2007 Great Refrigerator Roundup	2005	0	0.0134	$0	$0	$0
	2006	0	0.0222	$0	$0	$0
	2007	42,702	0.0224	$957	$89	$1,046
	2008	42,702	0.0224	$957	$44	$1,001
	2009	42,702	0.0225	$961	$16	$977
	2010	42,702	0.0216	$922	$9	$931
2007 Great Refrigerator Roundup Sum		170,807		$3,796	$159	$3,955
2008 Great Refrigerator Roundup	2005	0	0.0134	$0	$0	$0
	2006	0	0.0222	$0	$0	$0
	2007	0	0.0224	$0	$0	$0
	2008	131,509	0.0224	$2,946	$136	$3,082

Program	Year of savings	Energy savings (kWh)	Energy rate ($/kWh)	LRAM (programyear$)	Carrying charges ($)	LRAM (2011$)
	2009	131,509	0.0225	$2,959	$51	$3,010
	2010	131,509	0.0216	$2,841	$28	$2,868
2008 Great Refrigerator Roundup Sum		394,527		$8,745	$215	$8,960
2008 Summer Sweepstakes	2005	0	0.0134	$0	$0	$0
	2006	0	0.0222	$0	$0	$0
	2007	0	0.0224	$0	$0	$0
	2008	308,578	0.0224	$6,912	$320	$7,232
	2009	308,578	0.0225	$6,943	$119	$7,062
	2010	308,578	0.0216	$6,665	$65	$6,730
2008 Summer Sweepstakes Sum		925,735		$20,520	$504	$21,024
2009 Great Refrigerator Roundup	2005	0	0.0134	$0	$0	$0
	2006	0	0.0222	$0	$0	$0
	2007	0	0.0224	$0	$0	$0
	2008	0	0.0224	$0	$0	$0
	2009	87,226	0.0225	$1,963	$34	$1,996
	2010	87,226	0.0216	$1,884	$18	$1,902
2009 Great Refrigerator Roundup Sum		174,452		$3,847	$52	$3,899
2006 Secondary Refrigerator Retirement Pilot	2005	0	0.0134	$0	$0	$0
	2006	11,042	0.0222	$245	$34	$279
	2007	11,042	0.0224	$247	$23	$270
	2008	11,042	0.0224	$247	$11	$259
	2009	11,042	0.0225	$248	$4	$253
	2010	11,042	0.0216	$239	$2	$241
2006 Secondary Refrigerator Retirement Pilot Sum		55,211		$1,227	$75	$1,302
2006 Cool & Hot Savings Rebate	2005	0	0.0134	$0	$0	$0
	2006	27,259	0.0222	$605	$84	$690

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Program	Year of savings	Energy savings (kWh)	Energy rate ($/kWh)	LRAM (programyear$)	Carrying charges ($)	LRAM (2011$)
	2007	27,259	0.0224	$611	$57	$668
	2008	27,259	0.0224	$611	$28	$639
	2009	27,259	0.0225	$613	$11	$624
	2010	27,259	0.0216	$589	$6	$594
2006 Cool & Hot Savings Rebate Sum		136,293		$3,028	$186	$3,214
2007 Cool & Hot Savings Rebate	2005	0	0.0134	$0	$0	$0
	2006	0	0.0222	$0	$0	$0
	2007	43,019	0.0224	$964	$90	$1,053
	2008	43,019	0.0224	$964	$45	$1,008
	2009	43,019	0.0225	$968	$17	$985
	2010	43,019	0.0216	$929	$9	$938
2007 Cool & Hot Savings Rebate Sum		172,074		$3,824	$160	$3,984
2007 Social Housing Pilot	2005	0	0.0134	$0	$0	$0
	2006	0	0.0222	$0	$0	$0
	2007	23,437	0.0224	$525	$49	$574
	2008	23,437	0.0224	$525	$24	$549
	2009	23,437	0.0225	$527	$9	$536
	2010	23,437	0.0216	$506	$5	$511
2007 Social Housing Pilot Sum		93,749		$2,084	$87	$2,171
2008 Cool Savings Rebate	2005	0	0.0134	$0	$0	$0
	2006	0	0.0222	$0	$0	$0
	2007	0	0.0224	$0	$0	$0
	2008	45,938	0.0224	$1,029	$48	$1,077
	2009	45,938	0.0225	$1,034	$18	$1,051
	2010	45,938	0.0216	$992	$10	$1,002
2008 Cool Savings Rebate Sum		137,813		$3,055	$75	$3,130
2008 Every Kilowatt Counts Power Savings	2005	0	0.0134	$0	$0	$0

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Program	Year of savings	Energy savings (kWh)	Energy rate ($/kWh)	LRAM (programyear$)	Carrying charges ($)	LRAM (2011$)
Event						
	2006	0	0.0222	$0	$0	$0
	2007	0	0.0224	$0	$0	$0
	2008	233,191	0.0224	$5,223	$242	$5,465
	2009	232,177	0.0225	$5,224	$90	$5,314
	2010	232,177	0.0216	$5,015	$49	$5,064
2008 Every Kilowatt Counts Power Savings Event Sum		697,545		$15,462	$380	$15,843
2008 peaksaver®	2005	0	0.0134	$0	$0	$0
	2006	0	0.0222	$0	$0	$0
	2007	0	0.0224	$0	$0	$0
	2008	1,561	0.0224	$35	$2	$37
	2009	1,561	0.0225	$35	$1	$36
	2010	1,561	0.0216	$34	$0	$34
2008 peaksaver® Sum		4,684		$104	$3	$106
2009 Cool Savings Rebate	2005	0	0.0134	$0	$0	$0
	2006	0	0.0222	$0	$0	$0
	2007	0	0.0224	$0	$0	$0
	2008	0	0.0224	$0	$0	$0
	2009	72,123	0.0225	$1,623	$28	$1,651
	2010	72,123	0.0216	$1,558	$15	$1,573
2009 Cool Savings Rebate Sum		144,247		$3,181	$43	$3,224
2009 Every Kilowatt Counts Power Savings Event	2005	0	0.0134	$0	$0	$0
	2006	0	0.0222	$0	$0	$0
	2007	0	0.0224	$0	$0	$0
	2008	0	0.0224	$0	$0	$0
	2009	62,380	0.0225	$1,404	$24	$1,428

Program	Year of savings	Energy savings (kWh)	Energy rate ($/kWh)	LRAM (programyear$)	Carrying charges ($)	LRAM (2011$)
	2010	62,380	0.0216	$1,347	$13	$1,360
2009 Every Kilowatt Counts Power Savings Event Sum		124,760		$2,751	$37	$2,788
2009 peaksaver®	2005	0	0.0134	$0	$0	$0
	2006	0	0.0222	$0	$0	$0
	2007	0	0.0224	$0	$0	$0
	2008	0	0.0224	$0	$0	$0
	2009	3,015	0.0225	$68	$1	$69
	2010	3,015	0.0216	$65	$1	$66
2009 peaksaver® Sum		6,030		$133	$2	$135
2005 Conservation County - CFLs	2005	7,761	0.0134	$104	$20	$124
	2006	15,523	0.0222	$345	$48	$393
	2007	15,523	0.0224	$348	$32	$380
	2008	15,523	0.0224	$348	$16	$364
	2009	15,523	0.0225	$349	$6	$355
	2010	15,523	0.0216	$335	$3	$339
2005 Conservation County - CFLs Sum		85,374		$1,829	$125	$1,954
2005 Lighting your electricity bill	2005	24,950	0.0134	$334	$63	$397
	2006	49,900	0.0222	$1,108	$155	$1,262
	2007	49,900	0.0224	$1,118	$104	$1,222
	2008	49,900	0.0224	$1,118	$52	$1,170
	2009	49,900	0.0225	$1,123	$19	$1,142
	2010	49,547	0.0216	$1,070	$10	$1,081
2005 Lighting your electricity bill Sum		274,095		$5,871	$403	$6,274
2005 Cold water wash program	2005	82,002	0.0134	$1,099	$207	$1,306
	2006	82,002	0.0222	$1,820	$268	$2,089
	2007	0	0.0224	$0	$0	$0

Program	Year of savings	Energy savings (kWh)	Energy rate ($/kWh)	LRAM (programyear$)	Carrying charges ($)	LRAM (2011$)
	2008	0	0.0224	$0	$0	$0
	2009	0	0.0225	$0	$0	$0
	2010	0	0.0216	$0	$0	$0
2005 Cold water wash program Sum		164,005		$2,919	$475	$3,395
2006 Seasonal LED light exchange	2005	0	0.0134	$0	$0	$0
	2006	1,502	0.0222	$33	$4	$38
	2007	3,004	0.0224	$67	$6	$74
	2008	3,004	0.0224	$67	$3	$70
	2009	3,004	0.0225	$68	$1	$69
	2010	3,004	0.0216	$65	$1	$66
2006 Seasonal LED light exchange Sum		13,518		$300	$16	$316
2007 CDM other admin costs - NEPA	2005	0	0.0134	$0	$0	$0
	2006	0	0.0222	$0	$0	$0
	2007	5,433	0.0224	$122	$10	$132
	2008	10,866	0.0224	$243	$11	$255
	2009	10,866	0.0225	$244	$4	$249
	2010	10,866	0.0216	$235	$2	$237
2007 CDM other admin costs - NEPA Sum		38,030		$844	$28	$872
2007 Project porchlight	2005	0	0.0134	$0	$0	$0
	2006	0	0.0222	$0	$0	$0
	2007	10,245	0.0224	$229	$20	$249
	2008	20,490	0.0224	$459	$21	$480
	2009	20,490	0.0225	$461	$8	$469
	2010	20,490	0.0216	$443	$4	$447
2007 Project porchlight Sum		71,714		$1,592	$53	$1,645
2007 Walter's greenhouse/Nova Vita Ladies Night	2005	0	0.0134	$0	$0	$0

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Program	Year of savings	Energy savings (kWh)	Energy rate ($/kWh)	LRAM (programyear$)	Carrying charges ($)	LRAM (2011$)
	2006	0	0.0222	$0	$0	$0
	2007	3,105	0.0224	$70	$6	$76
	2008	6,209	0.0224	$139	$6	$146
	2009	6,209	0.0225	$140	$2	$142
	2010	6,209	0.0216	$134	$1	$135
2007 Walter's greenhouse/Nova Vita Ladies Night Sum		21,732		$482	$16	$499
2007 Seasonal LED light exchange	2005	0	0.0134	$0	$0	$0
	2006	0	0.0222	$0	$0	$0
	2007	2,797	0.0224	$63	$5	$68
	2008	5,594	0.0224	$125	$6	$131
	2009	5,594	0.0225	$126	$2	$128
	2010	5,594	0.0216	$121	$1	$122
2007 Seasonal LED light exchange Sum		19,579		$435	$15	$449
Residential Total		**7,868,383**		**$174,018**	**$8,759**	**$182,777**

1. Carrying charges are calculated quarterly, at the measure (not program) level to capture different carrying charge interest rates by quarter, program ramp up, and measure life.

Table 12 – GS < 50 kW LRAM contributions and carrying charges.

Program	Year of savings	Energy savings (kWh)	Energy rate ($/kWh)	LRAM (programyear$)	Carrying charges ($)	LRAM (2011$)
2007 ERIP	2005	0	0.0137	$0	$0	$0
	2006	0	0.0191	$0	$0	$0
	2007	5,642	0.0193	$109	$10	$119
	2008	5,642	0.0193	$109	$5	$114
	2009	5,642	0.0194	$109	$2	$111
	2010	5,642	0.0186	$105	$1	$106
2007 ERIP Sum		22,567		$432	$18	$450
2008 ERIP	2005	0	0.0137	$0	$0	$0
	2006	0	0.0191	$0	$0	$0
	2007	0	0.0193	$0	$0	$0
	2008	56,913	0.0193	$1,098	$51	$1,149
	2009	56,913	0.0194	$1,104	$19	$1,123
	2010	56,913	0.0186	$1,059	$10	$1,069
2008 ERIP Sum		170,738		$3,261	$80	$3,341
2008 High Performance New Construction	2005	0	0.0137	$0	$0	$0
	2006	0	0.0191	$0	$0	$0
	2007	0	0.0193	$0	$0	$0
	2008	713	0.0193	$14	$1	$14
	2009	713	0.0194	$14	$0	$14
	2010	713	0.0186	$13	$0	$13
2008 High Performance New Construction Sum		2,138		$41	$1	$42
2009 ERIP	2005	0	0.0137	$0	$0	$0
	2006	0	0.0191	$0	$0	$0
	2007	0	0.0193	$0	$0	$0
	2008	0	0.0193	$0	$0	$0

Program	Year of savings	Energy savings (kWh)	Energy rate ($/kWh)	LRAM (programyear$)	Carrying charges ($)	LRAM (2011$)
	2009	114,314	0.0194	$2,218	$38	$2,256
	2010	114,314	0.0186	$2,126	$21	$2,147
2009 ERIP Sum		228,628		$4,344	$59	$4,403
2009 High Performance New Construction	2005	0	0.0137	$0	$0	$0
	2006	0	0.0191	$0	$0	$0
	2007	0	0.0193	$0	$0	$0
	2008	0	0.0193	$0	$0	$0
	2009	21,975	0.0194	$426	$7	$434
	2010	21,975	0.0186	$409	$4	$413
2009 High Performance New Construction Sum		43,950		$835	$11	$846
2009 Power Savings Blitz	2005	0	0.0137	$0	$0	$0
	2006	0	0.0191	$0	$0	$0
	2007	0	0.0193	$0	$0	$0
	2008	0	0.0193	$0	$0	$0
	2009	1,383,665	0.0194	$26,843	$461	$27,304
	2010	1,352,281	0.0186	$25,152	$244	$25,396
2009 Power Savings Blitz Sum		2,735,947		$51,996	$705	$52,700
2008 peaksaver®	2005	0	0.0137	$0	$0	$0
	2006	0	0.0191	$0	$0	$0
	2007	0	0.0193	$0	$0	$0
	2008	82	0.0193	$2	$0	$2
	2009	82	0.0194	$2	$0	$2
	2010	82	0.0186	$2	$0	$2
2008 peaksaver® Sum		247		$5	$0	$5
2009 peaksaver®	2005	0	0.0137	$0	$0	$0
	2006	0	0.0191	$0	$0	$0
	2007	0	0.0193	$0	$0	$0

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Program	Year of savings	Energy savings (kWh)	Energy rate ($/kWh)	LRAM (programyear$)	Carrying charges ($)	LRAM (2011$)
	2008	0	0.0193	$0	$0	$0
	2009	159	0.0194	$3	$0	$3
	2010	159	0.0186	$3	$0	$3
2009 peaksaver® Sum		317		$6	$0	$6
2005 Garage door replacement	2005	5,766	0.0137	$79	$16	$95
	2006	5,766	0.0191	$110	$15	$126
	2007	5,766	0.0193	$111	$10	$122
	2008	5,766	0.0193	$111	$5	$116
	2009	5,766	0.0194	$112	$2	$114
	2010	5,766	0.0186	$107	$1	$108
2005 Garage door replacement Sum		34,596		$631	$50	$680
2005 Conservation County - lighting retrofit	2005	4,528	0.0137	$62	$12	$74
	2006	9,056	0.0191	$173	$24	$197
	2007	9,056	0.0193	$175	$16	$191
	2008	9,056	0.0193	$175	$8	$183
	2009	9,056	0.0194	$176	$3	$179
	2010	9,056	0.0186	$168	$2	$170
2005 Conservation County - lighting retrofit Sum		49,806		$929	$65	$994
GS < 50 kW total		**3,288,935**		**$62,479**	**$988**	**$63,467**

1. Carrying charges are calculated quarterly, at the measure (not program) level to capture different carrying charge interest rates by quarter, program ramp up, and measure life.

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Table 13 – GS 50 to 4,999 kW LRAM contributions and carrying charges.

Program	Year of savings	Demand savings (kW-mo)	Energy rate ($/kW/mo)	LRAM (programyear$)	Carrying charges ($)	LRAM (2011$)
2007 ERIP	2005	0	3.8976	$0	$0	$0
	2006	0	5.5451	$0	$0	$0
	2007	10	5.5950	$58	$5	$64
	2008	10	5.5950	$58	$3	$61
	2009	10	5.6124	$59	$1	$60
	2010	10	5.2549	$55	$1	$55
2007 ERIP Sum		42		$230	$10	$240
2008 ERIP	2005	0	3.8976	$0	$0	$0
	2006	0	5.5451	$0	$0	$0
	2007	0	5.5950	$0	$0	$0
	2008	42	5.5950	$237	$11	$248
	2009	42	5.6124	$238	$4	$242
	2010	42	5.2549	$222	$2	$225
2008 ERIP Sum		127		$697	$17	$714
2009 ERIP	2005	0	3.8976	$0	$0	$0
	2006	0	5.5451	$0	$0	$0
	2007	0	5.5950	$0	$0	$0
	2008	0	5.5950	$0	$0	$0
	2009	190	5.6124	$1,067	$18	$1,085
	2010	190	5.2549	$999	$10	$1,008
2009 ERIP Sum		380		$2,065	$28	$2,093
GS 50 to 4,999 kW total		**549**		**$2,992**	**$55**	**$3,047**

1. Carrying charges are calculated quarterly, at the measure (not program) level to capture different carrying charge interest rates by quarter, program ramp up, and measure life.

Table 14 – Street lighting LRAM contributions and carrying charges.

Program	Year of savings	Demand savings (kW-mo)	Energy rate ($/kW/mo)	LRAM (programyear$)	Carrying charges ($)	LRAM (2011$)
2008 Traffic light conversion	2008	73	4.4071	$321	$13	$334
	2009	146	4.4208	$644	$11	$655
	2010	146	4.1543	$605	$6	$611
2008 Traffic light conversion Sum		364		$1,570	$30	$1,599
2008 Streetlight conversion	2008	6	4.4071	$26	$1	$27
	2009	12	4.4208	$53	$1	$54
	2010	12	4.1543	$50	$0	$50
2008 Streetlight conversion Sum		30		$129	$2	$132
Street lighting total		**394**		**$1,699**	**$32**	**$1,731**

1. Carrying charges are calculated quarterly, at the measure (not program) level to capture different carrying charge interest rates by quarter, program ramp up, and measure life.

The LRAM without carrying charges (the sum of the grand totals from Table 11 to Table 14) is $241,188. The carrying charges are $9,834. Thus the LRAM claimed is $251,022.

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